UNITED STATES

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, 2006

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	***(I.R.S. Employer***
incorporation or organization)	***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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨

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

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 26, 2006**
Common Stock, No par value	5,641,564 Shares

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UNITIL CORPORATION AND SUBSIDIARY COMPANIES

FORM 10-Q

For the Quarter Ended September 30, 2006

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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 Unitil Corporation and subsidiaries (Unitil or the Company) 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 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 Earnings Applicable to Common Shareholders was $1.8 million for the third quarter of 2006, an increase of $0.2 million compared to the same period in 2005. The improvement in earnings was primarily driven by the recent approval of new electric distribution base rates for Unitil Energy Systems, Inc. (UES), Unitil s New Hampshire electric utility subsidiary. Earnings per common share were $0.32 for the third quarter of 2006, an improvement of $0.04 per share compared with earnings of $0.28 per share for the third quarter of 2005.

For the nine month period ended September 30, 2006, earnings were $5.2 million compared to $5.7 million in 2005. Through the first nine months, earnings per share were $0.93 for 2006 compared with $1.03 per share for 2005. This decrease in earnings for the nine-month period reflects lower gas and electric sales primarily due to milder weather this year compared to 2005. The impact of the New Hampshire electric distribution base case is reflected in the Company s consolidated financial statements for both the three and nine month periods ending September 30, 2006.

On October 6, 2006, UES received approval from the New Hampshire Public Utilities Commission (NHPUC) of a settlement agreement, resolving all issues in its electric distribution base rate case filed in November 2005. Included in this Settlement Agreement is an increase in UES electric base distribution rates of $2.3 million applied as of January 1, 2006; two future step increases to base rates totaling approximately $0.5 million related

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to utility plant additions in 2006; the recovery of $0.3 million of supply related costs through default service energy rates; a reduction of approximately $0.6 million in annual depreciation expense; and, the resolution of the recovery in rates of pension and other postretirement benefit costs and other operating costs.

Total electric kWh sales were 3.2% and 1.7% lower in the three and nine months ended September 30, 2006, respectively, reflecting milder weather and a decline in average energy usage per customer during the period of higher energy prices. The weather in the Company s service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, resulting in lower consumption of electricity for heating related purposes. During the summer of 2006 the weather in the Company s service territories was approximately 11% cooler than in the same period for 2005, resulting in lower consumption of electricity for air conditioning purposes. Although the Company established a new record for peak electricity demand use by its customers in early August of 2006, the duration of very hot weather during this period was shorter than the extended period of very hot weather experienced during the summer of 2005. As a result, weather sensitive electric kWh sales in 2006 lagged behind same period sales in 2005.

Electric sales margin was lower in the three and nine month periods ended September 30, 2006, primarily reflecting a decrease in revenue related to the expiration of the Seabrook Amortization Surcharge (SAS) in late 2005. This decrease in SAS revenue is largely matched with a corresponding decrease in amortization expenses on Regulatory Assets, and therefore has no material impact on net income (see discussion on Depreciation and Amortization below). Absent the decrease in SAS revenues, electric sales margin increased $0.3 million and $2.2 million in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The higher sales margins in the three and nine months ended September 30, 2006, primarily reflect the Company s recently approved base rate increase in New Hampshire.

Total therm sales of natural gas increased 32.0% and 11.7% in the three and nine months ended September 30, 2006, respectively, compared to the same periods in 2005. The increases in both of these periods were due to a new gas sales contract with a large industrial customer. Absent the sales from this new special contract, total gas therm sales were approximately 5.6% and 9.8% lower for the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The declines in sales, absent the sales from the new contract discussed above, reflect significantly milder winter weather in 2006 and lower average energy usage by customers during a period of higher energy prices. The weather in the Company s service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, and the region as a whole experienced a record warm January.

Gas sales margin for the three month period ended September 30, 2006 was flat to the same period in 2005 and decreased $0.6 million in the nine month period ended September 30, 2006 compared to the same period in 2005. The decrease in gas margin is attributable to lower therm sales volume to customers as discussed above. Margin sharing under the special contract with a large industrial customer discussed above is currently pending approval from the MDTE. Accordingly, pending the results of this proceeding, the Company is recording revenue from this contract on a reduced basis and therefore the significant increase in gas sales due to this contract is not matched by a similar increase in sales margin.

Total Operation and Maintenance expenses decreased $0.2 million in the three month period ended September 30, 2006 compared to the same period in 2005. For the nine month period ended September 30, 2006, Operation and Maintenance expenses increased $1.3 million compared to the same period in 2005, reflecting higher retiree and employee benefit costs of $0.7 million, higher salaries and compensation expenses of $0.6 million and an increase in all other operating expenses of $0.2 million, net, partially offset by lower audit and legal fees of $0.2 million.

Depreciation and Amortization expense decreased $1.4 million and $2.9 million for the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. These decreases were due to lower utility plant depreciation rates resulting from the New Hampshire rate settlement and lower amortization on regulatory assets as a result of the expiration of the SAS, discussed above, partially offset by increased depreciation on normal utility plant additions.

Interest Expense, Net increased by $0.4 million and $0.7 million in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The change in Interest Expense, Net was primarily driven by a higher weighted average cost of debt in 2006 compared to 2005. Unitil s subsidiary,

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UES issued and sold $15 million of Series O, 6.32% First Mortgage Bonds to institutional investors on September 26, 2006. The proceeds from this financing were used principally to permanently finance long-lived utility plant additions that had been previously financed on an interim basis with short-term bank borrowings.

Operating Revenues Electric

Electric Operating Revenues Total Electric Operating Revenues, increased by $8.6 million, or 16.4%, and by $25.5 million, or 17.5%, in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. Total 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 net increase in Total Electric Operating Revenues in the three month period reflects higher Purchased Electricity costs of $9.4 million, offset by lower sales margin of $0.8 million. The net increase in Total Electric Operating Revenues in the nine month period reflects higher Purchased Electricity costs of $26.6 million, offset by lower sales margin of $1.0 million and lower C&LM revenues of $0.1 million.

Purchased Electricity and C&LM revenues increased a net $9.4 million, or 17.9%, and $26.6 million, or 18.3%, of Total Electric Operating Revenues in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005, reflecting higher electric commodity prices and lower spending on energy efficiency programs that were implemented during those periods. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin was lower in the three and nine month periods ending September 30, 2006, primarily reflecting a decrease in revenue related to the expiration of the Seabrook Amortization Surcharge (SAS) in late 2005. This decrease in SAS revenue is largely matched with a corresponding decrease in amortization expenses on Regulatory Assets, and therefore has no material impact on net income (see discussion on Depreciation and Amortization below). Absent the decrease in SAS revenues, electric sales margin increased $0.3 million and $2.2 million in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The higher sales margins in the three and nine months ended September 30, 2006, primarily reflect the Company s recently approved base rate increase in New Hampshire.

The following table details total Electric Operating Revenues and Sales Margin for the three and nine month periods ended September 30, 2006 and 2005:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	**2005**	**$ Change**	**% Change[(1)]**	**2006**	**2005**	**$ Change**	**% Change[(1)]**
Electric Operating Revenue:								
Residential	**$ 29.3**	$ 22.4	$ 6.9	13.1%	**$ 76.9**	$ 62.0	$ 14.9	10.2%
Commercial / Industrial	**31.9**	30.2	1.7	3.2%	**94.1**	83.5	10.6	7.3%
Total Electric Operating Revenue	**$ 61.2**	$ 52.6	$ 8.6	16.4%	**$ 171.0**	$ 145.5	$ 25.5	17.5%
Cost of Electric Sales:								
Purchased Electricity	**$ 46.4**	$ 37.0	$ 9.4	17.9%	**$ 126.9**	$ 100.3	$ 26.6	18.3%
Conservation & Load Management	**0.9**	0.9			**2.7**	2.8	(0.1)	(0.1)%
Electric Sales Margin	**$ 13.9**	$ 14.7	$ (0.8)	(1.5)%	**$ 41.4**	$ 42.4	$ (1.0)	(0.7)%

(1) Represents change as a percent of Total Electric Operating Revenue.

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Kilowatt-hour Sales - Unitil s total electric kWh sales were 3.2% and 1.7% lower in the three and nine months ended September 30, 2006, respectively, reflecting milder weather and a decline in average energy usage per customer during the period of higher energy prices. The weather in the Company s service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, resulting in lower consumption of electricity for heating related purposes. During the summer of 2006 the weather in the Company s service territories was approximately 11% cooler than in the same period for 2005, resulting in lower consumption of electricity for air conditioning purposes. Although the Company established a new record for peak electricity demand use by its customers in early August of 2006, the duration of very hot weather during this period was shorter than the extended period of very hot weather experienced during the summer of 2005. As a result, weather sensitive electric kWh sales in 2006 lagged behind same period sales in 2005.

The following table details total kWh sales for the three and nine months ended September 30, 2006 and 2005 by major customer class:

kWh Sales (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	**2005**	**Change**	**% Change**	**2006**	**2005**	**Change**	**% Change**
Residential	**188.6**	193.8	(5.2)	(2.7)%	**521.5**	529.0	(7.5)	(1.4)%
Commercial / Industrial	**294.9**	305.5	(10.6)	(3.5)%	**825.5**	840.9	(15.4)	(1.8)%
Total	**483.5**	499.3	(15.8)	(3.2)%	**1,347.0**	1,369.9	(22.9)	(1.7)%

Operating Revenues - Gas

Gas Operating Revenues Total Gas Operating Revenues increased $0.9 million, or 25.7%, and $3.3 million, or 15.6%, in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The net increase in Total Gas Operating Revenues in the three month period reflects higher Purchased Gas costs of $0.9 million. The net increase in Total Gas Operating Revenues in the nine month period reflects higher Purchased Gas costs of $3.9 million, offset by lower sales margin of $0.6 million.

Purchased Gas and C&LM revenues increased a net $0.9 million, or 25.7%, and $3.9 million, or 18.4%, of Total Gas Operating Revenues in the three and nine month periods ended September 30, 2006, respectively, compared to the same period in 2005, reflecting higher gas commodity prices, higher unit sales and relatively flat spending on energy efficiency programs that were implemented during those periods. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Gas sales margin for the three month period ended September 30, 2006 was flat to the same period in 2005 and decreased $0.6 million in the nine month period ended September 30, 2006 compared to the same period in 2005. The decrease in gas margin is attributable to lower therm sales volume to customers. Margin sharing under the special contract with a large industrial customer discussed above is currently pending approval from the MDTE. Accordingly, pending the results of this proceeding, the Company is recording revenue from this contract on a reduced basis and therefore the significant increase in gas sales due to this contract is not matched by a similar increase in sales margin.

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The following table details total Gas Operating Revenues and Sales Margin for the three and nine months ended September 30, 2006 and 2005:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	**2005**	**$ Change**	**% Change[1]**	**2006**	**2005**	**$ Change**	**% Change[1]**
Gas Operating Revenue:								
Residential	**$ 2.0**	$ 1.8	$ 0.2	5.7%	**$ 13.0**	$ 12.4	$ 0.6	2.8%
Commercial / Industrial	**1.4**	1.6	(0.2)	(5.7)%	**9.2**	8.6	0.6	2.8%
Total Firm Gas Revenue	**$ 3.4**	$ 3.4	$		**$ 22.2**	$ 21.0	$ 1.2	5.6%
Interruptible Gas Revenue	**1.0**	0.1	0.9	25.7%	**2.2**	0.1	2.1	10.0%
Total Gas Operating Revenue	**$ 4.4**	$ 3.5	$ 0.9	25.7%	**$ 24.4**	$ 21.1	$ 3.3	15.6%
Cost of Gas Sales:								
Purchased Gas	**$ 2.8**	$ 1.9	$ 0.9	25.7%	**$ 17.1**	$ 13.2	$ 3.9	18.4%
Conservation & Load Management					**0.2**	0.2		
Gas Sales Margin	**$ 1.6**	$ 1.6	$		**$ 7.1**	$ 7.7	$ (0.6)	(2.8)%

[1] Represents change as a percent of Total Gas Operating Revenue.

Therm Sales Unitil s total therm sales of natural gas increased 32.0% and 11.7% in the three and nine months ended September 30, 2006, respectively, compared to the same periods in 2005. The increases in both of these periods were due to a new gas sales contract with a large industrial customer. Absent the sales from this new contract, total sales were approximately 5.6% and 9.8% lower for the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The declines in sales, absent the sales from the new contract discussed above, reflect significantly milder winter weather in 2006 and lower average energy usage by customers during a period of higher energy prices. The weather in the Company s service territories in the winter of 2006 was approximately 12% warmer than in the same period for 2005, and the region as a whole experienced a record warm January.

The following table details total firm therm sales for the three and nine months ended September 30, 2006 and 2005, by major customer class:

Therm Sales (millions)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	**2005**	**Change**	**% Change**	**2006**	**2005**	**Change**	**% Change**
Residential	**0.7**	0.7			**7.7**	8.6	(0.9)	(10.5)%
Commercial / Industrial	**2.6**	1.8	0.8	44.4%	**12.4**	9.4	3.0	31.9%
Total	**3.3**	2.5	0.8	32.0%	**20.1**	18.0	2.1	11.7%

Operating Revenue - Other

Total Other Revenue increased $0.2 million, or 28.7%, and $0.4 million, or 26.8% in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. These increases were the result of growth in revenues from the Company s unregulated energy brokering business, Usource. Usource s revenues are primarily derived from fees and charges billed to suppliers as customers take delivery of energy from these suppliers under term contracts brokered by Usource. The Company will also realize future fees, estimated at the end of September, of $3.7 million from executed energy supply contracts running 2007 through 2011.

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The following table details total Other Revenue for the three and nine months ended September 30, 2006 and 2005:

Other Revenue (000 s)

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2006	**2005**	**$ Change**	**% Change**	**2006**	**2005**	**$ Change**	**% Change**
Other	**$ 678**	$ 527	151	28.7%	**$ 1,877**	$ 1,480	$ 397	26.8%
Total Other Revenue	**$ 678**	$ 527	$ 151	28.7%	**$ 1,877**	$ 1,480	$ 397	26.8%

Operating Expenses

Purchased Electricity Purchased Electricity expenses include the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity increased $9.4 million, or 25.5%, and $26.6 million, or 26.5%, in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005, reflecting higher electric commodity 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 affect 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 increased $0.9 million, or 45.9%, and $4.0 million, or 30.2%, in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. These increases in Purchased Gas are attributable to increased therm sales and higher gas commodity costs. 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 affect 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 Operation and Maintenance expenses decreased $0.2 million in the three month period ended September 30, 2006 compared to the same period in 2005. For the nine month period ended September 30, 2006, Operation and Maintenance expenses increased $1.3 million compared to the same period in 2005, reflecting higher retiree and employee benefit costs of $0.7 million, higher salaries and compensation expenses of $0.6 million and an increase in all other operating expenses of $0.2 million, net, partially offset by lower audit and legal fees of $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 less than $0.1 million, or 1.8%, and $0.1 million, or 3.3%, in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The decreases reflect the timing of spending on the implementation of Energy Efficiency programs. These costs are collected from customers on a pass through basis and therefore, fluctuations in program costs have no impact on Net Income.

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Depreciation, Amortization and Taxes

Depreciation and Amortization - Depreciation and Amortization expense decreased $1.4 million, or 28.8%, and $2.9 million, or 19.3%, for the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. These decreases were primarily due to lower depreciation rates on utility plant resulting from the NHPUC s order in UES base rate case, and lower amortization on regulatory assets, partially offset by depreciation on normal utility plant additions. The Company s regulatory asset related to its former abandoned property investment in Seabrook Station became fully-amortized in the third quarter of 2005.

Local Property and Other Taxes - Local Property and Other Taxes increased by less than $0.1 million, or 2.0%, and $0.1 million, or 3.0%, for the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. The increase in the three month period was principally due to higher local property tax rates. The increase in the nine month period was principally due to higher payroll taxes.

Federal and State Income Taxes - Federal and State Income Taxes were higher by $0.4 million in the three months ended September 30, 2006 compared to the same period in 2005 reflecting higher pre-tax earnings. Federal and State Income Taxes in the nine months ended September 30, 2006 were flat compared to the same period in 2005, reflecting a higher effective income tax rate in 2006 due to the expiration of book/tax differences related to the Seabrook regulatory asset discussed above.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company s distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company s rate tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

Interest Expense, Net (000 s)	**Three Months Ended September 30,**		**Nine Months Ended September 30,**	
	2006	**2005**	**2006**	**2005**
Interest Expense				
Long-term Debt	**$ 2,339**	$ 2,099	**$ 6,962**	$ 6,301
Short-term Debt	**479**	282	**1,194**	723
Regulatory Liabilities	**80**		**189**	97
Subtotal Interest Expense	**2,898**	2,381	**8,345**	7,121
Interest Income				
Regulatory Assets	**(820)**	(755)	**(2,306)**	(1,975)
AFUDC and Other	**(131)**	(33)	**(213)**	(66)
Subtotal Interest Income	**(951)**	(788)	**(2,519)**	(2,041)
Total Interest Expense, Net	**$ 1,947**	$ 1,593	**$ 5,826**	$ 5,080

Interest Expense, Net increased by $0.4 million and $0.7 million in the three and nine month periods ended September 30, 2006, respectively, compared to the same periods in 2005. Interest expense on long-term borrowings increased in both the three and nine month periods in 2006 compared to 2005 due to the issuance of

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new fixed rate long-term debt. In December 2005 Unitil s Massachusetts utility subsidiary, FG&E issued $15 million of unsecured long-term notes to institutional investors. The notes have a term of 25 years and a coupon rate of 5.90%. Unitil s New Hampshire subsidiary, UES issued and sold $15 million of Series O, 6.32% First Mortgage Bonds to institutional investors on September 26, 2006. The proceeds from these long-term financings were used principally to permanently finance long-lived utility plant additions that had been previously financed on an interim basis with short-term bank borrowings. Interest expense on short-term debt increased in both the three and nine month periods in 2006 compared to 2005 primarily due to higher average short-term interest rates. These increases in interest expense were partially offset by an increase in interest income primarily due to higher carrying charges on regulatory assets.

Capital Requirements

Cash provided by operating activities was $17.1 million during the first nine months of 2006, a decrease of $3.9 million over the comparable period in 2005. Net Income was $0.5 million lower in the first nine months of 2006 compared to 2005. Depreciation and Amortization declined by $2.9 million in the three quarters ended September 30, 2006 as compared to the same period in 2005 reflecting the expiration of the Seabrook Amortization Surcharge in late 2005 (See Depreciation and Amortization above) and lower amortization on other regulatory assets, as well as, lower average book depreciation rates authorized for UES in its recently approved base rate case in New Hampshire. The Deferred Taxes provided an additional $1.5 million during the first nine months of 2006 as compared to the same period in 2005, reflecting a net change between current and deferred income taxes related principally to changes in the Accrued Revenue balances. Accounts Receivable provided $2.5 million over the current three quarters of 2006 and the comparable period in 2005. Cash sources from Accrued Revenue decreased by $6.3 million period over period due to higher energy costs and the recording of UES base rate relief for the January through September 2006 period, both of which will be collected from customers in future periods. Refundable Taxes declined by $1.1 million, reflecting higher tax payments in 2006 compared to 2005. Cash flow from Accounts Payable decreased by $1.4 million compared to last year reflecting a higher level of funding of energy costs and other operating expenses in 2006. In addition, cash used to fund Deferred Restructuring Costs declined by $5.3 million in the first nine months of 2006 as compared to the same period last year, reflecting a significant improvement in net cash inflows for the recovery of previously deferred costs related to industry restructuring. All other changes in cash flows from operating activities were a net decrease of $1.0 million in uses of cash in the nine months ended September 30, 2006 compared to the same period in 2005.

Cash used in investing activities was $24.7 million for the nine months ended September 30, 2006 an increase of $8.0 million over the comparable period in 2005. Annual capital expenditures are presently projected to be $33.5 million in 2006 compared to $24.4 million expended in fiscal 2005. These 2006 capital expenditures include approximately $6.7 million of cash outlays for the Automated Metering Infrastructure project, the first year of a two-year investment in the Company s metering infrastructure, expected to be completed in June 2007. Capital expenditure projections are subject to changes during the fiscal year.

Cash flows provided by financing activities were $8.1 million in the first nine months of 2006. In the comparable period of 2005 cash used in financing activities amounted to $3.8 million, a net change between the two periods of $11.9 million. Cash provided for financing activities in the current period included the issuance and sale of $15 million of First Mortgage Bonds, described below. Cash used in both periods reflect the payment of dividends to shareholders of approximately $5.9 million. Cash used for financing activities during the current period includes the repayment of $1.1 of short-term bank borrowings in 2006. The current period also reflects the repurchase of approximately $0.2 million of preferred stock. During the first nine months of 2006 and 2005, normal long-term note sinking fund payments amounted to approximately $0.2 million during both periods. Both the current and comparable prior last year included receipt of $0.8 million from the sale of Unitil Common Stock through the Dividend Reinvestment and Stock Purchase Plan and 401(k) plans. During the first nine months of 2006 and 2005, the Company repaid capital lease obligations of $0.1 million and $0.3, respectively.

Unitil s subsidiary, UES issued and sold $15 million of Series O, 6.32% First Mortgage Bonds to institutional investors on September 26, 2006 The proceeds from these long-term financings were used principally to permanently finance long-lived utility plant additions that had been previously financed on an interim basis with short-term bank borrowings.

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At September 30, 2006 and December 31, 2005, Unitil had an aggregate of $40.0 million and $44.0 million, respectively, in unsecured revolving bank lines of credit through three banks. Unitil renews its lines of credit annually, and on June 30, 2006 at its annual renewal, Unitil reduced its lines of credit by $4 million due to lower projected borrowing requirements. Average daily short-term borrowings during the first nine months of 2006 were approximately $25.4 million, an increase of approximately $1.0 million over the comparable period in 2005. At September 30, 2006, the Company had available approximately $22.4 million of unused bank lines of credit and had short-term debt outstanding through bank borrowings of approximately $17.6 million. In addition, Unitil had $3.8 million in cash at September 30, 2006.

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan s liability with any shortfall amortized over seven years, with lower (92% 100%) funding targets available to well-funded plans during the transition period. The Company will be consulting with its actuary to assess the impact of these new funding rules, along with the other provisions of the PPA, on its pension plan.

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, 2006, there were $8.0 million of guarantees outstanding and the longest term guarantee extends through May 31, 2008.

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 statements 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 Note 1 to the Consolidated Financial Statements in the Company s Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 22, 2006.

***Regulatory Accounting* -** The Company s principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the Federal Energy Regulatory Commission (FERC) and FG&E is regulated by the MDTE and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, Accounting for the Effects of Certain Types of Regulation. (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered or refunded in future electric and gas retail rates.

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

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

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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 and natural gas 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 FASB Statement 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 operations 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 estimated. 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 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. The Company is authorized by regulators to recover the supply-related portion of its written-off accounts from customers through periodically reconciling rate 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 FASB Statement No. 87, Employers Accounting for Pensions (SFAS No. 87) and FASB Statement No. 106, Employers Accounting for Postretirement Benefits other than Pensions (SFAS No. 106). 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.

In September 2006, the FASB issued FASB Statement No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans , (SFAS No. 158), an amendment of SFAS No. 87, SFAS No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination

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Benefits, SFAS No. 106 and SFAS No. 132(R), Employers Disclosures about Pensions and Other Postretirement Benefits. SFAS No. 158 requires companies to record on their balance sheets the overfunded or underfunded status of their pension and postretirement benefits other than pension plans. For pension plans, the benefit obligation will be measured using the projected benefit obligation while the accumulated benefit obligation will be used to measure the obligation for postretirement benefits other than pension. Additionally, SFAS No. 158 requires companies to recognize in their statements of earnings actuarial gains and losses and prior service costs and credits which have not yet been recorded as expense. The effective date of SFAS No. 158 is December 15, 2006. The Company has a Defined Benefit Pension Plan and a Postretirement Benefits Other than Pension (PBOP) Plan (See Note 8). The Company expects that the implementation of SFAS No. 158 will have a significant impact on the recognition of pension and PBOP assets and liabilities on the Company s Balance Sheet and is currently assessing the recording of these items for the year ending December 31, 2006.

On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan s liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. The Company will be consulting with its actuary to assess the impact of these new funding rules, along with the other provisions of the PPA, on its pension plan.

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. See Note 8.

Pension expense is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets. In developing the expected long-term rate of return assumption, the Company evaluated input from actuaries and investment managers. The Company s expected long-term rate of return on Plan assets is based on target asset allocation assumptions of 60% in common stock equities and 40% in fixed income securities. The Company will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary.

***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 current tax liabilities as well as assessing temporary and permanent differences resulting from the 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 FASB Statement 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 the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. A change in the estimated useful lives of these assets could have a material impact on the Company s consolidated financial statements. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company s fixed assets. The depreciation rates ultimately determined from this process are approved by state regulators.

***Commitments and Contingencies* -** The Company s accounting policy is to record and/or disclose commitments and contingencies in accordance with FASB Statement No. 5, Accounting for Contingencies (SFAS No. 5).

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SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible gain or 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.

LABOR RELATIONS

There are approximately 100 employees of the Company represented by labor unions. In May 2005, the Company reached agreements with its bargaining units for new five-year contracts, effective June 1, 2005. These agreements replace contracts that expired on May 31, 2005.

INTEREST RATE RISK

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, 2006 and September 30, 2005 were 5.82% and 4.01%, respectively. The average interest rates on the Company s short-term borrowings for the nine months ended September 30, 2006 and September 30, 2005 were 5.44% and 3.51%, respectively.

MARKET RISK

Although Unitil s utility operating companies were 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 which involves the pre-approval of the commodity prices included in rates. Additionally, as discussed below in Regulatory Matters, the Company has divested its long-term commodity-related contracts and therefore, has further reduced its exposure to commodity risk. In recent periods, the energy markets have experienced significant volatility, with unprecedented increases in energy prices. The Company is working with the regulatory commissions to address the issue of increasing energy prices and help the Company s customers work through this difficult period. The regulatory commissions in Massachusetts and New Hampshire have continued to approve full collection of these costs by Unitil s utility operating companies. However, the risk exists that the regulatory commissions would require the Company to finance, through deferrals, a portion of these costs for a period of time.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

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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, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Operating Revenues				
Electric	**$ 61,200**	$ 52,642	**$ 170,958**	$ 145,488
Gas	**4,409**	3,485	**24,381**	21,125
Other	**678**	527	**1,877**	1,480
Total Operating Revenues	**66,287**	56,654	**197,216**	168,093
Operating Expenses				
Purchased Electricity	**46,430**	36,998	**126,909**	100,280
Purchased Gas	**2,780**	1,906	**17,142**	13,169
Operation and Maintenance	**6,558**	6,770	**20,127**	18,785
Conservation & Load Management	**915**	932	**2,902**	3,001
Depreciation and Amortization	**3,452**	4,846	**11,972**	14,827
Provisions for Taxes:				
Local Property and Other	**1,336**	1,314	**4,240**	4,128
Federal and State Income	**1,004**	648	**2,848**	2,848
Total Operating Expenses	**62,475**	53,414	**186,140**	157,038
Operating Income	**3,812**	3,240	**11,076**	11,055
Non-Operating Expenses (Income)	**38**	46	**(55)**	128
Income Before Interest Expense	**3,774**	3,194	**11,131**	10,927
Interest Expense, Net	**1,947**	1,593	**5,826**	5,080
Net Income	**1,827**	1,601	**5,305**	5,847
Less: Dividends on Preferred Stock	**35**	39	**99**	117
Earnings Applicable to Common Shareholders	**$ 1,792**	$ 1,562	**$ 5,206**	$ 5,730
Average Common Shares Outstanding - Basic	**5,605,208**	5,558,238	**5,591,692**	5,546,194
Average Common Shares Outstanding - Diluted	**5,619,082**	5,577,051	**5,605,765**	5,563,114
Earnings Per Common Share (Basic and Diluted)	**$ 0.32**	$ 0.28	**$ 0.93**	$ 1.03
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.38**	$ 1.38

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

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UNITIL CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(000 s)

	(UNAUDITED) September 30, 2006	2005	December 31, 2005
ASSETS:			
Utility Plant:			
Electric	**$ 245,275**	$ 231,050	$ 234,153
Gas	**60,718**	54,906	58,675
Common	**25,292**	27,550	26,515
Construction Work in Progress	**14,557**	7,781	5,624
Total Utility Plant	**345,842**	321,287	324,967
Less: Accumulated Depreciation	**118,367**	111,654	111,646
Net Utility Plant	**227,475**	209,633	213,321
Current Assets:			
Cash	**3,821**	3,560	3,207
Accounts Receivable Net of Allowance for Doubtful Accounts of $1,285, $561 and $550	**22,616**	19,648	23,551
Accrued Revenue	**9,599**	5,115	8,905
Refundable Taxes			351
Materials and Supplies	**4,229**	3,709	3,675
Prepayments	**1,193**	1,366	1,612
Total Current Assets	**41,458**	33,398	41,301
Noncurrent Assets:			
Regulatory Assets	**161,526**	180,045	179,719
Prepaid Pension Costs	**9,142**	9,197	11,099
Debt Issuance Costs	**2,560**	2,187	2,343
Other Noncurrent Assets	**2,379**	2,339	2,218
Total Noncurrent Assets	**175,607**	193,768	195,379
TOTAL	**$ 444,540**	$ 436,799	$ 450,001

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

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UNITIL CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS (Cont.)

(000 s)

	(UNAUDITED) September 30, 2006	September 30, 2005	December 31, 2005
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 94,761**	$ 93,338	$ 96,283
Preferred Stock, Non-Redeemable, Non-Cumulative	**225**	225	225
Preferred Stock, Redeemable, Cumulative	**1,858**	2,101	2,102
Long-Term Debt, Less Current Portion	**140,114**	110,445	125,365
Total Capitalization	**236,958**	206,109	223,975
Current Liabilities:			
Long-Term Debt, Current Portion	**329**	302	308
Capitalized Leases, Current Portion	**261**	169	261
Accounts Payable	**16,085**	13,167	20,600
Short-Term Debt	**17,575**	27,525	18,700
Dividends Declared and Payable	**1,991**	1,978	50
Refundable Customer Deposits	**2,182**	1,938	2,031
Taxes Payable	**1,235**	1,723	
Interest Payable	**2,464**	2,195	1,353
Other Current Liabilities	**2,401**	2,314	2,597
Total Current Liabilities	**44,523**	51,311	45,900
Deferred Income Taxes	**50,540**	50,359	52,297
Noncurrent Liabilities:			
Power Supply Contract Obligations	**97,300**	121,291	114,906
Capitalized Leases, Less Current Portion	**252**	80	324
Other Noncurrent Liabilities	**14,967**	7,649	12,599
Total Noncurrent Liabilities	**112,519**	129,020	127,829
TOTAL	**$ 444,540**	$ 436,799	$ 450,001

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

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UNITIL CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(000 s)

(UNAUDITED)

	Nine Months Ended September 30, 2006	2005
Cash Flow from Operating Activities:		
Net Income	**$ 5,305**	$ 5,847
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	11,972	14,827
Deferred Taxes	(1,185)	(2,642)
Changes in Current Assets and Liabilities:		
Accounts Receivable	935	(1,529)
Accrued Revenue	(1,648)	4,639
Taxes Refundable / Payable	1,586	2,700
Materials and Supplies	(554)	(629)
Prepayments and Other	419	405
Accounts Payable	(4,515)	(3,082)
Refundable Customer Deposits	151	393
Interest Payable	1,111	867
Other Current Liabilities	(196)	948
Deferred Restructuring and Other Charges	210	(5,083)
Other, net	**3,552**	3,339
Cash Provided by Operating Activities	17,143	21,000
Cash Flows from Investing Activities:		
Property, Plant and Equipment Additions	(24,653)	(16,680)
Cash (Used in) Investing Activities	(24,653)	(16,680)
Cash Flows from Financing Activities:		
Proceeds from (Repayment) of Short-Term Debt, net	(1,125)	1,850
Proceeds from Issuance of Long-Term Debt	15,000	
Repayment of Long-Term Debt	(230)	(213)
Dividends Paid	(5,916)	(5,877)
Issuance of Common Stock	757	806
Retirement of Preferred Stock	(244)	(11)
Repayment of Capital Lease Obligations	(118)	(347)
Cash Provided by (Used in) Financing Activities	8,124	(3,792)
Net Increase in Cash	**614**	528
Cash at Beginning of Period	**3,207**	3,032
Cash at End of Period	**$ 3,821**	$ 3,560

Supplemental Cash Flow Information:

Interest Paid	$ 7,018	$ 6,154
Income Taxes Paid	$ 2,653	$ 3,544

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

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UNITIL CORPORATION AND SUBSIDIARY COMPANIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three and nine months ended September 30, 2006 are not necessarily indicative of results to be expected for the year ending December 31, 2006. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements Summary of Significant Accounting Policies of the Company s Form 10-K for the year ended December 31, 2005, as filed with the SEC on February 22, 2006, for a description of the Company s Basis of Presentation.

Nature of Operations Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. 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 and Exeter & Hampton Electric Company), 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 other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company s corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company s wholly-owned non-utility unregulated subsidiary that provides consulting and management related services. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Recently Issued Pronouncements In September 2006, the FASB issued FASB Statement No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans , (SFAS No. 158), an amendment of SFAS No. 87, SFAS No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, SFAS No. 106 and SFAS No. 132(R), Employers Disclosures about Pensions and Other Postretirement Benefits. SFAS No. 158 requires companies to record on their balance sheets the overfunded or underfunded status of their pension and postretirement benefits other than pension plans. For pension plans, the benefit obligation will be measured using the projected benefit obligation while the accumulated benefit obligation will be used to measure the obligation for postretirement benefits other than pension. Additionally, SFAS No. 158 requires companies to recognize in their statements of earnings

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actuarial gains and losses and prior service costs and credits which have not yet been recorded as expense. The effective date of SFAS No. 158 is December 15, 2006. The Company has a Defined Benefit Pension Plan and a Postretirement Benefits Other than Pension (PBOP) Plan. The Company expects that the implementation of SFAS No. 158 will have a significant impact on the recognition of pension assets and liabilities on the Company s Balance Sheet and is currently assessing the impact of recording these items for the year ending December 31, 2006.

In September 2006, the FASB issued FASB Statement No. 157, Fair Value Measurements , (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company does not expect SFAS No. 157 to have an impact on the Company s Consolidated Financial Statements.

In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). This interpretation clarified the accounting for uncertainty in income taxes recognized in accordance with FASB Statement No. 109, Accounting for Income Taxes (SFAS No. 109). Specifically, FIN 48 clarifies the application of SFAS No. 109 by defining a criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise s financial statements. Additionally, FIN 48 provides guidance on measurement, derecognition, classification, interest and penalties, accounting in interim periods of income taxes, as well as the required disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. The Company is in the process of completing its analysis of FIN 48 as it applies to the Company s operations and it does not expect that the adoption of FIN 48 will have a significant impact on the Company s Consolidated Financial Statements.

In February 2006, the FASB issued FASB Statement No. 155, Accounting for Certain Hybrid Financial Instruments , (SFAS No. 155), which amends FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities , (SFAS No.133) and FASB Statement No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities , (SFAS No. 140), effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation and clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133. The Company does not expect SFAS No. 155 have an impact on the Company s Consolidated Financial Statements.

In February 2006, the FASB issued FASB Staff Position No. FAS 123(R)-4, (FSP 123(R)-4), Classification of Options and Similar Instruments Issued as Employee Compensation That Allow for Cash Settlement Upon the Occurrence of a Contingent Event . FSP 123(R)-4 addresses the classification of options and similar instruments issued as employee compensation that allow for cash settlement upon the occurrence of a contingent event and amends paragraphs 32 and A229 of revised FASB Statement No. 123(R), Share-Based Payment , (SFAS No. 123(R)), which was issued in December 2004. SFAS No. 123(R) requires all entities to recognize the fair value of share-based payment awards classified in equity, unless they are unable to reasonably estimate the fair value of the award. The Company uses the fair value method for share-based payment awards and therefore the provisions of SFAS No. 123(R) have no impact on the Consolidated Financial Statements. The Company has adopted the provisions of FSP 123(R)-4.

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.

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NOTE 2 DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
09/29/06	11/15/06	11/01/06	$ 0.345
06/22/06	08/15/06	08/01/06	$ 0.345
03/23/06	05/15/06	05/01/06	$ 0.345
01/12/06	02/15/06	02/01/06	$ 0.345
09/23/05	11/15/05	11/01/05	$ 0.345
06/17/05	08/15/05	08/01/05	$ 0.345
03/24/05	05/13/05	04/29/05	$ 0.345
01/13/05	02/15/05	02/01/05	$ 0.345

NOTE 3 COMMON STOCK AND PREFERRED STOCK

During the first nine months of 2006, the Company sold 30,782 shares of its Common Stock, at an average price of $24.59 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $757,000 were used to reduce short-term borrowings.

During the first nine months of 2005, the Company sold 29,484 shares of its Common Stock, at an average price of $27.34 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $806,000 were used to reduce short-term borrowings.

The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company s shareholders. On February 16, 2006, 14,375 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $366,563. On March 8, 2005, 10,900 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $299,423. On April 29, 2004, 10,700 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $293,715. On May 12, 2003, 10,600 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $259,170. The compensation expense associated with the issuance of shares under the Plan is being accrued on a monthly basis over the vesting period.

Details on preferred stock at September 30, 2006, September 30, 2005 and December 31, 2005 are shown below:

(Amounts in Thousands)

	(Unaudited) September 30, 2006	(Unaudited) September 30, 2005	December 31, 2005
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 225**	$ 225	$ 225
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**874**	892	892
8.00% Series, $100 Par Value	**984**	1,210	1,210
Total Preferred Stock	**$ 2,083**	$ 2,327	$ 2,327

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NOTE 4 LONG-TERM DEBT

Details on long-term debt at September 30, 2006, September 30, 2005 and December 31, 2005 are shown below:

(Amounts in Thousands)

	(Unaudited) September 30, 2006	(Unaudited) September 30, 2005	December 31, 2005
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
6.32% Series, Due September 15, 2036	**15,000**		
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
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	10,000
5.90% Notes, Due December 15, 2030	**15,000**		15,000
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due August 1, 2017	**5,443**	5,747	5,673
Total	**140,443**	110,747	125,673
Less: Installments due within one year	**329**	302	308
Total Long-term Debt	**$ 140,114**	$ 110,445	$ 125,365

On September 26, 2006 UES issued and sold $15 million of Series O 6.32% First Mortgage Bonds, due September 15, 2036, to institutional investors in the form of a private placement. The proceeds from this long-term financing were used principally to permanently finance long-lived utility plant additions that had been previously financed on an interim basis with short-term bank borrowings. This issuance is reflected in the table above.

The fair value of the Company s long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company s long-term debt at September 30, 2006 is estimated to be in a range of up to approximately $154 million, before considering any costs, including prepayment costs, to market the Company s debt. Currently, management believes that there is no active market in the Company s debt securities, which have all been sold through private placements.

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, 2006 there are $8.0 million of guarantees outstanding and these guarantees extend through May 31, 2008. These guarantees are excluded from the recognition provisions of FASB Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.

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NOTE 5 SEGMENT INFORMATION

The following table provides significant segment financial data for the three and nine months ended September 30, 2006 and September 30, 2005 (unaudited):

Three Months Ended September 30, 2006 (000 s)	Electric	Gas	Other	Non-Regulated	Total
Revenues	**$ 61,200**	**$ 4,409**	**$**	**$ 678**	**$ 66,287**
Segment Profit (Loss)	**2,438**	**(720)**	**103**	**(29)**	**1,792**
Identifiable Segment Assets	**323,502**	**99,972**	**19,941**	**1,125**	**444,540**
Capital Expenditures	**6,934**	**3,258**	**9**	**14**	**10,215**
Three Months Ended September 30, 2005 (000 s)					
Revenues	$ 52,643	$ 3,485	$ (1)	$ 527	$ 56,654
Segment Profit (Loss)	2,040	(689)	226	(15)	1,562
Identifiable Segment Assets	322,324	95,050	18,352	1,073	436,799
Capital Expenditures	4,509	2,699	14	(40)	7,182
Nine Months Ended September 30, 2006 (000 s)					
Revenues	**$ 170,958**	**$ 24,381**	**$**	**$ 1,877**	**$ 197,216**
Segment Profit (Loss)	**5,494**	**(459)**	**362**	**(191)**	**5,206**
Identifiable Segment Assets	**323,502**	**99,972**	**19,941**	**1,125**	**444,540**
Capital Expenditures	**18,529**	**5,954**	**154**	**16**	**24,653**
Nine Months Ended September 30, 2005 (000 s)					
Revenues	$ 145,488	$ 21,125	$	$ 1,480	$ 168,093
Segment Profit (Loss)	5,545	(258)	485	(42)	5,730
Identifiable Segment Assets	322,324	95,050	18,352	1,073	436,799
Capital Expenditures	11,784	4,895	41	(40)	16,680

NOTE 6 REGULATORY MATTERS

UNITIL S REGULATORY MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION S FORM 10-K FOR DECEMBER 31, 2005 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 22, 2006.

Overview Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the SEC with respect to various matters, including: the issuance of securities, capital structure, and certain acquisitions and dispositions of assets. As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. Unitil s utility operations related to wholesale and interstate business activities are also regulated by FERC. The retail distribution utilities, UES and FG&E, are subject to regulation by the NHPUC and the Massachusetts Department of Telecommunications and Energy (MDTE), respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil s primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company s operations and financial position.

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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 an historical test year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, all of Unitil s customers have the opportunity to purchase their electric or natural gas supplies from third-party vendors. Most small and medium-sized customers, however, continue to purchase such supplies through UES and FG&E as the provider of last resort. UES and FG&E purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, 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 and 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 five to seven years, is $134.1 million as of September 30, 2006 and is included in Regulatory Assets on the Company s Consolidated Balance Sheet. 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.

FG&E Electric Division FG&E provides electric distribution service to customers under unbundled distribution rates approved by the MDTE. Its current retail electric distribution rates were approved by the MDTE in 2002. FG&E is required, as the provider of last resort, to purchase and provide power through Default Service for retail customers who chose not to buy, or were unable to purchase, energy from a competitive supplier. Prices for Default Service are set periodically based on market solicitations as approved by the MDTE. As of September 30, 2006, approximately 55 percent of FG&E s electric load was served by Default Service. The remaining portion was served by competitive third party suppliers.

As a result of the restructuring and the divestiture of FG&E s owned generation assets and buyout of FG&E s power supply obligations, Regulatory Assets on the Company s balance sheets include the following three categories: Power Supply Buyout Obligations associated with the divestiture of its long-term purchase power obligations; Recoverable Deferred Restructuring Charges resulting from the restructuring legislation s seven year rate cap; and Recoverable Generation-related Assets associated with the divestiture of its owned generation plant. FG&E earns carrying charges on the majority of the unrecovered balances of the Recoverable Deferred Restructuring Charges. The value of FG&E s Recoverable Deferred Restructuring Charges and Recoverable Generation-related Assets was approximately $36.6 million at September 30, 2006, and $36.7 million at September 30, 2005, and is expected to be recovered in FG&E s rates over the next five to seven years. In addition, as of September 30, 2006, FG&E had recorded on its balance sheets $52.0 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 s consolidated financial statements, and on which carrying charges are not earned as the timing of cash disbursements and cash receipts associated with these long-term obligations is matched through rates.

Recovery of the deferred amounts described above will be made pursuant to a Settlement Agreement among FG&E, the Massachusetts Office of the Attorney General (Attorney General), and representatives of industrial and low-income customers. The Settlement Agreement, which was approved by the MDTE in 2005, provides for a rate path to allow recovery of FG&E s deferred stranded costs.

On March 7, 2006, the MDTE approved FG&E s 2003 and 2004 annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan. FG&E s 2005 filing, which is subject to investigation, is pending. Management expects that this filing will be approved without material changes or adjustments.

FG&E Gas Division FG&E provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDTE. Its current retail distribution rates were approved by the MDTE in 2002. FG&E s customers may purchase gas supplies from third-party vendors or purchase their gas from FG&E as the provider of last resort. FG&E collects its gas supply costs through a seasonal reconciling CGAC and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

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FG&E Other On October 27, 2004, the MDTE approved FG&E s request for a reconciliation rate adjustment mechanism, the Pension / PBOP Adjustment Factor (PAF), to provide for the recovery of costs associated with the Company s employee pension benefits and PBOP expenses. 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 provides for an annual filing and rate adjustment with the MDTE. As of September 30, 2006, FG&E has a regulatory asset of $3.1 million which is included as part of Regulatory Assets in the Company s Consolidated Balance Sheets.

On November 30, 2005, the MDTE announced a change in its method for recovery of gas cost-related bad debt, and determined that it would allow for full recovery of these costs on a reconciling basis. Following this change in policy, FG&E made filings with the MDTE seeking approval to recover its actual gas and electric supply-related bad debt through appropriate reconciling rate mechanisms consistent with the MDTE s ruling. On September 7, 2006, the MDTE issued an order allowing FG&E to recover its actual gas and electric supply-related bad debt effective December 1, 2005. Prior to this final approval, FG&E had recovered supply related bad debt based on a fixed rate formula that was resulting in a significant underrecovery of these costs. On September 27, 2006, the Attorney General filed a Petition for Appeal with the Massachusetts Supreme Judicial Court seeking to set aside the MDTE s order of September 7, 2006. FG&E intends to support the MDTE s order but management can not predict the outcome of the Attorney General s appeal at this time.

UES UES provides electric distribution service to its customers pursuant to rates approved by the NHPUC. Its current retail electric distribution rates were approved by the NHPUC in 2006 under the Settlement Agreement discussed above. As the provider of last resort, UES also provides its customers with electric power through Default Service at rates which reflect UES costs for wholesale supply with no profit or markup. UES also provided a Transition Service supply for all rate classes through April 30, 2006. On May 1, 2006, customers previously on Transition Service were automatically placed on Default Service. Under a NHPUC approved settlement with the Office of the Consumer Advocate and the NHPUC Staff, UES procures Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts on a semi-annual basis. UES recovers its costs for this service on a pass-through basis through reconciling rate mechanisms. As of September 30, 2006, approximately 82 percent of UES electric load was served by Default Service. The remaining portion was served by competitive third party suppliers.

In the 2002 restructuring settlement, the NHPUC approved the divestiture of the long-term power supply portfolio by Unitil Power and tariffs for UES for stranded cost recovery and Transition and Default Service, including certain charges that are subject to annual or periodic reconciliation or future review. As of September 30, 2006, UES had recorded on its balance sheets $45.3 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 four years. The Company does not earn carrying charges on these regulatory assets as the timing of cash receipts and cash disbursements associated with these long-term obligations is matched through rates.

On March 17, 2006, UES made its third annual reconciliation and rate filing with the NHPUC under its restructuring plan, effective May 1, 2006, including reconciliation of prior year costs and revenues for the Transition Service Charge, Default Service Charge, Stranded Cost Charge, and External Delivery Charge. The NHPUC approved the filing on April 28, 2006.

On November 4, 2005, UES filed a request for a rate increase of $4.65 million with the NHPUC. The filing included a request to recover pension and PBOP costs through an annual reconciling rate mechanism, and the inclusion of a step adjustment for certain future rate base additions. The filing also requested that temporary rates be established at current rate levels effective December 4, 2005. On February 3, 2006, the NHPUC issued an order approving the request for temporary rates to be effective January 1, 2006. On August 24, 2006 a settlement agreement resolving all base rate issues among UES, the Office of the Consumer Advocate, and the NHPUC Staff was filed, and on October 6, 2006, the agreement was approved by the NHPUC. The terms of the settlement agreement provide for an increase in base distribution rates of $2.3 million annually, effective as of January 1, 2006. Additionally, the approved settlement agreement authorizes two future step increases in base distribution rates, related to utility plant additions in 2006, of approximately $400,000 and $130,000 annually, effective as of November 1, 2006 and May 1, 2007, respectively. Also, the settlement agreement provides for the recovery of over $300,000 annually of supply-related operating and administrative costs through default energy service rates and a reduction of approximately $600,000 in annual depreciation expense, primarily reflecting an increase in utility plant and equipment average service lives. The stipulated rate of return under the settlement is 8.70%, including a return on equity of 9.67%. As part of the Settlement Agreement, UES is allowed to recover its pension and PBOP expenses in base rates. Under the Settlement Agreement UES will amortize its deferred pension costs as these amortization costs are recovered over a six year period in base rates. UES had originally sought to recover pension and PBOP expenses in a reconciling mechanism similar to the PAF, described above. The approved settlement also authorizes a temporary rate surcharge for recovery of rate case expense and recoupment of the authorized distribution rate increase from January through October 2006.

FERC Wholesale Power Market Restructuring FG&E, UES and Unitil Power are members of NEPOOL, formed in 1971 to assure reliable operation of the bulk power system in the most economic manner for the region. NEPOOL is governed by the NEPOOL Agreement that is filed with and subject to the jurisdiction of the FERC. The regional bulk power system is operated by an independent corporate entity, ISO-NE, in order to avoid any opportunity for conflicting financial interests between the system operator and the market-driven participants.

As of February 1, 2005, a Regional Transmission Organization (RTO) was established in New England. ISO-NE became the entity responsible for operating the RTO. The market rules and requirements to participate in the markets previously covered under the NEPOOL Agreement were transferred to the new RTO structure under control of ISO-NE. FERC approved the formation of the RTO effective February 1, 2005. Several parties have appealed various issues associated with the FERC s approval of the RTO to Federal District Court of Appeals. Those proceedings are ongoing.

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. UES and FG&E intervened in the proceeding. On April 11, 2006, a contested Settlement to resolve the LICAP proceeding was submitted by the FERC Settlement Judge to the FERC. It proposed transition payments for capacity until a Forward Capacity Market can be implemented, possibly by 2010. On June 16, 2006 the FERC approved the Settlement, for implementation December 1, 2006. This case is subject to a Request for Rehearing at FERC and may be subject to subsequent appeal to the Federal Courts. The Company projects that that retail rates will be significantly increased over the next several years as the LICAP Settlement above is implemented.

The formation of an RTO, LICAP and other wholesale market changes, including changes to transmission rates, is not expected to have a material impact on Unitil s operations because of the cost recovery mechanisms for wholesale energy costs approved by the MDTE and NHPUC.

NOTE 7 ENVIRONMENTAL MATTERS

UNITIL S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION S FORM 10-K FOR DECEMBER 31, 2005 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 22, 2006.

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, 2006, 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

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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 (MCP) 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. FG&E is in the process of developing a long range plan for a Permanent Solution for the site, including alternatives for re-use of the site.

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, on June 9, 2006, FG&E filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. 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.

In September 2006, the FASB issued SFAS No. 158, an amendment of SFAS No. 87, SFAS No. 88, SFAS No. 106 and SFAS No. 132(R). SFAS No. 158 requires companies to record on their balance sheets the overfunded or underfunded status of their pension and postretirement benefits other than pension plans. For pension plans, the benefit obligation will be measured using the projected benefit obligation while the accumulated benefit obligation will be used to measure the obligation for postretirement benefits other than pension. Additionally, SFAS No. 158 requires companies to recognize in their statements of earnings actuarial gains and losses and prior service costs and credits which have not yet been recorded as expense. The effective date of SFAS No. 158 is December 15, 2006. The Company has a Defined Benefit Pension Plan and a Postretirement Benefits Other than Pension (PBOP) Plan as discussed below. The Company expects that the implementation of SFAS No. 158 will have a significant impact on the recognition of pension and PBOP assets and liabilities on the Company s Balance Sheet and is currently assessing the impact of recording these items for the year ending December 31, 2006.

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.

In December 2003 and 2002, UES and FG&E filed requests with their respective state regulatory commissions for approval of accounting orders to mitigate certain accounting requirements related to pension plan assets which had been triggered by the substantial decline in the capital markets. UES and FG&E were granted approval of this regulatory accounting treatment in January 2003 and 2004. As a result of these approvals, the Company has recorded as a Regulatory Asset the amount of the Plan s unfunded Accumulated Benefit Obligation (ABO) plus one dollar. These approvals allow UES and FG&E to treat their Additional Minimum Liability (AML) as Regulatory Assets under SFAS No. 71 and avoid the reduction in equity through other comprehensive income that would otherwise be required by SFAS No. 87. With the implementation of SFAS No. 158 for the year ending December 31, 2006, as discussed above, this treatment under SFAS No. 71 will no longer apply.

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On October 27, 2004 the MDTE approved FG&E s request for a reconciliation rate adjustment mechanism (the Pension / PBOP Adjustment Factor (PAF)) to recover the costs associated with the Company s pension and PBOP costs on an annually reconciling basis. As a result of this order, FG&E records a regulatory asset to recognize the deferral for the difference between the level of pension and PBOP expenses that are currently included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106 and amortizes increases and /or decreases in that deferral balance into the PAF for recovery over a three year period. The PAF provides for an annual filing and rate adjustment with the MDTE and requires that carrying charges on prepaid or (accrued) pension and PBOP assets and liabilities be collected from, or refunded to, utility customers. In 2005, FG&E received approval of its first annual filing and rate adjustment.

As discussed above, on October 6, 2006, the NHPUC approved a Settlement Agreement, resolving all issues in UES electric distribution base rate case filed in November 2005. As part of the Settlement Agreement, UES is allowed to recover its pension and PBOP expenses in base rates. Under the Settlement Agreement UES will amortize its deferred pension costs as these amortization costs are recovered over a six year period in base rates. UES had originally sought to recover pension and PBOP expenses in a reconciling mechanism similar to the PAF, described above.

The following tables show the components of net periodic pension cost, (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,	
	2006	**2005**	**2006**	**2005**
Components of NPPC (000 s)				
Service Cost	**$ 450**	$ 415	**$ 1,350**	$ 1,094
Interest Cost	**788**	765	**2,365**	2,314
Expected Return on Plan Assets	**(944)**	(851)	**(2,831)**	(2,553)
Amortization of Prior Service Cost	**27**	29	**80**	80
Amortization of Net Loss	**331**	377	**993**	859
Subtotal NPPC	**652**	735	**1,957**	1,794
Net Amounts Capitalized and Deferred	**(127)**	(366)	**(772)**	(1,050)
NPPC Recognized	**$ 525**	$ 369	**$ 1,185**	$ 744

Included in the 2006 amounts above for Amounts Capitalized and Deferred are approximately ($142,000) and $2,000 for the three and nine months ended September 30, 2006, respectively, recorded as increases (decreases) to Regulatory Assets on the Company s Balance Sheet. Included in the 2005 amounts above for Amounts Capitalized and Deferred are approximately $3,000 and $369,000 for the three and nine months ended September 30, 2005, respectively, recorded as increases to Regulatory Assets on the Company s Balance Sheet. The remaining amounts represent amounts capitalized to construction overheads.

Key Assumptions (Weighted Average)	**2006**	**2005**
Used to Determine Benefit Obligations:		
Discount Rate	5.50%	6.50% [(1)]
Rate of Compensation Increase	3.50%	3.50%
Used to Determine NPPC:		
Discount Rate	5.50%	6.50% [(1)]
Expected Long-Term Rate of Return on Plan Assets	8.50%	8.50%
Rate of Compensation Increase	3.50%	3.50%

(1) In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the Plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%.

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Employer Contributions As of September 30, 2006, the Company has not yet made any contributions to the Plan for 2006. The Company is required to make a minimum contribution to its pension plan this year in the amount of $2.5 million. The Company contributed $2.5 million in 2005. On August 17, 2006, the Pension Protection Act of 2006 (PPA) was signed into law. Included in the PPA are new minimum funding rules which will go into effect for plan years beginning in 2008. The funding target will be 100% of a plan s liability with any shortfall amortized over seven years, with lower (92% - 100%) funding targets available to well-funded plans during the transition period. The Company will be consulting with its actuary to assess the impact of these new funding rules, along with the other provisions of the PPA, on its pension plan.

Postretirement Benefits - The Company also sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan) primarily to provide health care and life insurance benefits to active employees. The Company has established Voluntary Employee Benefit Trusts, into which it funds contributions to the PBOP Plan.

In January 2004 and May 2004, the FASB issued, respectively, Statement No. 106-1 (SFAS No. 106-1) and Statement No. 106-2 (SFAS No. 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 No. 106-1 and SFAS No. 106-2 require the disclosure of the effects, if any, of the Act on the reported measure of the accumulated postretirement benefit obligation and how that effect has been, or will be, reflected in the net postretirement benefit costs of current or subsequent periods. On January 28, 2005, the final Medicare Part D Prescription Drug Rules were posted to the Federal Register. Based on these rules, the Company s estimated PBOP Projected Benefit Obligation was reduced by $5.1 million. Also, the Company has estimated that its annual PBOP costs will be reduced by $0.4 million under the Act. These reductions are reflected in the Company s Consolidated Financial Statements. The Company s health care insurance provider has concluded that the Company s PBOP Plan is equal to or better than standard Medicare Part D coverage. Additionally, the Company s recognition of the Act is not expected to have any impact on the rate of participation in the PBOP Plan or per capita claims.

As discussed above, on October 27, 2004 the MDTE approved FG&E s request for a reconciliation rate adjustment mechanism, the PAF, to recover the costs associated with the Company s pension and PBOP costs on an annually reconciling basis. As discussed above, on October 6, 2006, the NHPUC approved a Settlement Agreement, resolving all issues in UES electric distribution base rate case filed in November 2005. As part of the Settlement Agreement, UES is allowed to recover its pension and PBOP expenses in base rates. UES had originally sought to recover pension and PBOP expenses in a reconciling mechanism similar to the PAF, described above.

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,	
	2006	**2005**	**2006**	**2005**
Components of NPPBC (000 s)				
Service Cost	**$ 321**	$ 300	**$ 962**	$ 745
Interest Cost	**507**	435	**1,522**	1,346
Expected Return on Plan Assets	**(49)**	(1)	**(146)**	(31)
Amortization of Prior Service Cost	**340**	322	**1,020**	1,051
Amortization of Transition (Asset) Obligation	**5**	5	**16**	16
Amortization of Net (Gain) Loss	**40**	33	**120**	
Subtotal NPPBC	**1,164**	1,094	**3,494**	3,127
Amounts Capitalized and Deferred	**(559)**	(726)	**(1,673)**	(1,674)
NPPBC Recognized	**$ 605**	$ 368	**$ 1,821**	$ 1,453

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Included in the 2006 amounts above for Amounts Capitalized and Deferred are approximately $119,000 and $357,000 for the three and nine months ended September 30, 2006, respectively, recorded as increases to Regulatory Assets on the Company s Balance Sheet. Included in the 2005 amounts above for Amounts Capitalized and Deferred are approximately $196,000 and $474,000 for the three and nine months ended September 30, 2005, respectively, recorded as increases to Regulatory Assets on the Company s Balance Sheet. The remaining amounts represent amounts capitalized to construction overheads.

Weighted-Average Assumptions	**2006**	**2005**
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	6.50% (1)
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	7.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2013
Used to Determine NPPBC:		
Discount Rate	**5.50%**	6.50% (1)
Expected Long-Term Rate of Return on Plan Assets Union	**8.50%**	8.50%
Expected Long-Term Rate of Return on Plan Assets Non-Union	**5.50%**	5.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2013

(1) In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the Plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%.

Employer Contributions As of September 30, 2006, the Company has made $1.1 million of contributions to the PBOP Plan during 2006. The Company presently anticipates contributing an additional $1.5 million to fund the Plan in 2006 for an estimated total of $2.6 million. The Company contributed $2.5 million in 2005.

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,**	
	2006	**2005**	**2006**	**2005**
Components of NPSC (000 s)				
Service Cost	$ 36	$ 24	$ 110	$ 71
Interest Cost	26	20	78	61
Amortization of Transition Obligation	4	4	12	13
Amortization of Net Loss	10	1	29	3
Net Periodic SERP Cost	$ 76	$ 49	$ 229	$ 148

Employer Contributions As of September 30, 2006, the Company has made payments of $54,000 to beneficiaries during 2006. The Company presently anticipates making additional benefit payments of $18,000 in 2006 for a total of $72,000.

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Note 9: Subsequent Event

On October 6, 2006, UES received approval from the NHPUC of a Settlement Agreement, discussed above, resolving all issues in its electric distribution base rate case filed in November 2005. The key provisions of the Settlement Agreement approved by the Commission include:

- an increase in electric base distribution rates of $2,266,966 annually, effective as of January 2006;
- a stipulated overall rate of return of 8.70%, including a return on equity of 9.67%, applied to a proforma rate base of $96,046,267;
- two additional future step increases in electric base distribution rates, related to utility plant additions in 2006, of approximately $400,000 and $130,000 annually, effective as of November 1, 2006 and May 1, 2007, respectively;
- the recovery of over $300,000 annually of supply-related operating and administrative costs through default energy service rates;
- a reduction of approximately $600,000 in annual depreciation expense, primarily reflecting an increase in utility plant and equipment average service lives;
- the resolution of a multi-year effort by UES to recover in rates the rapidly escalating costs of pension and other postretirement benefit costs - the Settlement Agreement provides for the recovery of the costs sought by UES in the rate case as a component of base distribution rates;
- a comprehensive agreement on several rate design issues, including the allocation of the revenue increase to each customer class, the capping of the increase to low use residential customers and the maintenance of a discounted initial 250 kWh block for residential customers, and agreement on customer, volumetric and demand charges for each rate class;
- a provision for a temporary rate surcharge to provide for recovery of rate case expense and recoupment of the authorized distribution rate increase from January through October 2006.

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

As of the end of the quarter covered by this Form 10-Q, 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 Chief Accounting Officer, 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 Chief Accounting Officer 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 changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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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 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company s Form 10-K for the year-ended December 31, 2005 as filed with the Securities and Exchange Commission on February 22, 2006.

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, 2006.

(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]
7/1/06 7/31/06				n/a
8/1/06 8/31/06	92	$ 24.77	92	n/a
9/1/06 9/30/06				n/a
Total	92	$ 24.77	92	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.

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Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting 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
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer 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 26, 2006 Announcing Earnings For the Quarter Ended September 30, 2006	Filed herewith

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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 27, 2006	/s/ Mark H. Collin Mark H. Collin Chief Financial Officer
Date: October 27, 2006	/s/ Laurence M. Brock Laurence M. Brock Chief Accounting Officer