SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

# FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
**For Quarter Ended March 31, 2004**

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 office)* | *(Zip Code)* |

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

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_X__ No___

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes_X__ No___

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

| Class | Outstanding at April 27, 2004 |
|---|---|
| Common Stock, No par value | 5,510,579 Shares |

**UNITIL CORPORATION AND SUBSIDIARY COMPANIES**
**FORM 10-Q**
**For the Quarter Ended March 31, 2004**

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## PART I. FINANCIAL INFORMATION

### *Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations*

### SAFE HARBOR CAUTIONARY STATEMENT

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.

### RESULTS OF OPERATIONS

## Operating Revenues — Electric

***Electric Operating Revenues*** - Electric Operating Revenues, which represent approximately 80% of Unitil's total Operating Revenues, decreased by $4.6 million, or 8.9%, in the first three months of 2004 compared to the same period in 2003. 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 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 decreased $5.0 million in the first three months of 2004 compared to the same period in 2003, reflecting lower electric commodity prices. Conservation & Load Management expenses related to electric operations increased $0.4 million, or 97.1% in the first three months of 2004 compared to the same period in 2003, reflecting increased spending on energy efficiency programs that were implemented during the period. 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 $13.5 million in the first three months of 2004, a decrease of less than $0.1 million compared to the same period in 2003. Although total kWh unit sales increased 1.1% in the first three months of 2004 compared to the same period in 2003, peak demand billings to large industrial customers decreased 1.0%, resulting in lower period over period margins for these customers.

The following table details total Electric Operating Revenue and Sales Margin for the three months ended March 31, 2004 and 2003:

**Electric Operating Revenue and Sales Margin (000's)**

| | Three Months Ended March 31, | | |
|---|---|---|---|
| | **2004** | 2003 | % Change |
| Electric Operating Revenue | **$ 47,451** | $ 52,070 | (8.9%) |
| Purchased Electricity | **33,212** | 38,162 | (13.0%) |
| Conservation & Load Management | **786** | 399 | 97.1% |
| Electric Sales Margin | **$ 13,453** | $ 13,509 | (0.4%) |

***Kilowatt-hour Sales*** – Unitil's total electric kilowatt-hour (kWh) sales increased 1.1% in the first three months of 2004 compared to the same period in 2003. This increase reflects growth in sales to residential and commercial and industrial customer classes driven by customer growth.

Sales to residential customers increased 1.6% in the first three months of 2004 compared to the same period in 2003. Commercial and industrial sales of electricity increased 0.7% in the first three months of 2004 compared to the same period in 2003.

The following table details total kWh sales for the three months ended March 31, 2004 and 2003 by major customer class:

**kWh Sales (000's)**

| | Three Months Ended March 31, | | |
|---|---|---|---|
| | **2004** | 2003 | % Change |
| Residential | **184,878** | 181,885 | 1.6% |
| Commercial/Industrial | **270,391** | 268,540 | 0.7% |
| Total | **455,269** | 450,425 | 1.1% |

## Operating Revenues - Gas

***Gas Operating Revenues*** – Gas Operating Revenues, which represent approximately 20% of Unitil's total Operating Revenues, decreased $0.8 million, or 6.2%, in the first three months of 2004 compared to the same period in 2003. 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 decreased $0.8 million, or 9.3%, in the first three months of 2004 compared to the same period in 2003. Approximately 66% of this decrease reflects a decrease of approximately 6.1% in gas unit sales during the period while the remainder reflects lower gas commodity prices. Conservation & Load Management expenses related to gas operations increased less than $0.1 million in the first three months of 2004 compared to the same period in 2003. 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 $4.2 million in the first three months of 2004, a decrease of less than $0.1 million, or 1.4%, compared to the same period in 2003. This decrease was attributable to lower unit sales, reflecting a milder winter heating season in the first three months of 2004 compared to the same period in 2003.

The following table details total Gas Operating Revenue and Margin for the three months ended March 31, 2004 and 2003:

**Gas Operating Revenue and Sales Margin (000's)**

| | Three Months Ended March 31, | | |
|---|---|---|---|
| | **2004** | 2003 | % Change |
| Gas Operating Revenue | **$ 11,637** | $ 12,404 | (6.2%) |
| Purchased Gas | **7,305** | 8,055 | (9.3%) |
| Conservation & Load Management | **87** | 44 | 97.1% |
| Gas Sales Margin | **$ 4,245** | $ 4,305 | (1.4%) |

***Therm Sales*** – Unitil's total firm therm sales of natural gas decreased 6.1% in the first three months of 2004 compared to the same period in 2003, due to a milder winter heating season in 2004 and the continued impact of a poor economy on commercial and industrial customers. Sales to residential customers decreased 5.3% and sales to commercial and industrial customers decreased 6.9% in the first three months of 2004 compared to the same period in 2003.

The following table details total firm therm sales for the three months ended March 31, 2004 and 2003, by major customer class:

**Firm Therm Sales (000's)**

| | Three Months Ended March 31, | | |
|---|---|---|---|
| | **2004** | 2003 | % Change |
| Residential | **5,801** | 6,128 | (5.3%) |
| Commercial/Industrial | **5,670** | 6,089 | (6.9%) |
| Total | **11,471** | 12,217 | (6.1%) |

## *Operating Revenue - Other*

Total Other Revenues increased $0.1 million, or 21.6%, in the first three months of 2004 compared to the same period in 2003. This was primarily 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 two years:

**Other Revenue (000's)**

| | Three Months Ended March 31, | | |
|---|---|---|---|
| | **2004** | 2003 | % Change |
| Usource | **$ 405** | $ 325 | 24.6% |
| Other | **--** | 8 | (100%) |
| Total Other Revenue | **$ 405** | $ 333 | 21.6% |

## *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, decreased $5.0 million in the first three months of 2004 compared to the same period in 2003, reflecting lower electric commodity prices. The Company recovers the costs of Purchased Electricity in its rates at cost and therefore changes in these expenses do not impact net income.

**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 decreased by $0.8 million, or 9.3% in the first three months of 2004 compared to the same period in 2003. Approximately 66% of this decrease reflects a decrease of approximately 6.1% in gas unit sales during the period while the remainder reflects lower gas commodity prices. The Company recovers the costs of Purchased Gas in its rates at cost and therefore changes in these expenses do not impact net income.

**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 $0.1 million, or 1.7%, in the first three months of 2004 compared to the same period in 2003.

This increase reflects higher salaries and compensation expenses, $0.3 million, reflecting normal annual increases, partially offset by lower professional fees and other expenses, ($0.2 million).

**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 with 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 $0.4 million, or 97.1%, in the first three months of 2004 compared to the same period in 2003 reflecting increased spending on Energy Efficiency programs that were implemented in 2004. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs have no impact on earnings.

### *Depreciation, Amortization and Taxes*

**Depreciation and Amortization** - Depreciation and Amortization expense decreased $0.2 million, or 3.7%, in the first three months of 2004 compared to the same period in 2003, due mainly to the amortization expense on corporate intangible assets in 2003.

**Local Property and Other Taxes** - Local Property and Other Taxes increased by less than $0.1 million, or 1.9%, in the first three months of 2004 compared to the same period in 2003. This increase was due to increases in payroll and property taxes.

**Federal and State Income Taxes** - Federal and State Income Taxes increased less than $0.1 million, or 4.6%, in the first three months of 2004 compared to the same period in 2003 reflecting higher pre-tax earnings.

### *Interest Expense, net*

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on short- and 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.

In the first three months of 2004, Interest Expense, net, decreased by $0.3 million as compared to the same period in 2003. This decrease was primarily the result of a reduction of $0.3 million in short-term interest expense due to lower levels of short-term borrowings, and increased income on regulatory assets of $0.1 million, offset by an increase in long-term interest expense of $0.1 million due to a higher level of long-term debt.

## CAPITAL REQUIREMENTS

Cash provided by operating activities was $15.1 million for the three months ended March 31, 2004, an increase of $8.2 million over the same period last year. This increase is due to the positive changes in Working Capital. Recovery of deferred energy costs led to an increase in operating cash of $8.0 million from Accrued Revenues in the first quarter of 2004 compared to the same period in 2003. Changes in Accounts Receivable, Refundable Taxes and Prepayments and Other improved operating cash flows by $5.6 million in the first quarter of 2004 compared to the same period in 2003. Offsetting these positive impacts on operating cash flows were a reduction in deferred taxes of ($3.2 million), principally related to the change in accrued revenue, and a period over period decrease in Accounts Payable of ($3.7 million). Higher net income and all other working capital changes contributed a source of operating cash of $1.5 million, net.

Cash used in investing activities for capital expenditures for the three months ended March 31, 2004 were $4.4 million as compared to $6.0 million during the same period last year, a reduction of $1.6 million. The higher capital expenditures in the first quarter 2003 were mainly due to the construction of a new electric system supply lines from Stratham, NH that added needed capacity to the seacoast region of Unitil's service territory to accommodate customer growth. In total, 2004 capital expenditures are estimated to be $21.9 million, or equivalent to 2003 capital expenditures. These capital expenditures will be used for utility system expansions, replacements and other improvements.

Cash flows used in financing activities were $11.9 million in the first quarter 2004 compared with $5.5 million in the prior period. Cash used for financing activities in the current period includes a repayment of short-term borrowings of approximately $7.0 million from cash flow from operations. In addition, during the first quarter 2004 the Company repaid long-term debt amounting to $3.1 million, which retired the FG&E 8.55% Notes.

## 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, issued in January 2003, and revised Interpretation No. 46, issued in December 2003 (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.

**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 March 31, 2004, 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.

**INTEREST RATE RISK**

The Company meets its external financing needs by issuing short-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 (pre-tax). The average interest rates on the Company's short-term borrowings for the three months ended March 31, 2004 and March 31, 2003 were 1.55% and 1.87%, 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

**PLEASE ALSO REFER TO NOTE 6 TO THE CONSOLIDATED FINANCIAL STATEMENTS IN PART I, ITEM 1 OF THIS REPORT FOR A DETAILED DISCUSSION OF REGULATORY MATTERS.**

**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 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 March 31, 2004, UES had recorded on its balance sheets $88.4 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 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.

On March 17, 2004, UES filed its first annual reconciliation and rate filing with the NHPUC under its restructuring plan, seeking revised rates for the Transition Service Charge, Default Service Charge, Stranded Cost Charge, and External Delivery Charge. These rates are proposed to become effective on May 1, 2004. The net impact of all proposed rate changes for effect on May 1, 2004 (see discussion of UES' March 15, 2004 rate filing regarding PBOP costs, in "*Other Regulatory Procedings*, below) is a decrease of 1.4 percent. In this filing, UES is also seeking an accounting order to defer and amortize transaction and issuance costs associated with the reorganization of Concord Electric Company into Exeter & Hampton Electric Company to form UES.

**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 filing eliminates NEPOOL as an organization and requires all current NEPOOL members to be part of the RTO system. On March 24, 2004, FERC issued an order accepting the RTO proposal of the New England transmission owners and ISO-NE. In its order, FERC granted the request of UES and FG&E to be allowed to provide wholesale transmission services on a similar basis to other wholesale services provided by transmission owners in New England.

On March 1, 2004, ISO-NE filed a proposal to implement Locational Installed Capacity (LICAP) in New England to allow for the imposition of incentive pricing for transmission constrained areas. FGE and UES have intervened in the proceeding. Both FG&E and UES are located in a non-constrained area of the power pool which should have modest LICAP prices for several years under the filed proposal. ISO-NE also requested that FERC indicate what market entities should have the long-term obligation to contract for LICAP and recommended that the obligation should be the responsibility of distribution utilities. FG&E and UES commented that this question has significant implications on state retail choice programs and potentially on financial assurance issues for the distribution companies.

SMD, the formation of an RTO, LICAP and other wholesale market changes are not expected to have a material impact on Unitil's operations because of the 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 February 5, 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 March 15, 2004 UES filed a petition with the NHPUC for recovery of PBOP costs. UES proposes an increase to its distribution base rates of $1.0 million to provide for the recovery of these costs, effective May 1, 2004.

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. On March 18, 2004 FG&E filed its summer CGAC for effect May 1, 2004. Gas costs are projected to be approximately 2.3 percent lower on average than current rates. The temporary refund which reduced rates in February, March and April will cease, however, resulting in a net average increase to customers of 8.6 percent.

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 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 $600,000 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, and established a schedule for formal hearings beginning on August 24, 2004. 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

**Sawyer Passway MGP Site –** As discussed in Note 7 to Financial Statements included in this report, 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.

*__Item 1.  Financial Statements__*

**UNITIL CORPORATION AND SUBSIDIARY COMPANIES**
**CONSOLIDATED STATEMENTS OF EARNINGS**
(000's except common shares and per share data)
(UNAUDITED)

| | Three Months Ended March 31, 2004 | 2003 |
|---|---|---|
| **Operating Revenues** | | |
| Electric | **$ 47,451** | $ 52,070 |
| Gas | **11,637** | 12,404 |
| Other | **405** | 333 |
| Total Operating Revenues | **59,493** | 64,807 |
| **Operating Expenses** | | |
| Purchased Electricity | **33,212** | 38,162 |
| Purchased Gas | **7,305** | 8,055 |
| Operation and Maintenance | **5,965** | 5,864 |
| Conservation & Load Management | **873** | 443 |
| Depreciation and Amortization | **4,764** | 4,948 |
| Provisions for Taxes: | | |
| Local Property and Other | **1,410** | 1,384 |
| Federal and State Income | **1,338** | 1,279 |
| Total Operating Expenses | **54,867** | 60,135 |
| **Operating Income** | **4,626** | 4,672 |
| Non-Operating Expenses | **42** | 51 |
| **Income Before Interest Expense** | **4,584** | 4,621 |
| Interest Expense, Net | **1,778** | 2,082 |
| **Net Income** | **2,806** | 2,539 |
| Less Dividends on Preferred Stock | **59** | 60 |
| **Earnings Applicable to Common Shareholders** | **$ 2,747** | $ 2,479 |
| Average Common Shares Outstanding – Basic | **5,494,255** | 4,743,696 |
| Average Common Shares Outstanding – Diluted | **5,517,351** | 4,763,229 |
| Earnings Per Common Share (Basic and Diluted) | **$ 0.50** | $ 0.52 |
| Dividends Declared Per Share of Common Stock | **$ 0.69** | $ 0.69 |

*(The accompanying notes are an integral part of these statements.)*

**UNITIL CORPORATION AND SUBSIDIARY COMPANIES**
**CONSOLIDATED BALANCE SHEETS**
*(000's)*

| | (UNAUDITED) March 31, 2004 | (UNAUDITED) March 31, 2003 | (AUDITED) December 31, 2003 |
|---|---|---|---|
| **ASSETS:** | | | |
| **Utility Plant:** | | | |
| Electric | **$ 211,138** | $ 198,030 | $ 209,288 |
| Gas | **48,880** | 45,137 | 48,700 |
| Common | **27,720** | 28,982 | 27,441 |
| Construction Work in Progress | **3,583** | 4,781 | 3,228 |
| Total Utility Plant | **291,321** | 276,930 | 288,657 |
| Less: Accumulated Depreciation | **95,306** | 85,403 | 93,592 |
| Net Utility Plant | **196,015** | 191,527 | 195,065 |
| **Current Assets**: | | | |
| Cash | **2,560** | 2,581 | 3,766 |
| Accounts Receivable – Net of Allowance for Doubtful Accounts of $511, $594 and $541 | **19,159** | 22,645 | 17,461 |
| Accrued Revenue | **7,272** | 10,078 | 10,029 |
| Refundable Taxes | **(341)** | 2,025 | 3,816 |
| Materials and Supplies | **2,184** | 2,124 | 2,861 |
| Prepayments | **3,132** | 1,617 | 6,146 |
| Total Current Assets | **33,966** | 41,070 | 44,079 |
| **Noncurrent Assets:** | | | |
| Regulatory Assets | **220,115** | 255,753 | 227,528 |
| Prepaid Pension Costs | **10,818** | --- | 10,972 |
| Debt Issuance Costs | **1,822** | 1,735 | 1,844 |
| Other Noncurrent Assets | **5,159** | 4,883 | 4,389 |
| Total Noncurrent Assets | **237,914** | 262,371 | 244,733 |
| TOTAL | **$ 467,895** | $ 494,968 | $ 483,877 |

*(The accompanying notes are an integral part of these statements.)*

**UNITIL CORPORATION AND SUBSIDIARY COMPANIES**
**CONSOLIDATED BALANCE SHEETS (Cont.)**
*(000's)*

| | (UNAUDITED) March 31, 2004 | (UNAUDITED) March 31, 2003 | (AUDITED) December 31, 2003 |
|---|---|---|---|
| **CAPITALIZATION AND LIABILITIES:** | | | |
| **Capitalization:** | | | |
| Common Stock Equity | **$ 92,035** | $ 73,613 | $ 92,805 |
| Preferred Stock, Non-Redeemable, Non-Cumulative | **225** | 225 | 225 |
| Preferred Stock, Redeemable, Cumulative | **3,044** | 3,068 | 3,044 |
| Long-Term Debt, Less Current Portion | **110,892** | 101,162 | 110,961 |
| Total Capitalization | **206,196** | 178,068 | 207,035 |
| **Current Liabilities:** | | | |
| Long-Term Debt, Current Portion | **268** | 3,247 | 3,263 |
| Capitalized Leases, Current Portion | **525** | 719 | 567 |
| Accounts Payable | **16,156** | 19,049 | 15,024 |
| Short-Term Debt | **15,430** | 35,500 | 22,410 |
| Dividends Declared and Payable | **1,971** | 1,707 | 70 |
| Refundable Customer Deposits | **1,425** | 1,338 | 1,429 |
| Interest Payable | **2,020** | 1,880 | 1,356 |
| Other Current Liabilities | **4,567** | 6,548 | 4,254 |
| Total Current Liabilities | **42,362** | 69,988 | 48,373 |
| **Deferred Income Taxes** | **56,152** | 54,134 | 56,900 |
| **Noncurrent Liabilities:** | | | |
| Power Supply Contract Obligations | **159,897** | 187,969 | 167,341 |
| Capitalized Leases, Less Current Portion | **297** | 2,394 | 403 |
| Other Noncurrent Liabilities | **2,991** | 2,415 | 3,825 |
| Total Noncurrent Liabilities | **163,185** | 192,778 | 171,569 |
| TOTAL | **$ 467,895** | $ 494,968 | $ 483,877 |

*(The accompanying notes are an integral part of these statements.)*

**UNITIL CORPORATION AND SUBSIDIARY COMPANIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
*(000's)*
(UNAUDITED)

| | Three Months Ended March 31, | |
|---|---|---|
| | **2004** | 2003 |
| **Cash Flow from Operating Activities:** | | |
| Net Income | **$ 2,806** | $ 2,539 |
| Adjustments to Reconcile Net Income to Cash Provided by Operating Activities: | | |
| Depreciation and Amortization | **4,764** | 4,948 |
| Deferred Tax Provision | **(1,409)** | 1,745 |
| Changes in Current Assets and Liabilities: | | |
| Accounts Receivable | **(1,698)** | (3,132) |
| Accrued Revenue | **2,757** | (5,236) |
| Refundable Taxes | **4,157** | 2,826 |
| Materials and Supplies | **677** | 199 |
| Prepayments and Other | **3,014** | 118 |
| Accounts Payable | **1,132** | 4,828 |
| Interest Payable | **664** | 569 |
| Other Current Liabilities | **313** | (2,514) |
| Other, net | **(2,111)** | (101) |
| Cash Provided by Operating Activities | **15,066** | 6,789 |
| **Cash Flows from Investing Activities:** | | |
| Property, Plant and Equipment Additions | **(4,367)** | (5,865) |
| Cash Used in Investing Activities | **(4,367)** | (5,865) |
| **Cash Flows from Financing Activities:** | | |
| Repayment of Short-Term Debt | **(6,980)** | (490) |
| Repayment of Long-Term Debt | **(3,064)** | (3,060) |
| Dividends Paid | **(1,957)** | (1,703) |
| Issuance of Common Stock | **244** | --- |
| Retirement of Preferred Stock | **---** | (29) |
| Repayment of Capital Lease Obligations | **(148)** | (221) |
| Cash Provided By (Used in Financing) Activities | **(11,905)** | (5,503) |
| Net Decrease in Cash | **(1,206)** | (4,579) |
| Cash at Beginning of Period | **3,766** | 7,160 |
| Cash at End of Period | **$ 2,560** | $ 2,581 |
| **Supplemental Cash Flow Information:** | | |
| Interest Paid | **$ 1,603** | $ 1,737 |
| Income Taxes Refunded | **1,333** | 2,936 |

*(The accompanying notes are an integral part of these statements.)*

**NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

**UNITIL'S SIGNIFICANT ACCOUNTING POLICIES ARE DESCRIBED IN NOTE 1 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2003 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 27, 2004.**

**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, issued in January 2003, and revised Interpretation No. 46, issued in December 2003 (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. 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.

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 March 31, 2004. There are no significant intangible assets recorded by the Company at March 31, 2004. Therefore, the Company is not currently involved in making estimates or seeking valuations of these items.

**Off-Balance Sheet Arrangements –** As of March 31, 2004, 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.

**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 March 31, 2004, 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. 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.

**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.

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 March 31, 2004, 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.

**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.

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, "Consolidation of Variable Interest Entities" and in December 2003 issued a revised Interpretation No. 46, (together, 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 $0.3 million, in the three month period ending March 31, 2003, to the Unitil Retiree Trust. There are no other entities identified by the Company that qualify as VIE’s under FIN 46.

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.

**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 – DIVIDENDS DECLARED PER SHARE

| Declaration Date | Date Paid (Payable) | Shareholder of Record Date | Dividend Amount |
|---|---|---|---|
| 03/31/04 | 05/14/04 | 04/30/04 | $ 0.345 |
| 01/15/04 | 02/13/04 | 01/30/04 | $ 0.345 |
| | | | |
| 09/26/03 | 11/14/03 | 10/31/03 | $ 0.345 |
| 06/26/03 | 08/15/03 | 08/01/03 | $ 0.345 |
| 03/21/03 | 05/15/03 | 05/01/03 | $ 0.345 |
| 01/16/03 | 02/15/03 | 02/01/03 | $ 0.345 |

## NOTE 3 – COMMON STOCK AND PREFERRED STOCK

During the first quarter of 2004, the Company sold 9,130 shares of its Common Stock, at an average price of $26.73 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of $244,020 were used to reduce short-term borrowings.

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. 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 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.

During the first quarter of 2003, the Company did not sell any additional shares of its Common Stock.

Details on preferred stock at March 31, 2004, March 31, 2003 and December 31, 2003 are shown below:

(Amounts in Thousands)

| | (Unaudited) March 31, 2004 | (Unaudited) March 31, 2003 | (Audited) December 31, 2003 |
|---|---|---|---|
| Preferred Stock | | | |
| UES Preferred Stock, Non-Redeemable, Non-Cumulative: | | | |
| 6.00% Series, $100 Par Value | **$225** | $225 | $225 |
| UES Preferred Stock, Redeemable, Cumulative: | | | |
| 8.70% Series, $100 Par Value | **215** | 215 | 215 |
| 8.75% Series, $100 Par Value | **314** | 314 | 314 |
| 8.25% Series, $100 Par Value | **375** | 375 | 375 |
| FG&E Preferred Stock, Redeemable, Cumulative: | | | |
| 5.125% Series, $100 Par Value | **922** | 946 | 922 |
| 8.00% Series, $100 Par Value | **1,218** | 1,218 | 1,218 |
| Total Preferred Stock | **$3,269** | $3,293 | $3,269 |

**NOTE 4 – LONG-TERM DEBT**

Details on long-term debt at March 31, 2004, March 31, 2003 and December 31, 2003 are shown below:

(Amounts in Thousands)

| | (Unaudited) March 31, 2004 | (Unaudited) March 31, 2003 | (Audited) December 31, 2003 |
|---|---|---|---|
| **Unitil Energy Systems, Inc.:** | | | |
| First Mortgage Bonds: | | | |
| 8.49% Series, Due October 14, 2024 | **$ 15,000** | $ 15,000 | $ 15,000 |
| 6.96% Series, Due September 1, 2028 | **20,000** | 20,000 | 20,000 |
| 8.00% Series, Due May 1, 2031 | **15,000** | 15,000 | 15,000 |
| **Fitchburg Gas and Electric Light Company:** | | | |
| Long-Term Notes: | | | |
| 8.55% Notes, Due March 31, 2004 | **---** | 3,000 | 3,000 |
| 6.75% Notes, Due November 30, 2023 | **19,000** | 19,000 | 19,000 |
| 7.37% Notes, Due January 15, 2029 | **12,000** | 12,000 | 12,000 |
| 7.98% Notes, Due June 1, 2031 | **14,000** | 14,000 | 14,000 |
| 6.79% Notes, Due October 15, 2025 | **10,000** | --- | 10,000 |
| **Unitil Realty Corp.** | | | |
| Senior Secured Notes: | | | |
| 8.00% Notes, Due August 1, 2017 | **6,160** | 6,409 | 6,224 |
| Total | **111,160** | 104,409 | 114,224 |
| Less: Installments due within one year | **268** | 3,247 | 3,263 |
| Total Long-term Debt | **$ 110,892** | $ 101,162 | $ 110,961 |

## NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three months ended March 31, 2004 and March 31, 2003:

| Three Months Ended March 31, 2004 (000's) | Electric | Gas | Other | Non-Regulated | Eliminations | Total |
|---|---|---|---|---|---|---|
| Revenues | **$ 47,451** | **$ 11,637** | **$ ---** | **$ 405** | | **$ 59,493** |
| Segment Profit (Loss) | **1,555** | **1,189** | **79** | **(76)** | | **2,747** |
| Identifiable Segment Assets | **372,693** | **83,864** | **23,955** | **1,458** | **(14,075)** | **467,895** |
| Capital Expenditures | **3,701** | **479** | **187** | **---** | | **4,367** |
| **Three Months Ended March 31, 2003 (000's)** | | | | | | |
| Revenues | $ 52,070 | $ 12,404 | $ 8 | $ 325 | | $ 64,807 |
| Segment Profit (Loss) | 1,304 | 1,312 | 85 | (222) | | 2,479 |
| Identifiable Segment Assets | 388,148 | 84,445 | 21,314 | 1,710 | (649) | 494,968 |
| Capital Expenditures | 5,471 | 349 | 44 | 1 | | 5,865 |

## NOTE 6 – REGULATORY MATTERS

**UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 15 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2002 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON MARCH 28, 2003.**

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 and FG&E divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under 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 $195 million of power supply-related stranded costs and other restructuring-related regulatory assets 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 March 31, 2004, competitive suppliers were serving approximately 20 percent of FG&E's load, primarily for FG&E's largest customers.

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 $32.2 million and $29.1 million, respectively at March 31, 2004 and March 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 March 31, 2004, FG&E had recorded on its balance sheets $71.5 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 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 March 31, 2004, UES had recorded on its balance sheets $88.4 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.

On March 17, 2004, UES filed its first annual reconciliation and rate filing with the NHPUC under its restructuring plan, seeking revised rates for the Transition Service Charge, Default Service Charge, Stranded Cost Charge, and External Delivery Charge. These rates are proposed to become effective on May 1, 2004. The net impact of all proposed rate changes for effect on May 1, 2004 (see discussion of UES' March 15, 2004 rate filing regarding PBOP costs, in "*Other Regulatory Procedings*, below) is a decrease of 1.4 percent. In this filing, UES is also seeking an accounting order to defer and amortize transaction and issuance costs associated with the reorganization of Concord Electric Company into Exeter & Hampton Electric Company to form UES.

**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 filing eliminates NEPOOL as an organization and requires all current NEPOOL members to be part of the RTO system. On March 24, 2004, FERC issued an order accepting the RTO proposal of the New England transmission owners and ISO-NE. In its order, FERC granted the request of UES and FG&E to be allowed to provide wholesale transmission services on a similar basis to other wholesale services provided by transmission owners in New England.

On March 1, 2004, ISO-NE filed a proposal to implement Locational Installed Capacity (LICAP) in New England to allow for the imposition of incentive pricing for transmission constrained areas. FGE and UES have intervened in the proceeding. Both FG&E and UES are located in a non-constrained area of the power pool which should have modest LICAP prices for several years under the filed proposal. ISO-NE also requested that FERC indicate what market entities should have the long-term obligation to contract for LICAP and recommended that the obligation should be the responsibility of distribution utilities. FG&E and UES commented that this question has significant implications on state retail choice programs and potentially on financial assurance issues for the distribution companies.

SMD, the formation of an RTO, LICAP and other wholesale market changes are not expected to have a material impact on Unitil's operations because of the 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 February 5, 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 March 15, 2004 UES filed a petition with the NHPUC for recovery of PBOP costs. UES proposes an increase to its distribution base rates of $1.0 million to provide for the recovery of these costs, effective May 1, 2004.

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. On March 18, 2004 FG&E filed its summer CGAC for effect May 1, 2004. Gas costs are projected to be approximately 2.3 percent lower on average than current rates. The temporary refund which reduced rates in February, March and April will cease, however, resulting in a net average increase to customers of 8.6 percent.

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 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 $600,000 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, and established a schedule for formal hearings beginning on August 24, 2004. 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.

## NOTE 7 – ENVIRONMENTAL MATTERS

**UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 6 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2003 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 27, 2004.**

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 March 31, 2004, 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 –** During the fourth quarter of 2003, the Company completed an environmental remediation project at a former electric generating station located at Sawyer Passway.

## Note 8: 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 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) | Three Months Ended March 31, **2004** | 2003 |
|---|---|---|
| Service Cost | **$ 325** | $ 287 |
| Interest Cost | **757** | 735 |
| Expected Return on Plan Assets | **(848)** | (893) |
| Amortization of Prior Service Cost | **25** | 26 |
| Amortization of Net (Gain) Loss | **236** | 122 |
| Subtotal NPPC | **495** | 277 |
| Amounts Capitalized and Deferred | **(290)** | (190) |
| NPPC Recognized | **$ 205** | $ 87 |

Included in the 2004 amount above for Amounts Capitalized and Deferred is $143 thousand deferred and recorded as a Regulatory Asset on the Company’s Balance Sheet. The remaining amount in 2004 and the amount in 2003 represent amounts capitalized to construction overheads.

Employer Contributions – As of March 31, 2004, the Company has not made any contributions to the Plan for 2004. The Company is not required to make a funding of its pension plan this year but may elect to do so.

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

| | **Three Months Ended March 31,** | |
|---|---|---|
| **Components of NPPBC (000's)** | **2004** | 2003 |
| Service Cost | **$ 245** | $ 62 |
| Interest Cost | **497** | 140 |
| Expected Return on Plan Assets | **---** | --- |
| Amortization of Prior Service Cost | **365** | 91 |
| Amortization of Transition (Asset) Obligation | **5** | 5 |
| Amortization of Net (Gain) Loss | **---** | 1 |
| Subtotal NPPBC | **1,112** | 299 |
| Amounts Capitalized and Deferred | **(917)** | (236) |
| NPPBC Recognized | **$ 195** | $ 63 |

Included in the 2004 amount above for Amounts Capitalized and Deferred is $508 thousand deferred and recorded as a Regulatory Asset on the Company's Balance Sheet. The remaining amount in 2004 and the amount in 2003 represent amounts capitalized to construction overheads.

In addition to the amounts shown above, the Company also recorded expense for payments to URT of $0.3 million in the three months ended March 31, 2003.

Employer Contributions – As of March 31, 2004, the Company has made $0.4 million of contributions to the Plan. The Company presently anticipates contributing an additional $0.6 million to $1.6 million to fund the Plan in 2004 for a total of $1.0 million to $2.0 million.

**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 components of net periodic SERP cost are as follows:

| Components of Net Periodic SERP Cost (000's) | Three Months Ended March 31, **2004** | | 2003 | |
|---|---|---|---|---|
| Service Cost | **$** | **19** | $ | 15 |
| Interest Cost | | **17** | | 17 |
| Expected Return on Plan Assets | | **---** | | --- |
| Amortization of Prior Service Cost | | **(1)** | | (1) |
| Amortization of Transition Obligation | | **4** | | 4 |
| Amortization of Net Loss | | **1** | | --- |
| Net Periodic SERP Cost | **$** | **40** | $ | 35 |

Employer Contributions – As of March 31, 2004, the Company has made $18,000 of contributions to the Plan. The Company presently anticipates contributing an additional $52,000 to fund the Plan in 2004 for a total of $70 thousand.

### *Item 3. Quantitative and Qualitative Disclosures About Market Risk*

Reference is made to the “Interest Rate Risk” and “Market Risk” sections of Item 2. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” (above).

### *Item 4*. *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-15 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 II. OTHER INFORMATION

### *Item 1. Legal Proceedings*

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 2. Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities*

| Period | Total Number of Shares Purchased | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(1)] | Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs[(1)] |
|---|---|---|---|---|
| 1/1/04 – 1/31/04 | --- | --- | --- | n/a |
| 2/1/04 – 2/29/04 | 126 | $27.00 | 126 | n/a |
| 3/1/04 – 3/31/04 | --- | --- | --- | n/a |
| Total | 126 | $27.00 | 126 | n/a |

(1) Represents Common Stock purchased on the open market related to Board of Director Retainer Fees and Employee Length of Service Awards. Shares are not purchased as part of a specific plan or program and therefore there is no pool or maximum number of shares related to these purchases.

## *Item 6. Exhibits and Reports on Form 8-K*

(a) Exhibits

| Exhibit No. | Description of Exhibit | Reference |
|---|---|---|
| 11 | Computation in Support of Earnings Per Average Common Share | 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 |
| 99.1 | Unitil Corporation Press Release Dated April 28, 2004 Announcing Earnings For the Quarter Ended March 31, 2004 | Filed herewith |

(b) Reports on Form 8-K

On February 6, 2004, Unitil Corporation filed a Current Report on Form 8-K reporting that it had issued a press release announcing results of operations for the three and twelve month periods ended December 31, 2003.

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION
(Registrant)

Date: April 28, 2004 /s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Date: April 28, 2004 /s/ Laurence M. Brock
Laurence M. Brock
Controller