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, 2003

OR

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

Commission file number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (603) 772-0775

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

Title of Each Class	Name of Exchange on Which Registered
Common Stock, No Par Value	**American Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

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 ☒

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☒ No ☐

Based on the closing price of June 30, 2003, the aggregate market value of common stock held by non-affiliates of the registrant was $112,473,808.

The number of common shares outstanding of the registrant was 5,507,880 as of February 24, 2004.

Documents Incorporated by Reference:

Portions of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 15, 2004, are incorporated by reference into Part III of this Report.

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For the Fiscal Year Ended December 31, 2003
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PART I

Item 1. Business

UNITIL CORPORATION

Unitil Corporation (Unitil or the Company) was incorporated under the laws of the State of New Hampshire in 1984. Unitil is a registered public utility holding company under the Public Utility Holding Company Act of 1935 (PUHCA). The following companies are wholly-owned subsidiaries of Unitil:

Unitil Corporation Subsidiaries	State and Year of Organization	Principal Type of Business
Unitil Energy Systems, Inc. (UES)	NH -1901	Retail Electric Distribution Utility
Fitchburg Gas and Electric Light Company (FG&E)	MA -1852	Retail Electric & Gas Distribution Utility
Unitil Power Corp. (Unitil Power)	NH -1984	Wholesale Electric Power Utility
Unitil Service Corp. (Unitil Service)	NH -1984	Service Company
Unitil Realty Corp. (Unitil Realty)	NH -1986	Real Estate Management
Unitil Resources, Inc. and subsidiaries (Unitil Resources)	NH -1993	Non-utility, unregulated Energy Services
Usource Inc., Usource L.L.C. (Usource)	NH -2000	Energy Brokering and Advisory Services

In December 2002, Exeter & Hampton Electric Company (E&H), a wholly-owned subsidiary of Until, was merged with and into Concord Electric Company (CECo), also a wholly-owned subsidiary of Unitil. CECo changed its name to Unitil Energy Systems, Inc. (UES) immediately following the merger.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through our two utility subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities. Unitil's retail distribution utilities serve approximately 112,800 electric and natural gas customers in their franchise areas. Unitil's utility subsidiaries have effectively divested their ownership interest in electric generating facilities and do not own or operate major transmission facilities. Rather, the retail distribution companies are local "pipes and wires" electric and natural gas distribution companies with a combined investment in net utility plant of $195.1 million at December 31, 2003. Unitil's total revenues were $220.7 million in 2003. Net income applicable to common shareholders for 2003 was $7.7 million. Substantially all of Unitil's revenues and net income are derived from regulated utility operations.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company's corporate office building and property located in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company's wholly-owned unregulated subsidiary that provides energy brokering, consulting and management related services. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides energy brokering services, as well as various energy consulting services to large commercial and industrial customers in the northeastern United States.

OPERATIONS

Electric Utility Operations

Unitil's electric utility operations are conducted through the retail distribution utilities, UES and FG&E. Revenues from Unitil's electric utility operations were $190.9 million for 2003. Earnings from electric utility operations were $7.0 million for the same 12-month period.

The primary business of the Company's electric utility operations is the local distribution of electricity to customers in the retail distribution utilities' franchise areas. As a result of the implementation of retail choice in New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. Both UES and FG&E supply electricity to those customers who do not obtain their supply from third-party suppliers, with the costs associated with electricity supplied by the Company being recovered on a pass-through basis under periodically-adjusted rates.

UES is engaged principally in the retail distribution of electricity to approximately 70,000 customers in New Hampshire in the capital city of Concord as well as 12 surrounding towns and all or part of 16 towns in the southeastern and seacoast regions of New Hampshire, including the towns of Hampton, Exeter, Atkinson and Plaistow. UES's franchise areas consist of approximately 408 square miles.

The state capital of New Hampshire is located within UES's franchise areas, and includes the executive, legislative and judicial branches and offices and facilities for all major state government services as well as several federal government facilities. In addition, UES's franchise areas are retail trading and recreation centers for the north central and southeastern parts of the state. These areas serve diversified commercial and industrial businesses, including manufacturing firms engaged in the production of electronic components, wires and plastics. UES' franchise areas include popular resort areas and beaches along the Atlantic Ocean. UES's 2003 retail electric operating revenues were $130.4 million, of which approximately 42% were derived from residential sales and 58% from commercial/industrial sales. UES's earnings for the same 12-month period were $3.7 million.

FG&E is engaged in the retail distribution of both electricity and natural gas in the city of Fitchburg and several surrounding communities. FG&E's franchise area encompasses approximately 170 square miles. Electricity is supplied and distributed by FG&E to approximately 27,000 customers in the communities of Fitchburg, Ashby, Townsend and Lunenburg. FG&E's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and allied industries. FG&E's 2003 retail electric operating revenues were $60.5 million, of which approximately 38% were derived from residential sales and 62% from commercial/industrial sales. FG&E's earnings from electric utility operations were $3.3 million in 2003.

Gas Utility Operations

Natural gas is supplied and distributed by FG&E to approximately 15,000 retail customers in the communities of Fitchburg, Lunenburg, Townsend, Ashby, Gardner and Westminster, all located in Massachusetts. Revenues from FG&E's gas utility operations were $28.6 million in 2003. Earnings from FG&E's gas utility operations were $1.1 million for the same 12-month period.

As a result of the introduction of retail choice for all natural gas customers in Massachusetts, FG&E's customers are free to contract for their supply of natural gas with third-party suppliers. FG&E continues to provide natural gas supply services to those customers who do not obtain their supply from third-party suppliers, with the actual costs associated with natural gas supplied by FG&E being recovered on a pass-through basis under periodically-adjusted rates.

FG&E's 2003 gas operating revenues were $28.6 million, of which approximately 55% was derived from residential firm sales, 44% from commercial/industrial firm sales and 1% from interruptible sales.

Seasonality

Natural gas sales in New England are seasonal, and the Company's results of operations reflect this seasonal nature. Accordingly, results of operations are typically positively impacted by gas operations during the five heating season months, from November through March. Electric sales in New England are far less seasonal than natural gas sales; however, the highest usage typically occurs in both the summer and winter months due to air cooling and heating requirements, respectively.

Non-Utility, Unregulated Operations and Other

Unitil's non-utility, unregulated operations are comprised of Unitil Resources and its subsidiaries, which are collectively referred to as Usource. Unitil Resources provides energy brokering services, through Usource, as well as various energy consulting services to large commercial and industrial customers in the northeastern United States. Revenues from Unitil's unregulated operations were $1.1 million and $0.8 million in 2003 and 2002, respectively. Non-utility, unregulated operations recorded accounting book losses of $0.6 million in 2003.

Unitil's other subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries. The earnings of these subsidiaries are principally derived from income earned on short-term investments and real property owned for Unitil's and its subsidiaries' use and is reported in Other segment income. Other segment earnings for 2003 were approximately $254,000.

(For details on Unitil's Results of Operations, see Part II, Item 7 herein.)
(For segment information, see Part II, Item 8, Note 11 herein.)

RATES AND REGULATION

As a registered holding company under PUHCA, Unitil and its subsidiaries are regulated by the Securities and Exchange Commission (SEC) with respect to various matters, including: the issuance of securities, capital structure and certain acquisitions and dispositions of assets. UES and FG&E are subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Telecommunications and Energy (MDTE), respectively, with respect to their rates, issuance of securities and other accounting and operational matters. Certain aspects of the Company's utility operations as they relate to wholesale and interstate business activities are also regulated by the Federal Energy Regulatory Commission (FERC). In the past several years, the Company has completed the restructuring of its electric and natural gas operations resulting from the implementation of retail choice as mandated by the States of New Hampshire and Massachusetts.

Unitil's retail distribution utilities have franchises to deliver electricity and/or natural gas to all customers in their franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, through their distribution charges, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. In 2002, the retail distribution utilities completed rate proceedings and were authorized by the NHPUC and MDTE to implement increased rates for electric and natural gas distribution operations beginning in December of that year. UES and FG&E also recover the actual cost of any electricity or natural gas they supply to their customers, as well as certain costs associated with industry restructuring, through periodically-adjusted rates.

In recent years, there has been significant legislative and regulatory activity to restructure the utility industry in order to introduce greater competition in the supply and sale of electricity and natural gas, while continuing to regulate the distribution operations of Unitil's retail distribution utilities. Unitil implemented the restructuring of its electric and gas operations in Massachusetts in 1998 and 2000, respectively and implemented the final phase of a restructuring settlement for its New Hampshire electric operations on May 1, 2003. Following electric industry restructuring, Unitil's retail distribution utilities have a continuing obligation to submit filings in both states that demonstrate their compliance with legislative and regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

In connection with industry restructuring and the implementation of retail choice for our customers in New Hampshire and Massachusetts, Unitil Power divested of its long-term power supply contracts and FG&E divested of its long-term power supply contracts and owned generation assets. Unitil Power divested its long-term power supply contracts to a subsidiary of Mirant Corporation (Mirant) and FG&E divested its owned generation assets and long-term power supply contracts to Select Energy, Inc. (Select Energy), a subsidiary of Northeast Utilities, Inc. Unitil Power's and FG&E's long-term power supply contracts were divested through the sale of the entitlements to the electricity associated with those contracts and owned generation assets. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios as a result of electric industry restructuring.

Unitil's customers in both New Hampshire and Massachusetts now have the opportunity to purchase their electric supply from third party vendors, though most customers continue to purchase such supplies through Unitil as the provider of last resort. Accordingly, UES and FG&E contract with wholesale power suppliers for the electricity necessary to meet their regulated energy supply obligations. Similarly, FG&E's natural gas customers have the option to contract for their natural gas supply with third-party suppliers and FG&E remains the default service provider for these natural gas customers. The costs associated with the acquisition of such wholesale electric and natural gas supplies for customers who do not contract with third-party suppliers are recovered from those customers through periodic rate and cost recovery reconciliation mechanisms with no profit margin to UES or FG&E.

The Company has secured regulatory approval from both New Hampshire and Massachusetts state regulators for the recovery of approximately $203 million of power supply-related stranded costs principally over the next 6 to 8 years. Also, the Company has implemented comprehensive customer and financial information systems to accommodate the transition to competitive energy markets and retail choice. Unitil's utility customers in Massachusetts have had the ability to choose their electric or gas supplier since March 1, 1998 and November 1, 2000, respectively and retail choice became available to the Company's electric customers in New Hampshire on May 1, 2003.

ELECTRIC POWER SUPPLY

FG&E and UES contract directly for their electric supply with various wholesale suppliers. The wholesale power markets are conducted under the auspices of the New England Power Pool (NEPOOL) and the Independent System Operator—New England (ISO-NE).

FG&E, Unitil Power, and UES are members of NEPOOL. NEPOOL was formed in 1971 to assure reliable operation of the bulk power system in the most economic manner for the region. NEPOOL is governed by an agreement (NEPOOL Agreement) that is filed with and subject to the jurisdiction of the FERC. Under the NEPOOL Agreement and the NEPOOL Open Access Transmission Tariff (OATT), to which virtually all New England electric utilities are parties, substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The NEPOOL Agreement and the OATT impose generating capacity and reserve obligations and provide for the use of major transmission facilities and support payments associated therewith. The most notable benefits of NEPOOL are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The regional bulk power system is operated by an independent corporate entity, the ISO-NE, in order to avoid any opportunity for conflicting financial interests between the system operator and the market-driven participants.

There continue to be ongoing legislative and regulatory initiatives that are primarily focused on the deregulation of the generation and supply of electricity and the corresponding development of a competitive market place from which customers choose their electric energy supplier. As a result, the NEPOOL Agreement continues to be restructured. NEPOOL's membership provisions have been broadened to cover all entities engaged in the electricity business in New England, including power marketers and brokers, independent power producers, load aggregators and retail customers in states that have enacted retail access statutes. Various energy and capacity products are traded in open markets, with transmission access and pricing subject to the regional OATT designed to promote competition among power suppliers. On March 1, 2003, ISO-NE implemented a Standard Market Design (SMD) that is intended to improve the ability to trade power between New England and other regions throughout the northeast. On October 31, 2003, ISO-NE and the major transmission owners in New England filed with the FERC to form a Regional Transmission Organization (RTO) with a proposed effective date not earlier than March 1, 2004. The implementation of the RTO, which is being contested at FERC, will further revise the conduct of wholesale markets in New England. The filing also proposes to eliminate NEPOOL as an organization and require all current NEPOOL members to be part of the RTO system. SMD, the formation of an RTO and other wholesale market changes are not expected to have a material impact on Unitil's results of operations because of cost recovery mechanisms for wholesale energy costs approved by state regulators.

Energy Resources—In connection with industry restructuring and the implementation of retail choice in New Hampshire and Massachusetts, FG&E and Unitil Power have effectively divested their long-term power supply contracts and the owned generation assets of FG&E. Unitil Power divested its long-term power supply contracts to a subsidiary of Mirant Corporation, Mirant Americas Energy Marketing, LP (Mirant), which was approved by the NHPUC on March 14, 2003. The NHPUC Order completed the state approval process for Unitil's restructuring plan under which UES implemented customer choice for its customers on May 1, 2003.

FG&E divested its owned generation assets and long-term power supply contracts to Select Energy, a subsidiary of Northeast Utilities. Under the Select Energy contract, which was approved by the MDTE in January 2000, and went into effect February 1, 2000, FG&E began selling the entire output from its remaining long-term power supply contracts and the output of its two joint ownership units to Select Energy. Upon the sale of FG&E's share of Millstone Unit 3 in 2001, this portion of the contract sale ceased.

Unitil's customers in both New Hampshire and Massachusetts now have the opportunity to purchase their electric supply from third-party vendors, though most customers continue to purchase such supplies through Unitil as the provider of last resort. Accordingly, UES and FG&E contract with wholesale power suppliers for the electricity necessary to meet their regulated energy supply obligations which are provided through Standard Offer Service and Default Service in Massachusetts and Transition Service and Default Service in New Hampshire. The costs associated with the acquisition of such regulated wholesale electric supplies are recovered on a pass-through basis from customers through periodically-adjusted rates.

FG&E has a contract for Standard Offer Service with Constellation Power Source through the end of the Standard Offer Service period in Massachusetts in February 2005. Beginning December 1, 2000, through December 1, 2003, FG&E procured Default Service through a bid process every six months. Effective December 1, 2003, as a result of revised regulatory requirements ordered by the MDTE, FG&E procures 50% of its Small Customer Default Service requirements semi-annually, for twelve-month terms. FG&E procures 100% of its Large Customer Default Service requirements for a three-month period.

Under the agreement whereby Mirant purchased the entitlements to Unitil Power's long-term purchase power supply portfolio, it provides UES' Transition and Default Service through April 30, 2006 for Small Customers and through April 30, 2005 for Large Customers at fixed prices.

Since April 1, 1998, each electric utility has been required to carry an allocated share of the NEPOOL capability responsibility under the NEPOOL Agreement. FG&E's Standard Offer Service supplier, Constellation Power Source, and FG&E's periodic Default Service suppliers are responsible for serving FG&E's load obligations and associated capability responsibility under their respective contracts. Similarly, under the agreement between Unitil Power, UES and Mirant, whereby Mirant provides wholesale power to UES for

Transition and Default Service, Mirant is also responsible for serving UES' load obligations and associated capability responsibility. Unitil Power no longer has any load serving obligations in NEPOOL.

GAS SUPPLY

Unitil's customers in Massachusetts now have the opportunity to purchase their gas supply from third party vendors, though most customers continue to purchase such supplies through Unitil as the provider of last resort. The costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered through periodically-adjusted rates.

FG&E distributes natural gas purchased from domestic and Canadian suppliers under long-term contracts as well as gas purchased from producers and marketers on the spot market. The following tables summarize actual gas purchases by source of supply and the cost of gas sold for the years 2000 through 2003.

Sources of Gas Supply
(Expressed as percent of total MMBtu of gas purchased)

	2003	2002	2001
Natural Gas:			
Domestic firm	94.0%	73.9%	76.2%
Canadian firm	1.3%	8.4%	8.0%
Domestic spot market	1.3%	16.2%	14.5%
Total natural gas	96.6%	98.5%	98.7%
Supplemental gas	3.4%	1.5%	1.3%
Total gas purchases	100.0%	100.0%	100.0%

Cost of Gas Sold

	2003	2002	2001
Cost of gas purchased and sold per MMBtu	$7.14	$ 4.96	$7.13
Percent Increase (Decrease) from prior year	43.9%	(30.4%)	37.3%

As a supplement to pipeline natural gas, FG&E owns a propane air gas plant and a liquefied natural gas (LNG) storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

ENVIRONMENTAL MATTERS

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company is in general compliance with all applicable environmental and safety laws and regulations, and Management believes that as of December 31, 2003, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site—The Company continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows FG&E to work towards temporary remediation of the site. Work performed in 2002 was associated with the five-year review of the Temporary Solution submittal (Class C Response Action Outcome) under the Massachusetts Contingency Plan that was filed for the site in 1997. Completion of this work has confirmed the Temporary Solution status of the site for an additional five years. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

Since 1991, FG&E has recovered the environmental response costs incurred at this former MGP site pursuant to a MDTE approved Settlement Agreement (Agreement). The Agreement allows FG&E to amortize and recover from gas customers, over succeeding seven-year periods, the environmental response costs incurred each year. Environmental response costs are defined to include liabilities related to manufactured gas sites, waste disposal sites or other sites onto which hazardous material may have migrated as a result of the operation or decommissioning of Massachusetts gas manufacturing facilities from 1882 through 1978. In addition, any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers. The total annual charge for such costs assessed to gas customers cannot exceed five percent of FG&E's total revenue for firm gas sales during the preceding year. Costs in excess of five percent will be deferred for recovery in subsequent years.

Former Electric Generating Station—FG&E has remediated environmental conditions at a former electric generating station also located at Sawyer Passway in Fitchburg, Massachusetts, which FG&E sold in 1983 to a general partnership, Rockware, who demolished several exterior walls of the generating station in order to facilitate removal of certain equipment. The demolition of the walls and the removal of generating equipment resulted in damage to asbestos-containing insulation materials inside the building, which had been intact and encapsulated at the time of the sale of the structure.

When Rockware encountered financial difficulties and failed to respond adequately to Orders of the environmental regulators to remedy the situation, FG&E agreed to take steps at that time and obtained DEP approval to temporarily enclose, secure and stabilize the facility. Based on that approval, between September and December 1989, contractors retained by FG&E stabilized the facility and secured the building. This work did not permanently resolve the problems caused by Rockware, but was deemed sufficient for the then foreseeable future.

Due to the continuing deterioration of this former electric generating station and Rockware's continued lack of performance, FG&E, in concert with the DEP and the U.S. Environmental Protection Agency (EPA), conducted further testing and survey work during 2001 to ascertain the environmental status of the building. Those surveys revealed continued deterioration of the asbestos-containing insulation materials in the building.

By letter dated May 1, 2002, the EPA notified FG&E that it was a Potentially Responsible Party for planned remedial activities at the site and invited FG&E to perform or finance such activities. FG&E and the EPA entered into an Agreement on Consent, whereby FG&E, without an admission of liability, conducted environmental remedial action to abate and remove asbestos-containing and other hazardous materials. This project was completed during the fourth quarter of 2003. FG&E received complete coverage from its insurance carrier for this remediation project and the resolution of this matter did not have a material adverse impact on the Company's financial position.

EMPLOYEES

As of December 31, 2003, the Company and its subsidiaries had 322 full-time and part-time employees. Management considers the Company's relationship with employees to be good and has not experienced any major labor disruptions since the early 1960's.

There are approximately 100 employees represented by labor unions. In 2000, UES' predecessor companies, E&H and CECo, entered into five-year pacts with their employees covered by collective bargaining agreements, which expire May 31, 2005. In 2000, FG&E reached a five-year pact with its employees covered by a collective bargaining agreement, which also expires May 31, 2005. The agreements provided discreet salary adjustments, established work practices and provided uniform benefit packages. The Company expects to successfully negotiate new agreements prior to the expiration dates of these contracts.

AVAILABLE INFORMATION

Unitil's Internet address is *www.unitil.com*. There the Company makes available, free of charge, its SEC fillings, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other reports as well as amendments to those reports. These reports are made available through the Investors section of Unitil's website via a direct link to the section of the SEC's website which contains Unitil's SEC filings.

The Company's current Code of Ethics was approved by Unitil's Board of Directors on January 15, 2004. This Code of Ethics, along with any amendments or waivers, is also available on Unitil's website.

Unitil's common stock is listed on the American Stock Exchange under the ticker symbol "UTL."

MANAGEMENT

The following table provides information about our directors and senior management as of February 27, 2004:

Name	Age	Position
Robert G. Schoenberger	53	Chairman of the Board, Chief Executive Officer and President
Mark H. Collin	45	Senior Vice President and Chief Financial Officer
Thomas P. Meissner, Jr.	41	Senior Vice President, Operations
George R. Gantz	52	Senior Vice President, Customer Services and Communications
George E. Long, Jr.	47	Vice President, Administration
Raymond J. Morrissey	56	Vice President, Information Systems
Todd R. Black	39	Vice President, Usource
Laurence M. Brock	50	Vice President and Controller
David K. Foote	56	Vice President, Energy Contracts
Sandra L. Whitney	40	Corporate Secretary
David P. Brownell	60	Director
Michael J. Dalton	63	Director
Albert H. Elfner, III	59	Director
Ross B. George	71	Director
Edward F. Godfrey	54	Director
Michael B. Green	54	Director
Eben S. Moulton	57	Director
M. Brian O'Shaughnessy	61	Director
Charles H. Tenney, III	56	Director
Dr. Sarah P. Voll	61	Director

Robert G. Schoenberger has been Unitil's Chairman of the Board and Chief Executive Officer since 1997 and Unitil's President since 2003. Prior to his employment with Unitil, he was President and Chief Executive Officer of the New York Power Authority (a state owned public power enterprise) from 1993 until 1997. He is also a Director of the Greater Seacoast (NH) United Way, Director of Southwest Power Pool, Inc. and Director and Vice Chairman of Exeter Health Resources.

Mark H. Collin was appointed Unitil's Senior Vice President and Chief Financial Officer in February 2003. Mr. Collin has served as Unitil's Treasurer since 1998. Since 1992, he has been Treasurer of UES and FG&E. Mr. Collin joined Unitil in 1988.

Thomas P. Meissner, Jr. has been Unitil's Senior Vice President, Operations since February 2003. Mr. Meissner joined Unitil in 1994 and served as Unitil's Director of Engineering from 1998 to 2003. From 1985 to 1994, he was employed by the Public Service Company of New Hampshire.

George R. Gantz has been Unitil's Senior Vice President, Customer Services and Communications since January 2003. Mr. Gantz previously served as Unitil's Senior Vice President, Communication and Regulation from 1994 to 2003. Mr. Gantz joined Unitil in 1983.

George E. Long, Jr. has been Unitil's Vice President, Administration since February 2003. Mr. Long joined Unitil in 1994 and was Director, Human Resources from 1998 to 2003. Prior to his employment with Unitil, Mr. Long was the Director of Compensation and Benefits at Monarch Life Insurance Company from 1985 to 1994.

Raymond J. Morrissey has been Unitil's Vice President, Information Systems since February 2003. From 1992 to 2003, he served as Unitil's Vice President of Customer Service, and from 1991 to 1992, he was the General Manager of Unitil's subsidiary, FG&E. Mr. Morrissey joined Unitil in 1985.

Todd R. Black has been Unitil's Vice President, Usource since January 2003. He served as Vice President, Sales and Marketing for Usource from 1998 to 2003. Prior to his employment with Unitil, he served as Vice President, Services Delivery for Energy USA, the unregulated subsidiary of Bay State Gas Company, from 1988 until 1998.

Laurence M. Brock, Unitil's Vice President and Controller, joined Unitil in 1995 and is a Certified Public Accountant in the State of New Hampshire. Prior to his employment with Unitil, Mr. Brock served as a Corporate Controller with a group of diversified financial services and manufacturing companies. Mr. Brock gained his public accounting experience with Coopers & Lybrand in Boston, Massachusetts.

David K. Foote has been Unitil's Vice President, Energy Contracts since 1984. Mr. Foote previously served as Senior Vice President of Unitil's subsidiary, FG&E, where he began working for the Company in 1968.

Sandra L. Whitney has been Unitil's Corporate Secretary and Secretary of the Board since February 2003. Ms. Whitney has been the Corporate Secretary of Unitil's subsidiary companies, FG&E, UES, Unitil Power, Unitil Realty and Unitil Service since 1994. Ms. Whitney joined Unitil in 1990.

David P. Brownell was a Senior Vice President of Tyco International Ltd. from 1995 to 2003. He had been with Tyco since 1984. Mr. Brownell is also Vice Chairman of the University of New Hampshire Foundation.

Michael J. Dalton was Unitil's President and Chief Operating Officer from 1984 to 2003. Mr. Dalton is a member of the Advisory Board of the University of New Hampshire College of Engineering and Physical Sciences.

Albert H. Elfner, III was the Chairman, from 1994, and Chief Executive Officer, from 1995, of Evergreen Investment Management Company until his retirement in 1999. Mr. Elfner is also a Director of NGM Insurance Company and Optimum Q Funds.

Ross B. George is the Chairman of the Board of Five G Management, LLC. He resigned as a Director of Simonds Industries, Inc. in August 2003 and served as their Chairman of the Board from 1999-2001 and their Chief Executive Officer from 1995 to 1999.

Edward F. Godfrey was the Executive Vice President and Chief Operating Officer of Keystone Investments, Incorporated from 1997 until his retirement in 1998. While at Keystone Investments, he was also a Senior Vice President, Chief Financial Officer and Treasurer from 1988 to 1996. Mr. Godfrey is also a Director of Reilly Mortgage Group.

Michael B. Green has been the President and Chief Executive Officer of Capital Region Health Care and Concord Hospital since 1992. He serves as an adjunct faculty member of Dartmouth Medical School. He also serves as Chairman of the Board of the Foundation for Healthy Communities and as a Director on the Board of Merrimack County Savings Bank.

Eben S. Moulton has been the Managing Partner of Seacoast Capital Corporation since 1995. Mr. Moulton is also a Director of IEC Electronics, a Director of six private companies and a Trustee of Colorado College.

M. Brian O'Shaughnessy has been the Chairman of the Board, Chief Executive Officer and President of Revere Copper Products, Inc. since 1988. Mr. O'Shaughnessy also serves on the Board of Directors of the National Association of Manufacturers, the International Copper Association, the Copper Development Association and the Copper and Brass Fabricators Council. He also serves in New York State as Chairman of the Industrial Energy Consumer Coalition, and as a member of the Board of Directors of the Multiple Intervenors and the Economic Development Growth Enterprise.

Charles H. Tenney, III has been Director of Operations for Brainshift.com, Inc. since 2002. He served as a financial advisor for H&R Block Financial Advisors from 2001 to 2002 and as the Director of Corporate Services for Log On America, Inc. from 1999 to 2000. From 1997 to 1999, he served as the Secretary of both Northern Utilities, Inc. and Granite State Gas Transmission, Inc. From 1991 to 1999, he served as the Clerk of Bay State Gas Company, a subsidiary of NiSource, Inc.

Dr. Sarah P. Voll has been the Vice President, National Economic Research Associates, Inc. (NERA) since 1999. Dr. Voll was also a Senior Consultant at NERA from 1996 to 1999.

INVESTOR INFORMATION

Annual Meeting

The annual meeting of shareholders is scheduled to be held at the offices of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 15, 2004, at 10:30 a.m.

Transfer Agent

The Company's transfer agent, EquiServe, is responsible for shareholder records, issuance of stock certificates, and the distribution of Unitil's dividends and IRS Form 1099-DIV. Shareholders may contact EquiServe at:

Mail: EquiServe, P.O. Box 43010, Providence, RI 02940-3010

Telephone: 800-736-3001 (Outside MA); 781-575-3100 (Within MA)

Investor Information

For information about the Company and your investment, you may call the Company directly, toll-free, at: 800-999-6501 and ask for the Investor Relations Representative; visit the Investor page at *www.unitil.com*; or contact the transfer agent, EquiServe, at the number listed above.

Special Services & Shareholder Programs Available

- Internet Account Access is now available at *www.equiserve.com*.
- Dividend Reinvestment Plan:

  To enroll, please contact the Company's Investor Relations Representative at 800-999-6501.

- Dividend Direct Deposit Service:

  To enroll, please contact the Company's Investor Relations Representative at 800-999-6501.

- Direct Registration:

  For information, please contact EquiServe at the number listed above or the Company's Investor Relations Representative at 800-999-6501.

Item 2. Properties

As of December 31, 2003, Unitil owned, through its retail distribution utilities: two operation centers, approximately 2,113 pole miles of local transmission and distribution overhead electric lines and 371 conduit bank miles of underground electric distribution lines, along with 48 electric substations, including three mobile electric substations. FG&E's natural gas operations property includes a liquid propane gas plant, a liquid natural gas plant and 311 miles of underground gas mains. In addition, Unitil's real estate subsidiary, Unitil Realty, owns the Company's corporate headquarters building and the 12 acres on which it is located.

UES owns and maintains distribution operations centers in Concord, New Hampshire and Kensington, New Hampshire. UES's 31 electric distribution substations, including a 5,000 kilovolt ampere (kVA) mobile substation, constitute 224,237 kVA of capacity (includes spares and mobile) for the transformation of electric energy from the 34.5 kV subtransmission voltage to other primary distribution voltage levels. The electric substations are located on land owned by UES or occupied by UES pursuant to a perpetual easement.

UES has a total of approximately 1,567 pole miles of local transmission and distribution overhead electric lines and a total of 204 conduit bank miles of underground electric distribution lines. The electric distribution lines are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by UES without objection by the owners. In the case of certain distribution lines, UES owns only a part interest in the poles upon which its wires are installed, the remaining interest being owned by telephone companies.

Additionally, UES owns 137.7 acres of non-utility property located on the east bank of the Merrimack River in Concord, New Hampshire. Of the total acreage, 81.2 acres are located within an industrial park zone.

The physical utility properties of UES, with certain exceptions, and its franchises are pledged as security under its indenture of mortgage and deed of trust under which the respective series of first mortgage bonds of UES are outstanding.

FG&E's electric properties consist principally of 546 pole miles of local transmission and distribution overhead electric lines, 167 conduit bank miles of underground electric distribution lines and 17 transmission and distribution stations including two mobile electric substations. The capacity of these substations totals 562,650 kVA.

FG&E owns a liquid propane gas plant and a liquid natural gas plant and the land on which they are located. FG&E also has 311 miles of underground steel, cast iron and plastic gas mains.

FG&E's electric substations, with minor exceptions, are located on land owned by FG&E or occupied by FG&E pursuant to a perpetual easement. FG&E's electric distribution lines and gas mains are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by FG&E without objection by the owners. FG&E leases its distribution operations center located in Fitchburg, Massachusetts.

Management believes that the Company's facilities are currently adequate for their intended uses.

Item 3. Legal Proceedings

On January 25, 2002, Unitil Power and UES' predecessor companies, CECo and E&H, filed a proposal with the NHPUC to comprehensively restructure the operations of CECo and E&H (forming UES), to provide for the full recovery of stranded costs by UES and permit retail choice to their customers in order to comply with the New Hampshire restructuring law. On October 25, 2002, the NHPUC approved a multiparty settlement on all major issues in the proceeding, including a procedure under which Unitil Power would divest its existing power supply portfolio and UES would conduct a solicitation for new power supplies from which to meet its ongoing transition and default service energy obligations. On March 14, 2003, the NHPUC approved an agreement between Unitil Power, UES and Mirant Americas Energy Marketing, L.P., under which Mirant will purchase the entitlements to Unitil Power's Supply portfolio and provide transition and default service to the customers of UES (Mirant Agreement). The March, 2003, NHPUC Order completed the state approval process for Unitil's restructuring plan. On May 1, 2003, UES implemented customer choice and Mirant began providing transition and default service to the customers of UES. UES's new tariffs, effective May 1, 2003, include the recovery of certain restructuring related costs through several surcharges that are subject to reconciliation, or future audit and review, by the NHPUC. On May 6, 2003, the Company withdrew, with prejudice its challenge to the Final Plan in U.S. District Court . We refer you to the NHPUC's orders in DE 01-247 and the U.S. District Court's orders in Civil Docket No. 97-1216 for further information.

On July 14, 2003, Mirant and most of its subsidiaries, including MAEM, filed for bankruptcy under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Northern District of Texas. The pre-petition amount owed, and not paid, by MAEM under the Mirant Agreement was approximately $5.3 million. UES and Unitil Power elected to hold back pre-petition amounts due to Mirant of approximately $5.3 million against the amount owed by MAEM, and MAEM disputed UES' and Unitil Power's withholding of such payments. In September, 2003, Unitil Power and UES filed a motion with the Bankruptcy Court requesting that MAEM be required to assume or reject the Mirant Agreement by December 1, 2003. On November 14, 2003, MAEM, Unitil Power and UES filed a settlement with the Bankruptcy Court under which MAEM agreed to assume and cure all pre-petition obligations, and to settle certain other disputes. UES and Unitil Power agreed to accelerate the payment of amounts held back from MAEM. On December 10, 2003, the settlement was approved by the federal bankruptcy court and MAEM is continuing to fulfill its obligations under the Mirant Agreement.

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company's financial position.

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

None

PART II

Item 5. Market for Registrant's Common Equity and Related Shareholder Matters

The Registrant's Common Stock is traded on the American Stock Exchange. As of December 31, 2003, there were 1,946 Common Shareholders of record.

Common Stock Data

Dividends per Common Share	2003	2002
1st Quarter	**$0.345**	$0.345
2nd Quarter	**0.345**	0.345
3rd Quarter	**0.345**	0.345
4th Quarter	**0.345**	0.345
Total for Year	**$ 1.38**	$ 1.38

Price Range of Common Stock	2003 High/Ask	2003 Low/Bid	2002 High/Ask	2002 Low/Bid
1st Quarter	**$26.34**	**$23.31**	$26.80	$22.82
2nd Quarter	**$26.00**	**$22.92**	$31.40	$26.10
3rd Quarter	**$26.04**	**$24.17**	$29.22	$25.31
4th Quarter	**$26.00**	**$24.40**	$26.99	$24.80

Information regarding Securities Authorized for Issuance Under Equity Compensation Plans is set forth in the table below.

EQUITY COMPENSATION PLAN BENEFIT INFORMATION

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders			
KESOP (1)	34,495	$13.17	29,101
Restricted Stock Plan (2)	—	N/A	166,900
Equity compensation plans not approved by security holders			
1998 Option Plan (3)	107,000	$27.13	—
Total	141,495	$23.73	196,101

NOTES: (also see Note 3 to the Consolidated Financial Statements)

(1) The KESOP was approved by shareholders in July 1989. Options were granted between January 1989 and November 1997.

(2) The Restricted Stock Plan was approved by shareholders in April 2003. 10,600 shares of restricted stock were awarded to Plan participants in May 2003.

(3) The 1998 Option Plan was adopted by the Board of Directors of the Company in December 1998. At the time of adoption, the 1998 Option Plan was not required, under American Stock Exchange rules, to obtain shareholder approval. Options were granted in March 1999, January 2000, and January 2001. On January 16, 2003, the Board of Directors terminated the Option Plan upon the recommendation of the Compensation Committee. The Option Plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the Option Plan. No further grants of options will be made thereunder.

Item 6. Selected Financial Data

	2003	2002	2001	2000	1999
Consolidated Statements of Earnings: (all data in thousands except % and per share data)					
Operating Revenues	**$ 220,654**	$ 188,386	$ 207,022	$ 182,941	$ 172,373
Operating Income	**15,449**	13,248	14,394	14,280	15,408
(Gain) Loss on Non-Utility Investments, net of tax	**—**	(82)	2,400	—	—
Other Non-operating Expense	**(40)**	185	170	244	51
Income Before Interest Expense and Extraordinary Item	**15,489**	13,145	11,824	14,036	15,357
Interest Expense, net	**7,531**	7,057	6,797	6,820	6,919
Income before Extraordinary Item	**7,958**	6,088	5,027	7,216	8,438
Extraordinary Item, net of tax	**—**	—	3,937	—	—
Net Income	**7,958**	6,088	1,090	7,216	8,438
Dividends on Preferred Stock	**236**	253	257	263	268
Earnings Applicable to Common Shareholders	**$ 7,722**	$ 5,835	$ 833	$ 6,953	$ 8,170
Balance Sheet Data:					
Utility Plant (Original Cost)	**$ 288,657**	$ 272,402	$ 255,498	$ 238,023	$ 219,838
Total Assets	**$ 483,877**	$ 481,702	$ 376,762	$ 382,967	$ 363,527
Capitalization:					
Common Stock Equity	**$ 92,805**	$ 74,350	$ 74,746	$ 79,935	$ 78,675
Preferred Stock	**3,269**	3,322	3,609	3,690	3,757
Long-Term Debt	**110,961**	104,226	107,470	81,695	86,157
Total Capitalization	**$ 207,035**	$ 181,898	$ 185,825	$ 165,320	$ 168,589
Short-term Debt	**$ 22,410**	$ 35,990	$ 13,800	$ 32,500	$ 10,500
Capital Structure Ratios:					
Common Stock Equity	**40%**	34%	37%	40%	44%
Preferred Stock	**2%**	2%	2%	2%	2%
Long-Term Debt	**48%**	48%	54%	41%	48%
Short-Term Debt	**10%**	16%	7%	17%	6%
Earnings Per Share Data:					
Earnings Per Average Share	**$ 1.58**	$ 1.23	$ 0.18	$ 1.47	$ 1.74
Common Stock Data:					
Shares of Common Stock (Year-End)	**5,501**	4,744	4,744	4,735	4,712
Shares of Common Stock (Average)	**4,878**	4,744	4,744	4,723	4,682
Dividends Paid Per Share	**$ 1.38**	$ 1.38	$ 1.38	$ 1.38	$ 1.38
Book Value Per Share (Year-End)	**$ 16.87**	$ 15.67	$ 15.76	$ 16.88	$ 16.70
Electric and Gas Sales:					
Electric Distribution Sales (kWh)	**1,717,664**	1,659,136	1,596,390	1,587,536	1,608,824
Firm Gas Distribution Sales (Therms)	**24,592**	22,480	23,067	23,992	22,136

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (Note references are to Notes to the Consolidated Financial Statements in Item 8.)

EARNINGS & DIVIDENDS

Unitil's Net Income Applicable to Common Shareholders for 2003 was $7.7 million.

Earnings per Share was $1.58 for 2003; reflecting an improvement of $0.15, or 10%, measured with comparable earnings of $1.43 per share in 2002. Comparable results for 2002 exclude the restructuring charge of $0.20 per share for our management reorganization.

Contributing positively to the Company's earnings performance were higher electric and gas sales margins driven by higher utility rates and electric and gas sales volumes in 2003, and operating expense and capital overhead savings achieved as a result of a management restructuring at the beginning of the year. 2003 marked the first full year of revenues earned by Unitil's electric and gas utilities at their new higher base distribution rates, which went into effect on December 1, 2002. Partially offsetting these positive contributors were higher operating and maintenance expenses relating to employee benefits, uncollectible accounts expenses and collection costs, and higher system maintenance and regulatory compliance expenditures. Depreciation, Taxes and Interest expenses were also higher in 2003 supporting the higher utility investments and customer growth.

In 2003, the Company completed an unprecedented restructuring process brought about by the deregulation of the natural gas and electric industries in New Hampshire and Massachusetts. As a result of this process, Unitil's retail distribution utilities have divested their entire generation and power supply portfolio, transforming the Company's vertically integrated utility operations into principally a pipes-and-wires business providing natural gas and electric delivery services. The Company implemented the final phase of its electric industry restructuring in New Hampshire on May 1, 2003. Unitil had previously implemented state mandated restructuring of its electric and gas operations in Massachusetts in 1998 and 2000, respectively. Unitil's customers in both New Hampshire and Massachusetts now have the opportunity to purchase their electricity or natural gas supply from third party vendors, though most customers continue to purchase such supplies through Unitil as the provider of last resort.

Diluted earnings per average common share were $1.58 for the year ended December 31, 2003, compared to $1.43 and $1.51, before other items, for 2002 and 2001 respectively. The return on average common equity (ROE) was 9.9% for 2003. Unitil's annual common dividend was $1.38 in 2003, resulting in a payout ratio of 87%. At its January, 2004 meeting, the Unitil Board of Directors declared a regular quarterly dividend on the Company's common stock of $0.345 per share, maintaining the Company's continued commitment to a regular quarterly dividend.

Earnings & Dividends Data	**2003**	**2002**	**2001**
Earnings per Share Before Other Items **(non-GAAP)**	**$1.58**	$ 1.43	$ 1.51
Other Items, net of tax:			
Restructuring Charge	**—**	(0.20)	—
Investment Write-down	**—**	—	(0.50)
Extraordinary Item	**—**	—	(0.83)
Earnings per Share	**$1.58**	$ 1.23	$ 0.18
Annual Dividend Rate	**$1.38**	$ 1.38	$ 1.38

The presentation of earnings per share data in the table above includes a line item identified as "Earnings per Share Before Other Items." Though this measurement is based on Generally Accepted Accounting Principles (GAAP) consistently applied, the measurement itself is not specifically defined under GAAP and is therefore required to be presented as a non-GAAP measure. "Earnings per Share Before Other Items" is a non-GAAP measure and may not be comparable to other non-GAAP measures of earnings per share used by other companies. " Management believes this measure is useful to investors because it includes the same company-specific information that is used by Management to assess the Company's financial performance.

In 2002, Unitil recorded a Restructuring Charge of $1.6 million before taxes, or ($0.20) per share, related to the elimination of 19 management and administrative positions. In 2001, as a result of industry restructuring-related regulatory orders, Unitil recognized an Extraordinary Item to reduce Regulatory Assets by $3.9 million after tax, or ($0.83) per share. Also in 2001, Unitil recognized an Investment Write-down of $2.4 million after-tax, or ($0.50) per share, to recognize a decrease in the fair value of a non-utility energy technology investment.

A more detailed discussion of the Company's 2003 Results of Operations and a year-to-year comparison of changes in financial position for the three-year period 2001 through 2003 are presented below.

RESULTS OF OPERATIONS

Operating Revenues—Electric

Electric Operating Revenues—Electric Operating Revenues, which represent approximately 87% of Unitil's total Operating Revenues, increased by $23.5 million, or 14.1%, in 2003 compared to 2002. Electric Operating Revenues include the recovery of cost of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management in Operating Expenses. Approximately 90% of the Conservation & Load Management expenses are related to electric operations. Electric operating revenues increase or decrease annually due to changes in Purchased Electricity expenses, Conservation & Load Management expenses and electric sales margin (Electric Operating Revenues less Purchased Electricity and Conservation & Load Management). Purchased Electricity expenses include the cost of electric supply as well as the other energy supply related restructuring costs including power supply buyout costs. Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs.

The Purchased Electricity cost of sales component increased $17.2 million in 2003 compared to 2002. Approximately 75% of this increase reflects higher electric commodity prices while the remainder reflects an increase of approximately 3.5% in electric unit sales volume. Conservation & Load Management expenses related to electric operations increased $2.2 million, or 121.9% in 2003 compared to 2002 reflecting seven new energy efficiency programs that were implemented during the year. The Company recovers the costs of Purchased Electricity and Conservation & Load Management in its rates at cost and therefore changes in these revenues do not impact net income.

Electric sales margin was $52.7 million in 2003, an increase of $4.3 million over 2002. Approximately 60% of this increase reflects the impact of 2002 base rate cases, which resulted in higher base distribution rates for the Company's electric retail distribution utilities as of December 2002. The remainder of the increase in electric sales margin is due to a 3.5% increase in electric unit sales in 2003 compared to 2002.

In 2002, Electric Operating Revenues decreased by $16.5 million, or 9.0% compared to 2001, primarily reflecting a decrease in Purchased Electricity due to lower electric commodity prices overall as well as lower electric distribution rates, partially offset by an increase in unit sales. Electric sales margin increased $0.7 million, or 1.5% in 2002 compared to 2001, reflecting the increase in unit sales.

The following table details total Electric Operating Revenue and Sales Margin for the last three years by major customer class:

Electric Operating Revenue and Sales Margin (000's)

	2003	2002	2001	% Change 2003 vs. 2002	% Change 2002 vs. 2001
Electric Operating Revenue:					
Residential	**$ 76,893**	$ 65,746	$ 71,960	17.1%	(8.6%)
Commercial/Industrial	**113,971**	101,571	111,820	12.2%	(9.2%)
Total Electric Operating Revenue	**$190,864**	$167,317	$183,780	14.1%	(9.0%)
Purchased Electricity	**$134,575**	$117,409	$134,660	14.6%	(12.8%)
Conservation & Load Management	**3,644**	1,603	1,547	127.3%	3.6%
Electric Sales Margin	**$ 52,645**	$ 48,305	$ 47,573	9.0%	1.5%

Kilowatt-hour Sales—Unitil's total electric kilowatt-hour (kWh) sales increased 3.5% in 2003 compared to 2002. This increase reflects growth in sales to residential and commercial and industrial customer classes driven by a colder winter heating season and consistent customer growth year over year.

Sales to residential customers increased 4.2% in 2003 compared to 2002. The increase in energy sales reflects an increase in the number of residential customers as well as higher usage per customer, due to the colder winter heating season. Commercial and industrial sales of electricity increased 3.1% in 2003 compared to 2002, also reflecting an increase in the number of customers as well as the impact of the colder winter heating season.

Unitil's total electric kilowatt-hour (kWh) sales increased by 3.9% in 2002 compared to 2001. This increase reflected growth in sales to residential and commercial and industrial customer classes driven by higher average summer temperatures, as well as increased sales to Industrial customers.

The following table details total kWh sales for the last three years by major customer class:

kWh Sales (000's)

	2003	2002	2001	% Change 2003 vs. 2002	% Change 2002 vs. 2001
Residential	**645,711**	619,756	596,378	4.2%	3.9%
Commercial/Industrial	**1,071,953**	1,039,380	1,000,012	3.1%	3.9%
Total	**1,717,664**	1,659,136	1,596,390	3.5%	3.9%

Operating Revenues—Gas

Gas Operating Revenues—Gas Operating Revenues, which represent approximately 13% of Unitil's total Operating Revenues, increased $8.3 million, or 41.1%, in 2003 compared to 2002. Gas Operating Revenues include the recovery of cost of sales, which are recorded as Purchased Gas, and Conservation & Load Management in Operating Expenses. Approximately 10% of the Company's total Conservation & Load Management expenses are related to Gas operations. Gas Operating revenues increase or decrease annually due to changes in Purchased Gas costs, Conservation & Load Management costs and gas sales margin (Gas Operating Revenues less Purchased Gas and Conservation & Load Management). Purchased Gas costs include the cost of gas supply as well as the other energy supply related costs. Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the company's energy efficiency programs.

Purchased Gas increased $5.1 million, or 41.6%, in 2003 compared to 2002. Approximately 77% of this increase reflects higher natural gas commodity prices while the remainder reflects an increase of approximately

9.4% in gas unit sales. Conservation & Load Management expenses related to gas operations increased $0.1 million in 2003 compared to 2002. The Company recovers the costs of Purchased Gas and Conservation & Load Management in its rates at cost and therefore changes in these revenues do not impact net income.

Gas sales margin was $10.9 million in 2003, an increase of $3.1 million over 2002. Approximately 76% of this increase reflects the impact of 2002 base rate cases, which resulted in higher base distribution rates for the Company's gas retail distribution utility as of December 2002. The remainder of the increase in gas sales margin is due to higher gas unit sales in 2003 compared to 2002.

In 2002, Gas Operating Revenue decreased by $2.5 million, or 11.1%, compared to 2001. This was attributable to lower unit sales, reflecting a warmer than normal winter heating season combined with a decrease in wholesale natural gas commodity prices.

The following table details total Gas Operating Revenue and Margin for the last three years by major customer class:

Gas Operating Revenue and Sales Margin (000's)

				% Change	
	2003	**2002**	**2001**	**2003 vs. 2002**	**2002 vs. 2001**
Gas Operating Revenue:					
Residential	**$16,267**	$10,871	$12,779	49.6%	(14.9%)
Commercial/Industrial	**11,979**	8,007	9,505	49.6%	(15.8%)
Total Firm Gas Revenue	**$28,246**	$18,878	$22,284	49.6%	(15.3%)
Interruptible Gas Revenue	**366**	1,405	544	(74.0%)	158.3%
Total Gas Operating Revenue	**$28,612**	$20,283	$22,828	41.1%	(11.1%)
Purchased Gas	**$17,421**	$12,304	$15,184	41.6%	(19.0%)
Conservation & Load Management	**286**	168	182	70.2%	(7.7%)
Gas Sales Margin	**$10,905**	$ 7,811	$ 7,462	39.6%	4.7%

Therm Sales—Unitil's total firm therm sales of natural gas increased 9.4% in 2003 compared to 2002, due to a colder winter heating season in early 2003. Sales to residential customers increased 10.5% and sales to commercial and industrial customers increased 8.3% in 2003 compared to 2002.

In 2002, total firm therm sales decreased 2.5% compared to 2001, primarily due to a warmer winter heating season compared to the prior year.

The following table details total firm therm sales for the last three years, by major customer class:

Firm Therm Sales (000's)

				% Change	
	2003	**2002**	**2001**	**2003 vs. 2002**	**2002 vs. 2001**
Residential	**12,181**	11,022	11,175	10.5%	(1.4%)
Commercial/Industrial	**12,411**	11,458	11,892	8.3%	(3.6%)
Total	**24,592**	22,480	23,067	9.4%	(2.5%)

Operating Revenue—Other

Total Other Revenues increased $0.4 million, or 51.9%, in 2003 compared to 2002 and by $0.4 million, or 89.9%, in 2002 compared to 2001. This was the result of growth in revenues from the Company's unregulated energy brokering business, Usource.

The following table details total Other Revenue for the last three years:

Other Revenue (000's)

	2003	2002	2001	% Change 2003 vs. 2002	% Change 2002 vs. 2001
Usource	**$1,148**	$756	$384	51.9%	96.9%
Other	**30**	30	30	—	—
Total Other Revenue	**$1,178**	$786	$414	49.9%	89.9%

Operating Expenses

Purchased Electricity—Purchased Electricity expenses include the cost of electric supply as well as the other energy supply related restructuring costs, including power supply buyout costs. Purchased Electricity expenses, recoverable from customers through periodic cost recovery adjustment mechanisms increased $17.2 million in 2003 compared to 2002. Approximately 75% of this increase reflects higher electric commodity prices while the remainder reflects an increase of approximately 3.5% in electric unit sales during the period. The Company recovers the costs of Purchased Electricity in its rates at cost and therefore changes in these expenses do not impact net income.

In 2002, Purchased Electricity expenses decreased $17.3 million, or 12.8%, compared to 2001. This change was mainly due to a decrease in electric commodity prices compared to the prior year.

Purchased Gas—Purchased Gas expenses includes the cost of gas purchased and manufactured to supply the Company's total gas energy requirements. Gas supply costs are recoverable from customers through the Cost of Gas Adjustment mechanism. Purchased Gas expenses increased by $5.1 million, or 41.6% in 2003 compared to 2002. Approximately 77% of this increase reflects higher gas commodity prices while the remainder reflects an increase of approximately 9.4% in gas unit sales during the period. The Company recovers the costs of Purchased Gas in its rates at cost and therefore changes in these expenses do not impact net income.

In 2002, Purchased Gas decreased by $2.9 million, or 19.0%, compared to 2001, due to a decrease in gas commodity prices and lower gas unit sales, compared to 2001.

Operation and Maintenance (O&M)—O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expense increased $2.2 million, or 11.2%, in 2003 compared to 2002.

This increase reflects higher pension, insurance and employee medical benefit costs ($1.0 million) incurred in 2003 as well as annual increases in salaries and compensation expenses ($0.5 million). The Company also experienced higher uncollectible accounts expenses ($0.5 million) and higher legal and regulatory compliance costs ($0.4 million) in 2003. In addition, other utility operating and maintenance costs ($0.3 million) rose in 2003 due to the colder winter weather, as well as planned increases in distribution system maintenance programs. These increases were partially offset by operating expense savings of approximately $1.0 million achieved as a result of the management reorganization at the beginning of 2003.

Additionally, O&M expenses in 2003 reflect higher operating lease rent expense ($0.5 million) which, in prior years, was recognized under a capital lease and reflected in Depreciation and Amortization and Interest Expense, net. This change in accounting classification did not affect net income as the increase in O&M expense in 2003 was offset by a corresponding reduction in Depreciation and Amortization expense and Interest Expense, net. The change in classification was the result of a renegotiation of the lease terms in 2003.

In 2002, total O&M expense decreased $0.3 million, or 1.4%, compared to 2001.

Conservation & Load Management—Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy Efficiency programs are designed, in conformity to state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total Conservation & Load Management expenses increased $2.1 million, or 121.9%, in 2003 compared to 2002 reflecting seven new Energy Efficiency programs that were implemented during the year. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs have no impact on earnings.

In 2002, total Conservation & Load Management expenses increased less than $0.1 million, or 2.4%, compared to 2001.

Depreciation, Amortization and Taxes

Depreciation and Amortization—Depreciation and Amortization expense increased $3.8 million, or 25.8%, in 2003 compared to 2002, due mainly to higher utility depreciation rates, which were included as a component of the new rates implemented by our retail distribution utilities in December 2002, together with an increased investment in utility plant additions.

In 2002, Depreciation and Amortization expense increased $2.1 million, or 16.8%, compared to 2001, due to a higher level of utility plant investments and the accelerated amortization of restructuring-related Regulatory Assets.

Local Property and Other Taxes—Local Property and Other Taxes increased $0.1 million, or 1.6%, in 2003 compared to 2002 and by $0.1 million, or 1.4%, in 2002 compared to 2001. These increases were related to higher levels of utility plant in service.

Federal and State Income Taxes—Federal and State Income Taxes increased $1.1 million, or 42.8%, in 2003 compared to 2002, principally due to higher pre-tax operating income in 2003.

In 2002, Federal and State Income Taxes decreased $0.9 million, or 27.2%, compared to 2001, due to lower pre-tax operating income in 2002 and the amortization in 2002 of deferred tax liabilities related to the accelerated write-off of Regulatory Assets.

Interest Expense, net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and interest on regulatory liabilities. Interest income is mainly derived from carrying charges on restructuring related stranded costs and other deferred costs recorded as regulatory assets by the Company's retail distribution utilities as approved by regulators in New Hampshire and Massachusetts. Over the long run, as deferred costs are recovered through rates, the interest costs associated with these deferrals are expected to decrease together with a decrease in interest income. A summary of interest expense and interest income is provided in the following table:

Interest Expense, net	2003	2002	2001
Interest Expense			
Long-term Debt	**$ 8,170**	$ 8,336	$ 7,708
Short-term Debt	**1,071**	1,037	1,484
Subtotal Interest Expense	**9,241**	9,373	9,192
Interest Income			
Regulatory Assets	**(1,657)**	(2,090)	(1,952)
AFUDC	**(46)**	(52)	(61)
Other	**(7)**	(174)	(382)
Subtotal Interest Income	**(1,710)**	(2,316)	(2,395)
Total Interest Expense, net	**$ 7,531**	$ 7,057	$ 6,797

In 2003, Interest Expense, net, increased by $0.5 million over 2002. This increase was driven by lower interest income on regulatory assets, which decreased $0.4 million in 2003 compared with 2002 due mainly to lower carrying charges applicable to regulatory asset balances. In addition, interest expense declined $0.1 million compared with 2002.

In 2002, Interest Expense, net, increased $0.3 million compared with 2001. Interest expense associated with long-term debt increased $0.6 million. Short-term interest expense decreased by $0.4 million due to lower interest short-term interest rates applicable to short-term debt balances outstanding. Interest income was lower in 2002 compared to 2001 by $0.1 million.

Other Items

2002 Restructuring Charge—In the fourth quarter of 2002, the Company recognized a pre-tax Restructuring Charge of $1.6 million. The after-tax effect of the Restructuring Charge was a reduction of $0.20 in Earnings Per Common Share, assuming full dilution.

In December 2002, the Company undertook a strategic review of its business operations and committed to a formal transition and reorganization plan (the Reorganization Plan) to streamline its management structure, in order to improve operating efficiency and to align the organization to meet ongoing business requirements. The Reorganization Plan resulted in the elimination of 19 management and administrative positions. As a result of the elimination of these positions, and consistent with existing Company policy, certain benefits were extended to the employees whose positions were eliminated. On January 8, 2003, the Company implemented the remainder of the Reorganization Plan. The Company estimates that the result of this management restructuring process will be an annual cash savings of approximately $2.3 million in operating expenses and construction project overheads.

Investment Write-down and Sale of Equity Stake in Enermetrix—2001—Beginning in 1998, Unitil invested $5.5 million in Enermetrix, Inc. (Enermetrix), an energy technology start-up enterprise. In accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities," the Company recorded a non-cash charge of $3.7 million, or $2.4 million, net of tax, in the fourth quarter of 2001 to recognize the decrease in fair value of its non-utility investment in Enermetrix.

On April 11, 2002, the Company sold its equity ownership in Enermetrix for $1.5 million in cash and improved commercial terms for use of the Enermetrix Software Network. As a result of the sale, in 2002, the Company recognized the benefit of approximately $1.3 million from this capital loss as a carryback against capital gains in its 2002 tax return and recorded a gain, net of transaction costs, on the final disposition of $82 thousand, net of tax. In total, the final "book" loss on the investment was $2.3 million, net of tax.

Extraordinary Item—2001—In November 1997, the Massachusetts Legislature enacted the Massachusetts Electric Restructuring Act of 1997 (the Restructuring Act). The Restructuring Act required all electric utilities to file a restructuring plan with the MDTE by December 31, 1997. Among other things, the Restructuring Act resulted in the divestiture of electric generation assets and purchase power contracts, along with the restructuring of utility operations by all Massachusetts utilities to provide direct retail access to their customers by all qualified third-party energy suppliers.

The MDTE conditionally approved FG&E's Restructuring Plan (the Plan) in February 1998, and started an investigation and evidentiary hearings into FG&E's proposed recovery of Regulatory Assets related to stranded generation asset costs and power supply expenses related to the formulation and implementation of its Plan. In January 1999, the MDTE approved FG&E's Plan, which included provisions for the recovery of stranded costs through a transition charge in FG&E's electric rates. In September 1999, FG&E filed its first annual reconciliation of stranded generation asset costs and expenses and associated transition charge revenues and the MDTE initiated a lengthy investigation and hearing process.

On October 18 and 19, 2001, the MDTE issued a series of regulatory orders in several pending cases involving FG&E, including a final order on FG&E's initial reconciliation filing. Those orders included the review and disposition of issues related to FG&E's recovery of transition costs due to the restructuring of the electric industry in Massachusetts, as well as certain costs associated with gas industry restructuring and preparation and litigation of performance based rate proceedings initiated by the MDTE. The orders determined the final treatment of Regulatory Assets that FG&E had sought to recover from its Massachusetts electric customers over a multi-year transition period that began in 1998.

As a result of the industry restructuring-related orders, FG&E recorded a non-cash adjustment to Regulatory Assets of $5.3 million, which resulted in the recognition of an extraordinary charge of $3.9 million, net of taxes. The Company recognized the extraordinary charge of $0.83 per share, as of September 30, 2001.

As a result of all of these orders, the Company has been allowed recovery of its Massachusetts industry restructuring transition costs, estimated at $150 million after reconciliation, including the above-market or stranded generation and power supply related costs via a non-bypassable uniform transition charge. FG&E has been, and will continue to be, subject to annual MDTE investigation and review in order to reconcile the costs and revenues associated with the collection of transition charges from its customers over the next six to eight years.

Capital Requirements and Liquidity

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities, exclusive of payments of current dividends. The Company initially supplements internally generated funds through bank borrowings under unsecured short-term bank lines. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term lives of its utility assets.

At December 31, 2003, Unitil had an aggregate of $52.0 million in unsecured revolving lines of credit through three banks. On January 1, 2004, the Company reduced its aggregate unsecured short-term bank lines to

$45.0 million. The Company anticipates that it will be able to secure renewal or replacement of some or all of its revolving lines of credit, in accordance with projected requirements. Average short-term borrowings in 2003 were $39.1 million, an increase of $14.1 million over the average short-term debt outstanding in 2002. At December 31, 2003, the Company had available $29.6 million of unused bank lines of credit and had outstanding bank borrowings of $22.4 million. In addition, Unitil had $3.8 million in cash on hand as of December 31, 2003.

The maximum amount of short-term borrowings that may be incurred by Unitil and its subsidiaries is subject to periodic approval by the SEC under the Public Utility Holding Company Act of 1935 (PUHCA) and state regulators of the Company's retail distribution utilities, FG&E and UES. At December 31, 2003, Unitil had regulatory authorization to incur total short-term borrowings up to a maximum of $55 million, and FG&E and UES had regulatory authorizations to borrow up to a maximum of $35 million and $22 million, respectively. UES' short-term debt authorization is scheduled to be reduced to $16 million on May 1, 2004, reflecting reduced borrowing requirements. In 2003, UES and FG&E had average short-term debt outstanding of $9.4 million and $23.8 million, respectively. At December 31, 2003, UES and FG&E had short-term debt outstanding of $7.8 million and $14.6 million, respectively.

The Unitil Companies are individually and collectively members of the Unitil Cash Pool. The Cash Pool is the financing vehicle for day-to-day cash borrowing and investing by each of the Unitil companies. The Cash Pool Agreement allows an efficient exchange of cash among the Unitil companies. The Cash Pool Agreement and its transactions are strictly monitored by the SEC under PUHCA. The interest rates charged to the subsidiaries for borrowing from the Cash Pool are based on Unitil Corporation's actual interest costs from its banks under the revolving lines of credit. In addition, Unitil, UES and FG&E are required by the SEC to maintain a minimum 30% common equity ratio, including short-term debt, in order to utilize the Cash Pool resources. At December 31, 2003, all Unitil subsidiaries were in compliance with the requirements to participate in the Cash Pool.

The Company periodically repays its short-term borrowings with internally generated funds and through the issuance of long-term financings. The Company issued two long-term financings in 2003 in the form of Unitil Corporation Common Stock and FG&E Long-term Notes. The Common Stock offering provided net proceeds of $16.9 million which were used to make capital contributions of $6.0 million each to UES and FG&E (see Note 3) and for general corporate purposes. FG&E issued $10.0 million in Long-term Notes under a debenture note structure (see Note 4). The Company expects to continue to be able to satisfy its external financing needs by utilizing additional short-term bank borrowings and additional long-term financings in the form of first mortgage bonds, debentures and/or equity. The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions, if any; the level of the Company's net income, cash flows and financial position; and the competitive pricing offered by the financing source.

In 2003, the Company and its subsidiaries made cash contributions to their pension plans in the amount of $1.2 million. If the actual return on plan assets continues to be significantly below the expected returns, the Company may elect to fund the pension plans in future periods. Post-retirement benefits for employees of the Company and its subsidiaries were funded through contributions to the Unitil Retiree Trust (URT) in 2003. In January 2004, Unitil established Voluntary Employee Benefit Trusts (VEBT) to provide post-retirement benefits. Unitil expects to continue to make contributions to the VEBT's in future years in amounts consistent with the amounts recovered in retail distribution utility rates for these benefit costs.

The Company does not currently use, and is not dependent on the use of off-balance sheet financing arrangements, such as securitization of receivables or obtaining access to assets or cash through special purpose entities. We do have material energy supply commitments that are discussed in Note 5. Cash outlays for the purchase of electricity and natural gas to serve our customers are subject to full recovery through periodic changes in rates, with carrying charges on deferred balances. From year to year, there are likely to be timing differences associated with the cash recovery of such costs, creating under- or over-recovery situations at any point in time. Rate recovery mechanisms are typically designed to collect the under-recovered cash or refund the over collected cash over subsequent 6-12 month periods.

The table below lists the Company's significant contractual obligations as of December 31, 2003.

		Payments Due by Period			
Significant Contractual Obligations (000's) as of December 31, 2003	**Total**	**2004**	**2005-2006**	**2007-2008**	**2009 & Beyond**
Long-term Debt	$114,224	$ 3,264	$ 596	$ 700	$109,664
Capital Lease	1,050	616	408	18	8
Operating Leases	2,452	270	540	540	1,102
Power Supply Contract Obligations—MA	73,441	7,717	15,737	16,137	33,850
Power Supply Contract Obligations—NH	93,900	19,176	31,555	23,807	19,362
Gas Supply Contracts	18,622	8,706	7,279	2,637	—
Total Contractual Cash Obligations	**$303,689**	**$39,749**	**$56,115**	**$43,839**	**$163,986**

The Company also provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2003 there are $2.0 million of guarantees outstanding and these guarantees extend through October 21, 2005.

Financial Covenants and Restrictions

The agreements under which the long-term debt of Unitil's two principal subsidiaries, UES and FG&E, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations, as described below.

UES utilizes a First Mortgage Bond (FMB) structure of long-term debt. In order to issue new FMB securities, the customary covenants of the existing UES Indenture Agreement must be met, including that UES have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The UES agreements further require that if UES defaults on any UES FMB securities, it would constitute a default for all UES FMB securities. The UES default provisions are not triggered by the actions or defaults of other companies in the Unitil System.

FG&E utilizes a debenture structure of long-term debt. Accordingly, in order for FG&E to issue new long-term debt, the covenants of the existing long-term agreements must be satisfied, including that FG&E have total funded indebtedness less than 65% of total capitalization and earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the UES agreements, FG&E agreements require that if FG&E defaults on any FG&E long-term debt agreement, it would constitute a default under all FG&E long-term debt agreements. The FG&E default provisions are not triggered by the actions or defaults of other companies in the Unitil System.

Both the UES and FG&E instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into or to sell or otherwise dispose of all or substantially all of its assets.

In addition, the UES and FG&E long-term debt instruments and agreements contain certain restrictions on the payment of common dividends from Retained Earnings. On December 31, 2003, UES and FG&E had unrestricted Retained Earnings of $11,354,000 and $ 6,081,000, respectively, available for the payment of

Common dividends. (See Note 3). UES and FG&E pay dividends to their sole shareholder, Unitil Corporation, and these dividends are the primary source of cash for the payment of dividends to Unitil shareholders.

Sinking fund and principal payments on long-term debt will be required in 2004 in the amount of $3.3 million. This includes a final $3 million sinking fund payment due on FG&E's 8.55% Long-Term Notes, which will retire the issue.

Unitil Corporation has no long-term debt outstanding. The long-term debt and preferred stock of UES and FG&E are privately held, and the Company does not issue commercial paper. For these reasons, these securities of Unitil and its subsidiaries are not publicly rated.

Results of Operations—Cash Flows

Cash Provided by Operating Activities—Operating cash flows of $15.6 million in 2003 reflect an increase of $6.1 million over 2002 operating cash flow of $9.6 million. This increase is attributable to higher earnings in 2003, which when adjusted for depreciation and amortization and deferred taxes, provided $33.1 million in operating cash flow as compared to $21.9 million in 2002 and $13.2 million in 2001. The year over year change in depreciation and amortization primarily reflects the full year impact of higher book depreciation rates used by the Company's retail distribution utilities in 2003 compared to 2002 and 2001, as well as higher plant in service year to year. These higher depreciation rates took effect on December 1, 2002, as a component of the Company's retail distribution utilities new electric and gas base distribution rate increases. The change in deferred income taxes primarily reflects deferred tax impacts associated with a change in regulatory energy supply related cost deferrals year to year and a change in federal tax laws that allows for an additional 30% acceleration of tax depreciation on capital additions placed in service in 2003. Together with the normal accelerated tax depreciation on utility capital additions these factors resulted in an increase in the deferred tax provision. Also impacting operating cash flows in 2003 was a decrease in operating cash flow of $1.6 million due to the net change in current assets and liabilities. Changes in current assets and liabilities reflect cash timing differences generally of a shorter duration which taken together comprise the Company's working capital requirements (excluding short term borrowings and current portion of long term debt). A decrease in accounts receivable, lower electric and gas supply payables to wholesale suppliers and higher refundable income taxes, which positively impact estimated income tax payments, improved operating cash flow by $14.6 million in 2003 compared to 2002. These increases in operating cash flow were offset by higher accrued revenues, reflecting an increase of $3.3 million in the deferred rate recovery of energy supply related costs expended in 2003, as well as an increase in prepayments of $4.6 million, primarily related to payments to wholesale electricity suppliers. Another use of cash reflects the expenditure of insurance proceeds received by the Company in 2002 for the completion of an environmental remediation project in 2003 which was recorded in Other Current Liabilities. Other changes impacting operating cash flows in 2003 included an increase in deferred restructuring charges of $6 million. Deferred restructuring charges reflect unrecovered industry restructuring related costs which are recorded as regulatory assets and earn carrying charges until there subsequent recovery in future periods.

	2003	2002	2001
Cash Provided by Operating Activities ($000's)	**$15,621**	$9,568	$23,178

Cash Used in Investing Activities—Cash flows used in investing activities were $21.9 million in 2003. Cash used in investing activities is primarily for capital expenditures related to electric and gas distribution system additions. In 2002, the Company also received $1.5 million of proceeds from the sale of it ownership interest in a non-utility investment. In addition, in 2001, the Company received $0.3 million in proceeds from the sale of its ownership interest in Millstone Nuclear Generating Unit No. 3.

Capital expenditures are projected to be $21.9 million in 2004 reflecting normal electric and gas utility system additions.

	2003	2002	2001
Cash Used in Investing Activities ($000's)	**$(21,939)**	$(19,290)	$(19,548)

Cash Provided by (Used in) Financing Activities—Cash flow from financing activities in 2003 of $2.9 million primarily reflects financing proceeds of $27.7 million from the issuance of common stock equity and new long term debt, partially offset by the repayment of short-term borrowings of $13.6 million, long term debt sinking fund payments of $3.2 million and common and preferred stock dividends paid of $7.1 million.

On October 29, 2003, the Company raised approximately $16.9 million (after deducting underwriting discounts and commissions and the expenses of the offering) through the sale of 717,600 shares of its common stock at a price of $25.40 per share in a registered public offering. The offering was increased from an original 520,000 shares to reflect a 20% upsizing of the transaction (104,000 shares) and the exercise of a 15% underwriters' over-allotment (93,600 shares). The Company used $12.0 million of the proceeds from this offering to make capital contributions of $6.0 million to UES and $6.0 million to FG&E.

On October 28, 2003, FG&E completed a $10 million private placement of long-term unsecured notes with a major insurance company. The notes have a term of 22 years and a coupon rate of 6.79%. The net proceeds were used to repay short-term borrowings.

	2003	2002	2001
Cash Provided by (Used in) Financing Activities ($000's)	**$2,924**	$10,806	$(614)

Dividends

The Company is currently paying a dividend at an annual rate of $1.38 per common share.

The Company's dividend policy is reviewed annually by the Board of Directors. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

Interest Rate Risk

As discussed above, the Company meets its external financing needs by issuing short-term and long-term debt. The majority of the Company's debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities issued by the Company. In addition, the Company's short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease the Company's interest expense in future periods. For example, if the Company had an average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000. The average interest rate on the Company's short-term borrowings was 1.78%, 2.18% and 4.78% during 2003, 2002 and 2001, respectively.

Market Risk

Although Unitil's utility operating companies are subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of power and gas costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, has further reduced its exposure to commodity risk.

Regulatory Matters

As a registered holding company under PUHCA, Unitil and its subsidiaries are regulated by the Securities and Exchange Commission (SEC) with respect to various matters, including: the issuance of securities, capital structure and certain acquisitions and dispositions of assets. UES and FG&E are subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Telecommunications and Energy (MDTE), respectively, with respect to their rates, issuance of securities and other accounting and operational matters. Certain aspects of the Company's utility operations as they relate to wholesale and interstate business activities are also regulated by the Federal Energy Regulatory Commission (FERC). In the past several years, the Company has completed the restructuring of its electric and natural gas operations resulting from the implementation of retail choice as mandated by the States of New Hampshire and Massachusetts.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in their franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, through their distribution charges, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. In 2002, the retail distribution utilities completed rate proceedings and were authorized by the NHPUC and MDTE to implement increased rates for electric and natural gas distribution operations beginning in December of that year. UES and FG&E also recover the actual cost of any electricity or natural gas they supply to their customers, as well as certain costs associated with industry restructuring, through periodically adjusted rates.

In recent years, there has been significant legislative and regulatory activity to restructure the utility industry in order to introduce greater competition in the supply and sale of electricity and natural gas, while continuing to regulate the distribution operations of Unitil's retail distribution utilities. Unitil implemented the restructuring of its electric and gas operations in Massachusetts in 1998 and 2000, respectively, and implemented the final phase of a restructuring settlement for its New Hampshire electric operations on May 1, 2003. Following electric industry restructuring, Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

In connection with industry restructuring and the implementation of retail choice for customers in New Hampshire and Massachusetts, Unitil Power divested of its long-term power supply contracts and FG&E divested of its long-term power supply contracts and owned generation assets. Unitil Power divested its long-term power supply contracts to a subsidiary of Mirant Corporation (Mirant) and FG&E divested its owned generation assets and long-term power supply contracts to Select Energy, Inc. (Select Energy). Unitil Power's and FG&E's long-term power supply contracts were divested through the sale of the entitlements to the electricity associated with those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios as a result of electric industry restructuring.

Unitil's customers in both New Hampshire and Massachusetts now have the opportunity to purchase their electric supply from third party vendors, though most customers continue to purchase such supplies through Unitil as the provider of last resort. Accordingly, UES and FG&E contract with wholesale power suppliers for the electricity necessary to meet their regulated default service energy supply obligations. Similarly, FG&E's natural gas customers have the option to contract for their natural gas supply with third-party suppliers and FG&E remains the default service provider for these natural gas customers. The costs associated with the acquisition of such wholesale electric and natural gas supplies for customers who do not contract with third-party suppliers are recovered from those customers through periodic rate and cost recovery reconciliation mechanisms.

We have secured regulatory approval from both New Hampshire and Massachusetts state regulators for the recovery of approximately $203 million of power supply-related stranded costs principally over the next 6 to 8 years. Also, we have implemented comprehensive customer and financial information systems to accommodate the transition to competitive energy markets and retail choice.

Massachusetts Electric Operations Restructuring—Beginning March 1, 1998, FG&E implemented its Restructuring Plan under the Massachusetts Electric Utility Restructuring Act of 1997 (Restructuring Act). FG&E completed the divestiture of its entire regulated power supply business in 2000 in accordance with the Restructuring Plan. FG&E's rates provide for the recovery of stranded costs associated with the divestiture of FG&E's power portfolio including stranded, previously-owned generation assets. The Regulatory Assets that are being recovered in FG&E's rates have been approved by the MDTE as part of FG&E's Restructuring Plan and are reviewed each year as part of FG&E's annual rate reconciliation filings.

The Restructuring Act also requires FG&E to purchase and provide power as the default service provider, through either Standard Offer Service (SOS) or Default Service, for retail customers who choose not to buy, or are unable to purchase, energy from a competitive supplier. FG&E must provide SOS through February 2005 at rate levels which provide rate reductions as required by the Restructuring Act. New distribution customers and customers no longer eligible for SOS are eligible to receive Default Service at prices set periodically based on market solicitations as approved by regulators. As of December 31, 2003, competitive suppliers were serving approximately 37% of FG&E's load, primarily for FG&E's largest customers, although much of the load has since reverted back to FG&E's regulated Default Service.

As a result of the restructuring and the divestiture of FG&E's owned generation assets, FG&E recorded stranded generation-related costs as Regulatory Assets. These stranded generation-related Regulatory Assets are being amortized and recovered through the year 2009. FG&E earns carrying charges on the unamortized balance of these stranded generation-related Regulatory Assets. In addition, as a result of restructuring legislation in Massachusetts, the total rate FG&E may charge for the combination of distribution service, stranded costs and purchase power costs is subject to an inflation adjusted total rate cap for a seven year period, which began in March 1998. Any unrecovered balance of purchased power costs and stranded costs as a result of the total rate cap is deferred for future rate recovery as a Regulatory Asset. These deferred costs also earn carrying charges until their subsequent recovery in future periods. The value of FG&E's generation-related Regulatory Assets and deferred cost Regulatory Assets was approximately $31.7 million and $28.9 million, respectively at December 31, 2003, and are expected to be recovered in FG&E's rates principally over the next 6 to 8 years. In addition, as of December 31, 2003, FG&E had recorded on its balance sheets $73.4 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts. FG&E does not earn a carrying charge on this power supply component of Regulatory Assets as there is no significant difference between the time periods when payments are made to satisfy these purchase power contract obligations and their recovery in rates from FG&E's customers.

Massachusetts Gas Operations Restructuring—Following a three year state-wide collaborative process on the unbundling, or separation, of discrete services offered by natural gas local distribution companies (LDCs), the MDTE approved regulations and tariffs for FG&E and other LDCs operating in the Commonwealth to provide full customer choice effective November 1, 2000. The MDTE ruled that LDCs would continue to have an obligation to provide gas supply and delivery services for a five-year transition period, with a review after three years. The MDTE also required mandatory assignment of LDCs' pipeline capacity to competitive marketers supplying customers during the transition period. This mandatory capacity assignment protects LDCs from exposure to certain stranded gas supply costs during the transition period. In January 2004, the MDTE opened an investigation seeking comment on whether the mandatory assignment of pipeline capacity should be continued. This proceeding is pending.

New Hampshire Restructuring—In 2002, UES' predecessor companies, Concord Electric Company (CECo) and Exeter & Hampton Electric Company (E&H), received approval for a comprehensive restructuring proposal from the NHPUC. This approved proposal included the merger of E&H with and into CECo. CECo changed its name to Unitil Energy Systems, Inc. (UES) immediately following the merger. Under the New Hampshire restructuring plan, Unitil Power agreed to divest its existing long-term power supply portfolio and conduct a solicitation for new power supplies from which to meet UES' ongoing default service Transition and Default Service obligations in order to implement customer choice for UES' customers May 1, 2003. In March 2003, the NHPUC approved the contract among Unitil Power, UES and Mirant Americas Energy Marketing, LP (MAEM), under which MAEM purchased the entitlements to Unitil Power's long-term power supply portfolio and provided Transition and Default Service to the customers of UES. The NHPUC also approved final tariffs for UES for stranded cost recovery and Transition and Default Service, including certain surcharges that are subject to future reconciliation or review. As of December 31, 2003, UES had recorded on its balance sheets $93.9 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are expected to be recovered principally over a period of approximately 8 years. UES does not earn carrying charges on these Power Supply Regulatory Assets as there is no significant difference between the time periods when payments are made to satisfy these purchase power buyout obligations and their recovery in rates from UES's customers.

In July 2003, MAEM and its parent, Mirant Corporation (Mirant), filed for reorganization under Chapter 11 of the bankruptcy code. Under the contract with UES and Unitil Power discussed above, Mirant guaranteed the performance by MAEM. Unitil Power and UES filed a motion with the Bankruptcy Court in September, 2003, requesting that MAEM be required to make a decision to assume or reject the contract by December 1, 2003. On November 14, 2003, MAEM, Unitil Power and UES filed a Settlement with the bankruptcy court. Under the terms of the Settlement, MAEM agreed to assume and continue to fulfill its power purchase and sale obligations under the contract, to cure all pre-petition obligations, and to settle certain other disputes. UES and Unitil Power agreed to accelerate the payment of amounts held back from MAEM. On December 10, 2003, the settlement was approved by the federal bankruptcy court and MAEM is continuing to fulfill its obligations under the Mirant Agreement.

Wholesale Power Market Restructuring—FG&E, Unitil Power, and UES are members of the New England Power Pool (NEPOOL). NEPOOL was formed in 1971 to assure reliable operation of the bulk power system in the most economic manner for the region. NEPOOL is governed by an agreement (NEPOOL Agreement) that is filed with and subject to the jurisdiction of the FERC. Under the NEPOOL Agreement and the NEPOOL Open Access Transmission Tariff (OATT), to which virtually all New England electric utilities are parties, substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The NEPOOL Agreement and the OATT impose generating capacity and reserve obligations, and provide for the use of major transmission facilities and support payments associated therewith. The most notable benefits of NEPOOL are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The regional bulk power system is operated by an independent corporate entity, the Independent System Operator-New England (ISO-NE), in order to avoid any opportunity for conflicting financial interests between the system operator and the market-driven participants.

There continue to be ongoing legislative and regulatory initiatives that are primarily focused on the deregulation of the generation and supply of electricity and the corresponding development of a competitive market place from which customers choose their electric energy supplier. As a result, the NEPOOL Agreement continues to be restructured. NEPOOL's membership provisions have been broadened to cover all entities engaged in the electricity business in New England, including power marketers and brokers, independent power producers, load aggregators and retail customers in states that have enacted retail access statutes. Various energy and capacity products are traded in open markets, with transmission access and pricing subject to the regional OATT designed to promote competition among power suppliers. On March 1, 2003, ISO-NE implemented a Standard Market Design (SMD) that is intended to improve the ability to trade power between New England and other regions throughout the northeast. On October 31, 2003, ISO-NE and the major transmission owners in New England filed with the FERC to form a Regional Transmission Organization (RTO) with a proposed effective date not earlier than March 1, 2004. The implementation of the RTO, which is being contested at FERC, will further revise the conduct of wholesale markets in New England. The filing also proposes to eliminate NEPOOL as an organization and require all current NEPOOL members to be part of the RTO system. SMD, the formation of an RTO and other wholesale market changes are not expected to have a material impact on Unitil's results of operations because of cost recovery mechanisms for wholesale energy costs approved by state regulators.

Other Regulatory Proceedings—Between December 2002 and January 2003, FG&E and UES received approval from their respective state regulatory commissions for accounting orders to mitigate certain accounting requirements related to pension plan assets, which have been triggered by the substantial decline in the capital markets. These approvals allowed FG&E and UES to treat the additional minimum pension liability as Regulatory Assets and avoided the reduction in equity that would otherwise be required. These regulatory orders did not pre-approve the amount of pension expense to be recovered in future rates, which recovery will be determined in future proceedings. Based on these approvals, FG&E's and UES' additional minimum pension liabilities are included in Regulatory Assets on the Company's balance sheet.

On December 15, 2003, FG&E filed a request to defer and record, as a regulatory asset or liability, the difference between the level of pension and Post Retirement Benefits Other than Pension (PBOP) expenses that are included in its base rates and the amounts that are required to be booked in accordance with SFAS No. 87 and SFAS No. 106, since the effective date of its last base rate change. The MDTE issued an order on January 30, 2004 approving FG&E's request for this accounting order to defer these costs.

On December 19, 2003, UES filed with the NHPUC a Petition for Deferral of its PBOP expenses not recovered in base rates. On January 30, 2004 the NHPUC issued an order approving UES's request for this accounting order to defer these costs.

On January 30, 2004 the MDTE granted FG&E's request to voluntarily decrease its Cost of Gas Adjustment Clause (CGAC) during the remainder of the 2004 winter period by accelerating the payment of a multi-year refund that was ordered by the MDTE in May 2001, based upon a finding that FG&E had over-collected certain fuel inventory finance charges. In January, 2004, the Massachusetts Supreme Judicial Court (SJC) affirmed the MDTE's May 2001 Order requiring the refund, which Order FG&E had appealed. The MDTE subsequently approved FG&E's request to prepay the balance of the refund outstanding of approximately $1.2 million by reducing the CGAC in February through April, 2004. The MDTE also approved FG&E's request to amortize these charges against future revenues.

In March 2003, the MDTE opened an investigation into FG&E's dealings with Enermetrix, Inc. (Enermetrix). Enermetrix provides an internet-based energy auction service that is used by utilities to post their natural gas and electric power needs for bids. FG&E used the Enermetrix Exchange to post its electric default service solicitations in September 2001 and March 2002, and Enermetrix earned approximately $19,000 in fees from these transactions. In Management's view, these successful solicitations ultimately resulted in significant lower default service costs to FG&E's customers. At the time of these solicitations, FG&E's parent, Unitil Corporation, had an approximately 9% ownership interest in Enermetrix. The MDTE is investigating whether FG&E is in compliance with relevant statutes and regulations pertaining to transactions with affiliated companies and the MDTE's Order setting forth the requirements for the pricing and procurement of default service. FG&E and the Attorney General have completed briefing of the case and an MDTE decision is pending. Management believes the outcome of this matter will not have a material adverse effect on the financial position of the company.

In August 2003, Northeast Utilities (NU) filed with FERC to revise its comprehensive network service transmission rates to establish and implement a formula based rate, replacing a fixed rate tariff. As filed, the proposed rate change would increase UES' external transmission costs paid under the NU tariff for comprehensive network service by about $600 thousand per year. The Company has filed a Motion to Intervene and Limited Protest in this FERC proceeding, and has claimed that certain provisions of NU's filing are contrary to a settlement reached in 1997 with NU for comprehensive network transmission service. The FERC set NU's filing for settlement discussions and approved the new tariff effective October 28, 2003, subject to refund. On January 22, 2004, the Settlement Judge formally terminated the settlement discussions. The Company continues to have informal settlement discussions with NU. Further action on the NU filing is currently pending before FERC. Management cannot predict the outcome of this proceeding but believes it will not have a material impact on results of operations because of rate reconciling cost recovery mechanisms approved by state regulators.

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company is in general compliance with all applicable environmental and safety laws and regulations, and Management believes that as of December 31, 2003, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site—The Company continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows the Company to work towards temporary remediation of the site. Work performed in 2002 was associated with the five-year review of the Temporary Solution submittal (Class C Response Action Outcome) under the Massachusetts Contingency Plan that was filed for the site in 1997. Completion of this work has confirmed the Temporary Solution status of the site for an additional five years. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

Since 1991, FG&E has recovered the environmental response costs incurred at this former MGP site pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover from gas customers over succeeding seven-year periods the environmental response costs incurred each year. Environmental response costs are defined to include liabilities related to manufactured gas sites, waste disposal sites or other sites onto which hazardous material may have migrated as a result of the operation or decommissioning of Massachusetts gas manufacturing facilities from 1882 through 1978. In addition, any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers. The total annual charge for such costs assessed to gas customers cannot exceed five percent of FG&E's total revenue for firm gas sales during the preceding year. Costs in excess of five percent will be deferred for recovery in subsequent years.

Former Electric Generating Station—FG&E has remediated environmental conditions at a former electric generating station also located at Sawyer Passway in Fitchburg, Massachusetts, which FG&E sold in 1983 to a general partnership, Rockware, who demolished several exterior walls of the generating station in order to facilitate removal of certain equipment. The demolition of the walls and the removal of generating equipment resulted in damage to asbestos-containing insulation materials inside the building, which had been intact and encapsulated at the time of the sale of the structure.

When Rockware encountered financial difficulties and failed to respond adequately to Orders of the environmental regulators to remedy the situation, FG&E agreed to take steps at that time and obtained DEP approval to temporarily enclose, secure and stabilize the facility. Based on that approval, between September and

December 1989, contractors retained by FG&E stabilized the facility and secured the building. This work did not permanently resolve the asbestos problems caused by Rockware, but was deemed sufficient for the then foreseeable future.

Due to the continuing deterioration of this former electric generating station and Rockware's continued lack of performance, FG&E, in concert with the DEP and the U.S. Environmental Protection Agency (EPA), conducted further testing and survey work during 2001 to ascertain the environmental status of the building. Those surveys revealed continued deterioration of the asbestos-containing insulation materials in the building.

By letter dated May 1, 2002, the EPA notified FG&E that it was a Potentially Responsible Party for planned remedial activities at the site and invited FG&E to perform or finance such activities. FG&E and the EPA entered into an Agreement on Consent, whereby FG&E, without an admission of liability, conducted environmental remedial action to abate and remove asbestos-containing and other hazardous materials. This project was completed during the fourth quarter of 2003. FG&E received complete coverage from its insurance carrier for these costs and the resolution of this matter did not have a material adverse impact on the Company's financial position.

Critical Accounting Policies

The preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, management is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgment; the financial position of the Company could be materially affected and the results of operations of the Company could be materially different than reported. The following is a summary of the Company's most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company's significant accounting policies, refer to the financial statements and Note 1: Summary of Significant Accounting Policies.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas in the Company-owned retail distribution utilities: Fitchburg Gas and Electric Light Company (FG&E), and Unitil Energy Systems, Inc. (UES). Both FG&E and UES are subject to regulation by the Federal Energy Regulatory Commission (FERC) and FG&E is regulated by the Massachusetts Department of Telecommunications and Energy (MDTE) and UES is regulated by the New Hampshire Public Utilities Commission (NHPUC). Accordingly, the Company uses the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered or refunded in future electric and gas retail rates.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets" under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities" under SFAS No. 71.

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet. The Company is currently receiving or being credited with a return on all of its regulatory assets for which a cash outflow has been made. The Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received. The Company's regulatory assets and liabilities will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. Management must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. Management believes it is probable that the Company's regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of SFAS No. 101, "Regulated Enterprises—Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In management's opinion, the Company's regulated subsidiaries will be subject to SFAS No. 71 for the foreseeable future.

Consolidation—In accordance with current accounting pronouncements, the Company's consolidated financial statements include the accounts of Unitil and all of its wholly-owned subsidiaries and all intercompany transactions are eliminated in consolidation. During 2003, the Company assumed the obligations of the former Unitil Retiree Trust (URT). URT was an organization of retirees, that became effective in 1993 and operated under the direction of an independent board of trustees, whose voting members were comprised of former employees of the Company. URT was dissolved in the fourth quarter of 2003, by a vote of its trustees. URT met the classification criteria as a variable interest entity (VIE) under Financial Accounting Standards Board (FASB) Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities," which requires companies to consolidate the results of entities over which it has significant control with its own results, whether or not there is a majority controlling ownership standard that is met. The Company determined it had a variable interest in URT. Further, under FIN 46, the Company is required to consolidate all entities that are considered to have a non-independent relationship with the Company and the Company is required to disclose those relationships and associated transactions in its financial statements. The Company has reviewed its investments and affiliations and, with the dissolution of URT and the assumption of the obligations of the former URT by the Company, there are no other entities identified by the Company that qualify as VIE's under FIN 46.

Utility Revenue Recognition—Regulated utility revenues are based on rates approved by state and federal regulatory commissions. These regulated rates are applied to customers' accounts based on their actual or estimated use of energy. Energy sales to customers are based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Uncollectible Accounts—The Company recognizes a Provision for Uncollectible Accounts as a percent of revenues each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Uncollectible Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. Evaluating the adequacy of the Allowance for Uncollectible Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when State regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Uncollectible Accounts to maintain an adequate Allowance for Uncollectible Accounts balance.

Pension and Postretirement Benefit Obligations—The Company has a defined benefit pension plan covering substantially all its employees and also provides certain other post-retirement benefits (OPEB), primarily medical and life insurance benefits to retired employees. The Company also has a Supplemental Executive Retirement Plan (SERP) covering certain executives of the Company. The Company accounts for these benefits in accordance with SFAS No. 87, "Employers' Accounting for Pensions" and SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions." In applying these accounting policies, the Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit cost is based on several significant assumptions. The Company's reported costs of providing pension and OPEB benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company's health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. Pension and OPEB costs (collectively "postretirement costs") are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future postretirement costs. Postretirement costs may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the postretirement costs and benefit obligations. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's consolidated financial statements. Approximately 40% of the Company's net pension expense is capitalized as capital additions to utility plant.

Pension income is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets of 8.75% for 2003 and 9.25% for 2002 and 2001. In developing the expected long-term rate of return assumption, the Company evaluated input from actuaries, bankers and investment managers. The Company's expected long-term rate of return on Plan assets is based on target asset allocation assumptions of 60% in United States equities and 40% in fixed income securities. The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.75% for 2003. The Company will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary.

The Company bases the actuarial determination of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a three-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a three-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. The Company's pension expense (income) for the years 2003, 2002 and 2001 was $1,106,827, ($166,472) and ($716,411), respectively. Had the Company used the fair value of assets instead of the market-related value, pension expense (income) for the years 2003, 2002 and 2001 would have been $2,332,699, $614,685 and ($376,777), respectively.

The discount rate that is utilized in determining future pension obligations is based on a basket of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rates used for the 2003, 2002 and 2001 fiscal years were 7.00%, 7.25% and 7.75%, respectively. For 2003, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $150 thousand in the Net Periodic Pension Cost. Similarly, for 2001 and 2002, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $50 thousand in the Net Periodic Pension Cost. The effect of a change in discount rates for 2003 would have been greater than for 2001 and 2002 because of the significant market declines that affected 2003 pension costs. The compensation increase assumption used for 2001, 2002 and 2003 was 4% based on the expected increase in payroll for personnel covered by the Plan.

The value of the Plan assets has decreased from $40.9 million at December 31, 2001 to $39.3 million at December 31, 2003. The investment performance returns and declining discount rates have reduced the funded status of the Plan on a projected benefit obligation (PBO) basis from an over funded position of $2.0 million at December 31, 2001 to an under funded position of $8.0 million at December 31, 2003. The PBO includes expectations of future employee service and compensation increases. The Company contributed $1.2 million to the Plan in 2003. Future funding requirements are heavily dependent on actual return on plan assets. Therefore, if the actual return on plan assets continues to be significantly below the expected returns, we may elect to fund the pension plans in future periods. The accumulated benefit obligation (ABO) of the Plan was $1.3 million higher than Plan assets at December 31, 2003. The ABO is the obligation for employee service provided through December 31, 2003. The significant deterioration in the funded position of the Plan will likely result in Plan contributions sooner than previously expected. This deterioration has also led to the requirement under defined benefit plan accounting to record an additional minimum liability of $1.3 million.

The Company has been allowed by its State regulators to record a regulatory asset for $1.3 million to cover the unfunded ABO because the recording of pension expense and the collection of those expenses in rates occurs in different time periods. SFAS 71 allows for the deferral of expenses and income on the consolidated balance sheet as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate setting process in a period different from the period in which they would have been reflected in the consolidated statements of income. These deferred regulatory assets and liabilities are then recognized in the consolidated statement of income in the period in which the amounts are reflected in rates.

Income Taxes—Income tax expense is calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's actual current tax liabilities as well as assessing temporary differences resulting from differing treatment of items, such as timing of the deduction of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. The Company must also assess the likelihood that the deferred tax assets will be recovered from future taxable income, and to the extent that recovery is not likely, a valuation allowance must be established. Significant management judgment is required in determining income tax expense, deferred tax assets and liabilities and valuation allowances. The Company accounts for deferred taxes under SFAS No. 109, "Accounting for Income Taxes." The Company does not currently have any valuation allowances against its recorded deferred tax amounts.

Depreciation—Depreciation expense is calculated based on an asset's useful life, and judgment is involved when estimating the useful lives of certain assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5, "Accounting for Contingencies." SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2003, the Company is not aware of any material commitments or contingencies other than those disclosed in the Significant Contractual Obligations table in the Capital Requirements and Liquidity section above and the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Refer to "Recently Issued Accounting Pronouncements' in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

For further information regarding these types of activities, see Note 1, "Summary of Significant Accounting Policies," Note 8, "Income Taxes," Note 5, "Energy Supply," Note 9, "Benefit Plans," and Note 6, "Commitment and Contingencies," to the consolidated financial statements.

Forward-Looking Information

This report and the documents we incorporate by reference into this report contain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Company's future operations, are forward-looking statements.

These statements include declarations regarding Management's beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

- Variations in weather;
- Changes in the regulatory environment;
- Customers' preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions;
- Increased competition; and
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities.

Many of these risks are beyond the Company's control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 8. Financial Statements and Supplementary Data

Report of Independent Certified Public Accountants

To the Shareholders of Unitil Corporation:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Unitil Corporation and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of earnings, cash flows and changes in common stock equity for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Unitil Corporation and subsidiaries as of December 31, 2003 and 2002, and the consolidated results of their operations and their consolidated cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Boston, Massachusetts
February 6, 2004

CONSOLIDATED STATEMENTS OF EARNINGS

(000's, except common shares and per share data)

Year Ended December 31,	2003	2002	2001
Operating Revenues:			
Electric	**$ 190,864**	$ 167,317	$ 183,780
Gas	**28,612**	20,283	22,828
Other	**1,178**	786	414
Total Operating Revenues	**220,654**	188,386	207,022
Operating Expenses:			
Purchased Electricity	**134,575**	117,409	134,660
Purchased Gas	**17,421**	12,304	15,184
Operation and Maintenance	**22,167**	19,924	20,201
Conservation & Load Management	**3,930**	1,771	1,729
Restructuring Charge	**—**	1,598	—
Depreciation and Amortization	**18,756**	14,911	12,767
Provisions for Taxes:			
Local Property and Other	**4,805**	4,731	4,666
Federal and State Income	**3,551**	2,490	3,421
Total Operating Expenses	**205,205**	175,138	192,628
Operating Income	**15,449**	13,248	14,394
Sale of Non-Utility Investments, net of tax	**—**	(82)	2,400
Other Non-Operating Expenses	**(40)**	185	170
Income Before Interest Expense and Extraordinary Item	**15,489**	13,145	11,824
Interest Expense, net	**7,531**	7,057	6,797
Income before Extraordinary Item	**7,958**	6,088	5,027
Extraordinary Item, net of tax	**—**	—	3,937
Net Income	**7,958**	6,088	1,090
Less Dividends on Preferred Stock	**236**	253	257
Earnings Applicable to Common Shareholders	**$ 7,722**	$ 5,835	$ 833
Average Common Shares Outstanding—Basic	**4,877,933**	4,743,696	4,743,576
Average Common Shares Outstanding—Diluted	**4,899,488**	4,762,166	4,759,822
Earnings per Common Share			
Income before Extraordinary Item	**$ 1.58**	$ 1.23	$ 1.01
Extraordinary Item, net of tax	**—**	—	(0.83)
Net Income	**$ 1.58**	$ 1.23	$ 0.18

(The accompanying Notes are an integral part of these financial statements.)

CONSOLIDATED BALANCE SHEETS (000'S)

ASSETS

December 31,	2003	2002
Utility Plant:		
Electric	**$209,288**	$193,152
Gas	**48,700**	44,796
Common	**27,441**	28,796
Construction Work in Progress	**3,228**	5,658
Utility Plant	**288,657**	272,402
Less: Accumulated Depreciation	**93,592**	83,201
Net Utility Plant	**195,065**	189,201
Current Assets:		
Cash	**3,766**	7,160
Accounts Receivable—Net of Allowance for Doubtful Accounts of $541 and $434	**17,461**	19,513
Accrued Revenue	**10,029**	4,842
Refundable Taxes	**3,816**	4,851
Material and Supplies	**2,861**	2,323
Prepayments and Other	**6,146**	1,735
Total Current Assets	**44,079**	40,424
Noncurrent Assets:		
Regulatory Assets	**227,528**	234,051
Prepaid Pension	**10,972**	10,879
Debt Issuance Costs, net	**1,844**	1,755
Other Noncurrent Assets	**4,389**	5,392
Total Noncurrent Assets	**244,733**	252,077
TOTAL	**$483,877**	$481,702

(The accompanying Notes are an integral part of these financial statements.)

*CONSOLIDATED BALANCE SHEETS **(cont.)** (000'S)*

CAPITALIZATION AND LIABILITIES

December 31,	2003	2002
Capitalization:		
Common Stock Equity	**$ 92,805**	$ 74,350
Preferred Stock, Non-Redeemable, Non-Cumulative	**225**	225
Preferred Stock, Redeemable, Cumulative	**3,044**	3,097
Long-Term Debt, Less Current Portion	**110,961**	104,226
Total Capitalization	**207,035**	181,898
Current Liabilities:		
Long-Term Debt, Current Portion	**3,263**	3,243
Capitalized Leases, Current Portion	**567**	800
Accounts Payable	**15,024**	14,221
Short-Term Debt	**22,410**	35,990
Dividends Declared and Payable	**70**	77
Refundable Customer Deposits	**1,429**	1,336
Interest Payable	**1,356**	1,311
Other Current Liabilities	**4,254**	9,062
Total Current Liabilities	**48,373**	66,040
Deferred Income Taxes	**56,900**	52,294
Noncurrent Liabilities:		
Power Supply Contract Obligations	**167,341**	175,657
Capitalized Leases, Less Current Portion	**403**	2,534
Other Noncurrent Liabilities	**3,825**	3,279
Total Noncurrent Liabilities	**171,569**	181,470
TOTAL	**$483,877**	$481,702

(The accompanying Notes are an integral part of these financial statements.)

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(000's except number of shares and par value)

December 31,	2003	2002
Common Stock Equity		
Common Stock, No Par Value (Authorized—8,000,000 shares; Outstanding—5,500,610 and 4,743,696 shares)	**$ 58,848**	$ 41,220
Stock Compensation Plans	**908**	990
Retained Earnings	**33,049**	32,140
Total Common Stock Equity	**92,805**	74,350
Preferred Stock		
UES Preferred Stock, Non-Redeemable, Non-Cumulative:		
6.00% Series, $100 Par Value	**225**	225
UES Preferred Stock, Redeemable, Cumulative:		
8.70% Series, $100 Par Value	**215**	215
8.75% Series, $100 Par Value	**314**	333
8.25% Series, $100 Par Value	**375**	385
FG&E Preferred Stock, Redeemable, Cumulative:		
5.125% Series, $100 Par Value	**922**	946
8.00% Series, $100 Par Value	**1,218**	1,218
Total Preferred Stock	**3,269**	3,322
Long-Term Debt		
UES First Mortgage Bonds:		
8.49% Series, Due October 14, 2024	**15,000**	15,000
6.96% Series, Due September 1, 2028	**20,000**	20,000
8.00% Series, Due May 1, 2031	**15,000**	15,000
FG&E Long-Term Notes:		
8.55% Notes, Due March 31, 2004	**3,000**	6,000
6.75% Notes, Due November 30, 2023	**19,000**	19,000
7.37% Notes, Due January 15, 2029	**12,000**	12,000
7.98% Notes, Due June 1, 2031	**14,000**	14,000
6.79% Notes, Due October 15, 2025	**10,000**	—
Unitil Realty Corp. Senior Secured Notes:		
8.00% Notes, Due August 1, 2017	**6,224**	6,469
Total Long-Term Debt	**114,224**	107,469
Less: Long-Term Debt, Current Portion	**3,263**	3,243
Total Long-Term Debt, Less Current Portion	**110,961**	104,226
Total Capitalization	**$207,035**	$181,898

(The accompanying Notes are an integral part of these financial statements.)

CONSOLIDATED STATEMENTS OF CASH FLOWS *(000's)*

Year Ended December 31,	2003	2002	2001
Operating Activities:			
Net Income	**$ 7,958**	$ 6,088	$ 1,090
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation and Amortization	**18,756**	14,911	12,767
Deferred Tax Provision	**6,375**	856	(607)
(Gain) Loss on Sale of Investments, net	**—**	(82)	2,400
Changes in Current Assets and Liabilities:			
Accounts Receivable	**2,052**	(2,380)	2,924
Accrued Revenue	**(6,795)**	(3,512)	7,973
Refundable Taxes	**1,035**	(2,419)	(452)
Materials and Supplies	**(538)**	481	50
Prepayments and Other	**(4,411)**	154	(572)
Accounts Payable	**803**	(5,863)	1,545
Refundable Customer Deposits	**93**	(57)	141
Interest Payable	**45**	(64)	225
Other Current Liabilities	**(4,808)**	2,734	(49)
Deferred Restructuring Charges	**(6,058)**	(4,523)	(1,101)
Other, net	**1,114**	3,244	(3,156)
Cash Provided by Operating Activities	**15,621**	9,568	23,178
Investing Activities:			
Property, Plant and Equipment Additions	**(21,939)**	(20,825)	(19,890)
Proceeds from the Sale of Electric Generation Assets	**—**	—	342
Proceeds from the Sale of Investments	**—**	1,535	—
Cash Used In Investing Activities	**(21,939)**	(19,290)	(19,548)
Financing Activities:			
Proceeds from (Repayment of) Short-Term Debt	**(13,580)**	22,190	(18,700)
Issuance of Long-Term Debt	**10,000**	—	29,000
Repayment of Long-Term Debt	**(3,244)**	(3,225)	(3,208)
Retirement of Preferred Stock	**(53)**	(293)	(81)
Dividends Paid	**(7,056)**	(6,831)	(6,902)
Issuance of Common Stock	**17,628**	—	229
Repayment of Capital Lease Obligations	**(771)**	(1,035)	(952)
Cash Provided by (Used In) Financing Activities	**2,924**	10,806	(614)
Net Increase (Decrease) in Cash	**(3,394)**	1,084	3,016
Cash at Beginning of Year	**7,160**	6,076	3,060
Cash at End of Year	**$ 3,766**	$ 7,160	$ 6,076
Supplemental Information:			
Interest Paid	**$ 9,113**	$ 9,356	$ 8,988
Income Taxes Paid (Refunded)	**$ (2,541)**	$ 2,351	$ 4,265
Supplemental Schedule of Noncash Activities:			
Capital Leases Incurred	**$ 109**	$ 436	$ 691

(The accompanying Notes are an integral part of these financial statements.)

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(000's except number of shares)

	Common Shares	Stock Compensation Plans	Retained Earnings	Total
Balance at January 1, 2001	$40,991	$376	$38,568	**$79,935**
Net Income after Extraordinary Item for 2001			1,090	**1,090**
Dividends on Preferred Shares			(257)	**(257)**
Dividends on Common Shares			(6,544)	**(6,544)**
Stock Compensation Plans		293		**293**
Issuance of 11,279 Common Shares	287			**287**
Re-acquired and Retired Common Shares	(58)			**(58)**
Balance at December 31, 2001	41,220	669	32,857	**74,746**
Net Income for 2002			6,088	**6,088**
Dividends on Preferred Shares			(253)	**(253)**
Dividends on Common Shares			(6,546)	**(6,546)**
Stock Compensation Plans		321		**321**
Redemption Premium on Preferred Shares			(6)	**(6)**
Balance at December 31, 2002	41,220	990	32,140	**74,350**
Net Income for 2003			7,958	**7,958**
Dividends on Preferred Shares			(236)	**(236)**
Dividends on Common Shares			(6,813)	**(6,813)**
Stock Compensation Plans		(82)		**(82)**
Common Stock Offering—717,600 Shares	16,911			**16,911**
Issuance of 28,714 Common Shares	717			**717**
Balance at December 31, 2003	$58,848	$908	$33,049	**$92,805**

(The accompanying Notes are an integral part of these financial statements.)

Note 1: Summary of Significant Accounting Policies

Nature of Operations—Unitil Corporation (Unitil or the Company) is registered with the Securities and Exchange Commission (SEC) as a public utility holding company under the Public Utility Holding Company Act of 1935 (PUCHA). The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES) (formed in 2002 by the combination and merger of Unitil's former utility subsidiaries Concord Electric Company (CECo) and Exeter & Hampton Electric Company (E&H)), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil's principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company's two wholly-owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES' customers.

Unitil also has three wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Realty owns and manages the Company's corporate office building and property located in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Resources is the Company's wholly-owned unregulated subsidiary that provides energy brokering, consulting and management related services. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides energy brokering services, as well as various energy consulting services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation

Principles of Consolidation—In accordance with current accounting pronouncements, the Company's consolidated financial statements include the accounts of Unitil and all of its wholly-owned subsidiaries and all intercompany transactions are eliminated in consolidation. During 2003, the Company assumed the obligations of the former Unitil Retiree Trust (URT). URT was an organization of retirees, that became effective in 1993 and operated under the direction of an independent board of trustees, whose voting members were comprised of former employees of the Company. URT was dissolved in the fourth quarter of 2003, by a vote of its trustees. URT met the classification criteria as a variable interest entity (VIE) under Financial Accounting Standards Board (FASB) Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities," which requires companies to consolidate the results of entities over which it has significant control with its own results, whether or not there is a majority controlling ownership standard that is met. The Company determined it had a variable interest in URT. Further, under FIN 46, the Company is required to consolidate all entities that are considered to have a non-independent relationship with the Company and the Company is required to disclose those relationships and associated transactions in its financial statements. The Company has reviewed its investments and affiliations and, with the dissolution of URT and the assumption of the obligations of the former URT by the Company, there are no other entities identified by the Company that qualify as VIE's under FIN 46.

Regulatory Accounting—The Company's principal business is the distribution of electricity and natural gas in the Company-owned retail distribution utilities: FG&E and UES. Both FG&E and UES are subject to regulation by the Federal Energy Regulatory Commission (FERC) and FG&E is regulated by the Massachusetts Department of Telecommunications and Energy (MDTE) and UES is regulated by the New Hampshire Public Utilities Commission (NHPUC). Accordingly, the Company uses the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered in future electric and gas retail rates.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or "regulatory assets" under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or "regulatory liabilities" under SFAS No. 71.

The Company's principal regulatory assets and liabilities are detailed on the Company's Consolidated Balance Sheet and a summary of the Company's Regulatory Assets is provided below. The Company is currently receiving or being credited with a return on all of its regulatory assets for which a cash outflow has been made. The Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received. The Company's regulatory assets and liabilities will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. Management must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. Management believes it is probable that the Company's regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

	December 31,	
Regulatory Assets consist of the following (000's)	**2003**	**2002**
Power Supply Buyout Obligations	**$167,341**	$175,657
Income Taxes	**22,507**	24,799
Recoverable Deferred Charges	**28,311**	22,253
Recoverable Generation-related Assets	**7,291**	9,327
Pension / Post-retirement Benefits Other than Pension	**2,078**	2,015
Total Regulatory Assets	**$227,528**	$234,051

Massachusetts and New Hampshire have both passed utility industry restructuring legislation and the Company has filed and implemented its restructuring plans in both states. In Massachusetts, the Company is allowed to recover certain types of costs through ongoing assessments to be included in future regulated service rates. The Company is also deferring the recovery of certain restructuring related costs in order to meet the retail rate cap imposed under the Massachusetts restructuring legislation. Based on the recovery mechanism that allows recovery of all of its stranded costs and deferred costs related to restructuring, the Company has recorded regulatory assets that it expects to fully recover in future periods. The Company expects to continue to meet the criteria for the application of SFAS No. 71 for the distribution portion of its assets and operations for the foreseeable future. If a change in accounting were to occur to the distribution portion of the Company's operations, it could have a material adverse effect on the Company's earnings and retained earnings in that year and could have a material adverse effect on the Company's ongoing financial condition as well.

On January 25, 2002, the Company's New Hampshire electric utility subsidiaries, CECo, E&H and Unitil Power, filed a comprehensive restructuring proposal with the NHPUC. This proposal included the introduction of customer choice consistent with the New Hampshire restructuring law, the divestiture of Unitil Power's power supply portfolio, the recovery of stranded costs, the combination of CECo and E&H into a planned successor, UES, and new distribution rates for UES. On October 25, 2002, the NHPUC approved a multi-party settlement on all major issues in the proceeding. Under Unitil's approved restructuring plan, Unitil divested its existing New Hampshire power supply portfolio and conducted a solicitation for new power supplies from which to meet its ongoing transition and default service energy obligations. In early 2003, Unitil filed for final NHPUC approval of the executed agreements resulting from these divestiture and solicitation processes, including final tariffs for stranded cost recovery and transition and default services. The implementation of customer choice occurred on May 1, 2003.

Upon receipt of all requested approvals in the proceeding by the NHPUC, and the expiration of all periods of appeal with respect thereto, UES implemented retail choice and Unitil withdrew its intervention in a pending federal court action, with prejudice. In June 1997, Unitil and other utilities in NH intervened as plaintiffs in a suit filed in U.S. District Court by Northeast Utilities' affiliate Public Service Company of New Hampshire for protection from the NHPUC Final Plan to restructure the New Hampshire electric utility industry. Although the NHPUC found that UES' predecessor companies, CECo and E&H, were entitled to full interim stranded costs recovery, the NHPUC also made certain legal rulings that, if implemented, could affect the Company's long-term ability to recover all of their stranded costs. The Unitil Settlement approved in October 2002, provides for full stranded cost recovery by UES, and otherwise resolves all of the issues in the federal court action.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of SFAS No. 101, "Regulated Enterprises—Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71." In management's opinion, the Company's regulated subsidiaries will be subject to SFAS No. 71 for the foreseeable future.

Cash—Cash includes all cash and cash equivalents to which the Company has legal title. Cash equivalents include short-term investments with original maturities of three months or less and interest bearing deposits.

Goodwill and Intangible Assets—The Company does not have any goodwill recorded on its balance sheet as of December 31, 2003. There are no significant intangible assets recorded by the Company at December 31, 2003. Therefore, the Company is not currently involved in making estimates or seeking valuations of these items.

Off-Balance Sheet Arrangements—As of December 31, 2003, the Company does not have any significant arrangements that would be classified as Off-Balance Sheet Arrangements. In the ordinary course of business, the Company does contract for certain office and other equipment under operating leases and, in management's opinion, the amount of these transactions is not material.

Investments and Trading Activities—During the year, the Company does invest in U.S. Treasuries and short-term investments which traditionally have very little fluctuation in fair value. The Company does not engage in investing or trading activities involving non-exchange traded contracts or other instruments where a periodic analysis of fair value would be required for book accounting purposes.

Utility Revenue Recognition—Regulated utility revenues are based on rates approved by federal and state regulatory commissions. These regulated rates are applied to customers' accounts based on their actual or estimated use of energy. Energy sales to customers are based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Revenue Recognition–Non-regulated Operations—Usource, Unitil's competitive energy brokering subsidiary, records energy brokering revenues based upon the estimated amount of electricity and gas delivered to customers through the end of the accounting period.

Allowance for Uncollectible Accounts—The Company recognizes a Provision for Uncollectible Accounts as a percent of revenues each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Uncollectible Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. Evaluating the adequacy of the Allowance for Uncollectible Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when State regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Uncollectible Accounts to maintain an adequate Allowance for Uncollectible Accounts balance.

Pension and Postretirement Benefit Obligations—The Company has a defined benefit pension plan covering substantially all its employees and also provides certain other post-retirement benefits (OPEB), primarily medical and life insurance benefits to retired employees. The Company also has a Supplemental Executive Retirement Plan (SERP) covering certain executives of the Company. The Company accounts for these benefits in accordance with SFAS No. 87, "Employers' Accounting for Pensions" and SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions." In applying these accounting policies, the Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit cost is based on several significant assumptions. The Company's reported costs of providing pension and OPEB benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company's health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. Pension and OPEB costs (collectively "postretirement costs") are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future postretirement costs. Postretirement costs may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the postretirement costs and benefit obligations. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company's consolidated financial statements. Approximately 40% of the Company's net pension expense is capitalized as capital additions to utility plant.

Pension income is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets of 8.75% for 2003 and 9.25% for 2002 and 2001. In developing the expected long-term rate of return assumption, the Company evaluated input from actuaries, bankers and investment managers. The Company's expected long-term rate of return on Plan assets is based on target asset allocation assumptions of 60% in United States equities and 40% in fixed income securities. The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.75% for 2003. The Company will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary.

The Company bases the actuarial determination of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a three-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a three-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. The Company's pension expense (income) for the years 2003, 2002 and 2001 was $1,106,827, ($166,472) and ($716,411), respectively. Had the Company used the fair value of assets instead of the market-related value, pension expense (income) for the years 2003, 2002 and 2001 would have been $2,332,699, $614,685 and ($376,777), respectively.

The discount rate that is utilized in determining future pension obligations is based on a basket of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rates used for the 2003, 2002 and 2001 fiscal years were 7.00%, 7.25% and 7.75%, respectively. For 2003, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $150 thousand in the Net Periodic Pension Cost. Similarly, for 2001 and 2002, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $50 thousand in the Net Periodic Pension Cost. The effect of a change in discount rates for 2003 would have been greater than for 2001 and 2002 because of the significant market declines that affected 2003 pension costs. The compensation increase assumption used for 2001, 2002 and 2003 was 4% based on the expected increase in payroll for personnel covered by the Plan.

The value of the Plan assets has decreased from $40.9 million at December 31, 2001 to $39.3 million at December 31, 2003. The investment performance returns and declining discount rates have reduced the funded status of the Plan on a projected benefit obligation (PBO) basis from an over funded position of $2.0 million at December 31, 2001 to an under funded position of $8.0 million at December 31, 2003. The PBO includes expectations of future employee service and compensation increases. The Company contributed $1.2 million to the Plan in 2003. Future funding requirements are heavily dependent on the actual return on plan assets. Therefore, if the actual return on plan assets continues to be significantly below the expected returns, we may elect to fund the pension plans in future periods. The accumulated benefit obligation (ABO) of the Plan was $1.3 million higher than Plan assets at December 31, 2003. The ABO is the obligation for employee service provided through December 31, 2003. The significant deterioration in the funded position of the Plan will likely result in Plan contributions sooner than previously expected. This deterioration has also led to the requirement under defined benefit plan accounting to record an additional minimum liability of $1.3 million.

The Company has been allowed by its State regulators to record a regulatory asset for $1.3 million to cover the unfunded ABO because the recording of pension expense and the collection of those expenses in rates occurs in different time periods. SFAS 71 allows for the deferral of expenses and income on the consolidated balance sheet as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate setting process in a period different from the period in which they would have been reflected in the consolidated statements of income. These deferred regulatory assets and liabilities are then recognized in the consolidated statement of income in the period in which the amounts are reflected in rates.

Use of Estimates—The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and requires disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Commitments and Contingencies—The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with SFAS No. 5, "Accounting for Contingencies." SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2003, the Company is not aware of any material commitments or contingencies other than those disclosed in the Significant Contractual Obligations table in the Capital Requirements and Liquidity section above and the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Utility Plant—The cost of additions to Utility Plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The average interest rates applied to AFUDC were 2.14%, 3.48% and 5.37% in 2003, 2002 and 2001, respectively. The costs of current repairs and minor replacements are charged to appropriate operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. The Company does not account separately for negative salvage, or cost of retirement obligations as defined in SFAS No. 143, "Accounting for Asset Retirement Obligations", discussed in more detail below in "Recently Issued Pronouncements". The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, depreciation amounts to provide for future negative salvage value. At December 31, 2003 and December 31, 2002, the Company estimates that the negative salvage value of future retirements recorded on the balance sheet in Accumulated Depreciation is $12.2 million and $11.2 million, respectively.

Depreciation and Amortization—Depreciation expense is calculated based on an asset's useful life, and judgment is involved when estimating the useful lives of certain assets. A change in the estimated useful lives of these assets could have a material impact on the Company's consolidated financial statements. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets.

Depreciation provisions for Unitil's utility operating subsidiaries are determined on a group straight-line basis. Provisions for depreciation were equivalent to the following composite rates, based on the average depreciable property balances at the beginning and end of each year: 2003—4.73%, 2002—3.79% and 2001—3.75%.

Amortization provisions include the recovery of a portion of FG&E's former investment in Seabrook Station, a nuclear generating unit, in rates to its customers through the Seabrook Amortization Surcharge as ordered by the MDTE. In addition, FG&E is amortizing the balance of its unrecovered electric generating related assets, which are recorded as Regulatory Assets, in accordance with its electric restructuring plan approved by the MDTE (See Note 6).

Environmental Matters—The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company has recently performed work on two environmental remediation projects, the Sawyer Passway MGP Site and the Former Electric Generating Station. The Company has or will recover substantially all of the cost of the work performed to date from customers or from its insurance carriers. The Company is in general compliance with all applicable environmental and safety laws and regulations, and management believes that as of December 31, 2003, there are no material losses that would require additional liability reserves to be recorded. Changes in future environmental compliance regulations or in future cost estimates of environmental remediation costs could have a material effect on the Company's financial position if those amounts are not recoverable in regulatory rate mechanisms.

Stock-based Employee Compensation—Unitil accounts for stock-based employee compensation currently using the fair value based method (See Note 3).

Income Taxes—Income tax expense is calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's actual current tax liabilities as well as assessing temporary differences resulting from differing treatment of items, such as timing of the deduction of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. The Company must also assess the likelihood that the deferred tax assets will be recovered from future taxable income, and to the extent that recovery is not likely, a valuation allowance must be established. Significant management judgment is required in determining income tax expense, deferred tax assets and liabilities and valuation allowances. The Company accounts for deferred taxes under SFAS No. 109, "Accounting for Income Taxes." The Company does not currently have any valuation allowances against its recorded deferred tax amounts.

Dividends—The Company is currently paying a dividend at an annual rate of $1.38 per common share. The Company's dividend policy is reviewed annually by the Board of Directors. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

Recently Issued Pronouncements—In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which establishes new accounting and reporting standards for legal obligations associated with retiring tangible long-lived assets. The fair value of a liability for an asset retirement obligation must be recorded in the period in which it is incurred, with the cost capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company currently accounts for all of the costs of its long lived-assets, including the cost of removal to replace these assets, in accordance with guidelines published by the FERC for Utility plant accounting. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. Consistent with regulatory utility accounting guidance, the Company does not account separately for negative salvage, or cost of retirement obligations as defined in SFAS No. 143. The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, depreciation amounts to provide for future negative salvage value.

The Company owns and maintains local utility distribution systems and assets. The Company has not identified any material legal obligations associated with the operational retirement and replacement of its distribution property, plant and equipment which would require recording a liability for an Asset Retirement Obligation as defined in SFAS No. 143. The cost of removal that the Company is allowed to recover in its rates relates to removal cost estimates used for mass asset accounting for the various functional components of its local distribution system. Those removal costs are not asset specific and do not rise to the level of legal obligations as defined in SFAS No. 143. The Company has effectively divested of its ownership interest in generation facilities and has no ownership interest in nuclear power plants, and has no decommissioning obligations. At December 31, 2003 and December 31, 2002, Management estimates that the negative salvage value of future retirements recorded on the balance sheet in Accumulated Depreciation is $12.2 million and $11.2 million, respectively.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002. The Company initiated a reorganization of management and administrative positions in the fourth quarter of 2002 and recognized a Restructuring Charge, discussed below, under the provisions of Emerging Issues Task Force (EITF) Issue No. 94-3, the predecessor standard to SFAS 146.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure." SFAS No. 148 amends SFAS No. 123, "Accounting for Stock-Based Compensation" to provide alternative methods of transition for a voluntary change to the fair value-based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of

SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method on reported results. The Company recognizes compensation cost at fair value at the date of grant.

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities" and in December 2003 issued a revised FIN 46. This interpretation clarifies the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," and replaces the current accounting guidance relating to the consolidation of certain special purpose entities (SPE's). FIN 46 requires identification of the Company's participation in variable interest entities (VIE's) established on the basis of contractual, ownership or other monetary interests. A VIE is defined as an entity in which the equity investors do not have a controlling interest and the equity investment at risk is insufficient to fund future activities to permit the VIE to operate on a stand alone basis without receiving additional financial support.

For entities identified as VIE's, FIN 46 sets forth a model to evaluate potential consolidation based on an assessment of which party to the VIE bears a majority of the risk to the VIE's expected losses, or stands to gain from a majority of the expected returns of the VIE. The party with the majority variable interest is considered to be the Primary Beneficiary of the VIE. As a result, entities that are deemed to be VIE's in which the Company is identified as the Primary Beneficiary were required to be consolidated beginning in July 2003. At its Board meeting on October 8, 2003, the FASB decided to defer implementation of this requirement until the fourth quarter of 2003.

The Company reviewed its investments and affiliations and determined that it had a variable interest in the Unitil Retiree Trust (URT), a special purpose entity established January 1993. URT was an organization of retirees, incorporated in 1993 to provide social, health and welfare benefits to its members, who are eligible former employees of the Company. URT was under the direction of an independent Board of Trustees whose voting members were comprised of former employees of the Company, elected by and from the membership of URT.

In the fourth quarter of 2003, URT was dissolved by a vote of its trustees and the Company assumed the obligations of URT as of October 1, 2003. At October 1, 2003, the Transition Obligation for benefits previously provided by URT was $29.2 million and this obligation is being recognized on a delayed basis over the average remaining service period of active participants, not to exceed 20 years. In addition, the Company made payments of $1.3 million, $1.2 million and $1.0 million in 2003, 2002 and 2001 respectively, to the Unitil Retiree Trust. There are no other entities identified by the Company that qualify as VIE's under FIN 46. See Note 9 for additional discussion regarding FIN 46 and the Company's accounting for Postretirement Benefits other than Pension.

In April 2003, the FASB issued Statement No. 149 (SFAS 149), "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS 149 amends and clarifies financial accounting and reporting requirements for derivative instruments, including derivative instruments embedded in other contracts, and for hedging activities under FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities." In general, SFAS 149 is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The Company has determined that adoption of this statement will not have a material impact on the Company's financial position or results of operations.

In May 2003, the FASB issued Statement No. 150 (SFAS 150), "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." SFAS 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability, or in certain instances, as an asset. SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003, otherwise SFAS 150 is generally effective with interim periods beginning after June 15, 2003. The Company's adoption of this statement does not have a material impact on the Company's financial position or results of operations.

In December 2003, the FASB issued Statement No. 132(R) (SFAS 132(R)), a revision of its original Statement No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits" (SFAS 132). SFAS 132(R) revises employers' disclosures about pension plans and other postretirement benefit plans. It does not change the measurement or recognition of those plans required by FASB Statements No. 87, "Employers' Accounting for Pensions", No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits" and No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions". SFAS 132(R) retains the disclosure requirements contained in SFAS 132 and requires additional disclosures about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. The Company has adopted this statement for the year ended December 31, 2003.

Reclassifications—Certain amounts previously reported have been reclassified to conform to current year presentation. Most significant has been the reclassification of certain expenses between Purchased Electricity, Purchased Gas and Operation and Maintenance Expenses.

Note 2: Other Items

Restructuring Charge—2002

In the fourth quarter of 2002, Unitil recognized a pre-tax Restructuring Charge of $1.6 million.

In December 2002, the Company undertook a strategic review of its business operations and committed to a formal transition and reorganization plan (the Reorganization Plan) to streamline its management structure, in order to improve operating efficiency and to align the organization to meet ongoing business requirements. The Reorganization Plan resulted in the elimination of 19 management and administrative positions. As a result of the elimination of these positions, and consistent with existing Company policy, certain benefits are extended to the employees whose positions were eliminated. On January 8, 2003, the Company implemented the Reorganization Plan. The $1.6 million pre-tax Restructuring Charge established a liability at December 31, 2002, to cover the disbursement of severance and employee benefits and related costs committed to under the Reorganization Plan, substantially all of which were paid in fiscal 2003.

Extraordinary Item—2001

In November 1997, the Massachusetts Legislature enacted the Massachusetts Electric Restructuring Act of 1997 (the Restructuring Act). The Restructuring Act required all electric utilities to file a restructuring plan with the MDTE by December 31, 1997. Among other things, the Restructuring Act resulted in the divestiture of electric generation assets and purchase power contracts, along with the restructuring of utility operations by all Massachusetts utilities to provide direct retail access to their customers by all qualified third-party energy suppliers.

The MDTE conditionally approved FG&E's Restructuring Plan (the Plan) in February 1998, and started an investigation and evidentiary hearings into FG&E's proposed recovery of Regulatory Assets related to stranded generation asset costs and expenses related to the formulation and implementation of its Plan. In January 1999, the MDTE approved FG&E's Plan, which included provisions for the recovery of stranded costs through a transition charge in FG&E's electric rates. In September 1999, FG&E filed its first annual reconciliation of stranded generation asset costs and expenses and associated transition charge revenues and the MDTE initiated a lengthy investigation and hearing process.

On October 18 and 19, 2001, the MDTE issued a series of regulatory orders in several pending cases involving FG&E, including a final order on FG&E's initial reconciliation filing. Those orders included the review and disposition of issues related to FG&E's recovery of transition costs due to the restructuring of the electric industry in Massachusetts, as well as certain costs associated with gas industry restructuring and preparation and litigation of performance based rate proceedings initiated by the MDTE. The orders determined the final treatment of Regulatory Assets that FG&E had sought to recover from its Massachusetts electric customers over a multi-year transition period that began in 1998.

As a result of the industry restructuring-related orders, FG&E recorded a non-cash adjustment to Regulatory Assets of $5.3 million, which resulted in the recognition of an extraordinary charge of $3.9 million, net of taxes. The Company recognized the extraordinary charge of $0.83 per share, as of September 30, 2001.

As a result of all of these orders, the Company has been allowed recovery of its Massachusetts industry restructuring transition costs, estimated at $150 million, after reconciliation, including the above-market or stranded generation and power supply related costs via a non-bypassable uniform transition charge. FG&E has been and will continue to be subject to annual MDTE investigation and review in order to reconcile the costs and revenues associated with the collection of transition charges from its customers over the next six to eight years.

Investment Write-down and Sale of Equity Stake in Enermetrix—2001

Beginning in 1998, Unitil invested $5.5 million in Enermetrix, Inc. (Enermetrix), an energy technology start-up enterprise. In accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities," the Company recorded a non-cash charge of $3.7 million, or $2.4 million, net of tax, in the fourth quarter of 2001 to recognize the decrease in fair value of its non-utility investment in Enermetrix.

On April 11, 2002, the Company sold its equity ownership in Enermetrix for $1.5 million in cash and improved commercial terms for use of the Enermetrix Software Network. As a result of the sale, in 2002, the Company recognized the benefit of approximately $1.3 million from this capital loss as a carryback against capital gains in its 2002 tax return and recorded a gain, net of transaction costs, on the final disposition of $82 thousand, net of tax. In total, the final "book" loss on the investment was $2.3 million, net of tax.

Note 3: Equity

The Company has both common and preferred stock outstanding. Details regarding these forms of capitalization follow below.

Common Stock

New Shares Issued—On October 29, 2003, the Company raised approximately $16.9 million (after deducting underwriting discounts and commissions and the estimated expenses of the offering) through the sale of 717,600 shares of its common stock at a price of $25.40 per share in a registered public offering. The offering was increased from an original 520,000 shares to reflect a 20% upsizing of the transaction (104,000 shares) and the exercise of a 15% underwriters' over-allotment (93,600 shares). The Company used the proceeds from this offering to make capital contributions of $6 million to UES and $6 million to FG&E and other general corporate purposes.

During 2003, the Company sold 28,714 shares of its Common Stock, at an average price of $24.97 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan (DRP) and its 401(k) plans. Net proceeds of $716,936 were used to reduce short-term borrowings. The DRP provides participants in the plan a method for investing cash dividends on the Company's Common Stock and cash payments in additional shares of the Company's Common Stock. During 2002, the Company did not issue any additional shares of its Common Stock. During 2001, the Company raised $287,142 of additional common equity through the issuance of 11,279 shares of its common stock in connection with the DRP.

Restricted Stock Plan—On April 17, 2003, the Company's shareholders ratified and approved a Restricted Stock Plan (the Plan) which had been approved by the Company's Board of Directors at its January 16, 2003 meeting. Participants in the Plan are selected by the Compensation Committee of the Board of Directors from the eligible Participants to receive an annual award of restricted shares of Company Common Stock. The Compensation Committee has the power to determine the sizes of awards; determine the terms and conditions of awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to participants; and, subject to the provisions of the Plan, amend the terms and conditions of any outstanding award to the extent such terms and conditions are within the discretion of the Compensation Committee as provided in the Plan. Awards fully vest over a period of four years at a rate of 25% each year. During the vesting period, dividends on restricted shares underlying the Award may be credited to the participant's account. Awards may be grossed up to offset the participant's tax obligations in connection with the Award. Prior to the end of the vesting period, the restricted shares are subject to forfeiture if the participant ceases to be employed by the Company other than due to the participant's death. The maximum number of shares of Restricted Stock available for awards to participants under the Plan is 177,500. The maximum aggregate number of shares of Restricted Stock that may be awarded in any one calendar year to any one participant is 20,000. In the event of any change in capitalization of the Company, the Compensation Committee is authorized to make proportionate adjustments to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kinds of shares available for awards and in the annual award limit. On May 12, 2003, 10,600 restricted shares were issued in conjunction with the Plan. The aggregate market value of the restricted stock at the date of issuance was $259,170. The compensation expense associated with the issuance of shares under the Plan is being accrued on a monthly basis over the vesting period and was $50,000 in 2003. Issuances of shares under the Plan are subject to the prior approval of the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935. The Company has applied for such approval, which it expects to obtain prior to the initial vesting of awards made in 2003, which occurs in May of 2004.

Shares Repurchased, Cancelled and Retired—During 2003 and 2002, Unitil did not repurchase, cancel and retire any of its common stock. During 2001, in conjunction with the SEC's Emergency Orders of September 14 and 21, 2001, which suspended the applicability of certain of the conditions contained in its Rule 10b-18, the Company implemented an interim Common Stock repurchase program. Under this program, the Company used its cash on hand to repurchase, cancel and retire 2,500 shares of its outstanding Common Stock at a total cost of $58,500. The SEC has since lifted its suspension of the aforementioned conditions and accordingly, the Company's interim Common Stock repurchase program is no longer in effect.

Stock-Based Compensation Plans—Unitil maintains two stock option plans, which provided for the granting of options to key employees. Details of the plan are as follows:

Unitil Corporation Key Employee Stock Option Plan—The "Unitil Corporation Key Employee Stock Option Plan" was a 10-year plan which began in March 1989. The number of shares granted under this plan, as well as the terms and conditions of each grant, were determined by the Key Employee Stock Option Plan Committee of the Board of Directors, subject to plan limitations. At December 31, 2003, 29,101 shares had been approved and were available for future issuance as dividend equivalents earned under the plan. All options granted under this plan vested upon grant. The 10-year period in which options could be granted under this plan expired in March 1999. The expiration date of the remaining outstanding options is November 3, 2007. The plan provides dividend equivalents on options granted, which are recorded at fair value as compensation expense. The total compensation expenses recorded by the Company with respect to this plan were $46,000, $43,000 and $42,000 for the years ended December 31, 2003, 2002 and 2001, respectively.

Share Option Activity of the "Unitil Corporation Key Employee Stock Option Plan" is presented in the following table:

	2003	2002	2001
Beginning Options Outstanding and Exercisable	**25,000**	25,000	25,000
Dividend Equivalents Earned—Prior Years	**7,645**	5,996	4,358
Dividend Equivalents Earned—Current Year	**1,850**	1,649	1,638
Options Exercised	**—**	—	—
Ending Options Outstanding and Exercisable	**34,495**	32,645	30,996
Weighted Average Exercise Price per Share	**$13.17**	$13.91	$14.66
Range of Option Exercise Price per Share	**$12.11-$18.28**	$12.11-$18.28	$12.11-$18.28
Weighted Average Remaining Contractual Life	**3.9 years**	4.9 years	5.9 years

Unitil Corporation 1998 Stock Option Plan—The "Unitil Corporation 1998 Stock Option Plan" became effective on December 11, 1998. The number of shares granted under this plan, as well as the terms and conditions of each grant, are determined by the Compensation Committee of the Board of Directors, subject to plan limitations. All options granted under this plan vest over a three-year period from the date of the grant, with 25% vesting on the first anniversary of the grant, 25% vesting on the second anniversary, and 50% vesting on the third anniversary. Under the terms of this plan, key employees may be granted options to purchase the Company's Common Stock at no less than 100% of the market price on the date the option is granted. All options must be exercised no later than 10 years after the date on which they were granted. The total compensation expenses recorded by the Company with respect to this plan were ($178,000), $278,000 and $251,000 for the years ended December 31, 2003, 2002 and 2001, respectively. 2003 reflects a reversal of prior compensation expense due to stock option forfeitures. This plan was terminated on January 16, 2003. The plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the plan. No further grants of option will be made under this plan.

	2003		2002		2001	
	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price
Beginning Options Outstanding	**172,500**	**$26.99**	172,500	$26.99	113,500	$27.64
Options Granted	**—**	**—**	—	—	60,000	$25.88
Options Forfeited	**(65,500)**	**$26.77**	—	—	(1,000)	$33.56
Ending Options Outstanding	**107,000**	**$27.13**	172,500	$26.99	172,500	$26.99
Options Vested and Exercisable-end of year	**107,000**	**$27.13**	100,500	$26.11	42,750	$26.15

The Company has adopted SFAS No. 123, "Accounting for Stock Based Compensation," and recognizes compensation costs at fair value at the date of grant.

The following summarizes certain data for options outstanding at December 31, 2003:

Range of Exercise Prices	Options Vested, Exercisable and Outstanding	Weighted Average Exercise Price	Remaining Contractual Life
$20.00-$24.99	34,500	$23.38	5.2 years
$25.00-$29.99	37,500	$25.88	7.1 years
$30.00-$34.99	35,000	$32.17	6.1 years
	107,000		

There were no options granted during 2003 and 2002. The weighted average fair value per share of options granted during 2001 was $4.66. The fair value of options at the date of grant was estimated using the Black-Scholes model with the following weighted average assumptions:

	2003	2002	2001
Expected Life (years)	**N/A**	N/A	10.0
Interest Rate	**N/A**	N/A	5.8%
Volatility	**N/A**	N/A	23.6%
Dividend Yield	**N/A**	N/A	5.3%

Restrictions on Retained Earnings—Unitil Corporation has no restriction on the payment of common dividends from retained earnings.

Its two retail distribution subsidiaries, UES and FG&E, do have restrictions. Under the terms of the First Mortgage Bond Indentures, UES had $11,354,000 available for the payment of cash dividends on its Common

Stock at December 31, 2003. Under the terms of long-term debt purchase agreements, FG&E had $6,081,000 of retained earnings available for the payment of cash dividends on its Common Stock at December 31, 2003. Common dividends declared by UES and FG&E are paid exclusively to Unitil Corporation.

Preferred Stock

Unitil's two distribution operating subsidiaries, UES and FG&E, have Redeemable Cumulative Preferred Stock outstanding and one subsidiary, UES, has a Non-Redeemable, Non-Cumulative Preferred Stock issue outstanding. These subsidiaries are required to offer to redeem annually a given number of shares of each series of Redeemable Cumulative Preferred Stock and to purchase such shares that shall have been tendered by holders of the respective stock. In addition, UES and FG&E may opt to redeem the Redeemable Cumulative Preferred Stock at a given redemption price, plus accrued dividends.

The aggregate purchases of Redeemable Cumulative Preferred Stock during 2003, 2002 and 2001 related to the annual redemption offer were $53,400, $34,500 and $81,000, respectively. The aggregate amount of sinking fund requirements of the Redeemable Cumulative Preferred Stock for each of the five years following 2003 are $192,000 per year.

Also, during 2002, in conjunction with the merger of E&H into CECo to form UES, the 5% and 6% series of Redeemable Cumulative Preferred Stock were fully-redeemed at par plus premiums of 2% and 3%, respectively. These redemptions and related premiums resulted in an aggregate expenditure of $258,720.

Note 4: Long-Term Debt, Credit Arrangements, Leases and Guarantees

The Company funds a portion of its operations through the issuance of long-term debt and through short-term borrowing arrangements. The Company's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their machinery and office equipment. Details regarding long-term debt, short-term debt and leases follows below.

Long-Term Debt and Interest Expense

Substantially all the property of Unitil's New Hampshire utility operating subsidiary, UES, is subject to liens of indenture under which First Mortgage bonds have been issued. All of the long-term debt of Unitil's Massachusetts utility operating subsidiary, FG&E, is issued under Unsecured Promissory Notes with negative pledge provisions. Each issue of FG&E's long-term debt ranks pari passu with its other senior unsecured long-term debt. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt.

Total aggregate amount of sinking fund payments relating to bond issues and normal scheduled long-term debt repayments amounted to $3,244,156, $3,225,444 and $3,208,000 in 2003, 2002 and 2001, respectively.

The aggregate amount of bond sinking fund requirements and normal scheduled long-term debt repayments for each of the five years following 2003 is: 2004—$3,264,421, 2005—$286,368, 2006—$310,136, 2007—$335,877 and 2008—$363,755.

On October 28, 2003, FG&E completed a $10 million private placement of long-term unsecured notes with a major insurance company. The notes have a term of 22 years and a coupon rate of 6.79%. The net proceeds were used to replace short-term indebtedness.

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. In management's opinion, the carrying value of the debt approximated its fair value at December 31, 2003 and 2002.

The Company also provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2003, there are $2.0 million of guarantees outstanding and these guarantees extend through October 21, 2005.

The agreements under which the long-term debt of Unitil's two principal subsidiaries, UES and FG&E, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations, as described below.

UES utilizes a First Mortgage Bond (FMB) structure of long-term debt. In order to issue new FMB securities, the customary covenants of the existing UES Indenture Agreement must be met, including that UES have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The UES agreements further require that if UES defaults on any UES FMB securities, it would constitute a default for all UES FMB securities. The UES default provisions are not triggered by the actions or defaults of other companies in the Unitil System.

FG&E utilizes a debenture structure of long-term debt. Accordingly, in order for FG&E to issue new long-term debt, the covenants of the existing long-term agreements must be satisfied, including that FG&E have total funded indebtedness less than 65% of total capitalization and earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the UES agreements, FG&E agreements require that if FG&E defaults on any FG&E long-term debt agreement, it would constitute a default under all FG&E long-term debt agreements. The FG&E default provisions are not triggered by the actions or defaults of other companies in the Unitil System.

Both the UES and FG&E instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into or to sell or otherwise dispose of all or substantially all of its assets.

Interest Expense, net—Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest paid on long-term debt and interest paid on regulatory liabilities. Interest income is mainly derived from carrying charges on restructuring related stranded costs and other deferred costs recorded as regulatory assets by the Company's retail distribution utilities as approved by regulators in New Hampshire and Massachusetts. Over the long run, as deferred costs are recovered through rates, the interest costs associated with these deferrals are expected to decrease together with a decrease in interest income. A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (000's)	2003	2002	2001
Interest Expense			
Long-term Debt	**$ 8,170**	$ 8,336	$ 7,708
Short-term Debt	**1,071**	1,037	1,484
Subtotal Interest Expense	**9,241**	9,373	9,192
Interest Income			
Regulatory Assets	**(1,657)**	(2,090)	(1,952)
AFUDC	**(46)**	(52)	(61)
Other	**(7)**	(174)	(382)
Subtotal Interest Income	**(1,710)**	(2,316)	(2,395)
Total Interest Expense, net	**$ 7,531**	$ 7,057	$ 6,797

Credit Arrangements

At December 31, 2003, Unitil had unsecured committed bank lines for short-term debt in the aggregate amount of $52.0 million with three banks for which it pays commitment fees. The weighted average interest rates on all short-term borrowings were 1.78%, 2.18% and 4.78% during 2003, 2002 and 2001, respectively.

Leases

Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their machinery and office equipment. FG&E had a 22-year facility lease in which the Primary Term was scheduled to end on January 31, 2003. On February 1, 2003, a 10-year Extended Term commenced extending the lease term through January 31, 2013. Furthermore, the amended lease agreement allows for three additional five-year renewal periods at the option of FG&E. This lease, as well as other leases for equipment used by Unitil's subsidiaries, is recorded as an operating lease. In prior years, this lease was classified as a capital lease. The change in classification was the result of the renegotiation of the lease terms described above.

The following is a schedule of the leased property under capital leases by major classes:

	Asset Balances at December 31,	
Classes of Utility Plant (000's)	**2003**	**2002**
Common Plant	**$3,443**	$7,095
Less: Accumulated Depreciation	**2,507**	3,761
Net Plant	**$ 936**	$3,334

The following is a schedule by years of future minimum lease payments and present value of net minimum lease payments under capital leases, as of December 31, 2003:

Year Ending December 31 (000's)	
2004	$ 616
2005	355
2006	53
2007	10
2008	8
2009-2013	8
Total Minimum Lease Payments	$1,050
Less: Amount Representing Interest	114
Present Value of Net Minimum Lease Payments	$ 936

Total rental expense charged to operations for the years ended December 31, 2003, 2002 and 2001 amounted to $294,000, $4,000 and $12,000, respectively.

The following is a schedule by years of material future operating lease payment obligations as of December 31, 2003:

Year Ending December 31 (000's)	
2004	$ 270
2005	270
2006	270
2007	270
2008	270
2009-2013	1,102
Total Material Future Operating Lease Payments	$2,452

Guarantees

The Company also provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2003 there are $2.0 million of guarantees outstanding and these guarantees extend through October 21, 2005.

Note 5: Energy Supply

Electricity Supply:

Wyman Unit No. IV—FG&E continues to have a 0.1822% non-operating ownership interest in the Wyman Unit No. IV, an oil-fired electric generating station located in Yarmouth, Maine ("Wyman IV"). The lead operating owner of Wyman IV is FPL Energy Wyman IV, LLC. In accordance with the Massachusetts Restructuring Act, and pursuant to the generation assets and power supply divestiture process discussed below, FG&E effectively divested its economic interest in Wyman IV when it entered into an agreement to, among other things, sell its entire entitlement in the output from Wyman IV over the expected remaining operating life of the unit. Kilowatt-hour generation and operating expenses associated with Wyman IV are divided on the same basis as ownership. FG&E's proportionate ownership costs in Wyman IV are reflected in the Consolidated Statements of Earnings. Revenues from the entitlement sale of Wyman IV reflect a matching and collection of these costs. Accordingly, the cost associated with FG&E's ownership in Wyman IV does not have a material impact on net income.

Information with respect to FG&E's ownership in Wyman Unit No. IV, at December 31, 2003, is shown below:

Joint Ownership Unit	State	Proportionate Ownership	Share of Total MW	Company's Net Book Value (000's)
Wyman Unit No. IV	ME	0.1822%	1.13	$61

Energy Resources—In connection with industry restructuring and the implementation of retail choice in New Hampshire and Massachusetts, FG&E and Unitil Power have effectively divested their long-term power supply contracts and the owned generation assets of FG&E. Unitil Power divested its long-term power supply contracts to a subsidiary of Mirant Corporation, Mirant Americas Energy Marketing, LP (Mirant), which was approved by the NHPUC on March 14, 2003. The NHPUC Order completed the state approval process for Unitil's restructuring plan under which UES implemented customer choice for its customers on May 1, 2003. Total annual costs under these contracts are included in Purchased Electricity Supply in the Consolidated Statements of Earnings.

FG&E divested its owned generation assets and long-term power supply contracts to Select Energy, Inc. (Select Energy), a subsidiary of Northeast Utilities. Under the Select Energy contract, which was approved by the MDTE in January 2000, and went into effect February 1, 2000, FG&E began selling the entire output from its remaining long-term power supply contracts and the output of its two joint ownership units to Select Energy. Upon the sale of FG&E's share of Millstone Unit 3 in 2001, this portion of the contract sale ceased.

Although UES's and FG&E's electric customers have the option of contracting directly for their electricity needs with third-party suppliers, both companies remain the default service provider for their respective customers. Accordingly, UES and FG&E contract with wholesale power suppliers for the electricity necessary to meet their regulated energy supply obligations, which are provided through Standard Offer Service and Default Service in Massachusetts and Transition Service and Default Service in New Hampshire. The costs associated with the acquisition of such regulated wholesale electric supplies are recovered on a pass-through basis from customers through periodically-adjusted rates.

FG&E has a contract for Standard Offer Service from Constellation Power Source through the end of the Standard Offer Service period in Massachusetts in February 2005. Beginning December 1, 2000, through

December 1, 2003, FG&E procured Default Service through a bid process every six months. Effective December 1, 2003, as a result of revised regulatory requirements ordered by the MDTE, FG&E procures 50% of its Small Customer Default Service requirements semi-annually, for twelve-month terms. FG&E procures 100% of its Large Customer Default Service requirements for a three-month period.

Under the agreement whereby Mirant purchased the entitlements to Unitil Power's long-term purchase power supply portfolio, it provides UES' Transition and Default Service through April 30, 2006 for Small Customers and April 30, 2005 for Large Customers at fixed prices.

Since April 1, 1998, each electric utility has been required to carry an allocated share of the NEPOOL capability responsibility under the NEPOOL Agreement. FG&E's Standard Offer Service supplier, Constellation Power Source, and FG&E's periodic Default Service suppliers are responsible for serving FG&E's load obligations and associated capability responsibility under their respective contracts. Similarly, under the agreement between Unitil Power, UES and Mirant, whereby Mirant provides wholesale power to UES for Transition and Default Service, Mirant is also responsible for serving UES' load obligations and associated capability responsibility. Unitil Power no longer has any load serving obligations in NEPOOL.

Gas Supply:

FG&E's natural gas customers now have the opportunity to purchase their natural gas supply from third-party vendors, though most customers continue to purchase such supplies through FG&E as the provider of last resort. The costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

FG&E distributes natural gas purchased from domestic and Canadian suppliers under long-term contracts as well as gas purchased from producers and marketers on the spot market. The following tables summarize actual gas purchases by source of supply and the cost of gas sold for the years 2000 through 2003.

Sources of Gas Supply
(Expressed as percent of total MMBtu of gas purchased)

	2003	2002	2001
Natural Gas:			
Domestic firm	94.0%	73.9%	76.2%
Canadian firm	1.3%	8.4%	8.0%
Domestic spot market	1.3%	16.2%	14.5%
Total natural gas	96.6%	98.5%	98.7%
Supplemental gas	3.4%	1.5%	1.3%
Total gas purchases	100.0%	100.0%	100.0%

Cost of Gas Sold

	2003	2002	2001
Cost of gas purchased and sold per MMBtu	$7.14	$ 4.96	$7.13
Percent Increase (Decrease) from prior year	43.9%	(30.4%)	37.3%

As a supplement to pipeline natural gas, FG&E owns a propane air gas plant and a liquefied natural gas (LNG) storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Note 6: Commitments and Contingencies

Regulatory Matters—As a registered holding company under PUHCA, Unitil and its subsidiaries are regulated by the Securities and Exchange Commission (SEC) with respect to various matters, including: the issuance of securities, our capital structure and certain acquisitions and dispositions of assets. UES and FG&E are subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Telecommunications and Energy (MDTE), respectively, with respect to their rates, issuance of securities and other accounting and operational matters. Certain aspects of the Company's utility operations as they relate to wholesale and interstate business activities are also regulated by the Federal Energy Regulatory Commission (FERC). In the past several years, the Company has completed the restructuring of its electric and natural gas operations resulting from the implementation of retail choice as mandated by the States of New Hampshire and Massachusetts.

Unitil's retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in our franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, through their distribution charges, UES and FG&E recover the cost of providing distribution service to their customers based on a historical test year, in addition to earning a return on their capital investment in utility assets. In 2002, the retail distribution utilities completed rate proceedings and were authorized by the NHPUC and MDTE to implement increased rates for electric and natural gas distribution operations beginning in December of that year. UES and FG&E also recover the actual cost of any electricity or natural gas they supply to their customers, as well as certain costs associated with industry restructuring, through periodically adjusted rates.

In recent years, there has been significant legislative and regulatory activity to restructure the utility industry in order to introduce greater competition in the supply and sale of electricity and natural gas, while continuing to regulate the distribution operations of Unitil's retail distribution utilities. Unitil implemented the restructuring of its electric and gas operations in Massachusetts in 1998 and 2000, respectively, and implemented the final phase of a restructuring settlement for its New Hampshire electric operations on May 1, 2003. Following electric industry restructuring, Unitil's retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

In connection with industry restructuring and the implementation of retail choice for our customers in New Hampshire and Massachusetts, Unitil Power divested of its long-term power supply contracts and FG&E divested of its long-term power supply contracts and owned generation assets. Unitil Power divested its long-term power supply contracts to a subsidiary of Mirant Corporation (Mirant) and FG&E divested its owned generation assets and long-term power supply contracts to Select Energy, Inc. (Select Energy). Unitil Power's and FG&E's long-term power supply contracts were divested through the sale of the entitlements to the electricity associated with those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios as a result of electric industry restructuring.

Unitil's customers in both New Hampshire and Massachusetts now have the opportunity to purchase their electric supply from third party vendors, though most customers continue to purchase such supplies through Unitil as the provider of last resort. Accordingly, UES and FG&E contract with wholesale power suppliers for the electricity necessary to meet their regulated default service energy supply obligations. Similarly, FG&E's natural gas customers have the option to contract for their natural gas supply with third-party suppliers and FG&E remains the default service provider for these natural gas customers. The costs associated with the acquisition of such wholesale electric and natural gas supplies for customers who do not contract with third-party suppliers are recovered from those customers through periodic rate and cost recovery reconciliation mechanisms.

UES and FG&E have secured regulatory approval from both New Hampshire and Massachusetts state regulators for the recovery of approximately $203 million of power supply-related stranded costs principally over the next 6 to 8 years. Also, we have implemented comprehensive customer and financial information systems to accommodate the transition to competitive energy markets and retail choice.

Massachusetts Electric Operations Restructuring—Beginning March 1, 1998, FG&E implemented its Restructuring Plan under the Massachusetts Electric Utility Restructuring Act of 1997 (Restructuring Act). FG&E completed the divestiture of its entire regulated power supply business in 2000 in accordance with the Restructuring Plan. FG&E's rates provide for the recovery of stranded costs associated with the divestiture of FG&E's power portfolio including stranded, previously-owned generation assets. The Regulatory Assets that are being recovered in FG&E's rates have been approved by the MDTE as part of FG&E's Restructuring Plan and are reviewed each year as part of FG&E's annual rate reconciliation filings.

The Restructuring Act also requires FG&E to purchase and provide power as the default service provider, through either Standard Offer Service (SOS) or Default Service, for retail customers who choose not to buy, or are unable to purchase, energy from a competitive supplier. FG&E must provide SOS through February 2005 at rate levels which provide rate reductions as required by the Restructuring Act. New distribution customers and customers no longer eligible for SOS are eligible to receive Default Service at prices set periodically based on market solicitations as approved by regulators. As of December 31, 2003, competitive suppliers were serving approximately 37% of FG&E's load, primarily for FG&E's largest customers, although much of the load has since reverted back to FG&E's regulated Default Service.

As a result of the restructuring and the divestiture of FG&E's owned generation assets, FG&E recorded stranded generation-related costs as Regulatory Assets. These stranded generation-related Regulatory Assets are being amortized and recovered through the year 2009. FG&E earns carrying charges on the unamortized balance of these stranded generation-related Regulatory Assets. In addition, as a result of restructuring legislation in Massachusetts, the total rate FG&E may charge for the combination of distribution service, stranded costs and purchase power costs is subject to an inflation adjusted total rate cap for a seven year period, which began in March 1998. Any unrecovered balance of purchased power costs and stranded costs as a result of the total rate cap is deferred for future rate recovery as a Regulatory Asset. These deferred costs also earn carrying charges until their subsequent recovery in future periods. The value of FG&E's generation-related Regulatory Assets and deferred cost Regulatory Assets was approximately $31.7 million and $28.9 million, respectively at December 31, 2003, and are expected to be recovered in FG&E's rates principally over the next 6 to 8 years. In addition, as of December 31, 2003, FG&E had recorded on its balance sheets $73.4 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts. FG&E does not earn a carrying charge on this power supply component of Regulatory Assets as there is no significant difference between the time periods when payments are made to satisfy these purchase power contract obligations and their recovery in rates from FG&E's customers.

Massachusetts Gas Operations Restructuring—Following a three year state-wide collaborative process on the unbundling, or separation, of discrete services offered by natural gas local distribution companies (LDCs), the MDTE approved regulations and tariffs for FG&E and other LDCs operating in the Commonwealth to provide full customer choice effective November 1, 2000. The MDTE ruled that LDCs would continue to have an obligation to provide gas supply and delivery services for a five-year transition period, with a review after three years. The MDTE also required mandatory assignment of LDCs' pipeline capacity to competitive marketers supplying customers during the transition period. This mandatory capacity assignment protects LDCs from exposure to certain stranded gas supply costs during the transition period. In January 2004, the MDTE opened an investigation seeking comment on whether the mandatory assignment of pipeline capacity should be continued. This proceeding is pending.

New Hampshire Restructuring—In 2002, UES' predecessor companies, Concord Electric Company (CECo) and Exeter & Hampton Electric Company (E&H), received approval for a comprehensive restructuring proposal from the NHPUC. This approved proposal included the merger of E&H with and into CECo. CECo changed its name to Unitil Energy Systems, Inc. (UES) immediately following the merger. Under the New Hampshire restructuring plan, Unitil Power agreed to divest its existing long-term power supply portfolio and conduct a solicitation for new power supplies from which to meet UES' ongoing default service Transition and Default Service obligations in order to implement customer choice for UES' customers May 1, 2003. In

March 2003, the NHPUC approved the contract among Unitil Power, UES and Mirant Americas Energy Marketing, LP (MAEM), under which MAEM purchased the entitlements to Unitil Power's long-term power supply portfolio and provided Transition and Default Service to the customers of UES. The NHPUC also approved final tariffs for UES for stranded cost recovery and Transition and Default Service, including certain surcharges that are subject to future reconciliation or review. As of December 31, 2003, UES had recorded on its balance sheets $93.9 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are expected to be recovered principally over a period of approximately 8 years. UES does not earn carrying charges on these Power Supply Regulatory Assets as there is no significant difference between the time periods when payments are made to satisfy these purchase power buyout obligations and their recovery in rates from UES's customers.

In July 2003, MAEM and its parent, Mirant Corporation (Mirant), filed for reorganization under Chapter 11 of the bankruptcy code. Under the contract with UES and Unitil Power discussed above, Mirant guaranteed the performance by MAEM. Unitil Power and UES filed a motion with the Bankruptcy Court in September, 2003, requesting that MAEM be required to make a decision to assume or reject the contract by December 1, 2003. On November 14, 2003, MAEM, Unitil Power and UES filed a Settlement with the bankruptcy court. Under the terms of the Settlement, MAEM agreed to assume and continue to fulfill its power purchase and sale obligations under the contract, to cure all pre-petition obligations, and to settle certain other disputes. UES and Unitil Power agreed to accelerate the payment of amounts held back from MAEM. On December 10, 2003, the settlement was approved by the federal bankruptcy court and MAEM is continuing to fulfill its obligations under the Mirant Agreement.

Wholesale Power Market Restructuring—FG&E, Unitil Power, and UES are members of NEPOOL. NEPOOL was formed in 1971 to assure reliable operation of the bulk power system in the most economic manner for the region. NEPOOL is governed by an agreement (NEPOOL Agreement) that is filed with and subject to the jurisdiction of the FERC. Under the NEPOOL Agreement and the NEPOOL Open Access Transmission Tariff (OATT), to which virtually all New England electric utilities are parties, substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The NEPOOL Agreement and the OATT impose generating capacity and reserve obligations, and provide for the use of major transmission facilities and support payments associated therewith. The most notable benefits of NEPOOL are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The regional bulk power system is operated by an independent corporate entity, the ISO-NE, in order to avoid any opportunity for conflicting financial interests between the system operator and the market-driven participants.

There continue to be ongoing legislative and regulatory initiatives that are primarily focused on the deregulation of the generation and supply of electricity and the corresponding development of a competitive market place from which customers choose their electric energy supplier. As a result, the NEPOOL Agreement continues to be restructured. NEPOOL's membership provisions have been broadened to cover all entities engaged in the electricity business in New England, including power marketers and brokers, independent power producers, load aggregators and retail customers in states that have enacted retail access statutes. Various energy and capacity products are traded in open markets, with transmission access and pricing subject to the regional OATT designed to promote competition among power suppliers. On March 1, 2003, ISO-NE implemented a Standard Market Design (SMD) that is intended to improve the ability to trade power between New England and other regions throughout the northeast. On October 31, 2003, ISO-NE and the major transmission owners in New England filed with the FERC to form a Regional Transmission Organization (RTO) with a proposed effective date not earlier than March 1, 2004. The implementation of the RTO, which is being contested at FERC, will further revise the conduct of wholesale markets in New England. The filing also proposes to eliminate NEPOOL as an organization and require all current NEPOOL members to be part of the RTO system. SMD, the formation of an RTO and other wholesale market changes are not expected to have a material impact on Unitil's results of operations because of cost recovery mechanisms for wholesale energy costs approved by state regulators.

Other Regulatory Proceedings—Between December 2002 and January 2003, FG&E and UES received approval from their respective state regulatory commissions for accounting orders to mitigate certain accounting requirements related to pension plan assets, which have been triggered by the substantial decline in the capital markets. These approvals allowed FG&E and UES to treat the additional minimum pension liability as Regulatory Assets and avoided the reduction in equity that would otherwise be required. These regulatory orders did not pre-approve the amount of pension expense to be recovered in future rates, which recovery will be determined in future proceedings. Based on these approvals, FG&E's and UES' additional minimum pension liabilities are included in Regulatory Assets on the Company's balance sheet.

On December 15, 2003, FG&E filed a request to defer and record, as a regulatory asset or liability, the difference between the level of pension and Post Retirement Benefits Other than Pension (PBOP) expenses that are included in its base rates and the amounts that are required to be booked in accordance with SFAS No. 87 and SFAS No. 106, since the effective date of its last base rate change. The MDTE issued an order on January 30, 2004 approving FG&E's request for this accounting order to defer these costs.

On December 19, 2003, UES filed with the NHPUC a Petition for Deferral of its PBOP expenses not recovered in base rates. On January 30, 2004 the NHPUC issued an order approving UES's request for this accounting order to defer these costs.

On January 30, 2004 the MDTE granted FG&E's request to voluntarily decrease its Cost of Gas Adjustment Clause (CGAC) during the remainder of the 2004 winter period by accelerating the payment of a multi-year refund that was ordered by the MDTE in May 2001, based upon a finding that FG&E had over-collected certain fuel inventory finance charges. In January, 2004, the Massachusetts Supreme Judicial Court (SJC) affirmed the MDTE's May 2001 Order requiring the refund, which Order FG&E had appealed. The MDTE subsequently approved FG&E's request to prepay the balance of the refund outstanding of approximately $1.2 million by reducing the CGAC in February through April, 2004. The MDTE also approved FG&E's request to amortize these charges against future revenues.

In March 2003, the MDTE opened an investigation into FG&E's dealings with Enermetrix, Inc. (Enermetrix). Enermetrix provides an internet-based energy auction service that is used by utilities to post their natural gas and electric power needs for bids. FG&E used the Enermetrix Exchange to post its electric default service solicitations in September 2001 and March 2002, and Enermetrix earned approximately $19,000 in fees from these transactions. In Management's view, these successful solicitations ultimately resulted in significant lower default service costs to FG&E's customers. At the time of these solicitations, FG&E's parent, Unitil Corporation, had an approximately 9% ownership interest in Enermetrix. The MDTE is investigating whether FG&E is in compliance with relevant statutes and regulations pertaining to transactions with affiliated companies and the MDTE's Order setting forth the requirements for the pricing and procurement of default service. FG&E and the Attorney General have completed briefing of the case and an MDTE decision is pending. Management believes the outcome of this matter will not have a material adverse effect on the financial position of the company.

In August 2003, Northeast Utilities (NU) filed with FERC to revise its comprehensive network service transmission rates to establish and implement a formula based rate, replacing a fixed rate tariff. As filed, the proposed rate change would increase UES' external transmission costs paid under the NU tariff for comprehensive network service by about $600 thousand per year. The Company has filed a Motion to Intervene and Limited Protest in this FERC proceeding, and has claimed that certain provisions of NU's filing are contrary to a settlement reached in 1997 with NU for comprehensive network transmission service. The FERC set NU's filing for settlement discussions and approved the new tariff effective October 28, 2003, subject to refund. On January 22, 2004, the Settlement Judge formally terminated the settlement discussions. The Company continues to have informal settlement discussions with NU. Further action on the NU filing is currently pending before FERC. Management cannot predict the outcome of this proceeding but believes it will not have a material impact on results of operations because of rate reconciling cost recovery mechanisms approved by state regulators.

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company is in general compliance with all applicable environmental and safety laws and regulations, and Management believes that as of December 31, 2003, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

Sawyer Passway MGP Site—The Company continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows the Company to work towards temporary remediation of the site. Work performed in 2002 was associated with the five-year review of the Temporary Solution submittal (Class C Response Action Outcome) under the Massachusetts Contingency Plan that was filed for the site in 1997. Completion of this work has confirmed the Temporary Solution status of the site for an additional five years. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

Since 1991, FG&E has recovered the environmental response costs incurred at this former MGP site pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover from gas customers over succeeding seven-year periods the environmental response costs incurred each year. Environmental response costs are defined to include liabilities related to manufactured gas sites, waste disposal sites or other sites onto which hazardous material may have migrated as a result of the operation or decommissioning of Massachusetts gas manufacturing facilities from 1882 through 1978. In addition, any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers. The total annual charge for such costs assessed to gas customers cannot exceed five percent of FG&E's total revenue for firm gas sales during the preceding year. Costs in excess of five percent will be deferred for recovery in subsequent years.

Former Electric Generating Station—The Company has remediated environmental conditions at a former electric generating station located at Sawyer Passway, which FG&E sold to WRW, a general partnership, in 1983. Rockware International Corporation (Rockware), an affiliate of WRW, acquired rights to the electric equipment in the building and intended to remove, recondition and sell this equipment. During 1985, Rockware demolished several exterior walls of the generating station in order to facilitate removal of certain equipment. The demolition of the walls and the removal of generating equipment resulted in damage to asbestos-containing insulation materials inside the building, which had been intact and encapsulated at the time of the sale of the structure to WRW.

When Rockware and WRW encountered financial difficulties and failed to respond adequately to Orders of the environmental regulators to remedy the situation, FG&E agreed to take steps at that time and obtained DEP approval to temporarily enclose, secure and stabilize the facility. Based on that approval, between September and December 1989, contractors retained by FG&E stabilized the facility and secured the building. This work did not permanently resolve the asbestos problems caused by Rockware, but was deemed sufficient for the then foreseeable future.

Due to the continuing deterioration of this former electric generating station and Rockware's continued lack of performance, FG&E, in concert with the DEP and the U.S. Environmental Protection Agency (EPA), conducted further testing and survey work during 2001 to ascertain the environmental status of the building. Those surveys revealed continued deterioration of the asbestos-containing insulation materials in the building.

By letter dated May 1, 2002, the EPA notified FG&E that it was a Potentially Responsible Party for planned remedial activities at the site and invited FG&E to perform or finance such activities. FG&E and the EPA entered into an Agreement on Consent, whereby FG&E, without an admission of liability, conducted environmental remedial action to abate and remove asbestos-containing and other hazardous materials. This project was completed during the fourth quarter of 2003. FG&E received complete coverage from its insurance carrier and the resolution of this matter did not have a material adverse impact on the Company's financial position.

Note 7: Bad Debts

The Company recognizes a Provision for Uncollectible Accounts as a percent of revenues each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Uncollectible Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. Evaluating the adequacy of the Allowance for Uncollectible Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when State regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Uncollectible Accounts to maintain an adequate Allowance for Uncollectible Accounts balance. The following table shows the balances and activity in the Company's Allowance for Uncollectible Accounts for 2001—2003.

ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS

	Balance at Beginning of Period	Additions		Accounts Written Off	Balance at End of Period
		(A) Provision	Recoveries		
Year Ended December 31, 2003					
Electric	$271,679	$ 719,761	$ 87,922	$ 683,930	$395,432
Gas	100,300	609,037	67,398	643,771	132,964
Other	61,630	90,000	—	138,550	13,080
	$433,609	$1,418,798	$155,320	$1,466,251	$541,476
Year Ended December 31, 2002					
Electric	$456,850	$ 323,401	$138,010	$ 646,582	$271,679
Gas	142,843	294,051	64,570	401,164	100,300
Other	—	61,630	—	—	61,630
	$599,693	$ 679,082	$202,580	$1,047,746	$433,609
Year Ended December 31, 2001					
Electric	$452,872	$ 940,590	$ 86,161	$1,022,773	$456,850
Gas	142,810	656,953	54,162	711,082	142,843
Other	—	—	—	—	—
	$595,682	$1,597,543	$140,323	$1,733,855	$599,693

(A) The amounts charged to the Provision for Uncollectible Accounts include amounts related to the energy commodity portion of accounts receivable which are recovered through rate reconciling mechanisms.

Note 8: Income Taxes

Federal Income Taxes were provided for the following items for the years ended December 31, 2003, 2002 and 2001, respectively:

	2003	2002	2001
Current Federal Tax Provision (000's):			
Operating Income	**$(2,898)**	$1,960	$3,566
Amortization of Investment Tax Credits	**—**	(51)	(153)
Total Current Federal Tax Provision	**(2,898)**	1,909	3,413
Deferred Federal Tax Provision (000's)			
Accelerated Tax Depreciation	**3,329**	68	(401)
Abandoned Properties	**(778)**	(705)	(767)
Accrued Revenue	**2,034**	1,118	691
Allowance for Funds Used During Construction	**(23)**	(32)	(42)
Post Retirement Benefits Other Than Pensions	**(217)**	(38)	(34)
Deferred Pensions	**55**	86	89
Regulatory Assets and Liabilities	**146**	70	37
Insurance Proceeds	**1,172**	—	—
Contributions in Aid of Construction	**(201)**	(231)	(251)
Other, net	**51**	(47)	115
Total Deferred Federal Tax Provision	**5,568**	289	(563)
Total Federal Tax Provision	**$ 2,670**	$2,198	$2,850

The components of the Federal and State income tax provisions reflected as operating expenses in the accompanying consolidated statements of earnings for the years ended December 31, 2003, 2002 and 2001 were as follows:

Federal and State Tax Provisions (000's)	2003	2002	2001
Federal			
Current	**$(2,898)**	$1,960	$3,566
Deferred	**5,568**	289	(563)
Amortization of Investment Tax Credits	**—**	(51)	(153)
Total Federal Tax Provision	**2,670**	2,198	2,850
State			
Current	**74**	(275)	615
Deferred	**807**	567	(44)
Total State Tax Provision	**881**	292	571
Total Provision for Federal and State Income Taxes	**$ 3,551**	$2,490	$3,421

In 2001, the Company provided for a deferred tax benefit of $1.3 million on the capital loss from the write-down of its investment in Enermetrix. The Company recognized the benefit in 2002 of this capital loss as a carryback against capital gains in its tax return. Also in the third quarter of 2001, the Company recorded a deferred tax benefit of $1.4 million as adjustments to deferred taxes recognized when the Company recorded the extraordinary item.

The differences between the Company's provisions for Income Taxes and the provisions calculated at the statutory federal tax rate, expressed in percentages, are shown below:

	2003	2002	2001
Statutory Federal Income Tax Rate	**34%**	34%	34%
Income Tax Effects of:			
State Income Taxes, Net of Federal Benefit	**5**	2	4
Investment Tax Credit Amortization	**—**	(1)	(1)
Abandoned Property	**(7)**	(8)	(6)
Other, Net	**(1)**	2	(1)
Effective Income Tax Rate	**31%**	29%	30%

Temporary differences which gave rise to deferred tax assets and liabilities are shown below:

Deferred Income Taxes (000's)	2003	2002
Accelerated Depreciation	**$26,118**	$24,140
Deferred Restructuring Charges	**10,070**	7,820
Regulatory Assets and Liabilities	**12,750**	12,049
Employee Benefit Plan	**3,546**	3,624
Contributions in Aid to Construction	**(3,901)**	(3,654)
Retirement Loss	**3,613**	2,924
Abandoned Property	**1,783**	2,547
Percentage Repair Allowance	**2,407**	2,038
Other	**514**	806
Total Deferred Income Tax Liabilities	**$56,900**	$52,294

Note 9: Pension and Postretirement Benefit Plans

The Company provides certain pension and postretirement benefit plans for its retirees and current employees including defined benefit plans, postretirement health and welfare plans, a supplemental executive retirement plan and an employee 401(k) savings plan.

Defined Benefit Pension Plan—The Company sponsors the Unitil Corporation Retirement Plan (the Plan), a defined benefit pension plan covering substantially all its employees. Under the Plan retirement benefits are based upon an employee's level of compensation and length of service. The Company records annual expense and accounts for its defined benefit pension plan in accordance with SFAS No. 87, "Employers' Accounting for Pensions."

The following table represents information on the Plan's Projected Benefit Obligation (PBO), fair value of plan assets and the Plan's funded status. The PBO includes expectations of future employee service and compensation increases.

Change in PBO (000's)	2003	2002
PBO at Beginning of Year	**$42,745**	$38,922
Service Cost	**1,151**	1,116
Interest Cost	**2,940**	2,797
Plan Amendments	**—**	77
Benefits Paid	**(2,270)**	(2,165)
Actuarial (Gain) or Loss	**2,734**	1,998
PBO at End of Year	**$47,300**	$42,745

Change in Plan Assets (000's):	2003	2002
Fair Value of Plan Assets at Beginning of Year	**$34,244**	$40,943
Actual Return on Plan Assets	**6,163**	(4,534)
Employer Contributions	**1,200**	—
Benefits Paid	**(2,270)**	(2,165)
Fair Value of Plan Assets at End of Year	**$39,337**	$34,244

PBO and Funded Status (000's):	2003	2002
Fair Value of Plan Assets	**$39,337**	$34,244
PBO	**47,300**	42,745
Funded Status	**(7,963)**	(8,501)
Unrecognized Net (Gain) Loss	**18,118**	18,461
Unrecognized Transition (Asset) Obligation	**—**	—
Unrecognized Prior Service Cost	**817**	919
Net Amount Recognized as Prepaid Pension Asset	**$10,972**	$10,879

The following table represents information on the Plan's Accumulated Benefit Obligation (ABO), its funded status, the Company's Additional Minimum Liability (AML) and associated Regulatory Assets. The ABO is the Plan's obligation for employee service provided through December 31, 2003. An unfunded ABO represents an amount to be recognized as an additional minimum liability.

ABO and Funded Status (000's):	2003	2002
ABO	**$ 40,609**	$ 36,259
Fair Value of Plan Assets	**(39,337)**	(34,244)
Unfunded ABO/AML (Recognized as Regulatory Asset)	**$ 1,272**	$ 2,015

In December 2003 and 2002, FG&E and UES filed requests with their respective state regulatory commissions for approval of an accounting order to mitigate certain accounting requirements related to pension plan assets which had been triggered by the substantial decline in the capital markets. FG&E and UES were granted approval of this regulatory accounting treatment in January 2003 and 2004. As a result of these approvals, the Company has recorded as a Regulatory Asset the amount of the Plan's unfunded ABO plus one dollar. These approvals allow FG&E and UES to treat its AML as Regulatory Assets under SFAS No. 71 and avoid the reduction in equity through comprehensive income that would otherwise be required by SFAS No. 87. These regulatory Orders do not pre-approve the amount of pension expense to be recovered in future rates. Such recovery will be subject to review and approval in future rate proceedings.

The following tables show the components of net periodic pension cost (income), (NPPC), as well as key actuarial assumptions used in determining the various pension plan values:

Components of NPPC (000's)	2003	2002	2001
Service Cost	**$ 1,151**	$ 1,116	$ 914
Interest Cost	**2,940**	2,797	2,639
Expected Return on Plan Assets	**(3,573)**	(4,181)	(4,439)
Amortization of Prior Service Cost	**102**	102	96
Amortization of Transition (Asset) Obligation	**—**	—	84
Amortization of Net (Gain) Loss	**487**	—	(10)
Subtotal NPPC	**1,107**	(166)	(716)
Amounts Capitalized and Deferred	**(758)**	98	(24)
NPPC Recognized	**$ 349**	$ (68)	$ (740)

Included in the 2003 amount above for Amounts Capitalized and Deferred is $350 thousand deferred and recorded as a Regulatory Asset on the Company's Balance Sheet. The remaining amount in 2003 and the amounts in 2002 and 2001 represent amounts capitalized to construction overheads.

Key Assumptions (Weighted Average)	2003	2002	2001
Used to Determine Benefit Obligations at December 31:			
Discount Rate	**6.50%**	7.00%	7.25%
Rate of Compensation Increase	**3.50%**	4.00%	4.00%
Used to Determine NPPC for years ended December 31:			
Discount Rate	**7.00%**	7.25%	7.75%
Expected Long-Term Rate of Return on Plan Assets	**8.75%**	9.25%	9.25%
Rate of Compensation Increase	**4.00%**	4.00%	4.00%

The following table represents the Plan's weighted-average investment asset allocations at December 31:

	Target Allocation 2004	Actual Allocation at December 31		
		2003	2002	2001
Equity Securities	58-62%	61%	58%	61%
Debt Securities	38-42%	39%	42%	39%
Real Estate	0-2%	0%	0%	0%
Other	0-2%	0%	0%	0%
Total		**100%**	**100%**	**100%**

The desired investment objective is a long-term rate of return on assets that is approximately 6% greater than the assumed rate of inflation as measured by the Consumer Price Index. The target rate of return for the Plan has been based upon an analysis of historical returns supplemented with an economic and structural review for each asset class.

The following tables represent Plan contributions and benefit payments (000s):

	2003	2002	2001
Employer Contributions	**$1,200**	$ —	$ —
Participant Contributions	**$ —**	$ —	$ —
Benefit Payments	**$2,270**	$2,165	$2,152

Estimated Future Benefit Payments

2004	2005	2006	2007	2008	2009-2013
$2,289	$2,352	$2,380	$2,457	$2,616	$15,017

Postretirement Benefits—Postretirement Benefits—Prior to October 1, 2003, the Company funded certain postretirement benefits through the Unitil Retiree Trust (URT). URT was an organization of retirees, incorporated in 1993 to provide social, health and welfare benefits to its members, who are eligible former employees of the Company. URT was under the direction of an independent Board of Trustees whose voting members were comprised of former employees of the Company, elected by and from the membership of URT.

URT was determined to be a Variable Interest Entity (VIE) under Financial Interpretation No. 46 (FIN 46) as discussed above in Note 1. In the fourth quarter of 2003, URT was dissolved by a vote of its trustees and the Company assumed the obligations of URT as of October 1, 2003. At October 1, 2003, the Transition Obligation for benefits previously provided by URT was $29.2 million and this obligation is being recognized on a delayed basis over the average remaining service period of active participants, not to exceed 20 years. In addition, the Company made payments of $1.3 million, $1.2 million and $1.0 million in 2003, 2002 and 2001 respectively, to the Unitil Retiree Trust.

The Company also sponsors the Unitil Employee Health and Welfare Benefits Plan to provide health care and life insurance benefits to active employees. Effective January 1, 2004, this plan was amended to provide certain healthcare and life insurance benefits to Company retirees following their retirement (PBOP Plan).

The Company has established Voluntary Employee Benefit Trusts, into which it intends to fund contributions to the PBOP Plan beginning in the first quarter of 2004. The Company expects to recover these amounts as part of normal operating expenses in utility rates. In January 2004, FG&E and UES received approval in their respective jurisdictions from their regulators to defer the amount of current PBOP cost above that which is currently recovered in rates until the Company can complete the necessary filings for retail rate cost recovery. The Company expects to complete these filings in 2004.

The following table represents information on the PBOP Plan's fair value of plan assets and the PBOP Plan's funded status. The PBO includes expectations of future employee service and compensation increases.

Change in PBO (000's)	2003	2002
PBO at Beginning of Year	**$ 837**	$ 644
Service Cost	**246**	51
Interest Cost	**558**	46
Plan Amendments	**29,165**	—
Benefits Paid	**(331)**	(13)
Actuarial (Gain) or Loss	**1,516**	109
PBO at End of Year	**$ 31,991**	$ 837
Change in Plan Assets (000's):		
Fair Value of Plan Assets at Beginning of Year	**$ —**	$ —
Actual Return on Plan Assets	**—**	—
Employer Contributions	**331**	13
Benefits Paid	**(331)**	(13)
Fair Value of Plan Assets at End of Year	**$ —**	$ —
Obligation and Funded Status (000's):		
Fair Value of Plan Assets	**$ —**	$ —
PBO	**31,991**	837
Funded Status	**(31,991)**	(837)
Unrecognized Net (Gain) Loss	**1,633**	118
Unrecognized Transition (Asset) Obligation	**193**	214
Unrecognized Prior Service Cost	**28,799**	—
Net Amount Recognized	**$ (1,366)**	$(505)

The components of net periodic postretirement benefit cost (NPPBC) are as follows:

Components of NPPBC (000's)	2003	2002
Service Cost	**$ 246**	$ 51
Interest Cost	**558**	46
Expected Return on Plan Assets	**—**	—
Amortization of Prior Service Cost	**365**	—
Amortization of Transition (Asset) Obligation	**21**	22
Amortization of Net (Gain) Loss	**2**	—
Subtotal NPPBC	**1,192**	119
Amounts Capitalized and Deferred	**(942)**	(44)
NPPBC Recognized	**$ 250**	$ 75

Included in the 2003 amount above for Amounts Capitalized and Deferred is $457 thousand deferred and recorded as a Regulatory Asset on the Company's Balance Sheet. The remaining amount in 2003 and the amounts in 2002 and 2001 represent amounts capitalized to construction overheads.

In addition to the amounts shown above, the Company also recorded expense for payments to URT of $1.3 million and $1.2 million in 2003 and 2002, respectively.

The following table includes assumptions used in determining the various PBOP values.

Weighted-Average Assumptions	2003	2002
Used to Determine Benefit Obligations at December 31:		
Discount Rate	**6.50%**	7.00%
Rate of Compensation Increase	**N/A**	N/A
Health Care Cost Trend Rate Assumed for Next Year	**9.00%**	10.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2013**	2013
Used to Determine NPPBC for years ended December 31:		
Discount Rate	**7.00%**	7.25%
Expected Long-Term Rate of Return on Plan Assets	**N/A**	N/A
Rate of Compensation Increase	**N/A**	N/A
Health Care Cost Trend Rate Assumed for Next Year	**10.00%**	11.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2013**	2019

Assumed health care cost trend rates have a significant effect on the amounts reported. A one-percentage-point change in the assumed health care cost trend rates would have the following effects:

1-Percentage Point Increase (000's)	2003	2002
Effect on Total of Service and Interest Cost	$ 150	$ 14
Effect on Postretirement Benefit Obligation	$ 4,968	$ 95
1-Percentage Point Decrease (000's)		
Effect on Total of Service and Interest Cost	$ (118)	$(12)
Effect on Postretirement Benefit Obligation	$(4,007)	$(83)

The following tables represent PBOP contributions and benefit payments made in 2002-2003 and estimated future benefit payments. The employer contributions and benefit payments listed below reflect the Company's assumptions of the URT obligations, effective October 1, 2003:

(000s)	Expected 2004	2003	2002
Employer Contributions	**$1,348**	$331	$13
Participant Contributions	**$ —**	$ —	$—

	2003	2002
Benefit Payments	**$331**	$13

Estimated Future Benefit Payments

2004	2005	2006	2007	2008	2009-2013
$1,348	$1,428	$1,504	$1,589	$1,687	$9,904

Supplemental Executive Retirement Plan—The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (the SERP), with participation limited to executives selected by the Board of Directors. The cost associated with the SERP amounted to approximately $140,000, $137,000 and $136,000 for the years ended December 31, 2003, 2001 and 2000, respectively.

The following table represents information on the SERP's Projected Benefit Obligation (PBO), fair value of plan assets and the plan's funded status. The PBO includes expectations of future employee service and compensation increases.

Change in PBO (000's)	2003	2002
PBO Obligation at Beginning of Year	**$ 1,029**	$ 935
Service Cost	**59**	64
Interest Cost	**69**	59
Plan Amendments	**40**	—
Benefits Paid	**(64)**	(38)
Actuarial (Gain) or Loss	**60**	9
PBO at End of Year	**$ 1,193**	$ 1,029
Change in Plan Assets (000's):		
Fair Value of Plan Assets at Beginning of Year	**$ —**	$ —
Actual Return on Plan Assets	**—**	—
Employer Contributions	**64**	38
Benefits Paid	**(64)**	(38)
Fair Value of Plan Assets at End of Year	**$ —**	$ —
Obligation and Funded Status (000's):		
Fair Value of Plan Assets	**$ —**	$ —
PBO	**1,193**	1,029
Funded Status	**(1,193)**	(1,029)
Unrecognized Net (Gain) Loss	**213**	157
Unrecognized Transition (Asset) Obligation	**51**	68
Unrecognized Prior Service Cost	**17**	(25)
Net Amount Recognized	**$ (912)**	$ (829)

The components of net periodic SERP cost are as follows:

Components of Net Periodic SERP Cost (000's)	2003	2002	2001
Service Cost	**$ 59**	$ 64	$ 61
Interest Cost	**69**	59	60
Expected Return on Plan Assets	**—**	—	—
Amortization of Prior Service Cost	**(5)**	(3)	(4)
Amortization of Transition Obligation	**17**	17	17
Amortization of Net Loss	**—**	—	2
Net Periodic SERP Cost	**$140**	$137	$136

The following table includes information regarding Unitil's SERP costs as well as key actuarial assumptions:

Additional Information (000's):	2003	2002	2001
Accumulated Benefit Obligation	**$ 675**	$ 752	$ 704
Weighted-Average Assumptions			
Used to Determine Benefit Obligations at December 31:			
Discount Rate	**6.50%**	7.00%	7.25%
Rate of Compensation Increase	**3.50%**	4.00%	4.00%
Used to Determine Net Periodic SERP Cost for years ended December 31			
Discount Rate	**7.00%**	7.25%	7.75%
Expected Long-Term Rate of Return on Plan Assets	**N/A**	N/A	N/A
Rate of Compensation Increase	**4.00%**	4.00%	4.00%

The following tables represent SERP contributions and benefit payments made in 2001 – 2003 and estimated future benefit payments (000s):

	2003	2002	2001
Employer Contributions	**$ 64**	$ 38	$ 38
Participant Contributions	**$ —**	$ —	$ —

	2003	2002	2001
Benefit Payments	**$ 64**	$ 38	$ 38

Estimated Future Benefit Payments					
2004	2005	2006	2007	2008	2009-2013
$70	$68	$66	$64	$62	$471

Employee 401(k) Tax Deferred Savings Plan—The Company sponsors the Unitil Corporation Tax Deferred Savings and Investment Plan (the 401(k)) under Section 401(k) of the Internal Revenue Code, covering substantially all of the Company's employees. Participants may elect to defer current compensation by contributing to the plan. The Company matches contributions, with a maximum matching contribution of 3% of current compensation. Employees may direct, at their sole discretion, the investment of their savings plan balances (both the employer and employee portions) into a variety of investment options, including a Company Common Stock fund. Participants are 100% vested in contributions made on their behalf, once they have completed three years of service. The Company's share of contributions to the plan was $487,000, $483,000, and $446,000 for the years ended December 31, 2003, 2002, and 2001, respectively.

Note 10: Earnings Per Share

The following table reconciles basic and diluted earnings per share, assuming all dilutive outstanding stock options were converted to common shares per SFAS No. 128, "Earnings per Share."

(000's except share and per share data)	2003	2002	2001
Income before Extraordinary Item	**$ 7,722**	**$ 5,835**	$ 4,770
Extraordinary Item, net of tax	**—**	**—**	(3,937)
Earnings Available to Common Shareholders	**$ 7,722**	**$ 5,835**	$ 833
Weighted Average Common Shares Outstanding—Basic	**4,877,933**	**4,743,696**	4,743,576
Plus: Diluted Effect of Incremental Shares—from Assumed Conversion	**21,555**	**18,470**	16,246
Weighted Average Common Shares Outstanding—Diluted	**4,899,488**	**4,762,166**	4,759,822
Earnings per Share:			
Income before Extraordinary Item	**$ 1.58**	**$ 1.23**	$ 1.01
Extraordinary Item, net of tax	**—**	**$ —**	$ (0.83)
Earnings Available to Common Shareholders	**$ 1.58**	**$ 1.23**	$ 0.18

Weighted average options to purchase 72,500, 54,000 and 114,000 shares of Common Stock were outstanding during 2003, 2002 and 2001, respectively, but were not included in the computation of Weighted Average Common Shares Outstanding for purposes of computing diluted earnings per share, because the effect would have been antidilutive.

Note 11: Segment Information

Unitil reported four segments: utility electric operations, utility gas operations, other, and non-regulated. Unitil is engaged principally in the retail sale and distribution of electricity in New Hampshire and both electricity and natural gas service in Massachusetts through its retail distribution subsidiaries UES and FG&E. Unitil Resources provides an energy brokering service, through Usource, as well as various energy consulting activities. Unitil Realty and Unitil Service provide centralized facilities, operations and administrative services to support the affiliated Unitil companies.

Unitil Realty and Unitil Service are included in the "Other" column of the table below. Unitil Service provides centralized management and administrative services, including information systems management and financial record keeping. Unitil Realty owns certain real estate, principally the Company's corporate headquarters. Unitil Resources and Usource are included in the Non-Regulated column below.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies. Intersegment sales take place at cost and the effects of all intersegment and/or intercompany transactions are eliminated in the consolidated financial statements. Segment profit or loss is based on profit or loss from operations after income taxes. Expenses used to determine operating income before taxes are charged directly to each segment or are allocated based on factors under PUHCA rules and contained in cost-of-service studies, which were included in rate applications approved by the NHPUC and MDTE. Assets allocated to each segment are based upon specific identification of such assets provided by Company records.

The following table provides significant segment financial data for the years ended December 31, 2003, 2002 and 2001:

Year Ended December 31, 2003 (000's)	**Electric**	**Gas**	**Other**	**Non-Utility**	**Eliminations**	**Total**
Revenues	**$190,864**	**$28,612**	**$ 30**	**$ 1,148**		**$220,654**
Segment Profit (Loss)	**6,998**	**1,102**	**254**	**(632)**		**7,722**
Identifiable Segment Assets	**388,683**	**84,441**	**26,335**	**1,777**	**(17,359)**	**483,877**
Capital Expenditures	**17,318**	**4,083**	**519**	**19**		**21,939**
Year Ended December 31, 2002 (000's)						
Revenues	$167,317	$20,283	$ 30	$ 756		$188,386
Segment Profit (Loss)	6,249	(206)	456	(664)		5,835
Identifiable Segment Assets	385,293	85,703	24,651	1,958	(15,903)	481,702
Capital Expenditures	16,676	3,859	290	—		20,825
Year Ended December 31, 2001 (000's)						
Revenues	$183,780	$22,828	$ 30	$ 384		$207,022
Segment Profit (Loss)	8,771	(771)	172	(1,002)		7,170
Investment Write-down, net of tax	—	—	(2,400)	—		(2,400)
Extraordinary Item, net of tax	(3,937)	—	—	—		(3,937)
Identifiable Segment Assets	288,013	87,851	23,679	834	(23,615)	376,762
Capital Expenditures	14,328	4,817	745	—		19,890

Note 12: Quarterly Financial Information (unaudited; 000's except per share data)

Quarterly earnings per share may not agree with the annual amounts due to rounding. Basic and Diluted Earnings per Share are the same for the periods presented.

	Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	2003	2002	2003	2002	2003	2002	2003	2002
Total Operating Revenues	**$64,807**	$44,289	**$49,624**	$45,117	**$52,892**	$48,007	**$53,331**	$50,573
Operating Income	**$ 4,672**	$ 3,685	**$ 3,372**	$ 3,162	**$ 3,352**	$ 3,310	**$ 4,054**	$ 3,091
Net Income Applicable to Common	**$ 2,479**	$ 1,695	**$ 1,498**	$ 1,290	**$ 1,438**	$ 1,378	**$ 2,388**	$ 1,472
	Per Share Data:							
Earnings Per Common Share	**$ 0.52**	$ 0.36	**$ 0.30**	$ 0.27	**$ 0.30**	$ 0.29	**$ 0.46**	$ 0.31
Dividends Paid Per Common Share	**$ 0.345**	$ 0.345	**$ 0.345**	$ 0.345	**$ 0.345**	$ 0.345	**$ 0.345**	$ 0.345

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Within the 90 days prior to the date of this report, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer, Chief Financial Officer and Controller, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-14 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Controller concluded that the Company's disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company's periodic SEC filings.

There have been no significant changes in the Company's internal controls or in other factors, which could significantly affect internal controls subsequent to the date the Company carried out its evaluation.

PART III

Item 10. Directors and Executive Officers of the Registrant

Information required by this Item is set forth in the "Information About Directors" section of the 2003 Proxy Statement as filed with the Securities and Exchange Commission on February 27, 2004. Information regarding the Company's Code of Ethics is set forth in the "Corporate Governance and Policies of the Board" section of the 2003 Proxy Statement as filed with the Securities and Exchange Commission on February 27, 2004.

Item 11. Executive Compensation

Information required by this Item is set forth in the "Report of the Compensation Committee" section of the 2003 Proxy Statement as filed with the Securities and Exchange Commission on February 27, 2004.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Information required by this Item is set forth in the "Information About Directors" section of the 2003 Proxy Statement as filed with the Securities and Exchange Commission on February 27, 2004 as well as the Equity Compensation Plan Benefit Information table in Part II, Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions

None

Item 14. Principal Accountant Fees and Services

Information required by this Item is set forth in the "Report of the Audit Committee" section of the 2003 Proxy Statement as filed with the Securities and Exchange Commission on February 27, 2004.

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) (1) and (2) – **LIST OF FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES**

The following financial statements are included herein under Part II, Item 8, Financial Statements and Supplementary Data:

- Report of Independent Certified Public Accountants
- Consolidated Balance Sheets—December 31, 2003 and 2002
- Consolidated Statements of Earnings for the years ended December 31, 2003, 2002, and 2001
- Consolidated Statements of Capitalization—December 31, 2003 and 2002
- Consolidated Statements of Cash Flows for the years ended December 31, 2003, 2002, and 2001
- Consolidated Statements of Changes in Common Stock Equity for the years ended December 31, 2003, 2002, and 2001
- Notes to Consolidated Financial Statements

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions, are not applicable, or information required is included in the financial statements or notes thereto and, therefore, have been omitted.

(3) – **LIST OF EXHIBITS**

Exhibit Number	Description of Exhibit	Reference*
3.1	Articles of Incorporation of the Company.	Exhibit 3.1 to Form S-14 Registration Statement 2-93769
3.2	Articles of Amendment to the Articles of Incorporation Filed on March 4, 1992 and April 30, 1992.	Exhibit 3.2 to Form 10-K for 1991
3.3	By-laws of the Company.	Exhibit 3.2 to Form S-14 Registration Statement 2-93769
3.4	Articles of Exchange of Concord Electric Company (CECo), Exeter & Hampton Electric Company (E&H) and the Company.	Exhibit 3.3 to 10-K for 1984
3.5	Articles of Exchange of CECo, E&H, and the Company—Stipulation of the Parties Relative to Recordation and Effective Date.	Exhibit 3.4 to Form 10-K for 1984
3.6	The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg Gas and Electric Light Company (FG&E) and UMC Electric Co., Inc. (UMC).	Exhibit 25(b) to Form 8-K dated March 1, 1989
3.7	Amendment No. 1 to The Agreement and Plan of Merger dated March 1, 1989 among the Company, FG&E and UMC.	Exhibit 28(b) to Form 8-K dated December 14, 1989

Exhibit Number	Description of Exhibit	Reference*
4.1	Twelfth Supplemental Indenture of Unitil Energy Systems, Inc., successor to Concord Electric Company, dated as of December 2, 2002, amending and restating the Concord Electric Company Indenture of Mortgage and Deed of Trust dated as of July 15, 1958.	Exhibit 4.1 to Form 10-K for 2002
4.2	FG&E Purchase Agreement dated March 20, 1992 for the 8.55% Senior Notes due March 31, 2004.	Exhibit 4.18 to Form 10-K for 1993
4.3	FG&E Note Agreement dated November 30, 1993 for the 6.75% Notes due November 23, 2023.	Exhibit 4.18 to Form 10-K for 1993
4.4	FG&E Note Agreement dated January 26, 1999 for the 7.37% Notes due January 15, 2028.	Exhibit 4.25 to Form 10-K for 1999
4.5	FG&E Note Agreement dated June 1, 2001 for the 7.98% Notes due June 1, 2031.	Exhibit 4.6 to Form 10-Q for June 30, 2001
4.6	Unitil Realty Corp. Note Purchase Agreement dated July 1, 1997 for the 8.00% Senior Secured Notes due August 1, 2017.	Exhibit 4.22 to Form 10-K for 1997
4.7	FG&E Note Agreement dated October 15, 2003 for the 6.79% Notes due October 15, 2025.	Filed herewith
10.1	Unitil System Agreement dated June 19, 1986 providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.9 to Form 10-K for 1986
10.2	Supplement No. 1 to Unitil System Agreement providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.8 to Form 10-K for 1987
10.3	Transmission Agreement between Unitil Power Corp. and Public Service Company of New Hampshire, effective November 11, 1992.	Exhibit 10.6 to Form 10-K for 1993
10.4	Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.1 to Form 10-Q for September 30, 2003
10.5	Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.2 to Form 10-Q for September 30, 2003
10.6	Key Employee Stock Option Plan effective January 17, 1989.	Exhibit 10.56 to Form 8 dated April 12, 1989
10.7	Unitil Corporation Key Employee Stock Option Plan Award Agreement.	Exhibit 10.63 to Form 10-K for 1989
10.8	Unitil Corporation Management Performance Compensation Plan.	Exhibit 10.94 to Form 10-K/A for 1993
10.9	Unitil Corporation Supplemental Executive Retirement Plan effective as of January 1, 1987.	Exhibit 10.95 to Form 10-K/A for 1993
10.10	Unitil Corporation 1998 Stock Option Plan.	Exhibit 10.12 to Form 10-K for 1998
10.11	Unitil Corporation Management Incentive Plan.	Exhibit 10.13 to Form 10-K for 1998

Exhibit Number	Description of Exhibit	Reference*
10.12	Entitlement Sale and Administrative Service Agreement with Select Energy.	Exhibit 10.14 to Form 10-K for 1999
10.13	Purchase and Sale Agreement For New Haven Harbor.	Exhibit 10.15 to Form 10-K for 1999
10.14	Labor Agreement effective June 1, 2000 between CECo and The International Brotherhood of Electrical Workers, Local Union No. 1837.	Exhibit 10.13 to Form 10-K for 2000
10.15	Labor Agreement effective June 1, 2000 between E&H and The International Brotherhood of Electrical Workers, Local Union No. 1837.	Exhibit 10.14 to Form 10-K for 2000
10.16	Labor Agreement effective June 1, 2000 between FG&E and The Utility Workers of America, AFL-CIO., Local Union No. B340, The Brotherhood of Utility Workers Council.	Exhibit 10.15 to Form 10-K for 2000
10.17	Unitil Corporation 2003 Restricted Stock Plan.	Exhibit 10.16 to Form 10-K for 2002
10.18	Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement By and Among Unitil Power Corp., Unitil Energy Systems, Inc. and Mirant Americas Energy Marketing, LP.	Exhibit 10.17 to Form 10-K for 2002
11.1	Statement Re: Computation in Support of Earnings per Share For the Company.	Filed herewith
12.1	Statement Re: Computation in Support of Ratio of Earnings to Fixed Charges for the Company.	Filed herewith
21.1	Statement Re: Subsidiaries of Registrant.	Filed herewith
23.1	Consent of Independent Certified Public Accountants.	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
31.3	Certification of Controller Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Controller Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	Filed herewith

* The exhibits referred to in this column by specific designations and dates have heretofore been filed with the Securities and Exchange Commission under such designations and are hereby incorporated by reference.

(b) Report on Form 8-K

On December 11, 2003, Unitil Corporation filed a Current Report on Form 8-K announcing that the Federal Bankruptcy Court presiding over the Mirant (MIRKQ) bankruptcy proceeding approved the settlement between Unitil's New Hampshire based utility subsidiaries, Unitil Energy Systems, Inc. (UES) and Unitil Power Corp. (UPC), and Mirant's subsidiary Mirant Americas Energy Marketing, L.P. (Mirant Americas).

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION

Date February 27, 2004

By /s/ ROBERT G. SCHOENBERGER

Robert G. Schoenberger
Chairman of the Board Directors,
Chief Executive Officer and President

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

Signature	Capacity	Date
/s/ ROBERT G. SCHOENBERGER **Robert G. Schoenberger**	Principal Executive Officer; Director	February 27, 2004
/s/ MARK H. COLLIN **Mark H. Collin**	Principal Financial Officer	February 27, 2004
/s/ MICHAEL J. DALTON **Michael J. Dalton**	Director	February 27, 2004
/s/ ALBERT H. ELFNER, III **Albert H. Elfner, III**	Director	February 27, 2004
/s/ ROSS B. GEORGE **Ross B. George**	Director	February 27, 2004
/s/ M. BRIAN O'SHAUGHNESSY **M. Brian O'Shaughnessy**	Director	February 27, 2004
/s/ CHARLES H. TENNEY, III **Charles H. Tenney, III**	Director	February 27, 2004
/s/ DR. SARAH P. VOLL **Dr. Sarah P. Voll**	Director	February 27, 2004
/s/ EBEN S. MOULTON **Eben S. Moulton**	Director	February 27, 2004
/s/ DAVID P. BROWNELL **David P. Brownell**	Director	February 27, 2004
/s/ EDWARD F. GODFREY **Edward F. Godfrey**	Director	February 27, 2004
/s/ MICHAEL B. GREEN **Michael B. Green**	Director	February 27, 2004