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 September 30, 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 October 27, 2004
Common Stock, No par value	5,538,604 Shares

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
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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

Earnings Overview

The Company’s Net Income was $1.2 million for the third quarter of 2004 compared to $1.4 million for the third quarter of 2003. Results for the third quarter of 2004 compared to the prior year reflect lower quarterly sales and higher operating and maintenance expenses which were partially offset by lower interest expense. Electric and gas sales margins were adversely affected, by ($0.1 million), due to abnormally mild summer weather in our utility service territories. The mild summer temperatures in our area were 33% below normal and that resulted in reduced usage of electricity for air conditioning and other cooling purposes. In addition, the Company recorded a reserve in Operating and Maintenance Expenses for uncollectible amounts, of ($0.2 million), from a large customer who filed bankruptcy in September 2004. Other increases in Operating and Maintenance Expenses in the quarter, of ($0.3 million), primarily relate to higher retiree and employee benefit costs. Interest Expense in the third quarter was $0.3 million favorable to the same period last year and the total of all other changes in revenues and expenses and taxes, as discussed below, were a net $0.1 million favorable to prior year. Through the first nine months of 2004, Net Income was $5.5 million, an increase of 3% over the first nine months of 2003.

Earnings per common share were $0.22 for the third quarter of 2004 compared with earnings of $0.30 per share for the third quarter of 2003. Through the first nine months of 2004, earnings per share were $1.00 compared with earnings of $1.12 per share in the first nine months of 2003. The Earnings per share figures in 2004 reflect approximately 16% more shares outstanding due to the Company's public offering in the fourth quarter of 2003.

Operating Revenues — Electric

Electric Operating Revenues - Electric Operating Revenues, decreased by $2.8 million, or 5.7%, and by $7.9 million, or 5.4%, in the three and nine month periods ended September 30, 2004, respectively, compared to the same periods in 2003. Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The decreases in Operating Revenues primarily reflect lower Purchased Electricity costs compared to prior periods. The Purchased Electricity cost of sales component decreased $2.6 million, or 7.6%, and $8.9 million, or 8.6%, in the three and nine month periods ended September 30, 2004, respectively, compared to the same periods in 2003, reflecting lower electric commodity prices. Purchased Electricity expenses include the cost of electric supply as well as the other energy supply related restructuring costs, including long-term power supply contract buyout costs. The Company recovers the cost of Purchased Electricity in its rates at cost on a pass through basis. C&LM revenues related to electric operations decreased $0.1 million, or 14.1% in the three month period ended September 30, 2004 and increased $0.4 million, or 21.6% in the nine month period ended September 30, 2004, compared to the same periods in 2003. The net increase in the nine month period reflects increased spending on energy efficiency programs that were implemented during that period. The Company also recovers the costs of C&LM on a pass through basis.

Electric sales margin (Electric Operating Revenues less cost of electric sales) was $13.7 million and $40.5 million in the three and nine month periods ended September 30, 2004, respectively. This represents a decrease of less than $0.1 million in the three month period and an increase of $0.5 million in the nine month period, compared to the same periods in 2003. The decrease in the three month period reflects the impact on sales of the abnormally mild summer weather which drove lower kilowatt-hour (kWh) unit sales to residential customers as well as a 1.0% decrease in peak demand billings to large industrial customers, as compared to the same period in 2003. Peak demand billings are the primary determinant of electric service margins earned from the Company's commercial and industrial customer classes. On the other hand, kWh unit sales are the primary driver of electric service margins earned from the Company's residential customer class. The increase in the nine month period reflects increased kWh unit sales to both residential and commercial and industrial customer classes during these periods, partially offset by lower peak demand billings in 2004.

The following table details total Electric Operating Revenues and Sales Margin for the three and nine month periods ended September 30, 2004 and 2003:

Electric Operating Revenues and Sales Margin (000's)

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2004	2003	% Change	**2004**	2003	% Change
Electric Operating Revenue	**$ 46,547**	$ 49,362	(5.7%)	**$ 137,540**	$ 145,448	(5.4%)
Purchased Electricity	**32,010**	34,641	(7.6%)	**94,573**	103,463	(8.6%)
Conservation & Load Management	**854**	994	(14.1%)	**2,505**	2,060	21.6%
Electric Sales Margin	**$ 13,683**	$ 13,727	(0.3%)	**$ 40,462**	$ 39,925	1.3%

Kilowatt-hour Sales – Unitil's total electric kilowatt-hour (kWh) sales decreased (1.0%) in the three months ended September 30, 2004 compared to the same period in 2003 and increased 1.6% in the nine month period ended September 30, 2004 compared to the same period in 2003. The decrease in the three month period reflects lower kWh sales to residential customers, driven primarily by 33% cooler summer weather than in the same period of 2003, offset partially by increased kWh sales to commercial and industrial customer classes The increase in the nine month period was driven primarily by increased kWh sales to commercial and industrial customer classes. Despite higher kWh sales to commercial and industrial customers in the current periods, peak demand billings for this group of customers declined 1.0% and 0.1% in the three month and nine month periods, respectively. Peak demand billings are a measure of the maximum amount of electricity supply a customer requires from the system at a point in time during the billing period. This decline in peak demand billings reflects changes in usage patterns of commercial and industrial customers due to the impact of such factors as the cooler summer weather, energy efficiency improvements and changes in production processes. In addition, we have experienced the decline in peak demand billings for certain of our large manufacturing customers that are experiencing a slower-than-expected recovery during the current economic business cycle.

The following table details total kWh sales for the three and nine months ended September 30, 2004 and 2003 by major customer class:

kWh Sales (000's)

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2004	2003	% Change	**2004**	2003	% Change
Residential	**168,290**	174,657	(3.6%)	**499,021**	497,164	0.4%
Commercial/Industrial	**291,236**	289,491	0.6%	**831,378**	811,990	2.4%
Total	**459,526**	464,148	(1.0%)	**1,330,399**	1,309,154	1.6%

Operating Revenues - Gas

Gas Operating Revenues – Gas Operating Revenues decreased $0.1 million, or 3.2%, and $1.5 million, or 7.1%, in the three and nine month periods ended September 30, 2004, respectively, compared to the same periods in 2003. Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses.

Purchased Gas decreased $0.1 million, or 2.4%, and $1.1 million, or 8.6%, in the three and nine month periods ended September 30, 2004, respectively, compared to the same periods in 2003. The decrease in Purchased Gas in the three month period is primarily attributable to lower gas commodity costs while the decrease in the nine month period is primarily attributable to lower gas unit sales. Purchased Gas costs include the cost of gas supply as well as the other energy supply related costs. The Company recovers the cost of Purchased Gas in its rates at cost on a pass through basis. C&LM expenses related to gas operations decreased less than $0.1 million in the three month period ended September 30, 2004 and increased less than $0.1million in the nine month period ended September 30, 2004, compared to the same periods in 2003. The Company also recovers the costs of C&LM on a pass through basis.

Gas sales margin (Gas Operating Revenue less the costs of gas sales) was $1.3 million and $7.5 million in the three and nine month periods ended September 30, 2004, respectively. This represents decreases of less than $0.1 million and $0.4 million compared to the same periods in 2003, respectively. Although total firm therm unit sales increased 2.7% in the three month period ended September 30, 2004 compared to the same period in 2003, peak demand billings to large industrial gas customers decreased 2.9% resulting in lower period over period margins for these customers. The decrease in the nine month period is attributable to lower firm therm unit sales, reflecting milder weather through the first nine months of 2004 compared to the same period in 2003, as well as lower peak demand billings to large industrial gas customers, which decreased 7.8% period over period. This decline in peak demand billings reflects changes in usage patterns of commercial and industrial customers due to the impact of such factors as the cooler summer weather, energy efficiency improvements and changes in production processes. As discussed above, certain of our manufacturing customers have also been negatively affected by the slower-than-expected recovery during the current economic business cycle.

The following table details total Gas Operating Revenues and Margin for the three and nine months ended September 30, 2004 and 2003:

Gas Operating Revenues and Sales Margin (000's)

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2004	2003	% Change	**2004**	2003	% Change
Gas Operating Revenue	**$ 3,164**	$ 3,269	(3.2%)	**$ 19,531**	$ 21,029	(7.1%)
Purchased Gas	**1,727**	1,769	(2.4%)	**11,794**	12,909	(8.6%)
Conservation & Load Management	**95**	110	(13.6%)	**278**	229	21.4%
Gas Sales Margin	**$ 1,342**	$ 1,390	(3.5%)	**$ 7,459**	$ 7,891	(5.5%)

Therm Sales – Unitil's total firm therm sales of natural gas increased 2.7% in the three months ended September 30, 2004 compared to the same period in 2003 and decreased 6.3% in the nine months ended September 30, 2004 compared to the same period in 2003. The decrease in the nine month period was primarily due to a milder winter heating season in 2004 compared to the prior year and lower gas usage by our largest customers for production processes. Sales to residential customers decreased 0.9% and 6.7% in the three and nine months ended September 30, 2004, respectively, compared to the same periods in 2003. Sales to commercial and industrial customers increased 5.4% in the in the three months ended September 30, 2004 compared to the same period in 2003 and decreased 5.8% in the nine months ended September 30, 2004 compared to the same period in 2003.

The following table details total firm therm sales for the three and nine months ended September 30, 2004 and 2003, by major customer class:

Firm Therm Sales (000's)

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2004	2003	% Change	**2004**	2003	% Change
Residential	**777**	784	(0.9%)	**8,822**	9,454	(6.7%)
Commercial/Industrial	**1,087**	1,031	5.4%	**8,898**	9,448	(5.8%)
Total	**1,864**	1,815	2.7%	**17,720**	18,902	(6.3%)

Operating Revenue - Other

Total Other Revenues increased $0.1 million, or 29.5%, and $0.2 million, or 27.3% in the three and nine month periods ended September 30, 2004, respectively, compared to the same periods in 2003. These increases were the result of growth in revenues from the Company's unregulated energy brokering business, Usource.

The following table details total Other Revenue for the three and nine months ended September 30, 2004 and 2003:

Other Revenue (000's)

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2004	2003	% Change	**2004**	2003	% Change
Usource	**$ 338**	$ 254	33.1%	**$ 1,077**	$ 824	30.7%
Other	**---**	7	---	**---**	22	---
Total Other Revenue	**$ 338**	$ **261**	29.5%	**$ 1,077**	$ 846	27.3%

Operating Expenses

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as the other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity expenses decreased $2.6 million, or 7.6%, and $8.9 million, or 8.6%, in the three and nine month periods ended September 30, 2004, respectively, compared to the same periods in 2003, reflecting lower wholesale electric purchased power prices. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not impact Net Income.

Purchased Gas – Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas decreased $0.1 million, or 2.4%, and $1.1 million, or 8.6%, in the three and nine month periods ended September 30, 2004, respectively, compared to the same periods in 2003. The decrease in Purchased Gas in the three month period is primarily attributable to lower wholesale gas commodity costs while the decrease in the nine month period is primarily attributable to lower gas unit sales. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis 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 $0.5 million, or 9.1%, and $0.7 million, or 4.3% in the three and nine month periods ended September 30, 2004, respectively, compared to the same periods in 2003.

The increase in the three month period reflects the recording by the Company of a reserve for uncollectible amounts from a large customer which filed bankruptcy in September, $0.2 million, and higher compensation, and retiree and employee benefit and other costs of $0.3 million. The increase in the nine month period reflects higher compensation expenses of $0.5 million and higher retiree and employee benefit expenses of $0.4 million, partially offset by lower other net utility operating expenses, ($0.2 million).

Conservation & Load Management – C&LM expenses are 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 C&LM expenses decreased $0.2 million, or 14.0%, in the three month period ended September 30, 2004 and increased $0.5 million, or 21.6%, in the nine month period ended September 30, 2004, compared to the same periods in 2003. The decrease in the three month period and the increase in the nine month period reflect changes in spending on Energy Efficiency programs that were implemented in 2004. These costs are collected from customers on a pass through basis and therefore, fluctuations in program costs have no impact on Net Income.

Depreciation, Amortization and Taxes

Depreciation and Amortization - Depreciation and Amortization expense increased $0.2 million, or 3.9% and $0.1 million, or less than 1.0%, for the three and nine month periods ended September 30, 2004 compared to the same periods in 2003. These increases were primarily due to increased depreciation and amortization on normal plant additions and regulatory assets, partially offset by lower amortization of corporate intangible assets compared to last year.

Local Property and Other Taxes - Local Property and Other Taxes increased by less than $0.1 million, or 1.0%, and $0.1 million, or 2.5%, the three and nine month periods ended September 30, 2004, respectively, compared to the same periods in 2003. These increases were due to increases in payroll and property taxes.

Federal and State Income Taxes - Federal and State Income Taxes are lower by $0.3 million in the third quarter of 2004 compared to 2003 reflecting lower pre-tax earnings and lower by $0.1 million for the nine months ended September 30, 2004 due to higher amortization of deferred tax credits on Regulatory Assets through the first nine months of 2004.

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.

Interest Expense, net, decreased by $0.3 million and $0.8 million in the three and nine month periods ended September 30, 2004, respectively, as compared to the same periods in 2003. The decrease in the nine month period was the result of a reduction of $0.5 million in short-term interest expense due to lower levels of short-term borrowings, and increased interest income on regulatory assets of $0.6 million, offset by an increase in long-term interest expense of $0.3 million due to a higher level of long-term debt.

CAPITAL REQUIREMENTS

Cash provided by operating activities was $28.7 million during the first nine months of 2004, an increase of $13.7 million over the comparable period last year. This increase in cash provided by operating activities compared to last year primarily reflects changes in current assets and liabilities which taken together represent the Company's working capital requirements. A major source of cash in working capital through September 30, 2004, was the collection of Accrued Revenues, which represents an improvement of $8.8 million in operating cash flow compared to last year. This change in Accrued Revenues principally reflects the recovery of previously deferred energy costs from 2003 that that are being recovered over a 22-month period ending in April 2005. Cash flow from Other Current Liabilities increased $6.6 million over the comparable period in 2003 mainly due to the absence in 2004 of funding that was required in 2003 of approximately $3.5 million for an environmental remediation project and $1.4 million for nonrecurring restructuring charges. Other sources and uses of operating cash flow for the period are a net ($1.7million), including a $0.2 million source of cash from increases in Net Income.

Cash used in investing activities for the nine months ended September 30, 2004 was $17.1 million compared with $16.3 million during the same period last year, an increase of $0.8 million. Cash used in investing activities reflects normal electric and gas utility system capital additions, improvements and replacements.

Cash flows used in financing activities were $11.5 million in the first nine months of 2004 compared with $2.1 million in the comparable period of 2003. Cash used for financing activities in the current period includes repayment of short-term debt of $2.7 million, repayment of long-term debt of $3.2 million and payment of dividends to shareholders of $5.9 million. Other net sources provided $0.3 million. The repayment of long-term debt fully retired the FG&E 8.55% Notes that matured in March 2004. On October 15, 2004, UES redeemed all of its three Series of Redeemable Cumulative Preferred Stock in the amount of approximately $0.9 million. This transaction will be recorded in the Company's financial statements in the fourth quarter of 2004. (See Note 9.)

At September 30, 2004 and December 31, 2003, Unitil had an aggregate of $33.0 and $52.0 million, respectively, in unsecured revolving lines of credit through three banks. The revolving lines of credit were reduced after the October 2003 receipt of approximately $16.9 million (after deducting underwriting discounts, commissions and the other expenses of the offering) through the sale of Common Stock and the issuance of $10.0 million of long-term Notes by the Company's subsidiary, FG&E. The Company expects to renew its lines of credit annually on or about June 30, 2005 and anticipates that it will be able to secure, renew or replace its revolving lines of credit in the future in accordance with its projected requirements. Average daily short-term borrowings during the first nine months of 2004 were approximately $26.3 million, a decrease of approximately $14.3 million over the comparable period in 2003. At September 30, 2004, the Company had available approximately $13.3 million of unused bank lines of credit and had short-term debt outstanding through bank borrowings of approximately $19.7 million. In addition, Unitil had $3.8 million in cash at September 30, 2004.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to two years or less. As of September 30, 2004, there are $0.3 million of guarantees outstanding and these guarantees extend through October 21, 2005.

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 judgments, 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 recognizes the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and specifies 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 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.

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 recorded. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts - The Company recognizes a Provision for Doubtful 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 Doubtful 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 bad debts that are recoverable through regulatory rate reconciling mechanisms. Evaluating the adequacy of the Allowance for Doubtful 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 Doubtful Accounts to maintain an adequate Allowance for Doubtful 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, 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", (PBOP). 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 PBOP 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 PBOP 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 if the effect of those changes is not recoverable in regulatory rate mechanisms. 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.

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 September 30, 2004 and September 30, 2003 were 1.97% and 1.74%, respectively. The average interest rates on the Company's short-term borrowings for the nine months ended September 30, 2004 and September 30, 2003 were 1.70% and 1.82%, 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.

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). Over the past several years, the Company has completed the restructuring of its electric and natural gas operations in order to implement retail choice as mandated in 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, 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 delivery 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 its long-term power supply contracts and FG&E divested 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 reconciling rate mechanisms.

UES and FG&E have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next 6 to 8 years, is $181 million as of September 30, 2004 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet. Unitil's retail distribution utilities have also implemented comprehensive customer and financial information systems to accommodate the transition to competitive energy markets and retail choice.

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. In this filing, UES also sought an accounting order to defer and amortize transaction and issuance costs associated with the merger of E&H with and into CECo to form UES. The NHPUC issued orders approving the deferal and proposed rates, as modified by UES during the course of the proceeding, for effect on May 1, 2004. The net impact of the proposed rate changes (see discussion of UES' March 15, 2004 rate filing regarding PBOP costs, in "*Other Regulatory Procedings*, below) was a retail rate decrease of 1.8 percent.

On October 26, 2004, UES filed a Petition for Approval for a one year extension of Transition Service and Default Service for rate class G1, and approval of the associated solicitation process whereby UES intends to secure energy supplies for such extended service. UES' restructuring settlement provided that the provision of Transition and Default Service may be extended for the G1 class one year. If approved, UES' Transition Service supply obligation for all rate classes would end at the same time on April 30, 2006. The Company recovers the costs of Transition Service and Default Service in its rates at cost on a pass through basis and therefore changes in these expenses do not impact Net Income.

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 prepaid pension plan assets, which have been triggered by the substantial decline in the capital markets and a sharp decrease in interest rates. These approvals allowed FG&E and UES to offset the additional minimum pension liability obligation as a Regulatory Asset and avoid the reduction in equity that would otherwise have been 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 liability obligations are offset by amounts included in Regulatory Assets on the Company's balance sheet.

On April 30, 2004, FG&E filed new tariffs with the MDTE to establish a reconciliation adjustment mechanism for both its Gas Division and Electric Division to provide for the recovery of costs associated with the Company's employee pension benefits and Post Retirement Benefits Other than Pension (PBOP) expenses. On October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism related to pension and PBOP costs. As part of this ruling, FG&E is allowed to record a regulatory asset in lieu of taking a charge to expense for the difference between the level of pension and PBOP expenses that are included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106, since the effective date of its last base rate change. This mechanism removes the volatility in earnings that may result from requirements of existing accounting standards and provides for an annual filing and rate adjustment with the MDTE. For the nine month period ended September 30, 2004, FG&E was allowed to defer for recovery, through the rate adjustment mechanism, pension and PBOP expenses of $1.0 million. As of September 30, 2004, FG&E has recorded a regulatory asset of $1.6 million which is included as part of Regulatory Assets in the Company's Consolidated Balance Sheets.

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 proposed an increase to its distribution base rates of $1.0 million to provide for the recovery of these costs, effective May 1, 2004. The NHPUC issued orders approving the proposed rates, for effect on 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. The rates were approved as filed on April 29, 2004. Gas costs included in the new rates were projected to be approximately 2.3 percent lower on average than in the previous rates. However, the temporary refund which had reduced rates in February, March and April ended, resulting in a net average increase to customers of 8.6 percent. On September 17, 2004 FG&E filed its winter CGAC for effect November 1, 2004. The proposed rates result in an average increase to customers of 16.3% versus current summer rates.

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 accepted the new tariff effective October 28, 2003, subject to refund. A settlement among certain parties to the proceeding was approved by the FERC on September 16, 2004. The settlement, among other things, reduces the allowed Return on Equity that NU can use in the formula rates and will result in refunds to the tariff customers, including UES. The settlement does not address a specific issue raised by UES. A formal hearing on UES' protest was held and briefs and reply briefs were submitted to the Administrative Law Judge during the third quarter of 2004. The Administrative Law Judge's decision is expected during the fourth quarter of 2004, to be followed by review and final order by the 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 the NHPUC.

ENVIRONMENTAL MATTERS

PLEASE ALSO REFER TO NOTE 7 TO THE CONSOLIDATED FINANCIAL STATEMENTS IN PART I, ITEM 1 OF THIS REPORT FOR A DETAILED DISCUSSION OF ENVIRONMENTAL MATTERS.

As discussed in Note 7 to the Consolidated 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, to January 2008. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

On May 13, 2004 FG&E discovered an unauthorized excavation by a third party on the site at Sawyer Passway in which tainted soils related to MGP by-products were exposed and relocated by another property owner at the site onto property owned by FG&E. FG&E promptly reported this discovery to DEP and subsequently received a Notice of Responsibility on May 20, 2004. FG&E has properly disposed of the relocated materials and taken other steps in accordance with DEP directives to remedy the situation. Remediation costs related to this event are recoverable in gas rates, as discussed in the paragraph below, and should not have a material impact on the Company's financial status.

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 1822 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.

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 September 30,		Nine Months Ended September 30,	
	2004	2003	**2004**	2003
Operating Revenues				
Electric	**$ 46,547**	$ 49,362	**$ 137,540**	$ 145,448
Gas	**3,164**	3,269	**19,531**	21,029
Other	**338**	261	**1,077**	846
Total Operating Revenues	**50,049**	52,892	**158,148**	167,323
Operating Expenses				
Purchased Electricity	**32,010**	34,641	**94,573**	103,463
Purchased Gas	**1,727**	1,769	**11,794**	12,909
Operation and Maintenance	**6,038**	5,533	**17,728**	16,989
Conservation & Load Management	**949**	1,104	**2,783**	2,289
Depreciation and Amortization	**4,664**	4,488	**13,821**	13,752
Provisions for Taxes:				
Local Property and Other	**1,213**	1,201	**3,873**	3,780
Federal and State Income	**493**	804	**2,692**	2,745
Total Operating Expenses	**47,094**	49,540	**147,264**	155,927
Operating Income	**2,955**	3,352	**10,884**	11,396
Non-Operating (Income) Expenses	**41**	(71)	**150**	31
Income Before Interest Expense	**2,914**	3,423	**10,734**	11,365
Interest Expense, Net	**1,648**	1,926	**5,058**	5,853
Net Income	**1,266**	1,497	**5,676**	5,512
Less: Dividends on Preferred Stock	**59**	59	**176**	177
Earnings Applicable to Common Shareholders	**$ 1,207**	$ 1,438	**$ 5,500**	$ 5,335
Average Common Shares Outstanding - Basic	**5,514,611**	4,758,295	**5,504,582**	4,750,203
Average Common Shares Outstanding - Diluted	**5,529,433**	4,783,642	**5,519,380**	4,770,469
Earnings Per Common Share (Basic and Diluted)	**$ 0.22**	$ 0.30	**$ 1.00**	$ 1.12
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.38**	$ 1.38

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

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

	(UNAUDITED) September 30, 2004	(UNAUDITED) September 30, 2003	(AUDITED) December 31, 2003
ASSETS:			
Utility Plant:			
Electric	**$ 218,455**	$ 207,302	$ 209,288
Gas	**50,284**	46,285	48,700
Common	**27,987**	27,408	27,441
Construction Work in Progress	**6,328**	3,244	3,228
Total Utility Plant	**303,054**	284,239	288,657
Less: Accumulated Depreciation	**100,947**	91,122	93,592
Net Utility Plant	**202,107**	193,117	195,065
Current Assets:			
Cash	**3,821**	3,728	3,766
Accounts Receivable – Net of Allowance for Doubtful Accounts of $645, $709 and $541	**15,712**	17,276	17,461
Accrued Revenue	**5,607**	9,200	10,029
Refundable Taxes	**(2,930)**	262	3,816
Materials and Supplies	**3,519**	3,664	2,861
Prepayments	**1,632**	1,380	6,146
Total Current Assets	**27,361**	35,510	44,079
Noncurrent Assets:			
Regulatory Assets	**206,444**	230,969	227,528
Prepaid Pension Costs	**9,486**	10,161	10,972
Debt Issuance Costs	**2,290**	1,711	1,844
Other Noncurrent Assets	**4,236**	4,413	4,389
Total Noncurrent Assets	**222,456**	247,254	244,733
TOTAL	**$ 451,924**	$ 475,881	$ 483,877

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

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

	(UNAUDITED) September 30, 2004	(UNAUDITED) September 30, 2003	(AUDITED) December 31, 2003
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 91,515**	$ 73,470	$ 92,805
Preferred Stock, Non-Redeemable, Non-Cumulative	**225**	225	225
Preferred Stock, Redeemable, Cumulative	**3,017**	3,044	3,044
Long-Term Debt, Less Current Portion	**110,749**	101,029	110,961
Total Capitalization	**205,506**	177,768	207,035
Current Liabilities:			
Long-Term Debt, Current Portion	**279**	3,257	3,263
Capitalized Leases, Current Portion	**490**	601	567
Accounts Payable	**13,444**	13,834	15,024
Short-Term Debt	**19,745**	42,305	22,410
Dividends Declared and Payable	**1,981**	1,716	70
Refundable Customer Deposits	**1,513**	1,415	1,429
Interest Payable	**2,195**	1,884	1,356
Other Current Liabilities	**5,497**	3,717	4,254
Total Current Liabilities	**45,144**	68,729	48,373
Deferred Income Taxes	**51,540**	51,660	56,900
Noncurrent Liabilities:			
Power Supply Contract Obligations	**146,811**	174,826	167,341
Capitalized Leases, Less Current Portion	**249**	528	403
Other Noncurrent Liabilities	**2,674**	2,370	3,825
Total Noncurrent Liabilities	**149,734**	177,724	171,569
TOTAL	**$ 451,924**	$ 475,881	$ 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)

	Nine Months Ended September 30,	
	2004	2003
Cash Flow from Operating Activities:		
Net Income	**$ 5,676**	$ 5,512
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**13,821**	13,752
Deferred Tax Provision	**(2,397)**	1,010
Changes in Current Assets and Liabilities:		
Accounts Receivable	**1,749**	2,237
Accrued Revenue	**4,422**	(4,358)
Refundable Taxes	**6,746**	4,589
Materials and Supplies	**(658)**	(1,341)
Prepayments and Other	**914**	355
Accounts Payable	**(1,580)**	(387)
Interest Payable	**839**	573
Other Current Liabilities	**1,243**	(5,345)
Other, net	**(2,111)**	(1,643)
Cash Provided by Operating Activities	**28,664**	14,954
Cash Flows from Investing Activities:		
Property, Plant and Equipment Additions	**(17,074)**	(16,336)
Cash (Used in) Investing Activities	**(17,074)**	(16,336)
Cash Flows from Financing Activities:		
Proceeds From (Repayment of) Short-Term Debt	**(2,665)**	6,312
(Repayment of) Long-Term Debt	**(3,196)**	(3,183)
Dividends Paid	**(5,887)**	(5,102)
Issuance of Common Stock	**718**	476
(Retirement of) Preferred Stock	**(27)**	(53)
(Repayment of) Capital Lease Obligations	**(478)**	(503)
Cash (Used in Financing) Activities	**(11,535)**	(2,050)
Net Increase (Decrease) in Cash	**55**	(3,432)
Cash at Beginning of Period	**3,766**	7,160
Cash at End of Period	**$ 3,821**	$ 3,728
Supplemental Cash Flow Information:		
Interest Paid	**$ (5,910)**	$ (6,327)
Income Taxes (Paid) Refunded	**(869)**	2,581
Supplemental Schedule of Noncash Activities:		
Capital Leases Incurred	**$ 246**	$ 95

(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.

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 September 30, 2004. There are no significant intangible assets recorded by the Company at September 30, 2004. Therefore, the Company is not currently involved in making estimates or seeking valuations of these items.

Off-Balance Sheet Arrangements – As of September 30, 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 recorded. 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 Doubtful Accounts - The Company recognizes a Provision for Doubtful 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 Doubtful 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 Doubtful 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 Doubtful Accounts to maintain an adequate Allowance for Doubtful 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 (PBOP), 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 PBOP 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 PBOP 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. The Company prepares its financial statements in conformity with the guidance provided in The American Institute of Certified Public Accountant's Statement of Position 94-6, "Disclosure of Certain Significant Risks and Uncertainties".

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.

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. 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.

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

In January 2004 and May 2004, the FASB issued, respectively, Statement No. 106-1 (SFAS 106-1) and Statement No. 106-2 (SFAS 106-2), "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", (the Act). The Act includes a subsidy to a plan sponsor that is based on 28 percent of an individual beneficiary's annual prescription drug costs between $250 and $5,000 and the opportunity for a retiree to obtain a prescription drug benefit under Medicare. SFAS 106-1 and SFAS 106-2 require the disclosure of the effects, if any, of the Act on the reported measure of the accumulated postretirement benefit obligation, how that effect has been, or will be, reflected in the net postretirement benefit costs of current or subsequent periods and the effects of any changes in estimates of participation rates on per capita claims cost as a result of the Act. However, since specific authoritative guidance on the accounting for the federal subsidy associated with the Act is pending, a Plan sponsor can elect to defer recognition of the effects of the Act in the accounting for its Plan under SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" and in providing disclosures related to the Plan required by SFAS 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits", until that guidance is issued. The Company has elected to defer recognition of the effects of the Act until specific authoritative guidance on the accounting for the federal subsidy associated with the Act is issued. Please refer to Note 8 to the Consolidated Financial Statements, Pension and Postretirement Benefit Plans, for required disclosures related to the Company's deferral of the recognition of the effects of the Act.

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
09/24/04	11/15/04	11/01/04	$ 0.345
06/24/04	08/13/04	07/30/04	$ 0.345
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 third quarter of 2004, the Company sold 8,454 shares of its Common Stock, at an average price of $25.35 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of $214,284 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, May 12, 2003, was $259,170. On April 29, 2004, 10,700 shares were issued in conjunction with the Plan. The aggregate market value of the restricted stock at the date of issuance, April 29, 2004, was $293,715. 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 third quarter of 2003, the Company sold 9,242 shares of its Common Stock, at an average price of $25.46 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of $235,317 were used to reduce short-term borrowings.

Details on preferred stock at September 30, 2004, September 30, 2003 and December 31, 2003 are shown below:

(Amounts in Thousands)

	(Unaudited) September 30,		(Audited) December 31,
	2004	2003	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	**899**	922	922
8.00% Series, $100 Par Value	**1,214**	1,218	1,218
Total Preferred Stock	**$3,242**	$3,269	$3,269

NOTE 4 – LONG-TERM DEBT

Details on long-term debt at September 30, 2004, September 30, 2003 and December 31, 2003 are shown below:

(Amounts in Thousands)

	(Unaudited) September 30,		(Audited) December 31,
	2004	2003	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	**6,028**	6,286	6,224
Total	**111,028**	104,286	114,224
Less: Installments due within one year	**279**	3,257	3,263
Total Long-term Debt	**$ 110,749**	$ 101,029	$ 110,961

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company's policy is to limit these guarantees to two years or less. As of September 30, 2004, there are $0.3 million of guarantees outstanding and these guarantees extend through October 21, 2005.

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three and nine months ended September 30, 2004 and September 30, 2003:

Three Months Ended September 30, 2004 (000's)	**Electric**	**Gas**	**Other**	**Non-Regulated**	**Total**
Revenues	**$ 46,547**	**$ 3,164**	**$ ---**	**$ 338**	**$ 50,049**
Segment Profit (Loss)	**1,784**	**(596)**	**51**	**(32)**	**1,207**
Identifiable Segment Assets	**358,978**	**82,888**	**9,316**	**742**	**451,924**
Capital Expenditures	**4,359**	**2,071**	**8**	**---**	**6,438**

Three Months Ended September 30, 2003 (000's)					
Revenues	$ 49,361	$ 3,269	$ 7	$ 255	$ 52,892
Segment Profit (Loss)	1,936	(497)	134	(135)	1,438
Identifiable Segment Assets	384,458	81,818	8,138	1,467	475,881
Capital Expenditures	3,341	1,363	258	---	4,962

Nine Months Ended September 30, 2004 (000's)	**Electric**	**Gas**	**Other**	**Non-Regulated**	**Total**
Revenues	**$137,540**	**$ 19,531**	**$ ---**	**$ 1,077**	**$ 158,148**
Segment Profit (Loss)	**5,213**	**251**	**202**	**(166)**	**5,500**
Identifiable Segment Assets	**358,978**	**82,888**	**9,316**	**742**	**451,924**
Capital Expenditures	**12,919**	**3,955**	**200**	**---**	**17,074**

Nine Months Ended September 30, 2003 (000's)					
Revenues	$145,448	$ 21,029	$ 23	$ 823	$ 167,323
Segment Profit (Loss)	5,016	757	146	(584)	5,335
Identifiable Segment Assets	384,458	81,818	8,138	1,467	475,881
Capital Expenditures	13,150	2,865	320	1	16,336

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, 2003 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 27, 2004.

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). Over the past several years, the Company has completed the restructuring of its electric and natural gas operations in order to implement retail choice as mandated in 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, 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 delivery 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 its long-term power supply contracts and FG&E divested 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 reconciling rate mechanisms.

UES and FG&E have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next 6 to 8 years, is $181 million as of September 30, 2004 and is included in Regulatory Assets on the Company's Consolidated Balance Sheet. Unitil's retail distribution utilities have also 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 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 the MDTE. As of September 30, 2004, competitive suppliers were serving approximately 39 percent of FG&E's electric 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, which are included in Unitil Corporation's consolidated financial statements. 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 the Restructuring Act, 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 ends on February 28, 2005. 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 and deferred-cost Regulatory Assets was approximately $33.9 million at September 30, 2004 and $31.7 million at September 30, 2003, and is expected to be recovered in FG&E's rates over the next 6 to 8 years. In addition, as of September 30, 2004, FG&E had recorded on its balance sheets $67.7 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts, which are included in Unitil Corporation's consolidated financial statements . 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 services offered by natural gas local distribution companies (LDCs), the MDTE approved regulations and tariffs for FG&E 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 on whether the mandatory assignment of pipeline capacity should be continued, and that proceeding is ongoing.

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 restructuring included the merger of E&H with and into CECo under a new name, Unitil Energy Systems, Inc. (UES). Pursuant to the approved restructuring plan, Unitil Power agreed to divest its existing long-term power supply portfolio and UES agreed to conduct a solicitation for new power supplies from which to meet its ongoing Transition and Default Service obligations in order to implement customer choice for its 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 for the remaining term of those contracts and agreed to provide Transition and Default

Service supply to UES for up to three years. The NHPUC also approved final tariffs for UES for stranded cost recovery and Transition and Default Service, including certain surcharges that are subject to annual or periodic reconciliation or future review. As of September 30, 2004, UES had recorded on its balance sheets $79.1 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation's consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately 7 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. UES and Unitil Power continue to pursue claims in the bankruptcy proceeding in regard to the Mirant guarantee of MAEM's performance in the event of a future default.

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. In this filing, UES also sought an accounting order to defer and amortize transaction and issuance costs associated with the merger of E&H with and into CECo to form UES. The NHPUC issued orders approving the deferal and proposed rates, as modified by UES during the course of the proceeding, for effect on May 1, 2004. The net impact of the proposed rate changes (see discussion of UES' March 15, 2004 rate filing regarding PBOP costs, in "*Other Regulatory Procedings*, below) was a retail rate decrease of 1.8 percent.

On October 26, 2004, UES filed a Petition for Approval for a one year extension of Transition Service and Default Service for rate class G1, and approval of the associated solicitation process whereby UES intends to secure energy supplies for such extended service. UES' restructuring settlement provided that the provision of Transition and Default Service may be extended for the G1 class one year. If approved, UES' Transition Service supply obligation for all rate classes would end at the same time on April 30, 2006. The Company recovers the costs of Transition Service and Default Service in its rates at cost on a pass through basis and therefore changes in these expenses do not impact Net Income.

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). The filing proposed eliminating NEPOOL as an organization and required 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. The continuation of NEPOOL was affirmed in the FERC order although it would only have advisory review of future RTO changes. FG&E and UES were part of the transmission owners' compliance filing with the FERC on June 22, 2004. That filing included local transmission service tariffs for FG&E and UES. The RTO is scheduled to be implemented not earlier than December 1, 2004. A Settlement filed in September 2004 is actively being contested by several state regulatory agencies, and the FERC proceedings continue to be subject to possible regulatory or judicial challenges which could further delay the implementation of an RTO 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. On June 2, 2004 the FERC issued an order generally accepting the ISO-NE approach to LICAP, but delayed implementation until January 1, 2006 and set many of the issues for hearing, with an initial decision due June 1, 2005. On August 31, 2004, ISO-NE substantially replaced the March 1, 2004 filing with a major updated proposal. Some settlement and informational discussions were held in September, 2004, but this case continues to be heavily contested at FERC.

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 the Company's 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 prepaid pension plan assets, which have been triggered by the substantial decline in the capital markets and a sharp decrease in interest rates. These approvals allowed FG&E and UES to offset the additional minimum pension liability obligation as a Regulatory Asset and avoid the reduction in equity that would otherwise have been 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 liability obligations are offset by amounts included in Regulatory Assets on the Company's balance sheet.

On April 30, 2004, FG&E filed new tariffs with the MDTE to establish a reconciliation adjustment mechanism for both its Gas Division and Electric Division to provide for the recovery of costs associated with the Company's employee pension benefits and Post Retirement Benefits Other than Pension (PBOP) expenses. On October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism related to pension and PBOP costs. As part of this ruling, FG&E is allowed to record a regulatory asset in lieu of taking a charge to expense for the difference between the level of pension and PBOP expenses that are included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106, since the effective date of its last base rate change. This mechanism removes the volatility in earnings that may result from requirements of existing accounting standards and provides for an annual filing and rate adjustment with the MDTE. For the nine month period ended September 30, 2004, FG&E was allowed to defer for recovery, through the rate adjustment mechanism, pension and PBOP expenses of $1.0 million. As of September 30, 2004, FG&E

has recorded a regulatory asset of $1.6 million which is included as part of Regulatory Assets in the Company's Consolidated Balance Sheets.

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 proposed an increase to its distribution base rates of $1.0 million to provide for the recovery of these costs, effective May 1, 2004. The NHPUC issued orders approving the proposed rates, for effect on 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. The rates were approved as filed on April 29, 2004. Gas costs included in the new rates were projected to be approximately 2.3 percent lower on average than in the previous rates. However, the temporary refund which had reduced rates in February, March and April ended, resulting in a net average increase to customers of 8.6 percent. On September 17, 2004 FG&E filed its winter CGAC for effect November 1, 2004. The proposed rates result in an average increase to customers of 16.3% versus current summer rates.

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 accepted the new tariff effective October 28, 2003, subject to refund. A settlement among certain parties to the proceeding was approved by the FERC on September 16, 2004. The settlement, among other things, reduces the allowed Return on Equity that NU can use in the formula rates and will result in refunds to the tariff customers, including UES. The settlement does not address a specific issue raised by UES. A formal hearing on UES' protest was held and briefs and reply briefs were submitted to the Administrative Law Judge during the third quarter of 2004. The Administrative Law Judge's decision is expected during the fourth quarter of 2004, to be followed by review and final order by the 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 the NHPUC.

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 September 30, 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, to January 2008. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed.

On May 13, 2004 FG&E discovered an unauthorized excavation by a third party on the site at Sawyer Passway in which tainted soils related to MGP by-products were exposed and relocated by another property owner at the site onto property owned by FG&E. FG&E promptly reported this discovery to DEP and subsequently received a Notice of Responsibility on May 20, 2004. FG&E has properly disposed of the relocated materials and taken other steps in accordance with DEP directives to remedy the situation. Remediation costs related to this event are recoverable in gas rates, as discussed in the paragraph below, and should not have a material impact on the Company's financial status.

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 1822 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.

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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	**2004**	2003
Components of NPPC (000's)				
Service Cost	**$ 325**	$ 287	**$ 975**	$ 861
Interest Cost	**757**	735	**2,271**	2,205
Expected Return on Plan Assets	**(848)**	(893)	**(2,544)**	(2,679)
Amortization of Prior Service Cost	**25**	26	**75**	78
Amortization of Net (Gain) Loss	**236**	122	**708**	366
Subtotal NPPC	**495**	277	**1,485**	831
Amounts Capitalized and Deferred	**(338)**	(190)	**(930)**	(570)
NPPC Recognized	**$ 157**	$ 87	**$ 555**	$ 261

Included in the 2004 amounts above for Amounts Capitalized and Deferred are $147 thousand and $438 thousand for the three and nine months ended September 30, 2004, respectively, deferred and recorded as a Regulatory Asset on the Company's Balance Sheet. The remaining amounts in 2004 and the amounts in 2003 represent amounts capitalized to construction overheads.

Employer Contributions – As of September 30, 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. The Company contributed $1.2 million in 2003.

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). 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 under its Employee Health and Welfare Benefits Plan discussed below. 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.

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 healthcare and life insurance benefits to Company retirees following their retirement (PBOP Plan).

The Company has established Voluntary Employee Benefit Trusts, into which it began funding contributions to the PBOP Plan 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. On March 15, 2004, UES submitted its filing for retail rate cost recovery with the New Hampshire Public Utilities Commission (NHPUC). On May 3, 2004, the NHPUC approved UES' request for retail rate cost recovery. Accordingly, UES increased its distribution base rates, effective May 1, 2004, to recover PBOP costs. The Company expects to complete its FG&E filing in 2004.

In January 2004 and May 2004, the FASB issued, respectively, Statement No. 106-1 (SFAS 106-1) and Statement No. 106-2 (SFAS 106-2), “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003”, (the Act). The Act includes a subsidy to a plan sponsor that is based on 28 percent of an individual beneficiary’s annual prescription drug costs between $250 and $5,000 and the opportunity for a retiree to obtain a prescription drug benefit under Medicare. SFAS 106-1 and SFAS 106-2 require the disclosure of the effects, if any, of the Act on the reported measure of the accumulated postretirement benefit obligation, how that effect has been, or will be, reflected in the net postretirement benefit costs of current or subsequent periods and the effects of any changes in estimates of participation rates on per capita claims cost as a result of the Act. However, since specific authoritative guidance on the accounting for the federal subsidy associated with the Act is pending, a Plan sponsor can elect to defer recognition of the effects of the Act in the accounting for its Plan under SFAS 106, “Employers’ Accounting for Postretirement Benefits Other Than Pensions” and in providing disclosures related to the Plan required by SFAS 132 (revised 2003), “Employers’ Disclosures about Pensions and Other Postretirement Benefits”, until that guidance is issued. The Company has elected to defer recognition of the effects of the Act until specific authoritative guidance on the accounting for the federal subsidy associated with the Act is issued. Accordingly, the effects of the Act on the measurement of the Accumulated Postretirement Benefit Obligation and the Net Periodic Postretirement Benefit Cost are not reflected in the Company’s financial statements or footnotes because, with specific authoritative guidance, the Company is unable to conclude whether the benefits provided by its postretirement medical benefits plan are actuarially equivalent to the benefits under Medicare Part D under the Act. The specific authoritative guidance on the accounting for the federal subsidy, when issued, could require the Company to change previously reported information.

The following tables show the components of net periodic postretirement benefit cost (NPPBC), as well as key actuarial assumptions used in determining the various PBOP Plan values:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	**2004**	2003
Components of NPPBC (000’s)				
Service Cost	**$ 245**	$ 7	**$ 735**	$ 22
Interest Cost	**497**	16	**1,491**	49
Expected Return on Plan Assets	**---**	---	**---**	---
Amortization of Prior Service Cost	**365**	11	**1,095**	32
Amortization of Transition (Asset) Obligation	**5**	1	**15**	2
Amortization of Net (Gain) Loss	**---**	---	**---**	---
Subtotal NPPBC	**1,112**	35	**3,336**	105
Amounts Capitalized and Deferred	**(644)**	(9)	**(2,140)**	(27)
NPPBC Recognized	**$ 468**	$ 26	**$ 1,196**	$ 78

Included in the 2004 amounts above for Amounts Capitalized and Deferred are $179 thousand and $926 thousand for the three and nine months ended September 30, 2004, respectively, deferred and recorded as a Regulatory Asset on the Company’s Balance Sheet. The remaining amounts in 2004 and the amounts 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 $0.4 million and $1.1 million in the three and nine months ended September 30, 2003, respectively.

Employer Contributions – As of September 30, 2004, the Company has made $1.3 million of contributions to the PBOP Plan. The Company presently anticipates contributing an additional $0.8 million to fund the Plan in 2004 for an estimated total of $2.1 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	**2004**	2003
Components of NPPC (000's)				
Service Cost	**$ 19**	$ 15	**$ 55**	$ 45
Interest Cost	**17**	17	**53**	51
Expected Return on Plan Assets	**---**	---	**---**	---
Amortization of Prior Service Cost	**(1)**	(1)	**(3)**	(3)
Amortization of Transition Obligation	**4**	4	**12**	12
Amortization of Net Loss	**1**	---	**3**	---
Net Periodic SERP Cost	**$ 40**	$ 35	**$ 120**	$ 105

Employer Contributions – As of September 30, 2004, the Company has made payments of $54,000 to beneficiaries. The Company presently anticipates making additional benefit payments of $16,000 in 2004 for a total of $70,000.

Note 9: Subsequent Events

Unitil Energy Systems, Inc. Preferred Stock Redemption and Retirement - On October 15, 2004, Unitil Corporation's wholly owned subsidiary, Unitil Energy Systems, Inc. (UES), redeemed and retired the three outstanding issues of its Redeemable, Cumulative Preferred Stock at par, aggregating $904,100. The three issues redeemed and retired were the 8.70% Series (aggregate par value of $215,000), the 8.75% Series (aggregate par value of $313,600) and the 8.25% Series (aggregate par value of $375,500). UES used operating cash to effect this transaction.

Fitchburg Gas and Electric Light Company Pension and Postretirement Benefits Other Than Pension (PBOP) Adjustment Mechanism Tariff Filing - On April 30, 2004, Unitil Corporation's wholly owned subsidiary, Fitchburg Gas and Electric Light Company (FG&E), filed new tariffs with the MDTE to establish a reconciliation adjustment mechanism for both its Gas Division and Electric Division to provide for the recovery of costs associated with the Company's employee pension benefits and Post Retirement Benefits Other than Pension (PBOP) expenses. On October 27, 2004 the MDTE approved FG&E's request for a reconciliation rate adjustment mechanism related to pension and PBOP costs. As part of this ruling, FG&E is allowed to record a regulatory asset in lieu of taking a charge to expense for the difference between the level of pension and PBOP expenses that are included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106, since the effective date of its last base rate change. This mechanism removes the volatility in earnings that may result from requirements of existing accounting standards and provides for an annual filing and rate adjustment with the MDTE. For the nine month period ended September 30, 2004, FG&E was allowed to defer for recovery, through the rate adjustment mechanism, pension and PBOP expenses of $1.0 million. As of September 30, 2004, FG&E has recorded a regulatory asset of $1.6 million which is included as part of Regulatory Assets in the Company's Consolidated Balance Sheets.

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. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. 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. Unregistered Sales of Equity Securities and Use of Proceeds

(a) There were no sales of unregistered equity securities by the Company for the fiscal period ended September 30, 2004.

(b) Not applicable.

(c) Issuer repurchases are shown in the table below for the monthly periods noted:

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)
7/1/04 – 7/31/04	---	---	---	n/a
8/1/04 – 8/31/04	365	$26.90	365	n/a
9/1/04 – 9/30/04	---	---	---	n/a
Total	365	$26.90	365	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

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
10.1	Unitil Corporation Tax Deferred Savings and Investment Plan – Trust Agreement	Filed herewith
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 October 28, 2004 Announcing Earnings For the Quarter Ended September 30, 2004	Filed herewith

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

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

EXHIBIT 11.

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING

(000's except for per share data)

(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(000's, except per share data	**2004**	2003	**2004**	2003
Net Income	**$1,266**	$1,497	**$5,676**	$5,512
Less: Dividend Requirements on Preferred Stock	**59**	59	**176**	177
Net Income Applicable to Common Stock	**$1,207**	$1,438	**$5,500**	$5,335
Average Number of Common Shares Outstanding – Basic	**5,514,611**	4,758,295	**5,504,582**	4,750,203
Dilutive Effect of Stock Options and Restricted Stock	**14,822**	25,347	**14,798**	20,266
Average Number of Common Shares Outstanding – Diluted	**5,529,433**	4,783,642	**5,519,380**	4,770,469
Earnings Per Share – Basic	**$0.22**	$0.30	**$1.00**	$1.12
Earnings Per Share – Diluted	**$0.22**	$0.30	**$1.00**	$1.12