North Atlantic

North Atlantic Energy Service Corporation
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Seabrook, NH 03874
(603) 474-9521

The Northeast Utilities System

December 20, 2001

Docket 50-443
NYN-01098
CR 97-01187-05

United States Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Seabrook Station
Guarantees of Payments of Deferred Premiums

Pursuant to 10CFR 140.21(e), North Atlantic Energy Service Corporation (North Atlantic), on behalf of the licensees named in Facility Operating License NPF-86, provides herewith, the Annual Reports for 2000. The Annual Reports provided below demonstrate the collective ability of the licensees to meet their obligation for payment of deferred premiums.

Annual Reports for 2000 (containing certified financial statements) are enclosed for the following:

- North Atlantic Energy Corporation
- Connecticut Light and Power Company
- The United Illuminating Company
- Massachusetts Municipal Wholesale Electric Company
- New England Power Company
- Commonwealth Energy System (for subsidiary Canal Electric Company)
- New Hampshire Electric Cooperative, Inc.
- Taunton Municipal Lighting Plant
- Hudson Light and Power Department
- Bay Corp Holdings, LTD. (for subsidiary Great Bay Power Corporation and Little Bay Power Corporation)

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In addition, the Agreement of Joint Ownership, Construction and Operation of New Hampshire Nuclear Units, dated May 1, 1973 as amended, and specifically the provisions of Paragraph 10.1, as amended by the Eighteenth Amendment, dated March 14, 1986, is incorporated by reference.

The enclosed annual reports are submitted pursuant to 10 CFR 50.71 (b).

Should you have any questions regarding this matter, please contact Mr. James M. Peschel, Manager - Regulatory Programs, at (603) 773-7194.

Very truly yours,

NORTH ATLANTIC ENERGY SERVICE CORP.

Ted C. Feigenbaum
Executive Vice President and
Chief Nuclear Officer

cc: (without enclosures)

H. J. Miller, NRC Region I Administrator
G. F. Wunder, NRC Project Manager, Project Directorate I-2
G. T. Dentel, NRC Senior Resident Inspector

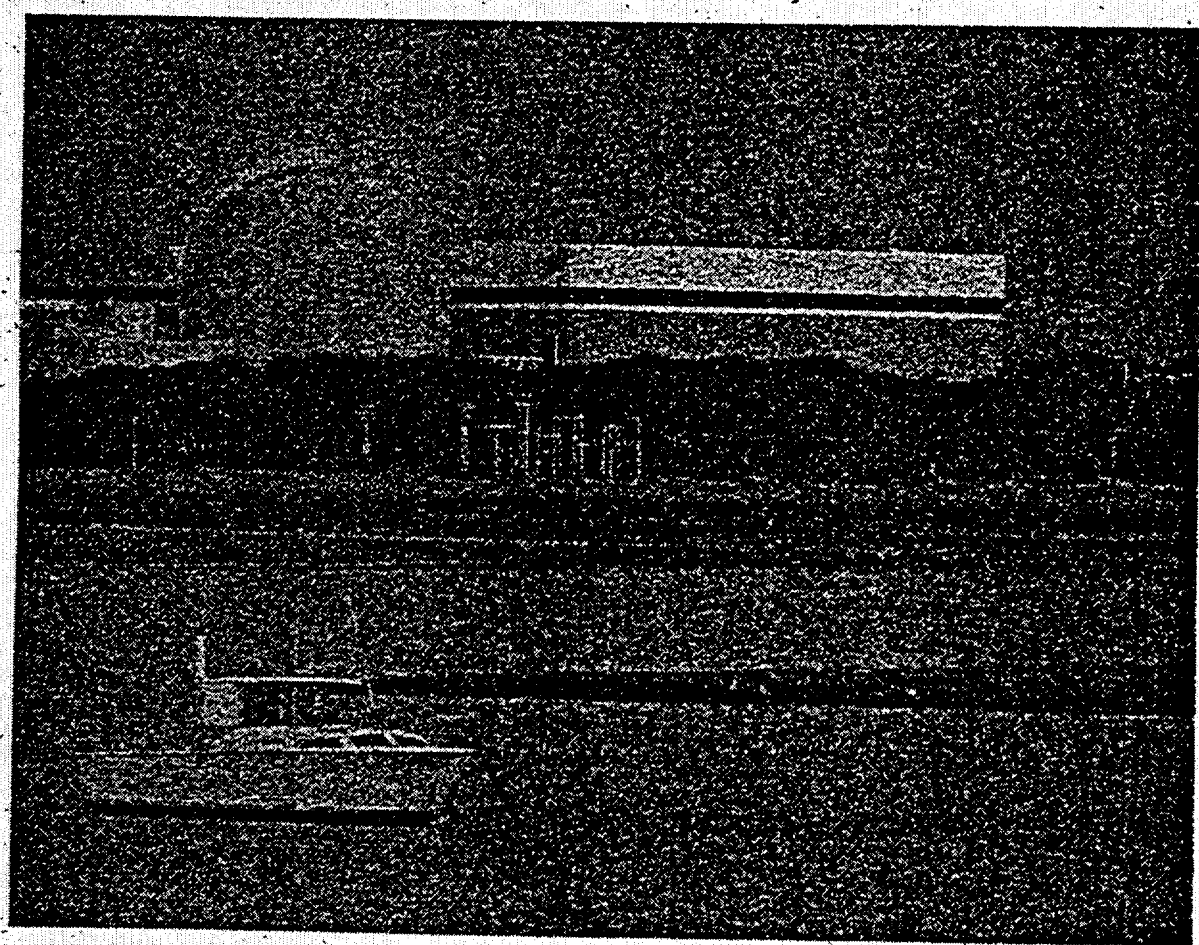
cc: (with enclosures):

United States Nuclear Regulatory Commission
Attention: Director of Nuclear Reactor Regulation
Washington, DC 20555

ENCLOSURE TO NYN-01098

2000

Annual Report



North Atlantic

The Northeast Utilities System

Directors

Georgte R. Gram II
Director—Support Services
Seabrook Station

Ted C. Feigenbaum
Executive Vice President and
Chief Nuclear Officer

Bruce D. Kenyon
President and
Chief Executive Officer

Officers

Bruce D. Kenyon
President and
Chief Executive Officer

Ted C. Feigenbaum
Executive Vice President and
Chief Nuclear Officer

Lillian M. Cuoco
Secretary

Robert A. Bersak
Assistant Secretary

Jennifer F. Powers
Assistant Secretary

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Financial Condition

Overview

North Atlantic Energy Corporation, (NAEC or the company), is a wholly owned operating subsidiary of Northeast Utilities (NU) and is part of the Northeast Utilities system (NU system). Public Service Company of New Hampshire (PSNH), is another wholly owned subsidiary of NU. PSNH is obligated to purchase the capacity and output from NAEC's 35.98 percent joint ownership interest in the Seabrook Station nuclear unit (Seabrook) under the terms of two life-of-unit, full cost recovery contracts (Seabrook Power Contracts).

The company's only assets are Seabrook and other Seabrook-related assets and its only source of revenues are the Seabrook Power Contracts. PSNH's obligations under the Seabrook Power Contracts are solely its own and have not been guaranteed by NU. The Seabrook Power Contracts contain no provisions entitling PSNH to terminate its obligations. If, however, PSNH were to fail to perform its obligations under the Seabrook Power Contracts, the company would be required to find other purchasers for Seabrook's power.

With the implementation of the "Agreement to Settle PSNH Restructuring" (Settlement Agreement), PSNH and NAEC will restructure the power contracts to provide for the buydown of the value of the Seabrook asset to $100 million. NAEC will use a portion of these cash proceeds to retire its existing long-term debt obligation. NAEC will also return to NU parent another portion of these cash proceeds in the form of a dividend. The Settlement Agreement also requires NAEC to sell via public auction its share of Seabrook, with the sale to occur no later than December 31, 2003. Upon a successful sale of NAEC's share of Seabrook, the existing Seabrook Power Contracts between PSNH and NAEC will be terminated. However, PSNH will continue to be responsible for funding NAEC's ownership share of Seabrook's decommissioning liability.

In 2000, NAEC's revenues decreased to $274.3 million, down 4.5 percent from revenues of $287.4 million in 1999. Revenues were $276.7 million in 1998. In 2000, NAEC had net income of $32.5 million, compared to $29.6 million in 1999 and $29.5 million in 1998.

Consolidated Edison, Inc. Merger

In 2000, NU and Consolidated Edison, Inc. (Con Edison) received most of the approvals needed to complete the merger announced in October 1999. Shareholders from both companies approved the merger in April 2000, and all state regulatory approvals were granted by the end of the year. Additionally, the Federal Energy Regulatory Commission (FERC) approved the merger in May 2000, the Nuclear Regulatory Commission approved the transaction in August 2000, and the United

States Department of Justice approved the merger in February 2001. Necessary approval from the Securities and Exchange Commission (SEC) was expected to be received in mid-March 2001.

On February 28, 2001, NU's Board of Trustees requested that Con Edison provide reasonable assurance, in writing, that it intended to comply with the terms of the definitive merger agreement between the two companies. This included assurances that Con Edison would consummate the pending merger at the price set forth in the agreement promptly following the receipt of SEC approval. The original request for assurance was to be received by March 2, 2001, however that date was later extended to March 5, 2001. On March 5, 2001, Con Edison advised NU that it was not willing to close the merger on the agreed terms. NU notified Con Edison that it was treating its refusal to proceed on the terms set forth in the merger agreement as a repudiation and breach of the merger agreement, and that NU would file suit to obtain the benefits of the transaction as negotiated for NU shareholders. On March 6, 2001, Con Edison filed suit in the U.S. District Court for the Southern District of New York (Southern District), seeking a declaratory judgment that NU failed to satisfy conditions precedent under the merger agreement. On March 12, 2001, NU filed suit against Con Edison in the Southern District seeking damages in excess of $1 billion arising from Con Edison's breach of the merger agreement. NU cannot predict the outcome of this matter nor its effect on NU.

Liquidity

During 2000, net cash flows provided by operations were $117.6 million, compared to $181.4 million in 1999 and $128.7 million in 1998. The decrease in 2000 was primarily due to an increase in receivables and an increase in deferred income tax benefit due to lower tax depreciation.

Net cash flows used in financing activities were $112 million in 2000, compared to $130 million in 1999 and $75 million in 1998. This included $270 million to retire long-term debt, compared to $70 million and $20 million in 1999 and 1998, respectively. Cash dividends on common shares paid in 2000 were $42 million, compared to $60 million in 1999 and $45 million in 1998.

Including investments made in the NU System Money Pool, construction expenditures and investments in nuclear decommissioning trusts, net cash flows used in investing activities were $5.5 million in 2000, compared to $51.5 million in 1999 and $53.7 million in 1998. NAEC currently forecasts construction expenditures of $6.6 million for the year 2001.

In 2000, NAEC renewed its $200 million term credit agreement for 364 days. In April 2000, Moody's Investors Service (Moody's) upgraded its credit ratings for NAEC, and in October 2000, Fitch IBCA (Fitch) upgraded its credit ratings for NAEC. In January 2001, Moody's and Standard and Poor's upgraded their credit ratings for NAEC, primarily as a result of the New Hampshire Supreme Court's decision to uphold that state's restructuring plan and NU's general financial recovery.

By the end of 2002, PSNH expects to complete the auction of approximately 1,200 MW of fossil and hydroelectric generation assets, as well NAEC's share of Seabrook. PSNH's restructuring settlement was predicated upon receiving approximately $400 million of net proceeds from those sales. Cash proceeds will be used to retire debt and to return equity capital to the parent company.

In September 2000, the New Hampshire Public Utilities Commission (NHPUC) approved a comprehensive restructuring settlement that allows PSNH to securitize up to $670 million of stranded costs. In January 2001, the New Hampshire Supreme Court upheld this restructuring order on appeal. However, one of the appellants indicated publicly it would request a review of the New Hampshire Supreme Court decision by the United States Supreme Court. Such a request must be filed by May 1, 2001. Management believes that such an appeal would have a low probability of success, but cannot determine what effect it might have on the timing of the issuance of securitization bonds and the implementation of customer choice in New Hampshire. PSNH currently expects to work with the State of New Hampshire to issue securitization bonds early in the second quarter of 2001. Cash proceeds would be combined with cash on hand and used primarily to buydown the power contract between PSNH and NAEC, retire debt at the two companies of approximately $300 million and return equity capital to the parent company from PSNH and NAEC of another $375 million.

Restructuring

On September 8, 2000, the NHPUC issued two orders. The first order approved an Amended Settlement Agreement. The Amended Settlement Agreement, as approved by the NHPUC, will resolve 11 NHPUC dockets and PSNH's federal lawsuit which had enjoined the state of New Hampshire from implementing its restructuring legislation, will require PSNH to write off in excess of $200 million after-tax of its stranded costs and allow for the recovery of the remaining amount.

The second order issued by the NHPUC was an order addressing financing issues, primarily securitization. The order, among other things, authorizes PSNH to issue up to $670 million of rate reduction bonds (RRB), permits PSNH to establish a RRB charge, and establishes the terms of the RRB charge, including the requirement that it be non-bypassable. The New Hampshire legislature had previously passed legislation, that permitted PSNH to issue up to $670 million in RRBs to securitize certain regulatory assets.

The Settlement Agreement also requires NAEC to sell its share of the Seabrook power plant, including Seabrook 2. NAEC will use the proceeds of such a sale to pay off any outstanding obligations. Net proceeds in excess of book value will be transferred to PSNH and applied against PSNH's stranded costs. The sales would be accomplished through an auction process subject to NHPUC administration.

Nuclear Plant Performance and Divestiture

Seabrook
Seabrook operated at a capacity factor of 78 percent in 2000. The unit began a scheduled refueling outage on October 21, 2000. The outage was extended by approximately two months as a result of the need to repair extensive problems with a back-up diesel generator. Seabrook returned to service on January 29, 2001.

On December 15, 2000, NU filed its divestiture plan for Seabrook with the NHPUC and the Connecticut Department of Public Utility Control. NU hopes to complete the sale in 2002.

Nuclear Decommissioning
For further information regarding nuclear decommissioning, see Note 2, "Nuclear Decommissioning and Plant Closure Costs," to the financial statements.

Spent Nuclear Fuel Disposal Costs
The United States Department of Energy (DOE) originally was scheduled to begin accepting delivery of spent nuclear fuel in 1998. However, delays in confirming the suitability of a permanent storage site continually have postponed plans for the DOE's long-term storage and disposal site. Extended delays or a default by the DOE could lead to consideration of costly alternatives. NU has the primary responsibility for the interim storage of its spent nuclear fuel prior to divestiture of its nuclear units.

For further information regarding spent nuclear fuel disposal costs, see Note 7C, "Commitments and Contingencies - Spent Nuclear Fuel Disposal Costs," to the financial statements.

Other Matters

Environmental Matters
NAEC is subject to environmental laws and regulations structured to mitigate or remove the effect of past operations and to improve or maintain the quality of the environment. For further information regarding environmental matters, see Note 7B, "Commitments and Contingencies - Environmental Matters," to the financial statements.

Other Commitments and Contingencies
For further information regarding these other commitments and contingencies, see Note 7, "Commitments and Contingencies," to the financial statements.

Forward Looking Statements
This discussion and analysis includes forward looking statements, which are statements of future expectations and not facts including, but not limited to, statements regarding future earnings, refinancing, the use of proceeds from restructuring, and the recovery of operating costs. Words such as *estimates, expects, anticipates, intends, plans,* and similar expressions identify forward looking statements. Actual results or outcomes could differ materially as a result of further actions by state and federal regulatory bodies, competition and

industry restructuring, changes in economic conditions, changes in historical weather patterns, changes in laws, developments in legal or public policy doctrines, technological developments, and other presently unknown or unforeseen factors.

RESULTS OF OPERATIONS

The components of significant income statement variances for the past two years are provided in the table below.

Income Statement Variances
(Millions of Dollars)

	2000 over/(under) 1999		1999 over/(under) 1998	
	Amount	Percent	Amount	Percent
Operating Revenues	$(13)	(5%)	$11	4%
Operating Expenses:				
Fuel, purchased and interchange power, net	(3)	(17)	2	17
Other operation and maintenance expense	-	-	10	19
Depreciation	-	-	2	9
Amortization of regulatory assets	-	-	-	-
Federal and state income taxes	1	2	(1)	(4)
Taxes other than income taxes	(6)	(42)	2	17
Total operating expenses	(7)	(3)	15	7
Operating Income	(6)	(11)	(4)	(8)
Other Income:				
Deferred Seabrook return - other funds	(2)	(52)	(2)	(34)
Other, net	1	12	1	12
Other income tax	4	19	5	33
Net other income	2	14	3	27
Interest charges	(6)	(17)	(1)	(3)
Net Income/(Loss)	$ 3	10	$ -	-

Operating Revenues
Total operating revenues decreased by $13 million or 5 percent for 2000, as compared to 1999, primarily due to lower operating costs billed to PSNH through the Seabrook Power Contracts.

Operating revenues increased in 1999, primarily due to the higher operating expenses related to the Seabrook refueling and maintenance outage in 1999.

Fuel, Purchased and Interchange Power, Net
Fuel expense decreased in 2000, as compared to 1999, primarily due to the extended nuclear refueling outage in 2000.

Fuel expense increased in 1999, primarily due to a higher fuel amortization rate since the Seabrook refueling outage.

Other Operation and Maintenance Expense
Other operation and maintenance (O&M) expenses were relatively unchanged in 2000, as compared to 1999.

Other O&M expenses increased in 1999, primarily due to higher costs relating to the Seabrook refueling outage.

Depreciation
Depreciation expense was unchanged in 2000.

Depreciation increased in 1999 due to shorter useful lives for 1999 plant asset additions.

Federal and State Income Taxes
Federal and state income taxes decreased during 2000, due to lower book taxable income.

Federal and state income taxes decreased during 1999, due to lower book taxable income.

Taxes Other Than Income Taxes
Taxes other than income taxes decreased in 2000, primarily due to the tax true-up in the third quarter of 1999 as a result of a change to the statewide utility property tax.

Taxes other than income taxes increased in 1999, as the result of the New Hampshire change to a statewide utility property tax in place of the nuclear station tax.

Deferred Seabrook Return - Other Funds
The deferred Seabrook return income decreased in 2000, as compared to 1999, as NAEC continues to recover the Seabrook deferred return, reducing the outstanding balance.

The deferred Seabrook return income decreased in 1999, as compared to 1998, as NAEC continues to recover the Seabrook deferred return, reducing the outstanding balance.

Other, Net
Other income, net increased in 2000, primarily due to higher interest income on investments in the NU System Money Pool.

Other income, net increased in 1999, primarily due to higher interest income on investments in the NU System Money Pool.

Interest Charges
Interest charges decreased in 2000, primarily due to lower long-term debt outstanding.

Interest charges decreased in 1999, primarily due to lower long-term debt outstanding.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors
of North Atlantic Energy Corporation:

We have audited the accompanying balance sheets of North Atlantic Energy Corporation (a New Hampshire corporation and a wholly owned subsidiary of Northeast Utilities) as of December 31, 2000 and 1999, and the related statements of income, common stockholder's equity and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of North Atlantic Energy Corporation as of December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

/s/ ARTHUR ANDERSEN LLP
ARTHUR ANDERSEN LLP

Hartford, Connecticut
January 23, 2001 (except with
respect to the matter discussed
in Note 11, as to which the
date is March 13, 2001)

NORTH ATLANTIC ENERGY CORPORATION

STATEMENTS OF INCOME

FOR THE YEAR ENDED DECEMBER 31,	2000	1999	1998
	(Thousands of Dollars)		
Operating Revenues	$ 274,319	$ 287,369	$ 276,685
Operating Expenses:			
Operation -			
Fuel	12,923	15,596	13,305
Other	40,650	41,727	36,763
Maintenance	20,268	19,030	14,120
Depreciation	27,823	27,576	25,381
Amortization of regulatory assets, net	85,176	85,488	85,464
Federal and state income taxes	35,675	34,854	36,194
Taxes other than income taxes	7,727	13,370	11,401
Total operating expenses	230,242	237,641	222,628
Operating Income	44,077	49,728	54,057
Other Income/(Loss):			
Deferred Seabrook return - other funds	2,112	4,417	6,731
Other, net	(6,544)	(7,432)	(8,435)
Income taxes	22,792	19,131	14,378
Other income, net	18,360	16,116	12,674
Income before interest charges	62,437	65,844	66,731
Interest Charges:			
Interest on long-term debt	32,247	45,297	50,082
Other interest	1,423	(542)	(676)
Deferred Seabrook return - borrowed funds	(3,726)	(8,467)	(12,169)
Interest charges, net	29,944	36,288	37,237
Net Income	$ 32,493	$ 29,556	$ 29,494

The accompanying notes are an integral part of these financial statements.

NORTH ATLANTIC ENERGY CORPORATION

BALANCE SHEETS

AT DECEMBER 31,	2000	1999
	(Thousands of Dollars)	
ASSETS		
Utility Plant, at original cost:		
Electric	$ 719,353	$ 736,472
Less: Accumulated provision for depreciation	223,465	196,694
	495,888	539,778
Construction work in progress	8,710	10,274
Nuclear fuel, net	28,369	21,149
Total net utility plant	532,967	571,201
Other Property and Investments:		
Nuclear decommissioning trusts, at market	50,863	43,667
	50,863	43,667
Current Assets:		
Cash	118	-
Notes receivable from affiliated companies	27,800	56,400
Accounts receivable from affiliated companies	50,796	22,840
Taxes receivable	722	11,717
Materials and supplies, at average cost	14,003	13,088
Prepayments and other	2,000	1,773
	95,439	105,818
Deferred Charges:		
Regulatory assets	48,068	129,641
Unamortized debt expense	847	1,780
Prepaid property tax	630	-
Other	150	-
	49,695	131,421
Total Assets	$ 728,964	$ 852,107

The accompanying notes are an integral part of these financial statements.

NORTH ATLANTIC ENERGY CORPORATION

BALANCE SHEETS

AT DECEMBER 31,	2000	1999
	(Thousands of Dollars)	
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, $1 par value - authorized 1,000 shares; 1,000 shares outstanding in 2000 and 1999	$ 1	$ 1
Capital surplus, paid in	160,999	160,999
Retained earnings	(41)	12,752
Total common stockholder's equity	160,959	173,752
Long-term debt	65,000	135,000
Total capitalization	225,959	308,752
Current Liabilities:		
Notes payable to banks	200,000	-
Long-term debt - current portion	70,000	270,000
Accounts payable	16,543	11,694
Accounts payable to affiliated companies	1,389	806
Accrued interest	2,716	2,340
Other	276	272
	290,924	285,112
Deferred Credits and Other Long-term Liabilities:		
Accumulated deferred income taxes	184,763	222,601
Deferred obligation to affiliated company	3,240	12,984
Other	24,078	22,658
	212,081	258,243
Commitments and Contingencies (Note 7)		
Total Capitalization and Liabilities	$ 728,964	$ 852,107

The accompanying notes are an integral part of these financial statements.

NORTH ATLANTIC ENERGY CORPORATION

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Common Stock	Capital Surplus, Paid In	Retained Earnings (a)	Total
		(Thousands of Dollars)		
Balance at January 1, 1998..............	$ 1	$ 160,999	$ 58,702	$ 219,702
Net income for 1998.................			29,494	29,494
Cash dividends on common stock......			(45,000)	(45,000)
Balance at December 31, 1998............	1	160,999	43,196	204,196
Net income for 1999.................			29,556	29,556
Cash dividends on common stock......			(60,000)	(60,000)
Balance at December 31, 1999............	1	160,999	12,752	173,752
Net income for 2000.................			32,493	32,493
Cash dividends on common stock......			(42,000)	(42,000)
Tax expense for 1993-1999 from reduction on NU parent company losses (b)........................			(3,286)	(3,286)
Balance at December 31, 2000............	$ 1	$ 160,999	$ (41)	$ 160,959

(a) The dividend restriction allows all the retained earnings plus an allowance of $10,000,000 to be available. However the company has a 25% common equity ratio test to meet. Since the company's retained earnings are negative, only $9,959,000 of the allowance can be paid.

(b) The amount in 2000 represents the tax expense related to the previously unallocated 1993 through 1999 NU parent losses.

The accompanying notes are an integral part of these financial statements.

NORTH ATLANTIC ENERGY CORPORATION

STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	For the Years Ended December 31, 2000	1999	1998
Operating Activities:			
Net income	$ 32,493	$ 29,556	$ 29,494
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation	27,823	27,576	25,381
Amortization of nuclear fuel	10,221	12,642	10,453
Deferred income taxes and investment tax credits, net	(25,579)	452	6,010
Deferred return - Seabrook	(5,838)	(12,884)	(18,900)
Amortization of regulatory assets, net	85,176	85,488	85,464
Tax expense for 1993-1999 from reduction of NU parent losses	(3,286)	-	-
Deferred obligation to affiliated company	(9,744)	(9,744)	(9,744)
Net other sources of cash	18,645	35,486	18,214
Changes in working capital:			
Receivables	(27,956)	964	1,891
Materials and supplies	(915)	(276)	191
Accounts payable	5,432	5,709	(7,161)
Accrued taxes	-	(710)	710
Other working capital (excludes cash)	11,148	7,133	(13,258)
Net cash flows provided by operating activities	117,620	181,392	128,745
Investing Activities:			
Investments in plant:			
Electric utility plant	(6,586)	(7,895)	(9,028)
Nuclear fuel	(17,222)	(9,934)	(6,474)
Net cash flows used for investments in plant	(23,808)	(17,829)	(15,502)
Investment in NU system Money Pool	28,600	(26,050)	(30,350)
Investments in nuclear decommissioning trusts	(10,294)	(7,584)	(7,885)
Net cash flows used in investing activities	(5,502)	(51,463)	(53,737)
Financing Activities:			
Net increase/(decrease) in short-term debt	200,000	-	(9,950)
Reacquisitions and retirements of long-term debt	(270,000)	(70,000)	(20,000)
Cash dividends on common stock	(42,000)	(60,000)	(45,000)
Net cash flows used in financing activities	(112,000)	(130,000)	(74,950)
Net increase/(decrease) in cash for the period	118	(71)	58
Cash - beginning of period	-	71	13
Cash - end of period	$ 118	$ -	$ 71
Supplemental Cash Flow Information:			
Cash paid during the year for:			
Interest, net of amounts capitalized	$ 28,349	$ 38,042	$ 42,498
Income taxes	$ 28,053	$ 3,000	$ 22,136

The accompanying notes are an integral part of these financial statements.

North Atlantic Energy Corporation

NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. About North Atlantic Energy Corporation

North Atlantic Energy Corporation (NAEC or the company) along with The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH), Western Massachusetts Electric Company (WMECO), and Holyoke Water Power Company (HWP) are the operating companies comprising the Northeast Utilities system (NU system) and are wholly owned by Northeast Utilities (NU). The NU system serves in excess of 30 percent of New England's electric needs and is one of the 25 largest electric utility systems in the country as measured by revenues. The NU system furnishes franchised retail electric service in New Hampshire, Connecticut and western Massachusetts through PSNH, CL&P and WMECO. NAEC owns 35.98 percent of the Seabrook Station nuclear unit (Seabrook) and sells all of its entitlement to the capacity and output of Seabrook to PSNH under the terms of two life-of-unit, full cost recovery contracts (Seabrook Power Contracts). HWP, also is engaged in the production and distribution of electric power.

NU is registered with the Securities and Exchange Commission (SEC) as a holding company under the Public Utility Holding Company Act of 1935 (1935 Act) and the NU system, including NAEC, is subject to provisions of the 1935 Act. Arrangements among the NU system companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the Federal Energy Regulatory Commission (FERC) and/or the SEC. NAEC is subject to further regulation for rates, accounting and other matters by the FERC and/or the New Hampshire Public Utilities Commission (NHPUC).

Several wholly owned subsidiaries of NU provide support services for the NU system companies and, in some cases, for other New England utilities. Northeast Utilities Service Company (NUSCO) provides centralized accounting, administrative, information resources, engineering, financial, legal, operational, planning, purchasing, and other services to the NU system companies. Northeast Nuclear Energy Company acts as agent for the NU system companies and other New England utilities in operating the Millstone nuclear units. North Atlantic Energy Service Corporation (NAESCO) has operational responsibility for Seabrook.

B. Presentation

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and

expenses during the reporting period. Actual results could differ from those estimates.

Certain reclassifications of prior years' data have been made to conform with the current year's presentation.

All transactions among affiliated companies are on a recovery of cost basis which may include amounts representing a return on equity and are subject to approval by various federal and state regulatory agencies.

C. New Accounting Standards

Derivative Instruments: Effective January 1, 2001, NAEC adopted Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. SFAS No. 133 requires that derivative instruments be recorded as an asset or liability measured at its fair value and that changes in the fair value of derivative instruments be recognized currently in earnings unless specific hedge accounting criteria are met.

In order to implement SFAS No. 133 by January 1, 2001, NU established a cross-functional project team to identify all derivative instruments, measure the fair value of those derivative instruments, designate and document various hedge relationships, and evaluate the effectiveness of those hedge relationships. NU has completed the process of identifying all derivative instruments and has established appropriate fair value measurements of those derivative instruments in place at January 1, 2001. In addition, for those derivative instruments which are hedging an identified risk, NU has designated and documented all hedging relationships anew.

Management believes the adoption of this new standard will not have a material impact on NAEC's financial position or results of operations.

D. Jointly Owned Electric Utility Plant

Seabrook: NAEC has a 35.98 percent ownership interest in Seabrook, a 1,148 megawatt nuclear generating unit. NAEC sells all of its share of the power generated by Seabrook to PSNH under the Seabrook Power Contracts. NAEC expects to auction its investment in Seabrook in 2001 with a closing on the sale expected in 2002.

NAEC's share of Seabrook's plant-in-service as of December 31, 2000 and 1999, was $734.6 million and $728 million, respectively, and the accumulated provision for depreciation was $172.6 million and $153 million, respectively.

E. Depreciation

The provision for depreciation is calculated using the straight-line method based on estimated remaining useful lives of depreciable utility plant-in-service, adjusted for salvage value and removal costs, as approved by the appropriate regulatory agency, where applicable. Except for major facilities, depreciation rates are applied to the average plant-in-service during the period. Major facilities are depreciated from the time they are placed in service. When plant is retired from service, the original cost of the plant, including costs of removal less salvage, is charged to the accumulated provision for depreciation. The costs of closure and removal of nonnuclear facilities are accrued over the life of the plant as a component of depreciation. The depreciation rates for the several classes of electric plant-in-service are equivalent to a composite rate of 2.9 percent in 2000, 3.8 percent in 1999 and 3.5 percent in 1998.

F. Seabrook Power Contracts

NAEC and PSNH have entered into two power contracts that obligate PSNH to purchase NAEC's 35.98 percent ownership of the capacity and output of Seabrook for the term of Seabrook's operating license. Under these power contracts, PSNH is obligated to pay NAEC's cost of service during this period, regardless of whether Seabrook is operating. NAEC's cost of service includes all of its Seabrook-related costs, including operation and maintenance (O&M) expenses, fuel expense, income and property tax expense, depreciation expense, certain overhead and other costs, and a return on its allowed investment.

The Seabrook Power Contracts established the value of the initial investment in Seabrook at $700 million. As prescribed by the 1989 rate agreement between NU, PSNH, and the state of New Hampshire (Rate Agreement), as of May 1, 1996, NAEC phased into rates 100 percent of the recoverable portion of its investment in Seabrook. From June 5, 1992 (the date NU acquired PSNH and NAEC acquired Seabrook from PSNH - the Acquisition Date) through November 1997, NAEC recorded a $203.9 million deferred return on its investment in Seabrook. At November 30, 1997, NAEC's utility plant included $84.1 million of the deferred return that was transferred as part of the Seabrook plant assets to NAEC on the Acquisition Date.

With the implementation of the "Agreement to Settle PSNH Restructuring" (Settlement Agreement), NAEC and PSNH will restructure the power contracts to provide for the buydown of the value of the Seabrook asset to $100 million. The Settlement Agreement also requires NAEC to sell via public auction its share of Seabrook, with the sale to occur no later than December 31, 2003. Upon a successful sale of NAEC's share of Seabrook, the existing Seabrook Power Contracts between NAEC and PSNH will be terminated.

Under the current Seabrook Power Contracts, if Seabrook is shut down prior to the expiration of its operating license, PSNH will be unconditionally required to pay NAEC termination costs for 39 years, less the period during which Seabrook has operated. These termination costs will reimburse NAEC for its share of Seabrook shut-down and decommissioning costs, and will pay NAEC a return of and on any undepreciated balance of its initial investment over the remaining term of the power contracts, and the return of and on any capital additions to the plant made after the Acquisition Date over a period of five years after shut down (net of any tax benefits to NAEC attributable to the cancellation).

G. Regulatory Accounting and Assets

The accounting policies of NAEC and the accompanying financial statements conform to accounting principles generally accepted in the United States applicable to rate-regulated enterprises and historically reflect the effects of the rate-making process in accordance with SFAS No. 71. During the fourth quarter of 2000, the Settlement Agreement became probable of implementation, therefore, PSNH discontinued the application of SFAS No. 71 for the generation portion of its business. In accordance with the power contracts, NAEC will be paid for the cost of Seabrook, therefore, PSNH's discontinuation of SFAS No. 71 did not impact NAEC.

Management continues to believe it is probable that NAEC will recover their investments in long-lived assets, including regulatory assets. In addition, all material regulatory assets are earning a return. The components of NAEC's regulatory assets are as follows:

At December 31,	2000	1999
	(Millions of Dollars)	
Deferred costs-Seabrook	$23.2	$ 88.5
Income taxes, net	23.4	35.6
Recoverable energy costs	1.5	1.7
Unamortized loss on reacquired debt .	-	3.8
	$48.1	$129.6

Upon the implementation of the Settlement Agreement, as filed, PSNH will make a payment to NAEC to buydown the Seabrook Power Contracts to $100 million. NAEC will reduce the Seabrook assets to $100 million. Upon the final sale of Seabrook, the Seabrook Power Contracts will be terminated and any difference between the net proceeds and the Seabrook book value at the time will be transferred to PSNH and applied against PSNH's stranded costs.

H. Income Taxes

The tax effect of temporary differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income) is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions.

The tax effect of temporary differences, including timing differences accrued under previously approved accounting standards, which give rise to the accumulated deferred tax obligation is as follows:

At December 31,	2000	1999
	(Millions of Dollars)	
Accelerated depreciation and other plant-related differences ...	$197.8	$205.1
Regulatory assets - income tax gross up	7.6	12.2
Other	(20.6)	5.3
	$184.8	$222.6

I. Recoverable Energy Costs

Under the Energy Policy Act of 1992 (Energy Act), NAEC is assessed for its proportionate shares of the costs of decontaminating and decommissioning uranium enrichment plants owned by the United States Department of Energy (DOE) (D&D Assessment). The Energy Act requires that regulators treat D&D Assessments as a reasonable and necessary current cost of fuel, to be fully recovered in rates like any other fuel cost. NAEC is currently recovering these costs through the Seabrook Power Contracts. As of December 31, 2000 and 1999, NAEC's total D&D Assessment deferral was $1.5 million and $1.7 million, respectively.

2. NUCLEAR DECOMMISSIONING AND PLANT CLOSURE COSTS

Seabrook: Under the terms of the Rate Agreement, PSNH is obligated to pay NAEC's share of Seabrook's decommissioning costs, even if the unit is shut down prior to the expiration of its operating license. Accordingly, NAEC bills PSNH directly for its share of the costs of decommissioning Seabrook. PSNH records its Seabrook decommissioning costs as a component of purchased-power expense. Under the Rate Agreement, these costs are recovered through base rates. The Seabrook decommissioning costs will continue to be increased annually by its respective escalation rates until the unit is sold.

NAEC's existing decommissioning trusts will be increased at the time of the plant sale, however, PSNH will continue to be responsible for funding NAEC's ownership share of the remainder of Seabrook's decommissioning liability after its share of the unit is sold. PSNH's obligation will be limited to the future funding of

the decommissioning cost level in effect at the time of sale. The Settlement Agreement provides PSNH for the recovery of these costs through a stranded cost recovery charge within rates.

Under New Hampshire law, Seabrook decommissioning funding requirements are set by the New Hampshire Nuclear Decommissioning Financing Committee (NDFC). During January 2000, the NDFC issued an order that adjusted the decommissioning collection period and funding levels assuming that Seabrook's anticipated energy producing life was 25 years from the date it went into commercial operation. Decommissioning collections are now expected to be completed by October 2015, as opposed to 2026, for the decommissioning collection period only. The cost of funding decommissioning Seabrook is now accrued over the estimated remaining accelerated funding period that was ordered by the NDFC. This is eleven years earlier than the service life established by Seabrook's Nuclear Regulatory Commission's (NRC) operating license.

Upon retirement, Seabrook must be decommissioned. Current decommissioning studies conclude that complete and immediate dismantlement as soon as practical after retirement continues to be the most viable and economic method of decommissioning a unit. These studies are reviewed and updated periodically to reflect changes in decommissioning requirements, costs, technology, and inflation. Changes in requirements or technology, the timing of funding or dismantling or adoption of a decommissioning method other than immediate dismantlement would change decommissioning cost estimates and the amounts required to be recovered.

The estimated cost of decommissioning NAEC's share of Seabrook, in year end 2000 dollars is $210.8 million. Nuclear decommissioning costs are accrued over the expected service life of the unit and are included in depreciation expense. Nuclear decommissioning expenses for the unit amounted to $6.9 million in 2000, $6.8 million in 1999 and $4.7 million in 1998. Nuclear decommissioning, as a cost of removal, is included in the accumulated provision for depreciation.

Payments for NAEC's ownership share of the cost of decommissioning Seabrook are paid to an independent decommissioning financing fund managed by the state of New Hampshire. Funding of the estimated decommissioning costs assumes escalated collections and after-tax earnings on the Seabrook decommissioning fund of 6.5 percent.

As of December 31, 2000 and 1999, NAEC has paid $39.6 million and $32.7 million (including payments made prior to the Acquisition Date by PSNH), into Seabrook's decommissioning financing fund. Earnings on the decommissioning financing fund increase the decommissioning trust balance and the accumulated reserve for depreciation. Unrealized gains and losses associated with the decommissioning financing fund also impact the balance of the trust and the accumulated reserve for depreciation. The fair values of the amounts in the external decommissioning trust for

NAEC were $50.9 million and $43.7 million at December 31, 2000 and 1999, respectively.

3. SHORT-TERM DEBT

Limits: The amount of short-term borrowings that may be incurred by NAEC is subject to periodic approval by either the SEC under the 1935 Act or by the NHPUC. As of December 31, 2000, NAEC is authorized by the NHPUC and the SEC to incur short-term borrowings up to a maximum of $260 million.

Credit Agreements: On November 9, 2000, NAEC entered into an unsecured 364-day term credit agreement for $200 million, replacing a $225 million term loan which was to expire on November 9, 2000. The proceeds from the term credit agreement were used to repay the $200 million outstanding under the previous term loan. Additionally, the interest rate swaps and collar related to the previous term loan expired and were not replaced. The term credit agreement also contains two mandatory prepayment provisions; the first is a 50 percent mandatory principal repayment of amounts outstanding to $100 million within two days of the buydown of the Seabrook Power Contracts and the second is 100 percent prepayment within two days of the sale of Seabrook. Any amounts prepaid can not be reborrowed. Unless extended, the term credit agreement will expire on November 8, 2001. At December 31, 2000 and 1999, there were $200 million in borrowings under the credit agreement and previous term loan.

Under the aforementioned credit agreements, the respective borrowers may borrow at fixed or variable rates plus an applicable margin based upon certain debt ratings, as rated by the lower of Standard and Poor's or Moody's Investors Service. The weighted average interest rate on NAEC's notes payable to banks outstanding on December 31, 2000, was 8.3 percent. Maturities of short-term debt obligations were for periods of three months or less.

These credit agreements provide that NAEC must comply with certain financial and nonfinancial covenants as are customarily included in such agreements, including, but not limited to, common equity ratios and interest coverage ratios. NAEC currently is and expects to remain in compliance with these covenants.

Money Pool: Certain subsidiaries of NU, including NAEC, are members of the Northeast Utilities System Money Pool (Pool). The Pool provides a more efficient use of the cash resources of the NU system, and reduces outside short-term borrowings. NUSCO administers the Pool as agent for the member companies. Short-term borrowing needs of the member companies are first met with available funds of other member companies, including funds borrowed by NU parent. NU parent may lend to the Pool but may not borrow. Funds may be withdrawn from or repaid to the Pool at any time without prior notice. Investing and borrowing subsidiaries receive or pay interest based on the average daily federal funds rate. Borrowings based on loans from NU parent, however, bear interest at NU parent's cost and must be repaid based upon the terms of NU

parent's original borrowing. At December 31, 2000 and 1999, NAEC had no borrowings outstanding from the Pool.

4. LONG-TERM DEBT

Details of long-term debt outstanding are:

At December 31,	2000	1999
	(Millions of Dollars)	
First Mortgage Bonds:		
9.05% Series A, due 2002	$135	$205
Notes:		
Variable - Rate Facility, due 2000	-	200
Less amounts due within one year	70	270
Long-term debt, net	$ 65	$135

Long-term debt maturities and cash sinking fund requirements on debt outstanding at December 31, 2000, for the years 2001 and 2002 are $70 million and $65 million, respectively.

Essentially all utility plant of NAEC is subject to the liens of the company's first mortgage bond indenture. NAEC's first mortgage bonds are also secured by payments made to NAEC by PSNH under the terms of the Seabrook Power Contracts.

In 1999, interest rate swaps effectively fix the interest rate of NAEC's $200 million variable-rate bank note at interest rates ranging from 5.81 percent to 6.07 percent.

5. INCOME TAX EXPENSE

The components of the federal and state income tax provisions were charged/(credited) to operations as follows:

For the Years Ended December 31,	2000	1999	1998
	(Millions of Dollars)		
Current income taxes:			
Federal	$37.5	$15.1	$15.2
State	1.0	0.2	0.6
Total current	38.5	15.3	15.8
Deferred income taxes, net:			
Federal	(23.6)	0.4	4.0
State	(2.0)	-	2.0
Total deferred	(25.6)	0.4	6.0
Total income tax expense	$12.9	$15.7	$21.8

The components of total income tax expense/(credit) are classified as follows:

For the Years Ended December 31,	2000	1999	1998
	(Millions of Dollars)		
Income taxes charged to operating expenses..........	$35.7	$ 34.8	$ 36.2
Other income taxes............	(22.8)	(19.1)	(14.4)
Total income tax expense......	$12.9	$ 15.7	$ 21.8

Deferred income taxes are comprised of the tax effects of temporary differences as follows:

For the Years Ended December 31,	2000	1999	1998
	(Millions of Dollars)		
Depreciation..................	$ (6.5)	$ 19.5	$ 21.8
Bond redemptions..............	(1.4)	(2.8)	(2.8)
Seabrook deferred return......	(17.3)	(15.7)	(14.2)
Other.........................	(0.4)	(0.6)	1.2
Deferred income taxes, net....	$(25.6)	$ 0.4	$ 6.0

A reconciliation between income tax expense and the expected tax expense at 35 percent of pretax income is as follows:

For the Years Ended December 31,	2000	1999	1998
	(Millions of Dollars)		
Expected federal income tax....	$15.9	$15.8	$18.0
Tax effect of differences:			
Amortization of regulatory assets.........	7.1	7.0	7.1
Depreciation................	(1.5)	(3.2)	1.6
Deferred Seabrook return.....	(0.7)	(1.5)	(2.4)
State income taxes, net of federal benefit...........	(0.7)	0.1	1.7
Allocation of Parent Company's loss............	(6.3)	(2.1)	(3.9)
Other, net..................	(0.9)	(0.4)	(0.3)
Total income tax expense.......	$12.9	$15.7	$21.8

6. DEFERRED OBLIGATION TO AFFILIATED COMPANY

At the time PSNH emerged from bankruptcy on May 16, 1991, in accordance with the phase-in under the Rate Agreement, it began to accrue a deferred return on a portion of its Seabrook investment. From May 16, 1991, to the Acquisition Date, PSNH accrued a deferred return of $50.9 million. On the Acquisition Date, PSNH sold the $50.9 million deferred return to NAEC as part of the Seabrook-related assets.

At the time PSNH transferred the deferred return to NAEC, it realized, for income tax purposes, a gain that was deferred under the consolidated income tax rules. Beginning December 1, 1997, the gain is being amortized into income for income tax purposes, as the deferred return of $50.9 million, and the associated income taxes of $32.9 million, are being collected by NAEC through the Seabrook Power Contracts. As NAEC recovers the $32.9 million in years eight through ten of the Rate Agreement, corresponding payments are being made to PSNH. The balance of the deferred obligation to PSNH at December 31, 2000 and 1999, was $3.2 million and $13 million, respectively.

7. COMMITMENTS AND CONTINGENCIES

A. Restructuring

In September 2000, the NHPUC approved a comprehensive restructuring order that would allow PSNH to securitize up to $670 million of stranded costs. In January 2001, the New Hampshire Supreme Court upheld this restructuring order on appeal. However, one of the appellants indicated publicly it would request a review of the New Hampshire Supreme Court decision by the United States Supreme Court. Such a request must be filed by May 1, 2001. Management believes that such an appeal would have a low probability of success, but cannot determine what effect it might have on the timing of the issuance of securitization bonds and the implementation of customer choice in New Hampshire. PSNH currently expects to work with the State of New Hampshire to issue securitization bonds early in the second quarter of 2001.

B. Environmental Matters

The NU system, including NAESCO on behalf of NAEC, is subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of our environment. As such, the NU system and NAESCO, have an active environmental auditing and training program and believe they are substantially in compliance with the current laws and regulations.

However, the normal course of operations may involve activities and substances that expose NAEC to potential liabilities of which management cannot determine the outcome. Additionally, management cannot determine the outcome for liabilities that may be imposed for past acts, even though such past acts may have been lawful at the time they occurred. Management does not believe, however, that this will have a material impact on NAEC's financial statements.

C. Spent Nuclear Fuel Disposal Costs

Under the Nuclear Waste Policy Act of 1982, NAEC must pay the DOE for the disposal of spent nuclear fuel and high-level radioactive waste. The DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. Fees for

nuclear fuel burned are billed currently to customers and paid to the DOE on a quarterly basis.

D. Nuclear Insurance Contingencies

Insurance policies covering NAEC's ownership share of Seabrook have been purchased for the primary cost of repair, replacement or decontamination of utility property and certain extra costs for repair, replacement or decontamination or premature decommissioning of utility property.

NAEC is subject to retroactive assessments if losses under those policies exceed the accumulated funds available to the insurer. The maximum potential assessments against NAEC, including costs resulting from PSNH's contracts with NAEC, with respect to losses arising during the current policy year for the primary property insurance program and the excess property damage policies are $2 million and $2.4 million, respectively. In addition, insurance has been purchased by the NU system in the aggregate amount of $200 million on an industry basis for coverage of worker claims.

Under certain circumstances, in the event of a nuclear incident at one of the nuclear facilities covered by the federal government's third-party liability indemnification program, the NU system, including NAEC, could be assessed liabilities in proportion to its ownership interest in each of its nuclear units up to $83.9 million. The NU system's payment of this assessment would be limited to, in proportion to its ownership interest in each of its nuclear units, $10 million in any one year per nuclear unit. In addition, if the sum of all claims and costs from any one nuclear incident exceeds the maximum amount of financial protection, the NU system would be subject to an additional 5 percent, or $4.2 million, liability, in proportion to its ownership interest in each of its nuclear units. Under the terms of the Seabrook Power Contracts with NAEC, PSNH could be obligated to pay for any assessment charged to NAEC as a cost of service. Based upon NAEC's ownership interest in Seabrook, PSNH's maximum liability, including any additional assessments, would be $31.3 million per incident, of which payments would be limited to $3.6 million per year.

8. MARKET RISK AND MANAGEMENT INSTRUMENTS

Interest Rate Risk Management: In 2000 and 1999, NAEC used interest rate collar and swap instruments with financial institutions to hedge against interest rate risk associated with its $200 million variable-rate bank note. On November 9, 2000, this facility was replaced with a fixed-rate bank note. The collar and swap instruments expired and were not replaced.

Credit Risk: These agreements have been made with various financial institutions, each of which is rated "A3" or better by Moody's Investors Service rating group. NAEC is exposed to credit risk on its respective market risk management instruments if the

counterparties fail to perform their obligations. Management anticipates that the counterparties will fully satisfy their obligations under the agreements.

9. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Cash and Cash Equivalents: The carrying amounts approximate fair value due to the short-term nature of cash and cash equivalents.

Nuclear Decommissioning Trust: The investments held in NAEC's nuclear decommissioning trust were marked-to-market by $0.1 million as of December 31, 2000, and by $3.2 million as of December 31, 1999, with corresponding offsets to the accumulated provision for depreciation. The amounts adjusted in 2000 and in 1999 represent cumulative net unrealized gains. Cumulative gross unrealized holding losses were immaterial for both 2000 and 1999.

Long-Term Debt: The fair value of NAEC's fixed-rate security is based upon the quoted market price for that issue or similar issues. The adjustable rate security is assumed to have a fair value equal to its carrying value.

The carrying amounts of NAEC's financial instruments and the estimated fair values are as follows:

	At December 31, 2000	
(Million of Dollars)	Carrying Amount	Fair Value
First mortgage bonds	$135.0	$136.8

	At December 31, 1999	
(Million of Dollars)	Carrying Amount	Fair Value
First mortgage bonds	$205.0	$207.8
Other long-term debt	$200.0	$200.0

10. SEGMENT INFORMATION

Effective January 1, 1999, the NU system companies, including NAEC, adopted SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." The NU system is organized between regulated utilities and competitive energy subsidiaries. NAEC is included in the regulated utilities segment of the NU system and has no other reportable segments.

11. SUBSEQUENT EVENT

Merger Agreement with Consolidated Edison, Inc.: In 2000, NU and Consolidated Edison, Inc. (Con Edison) received most of the approvals needed to complete the merger announced in October 1999. Shareholders from both companies approved the merger in April 2000, and all state regulatory approvals were granted by the end of the year. Additionally, the FERC approved the merger in May 2000, the NRC approved the transaction in August 2000, and the United States Department of Justice approved the merger in February 2001. Necessary approval from the SEC was expected to be received in mid-March 2001.

On February 28, 2001, NU's Board of Trustees requested that Con Edison provide reasonable assurance, in writing, that it intended to comply with the terms of the definitive merger agreement between the two companies. This included assurances that Con Edison would consummate the pending merger at the price set forth in the agreement promptly following the receipt of SEC approval. The original request for assurance was to be received by March 2, 2001, however that date was later extended to March 5, 2001. On March 5, 2001, Con Edison advised NU that it was not willing to close the merger on the agreed terms. NU notified Con Edison that it was treating its refusal to proceed on the terms set forth in the merger agreement as a repudiation and breach of the merger agreement, and that NU would file suit to obtain the benefits of the transaction as negotiated for NU shareholders. On March 6, 2001, Con Edison filed suit in the U.S. District Court for the Southern District of New York (Southern District), seeking a declaratory judgment that NU failed to satisfy conditions precedent under the merger agreement. On March 12, 2001, NU filed suit against Con Edison in the Southern District seeking damages in excess of $1 billion arising from Con Edison's breach of the merger agreement.

North Atlantic Energy Corporation

SELECTED FINANCIAL DATA	2000	1999	1998	1997	1996
			(Thousands of Dollars)		
Operating Revenues	$274,319	$287,369	$276,685	$ 192,381	$ 162,152
Operating Income	44,077	49,728	54,057	57,061	54,889
Net Income	32,493	29,556	29,494	29,953	32,072
Cash Dividends on Common Stock	42,000	60,000	45,000	25,000	38,000
Total Assets	728,964	852,107	945,153	1,014,639	1,017,388
Long-Term Debt (a)	135,000	405,000	475,000	495,000	515,000

QUARTERLY FINANCIAL DATA (Unaudited)

	Quarter Ended			
2000	March 31	June 30	September 30	December 31
		(Thousands of Dollars)		
Operating Revenues	$66,276	$66,106	$66,921	$75,016
Operating Income	$11,657	$11,185	$10,470	$10,765
Net Income	$ 7,753	$ 8,272	$ 8,063	$ 8,405
1999				
Operating Revenues	$70,289	$77,203	$69,779	$70,098
Operating Income	$12,475	$12,303	$12,122	$12,828
Net Income	$ 6,461	$ 6,243	$ 6,442	$10,410

STATISTICS (Unaudited)	2000	1999	1998	1997	1996
Gross Electric Utility Plant at December 31, (Thousands of Dollars)	$756,432	$767,895	$784,113	$811,140	$816,446
kWh Sales (Millions) for the year ended December 31,	2,850	3,125	3,018	2,859	3,542

(a) Includes portion due within one year.

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North Atlantic Energy Corporation

First Mortgage Bonds

Trustee and Interest Paying Agent
United States Trust Company of New York
114 West 47th Street
New York, NY 10036

Address General Correspondence in Care of:
Northeast Utilities Service Company
Investor Relations Department
P.O. Box 270
Hartford, CT 06141-0270
Telephone: (860) 665-5000

Data contained in this Annual Report are submitted for the sole purpose of providing information to present security holders about the company.

General Offices
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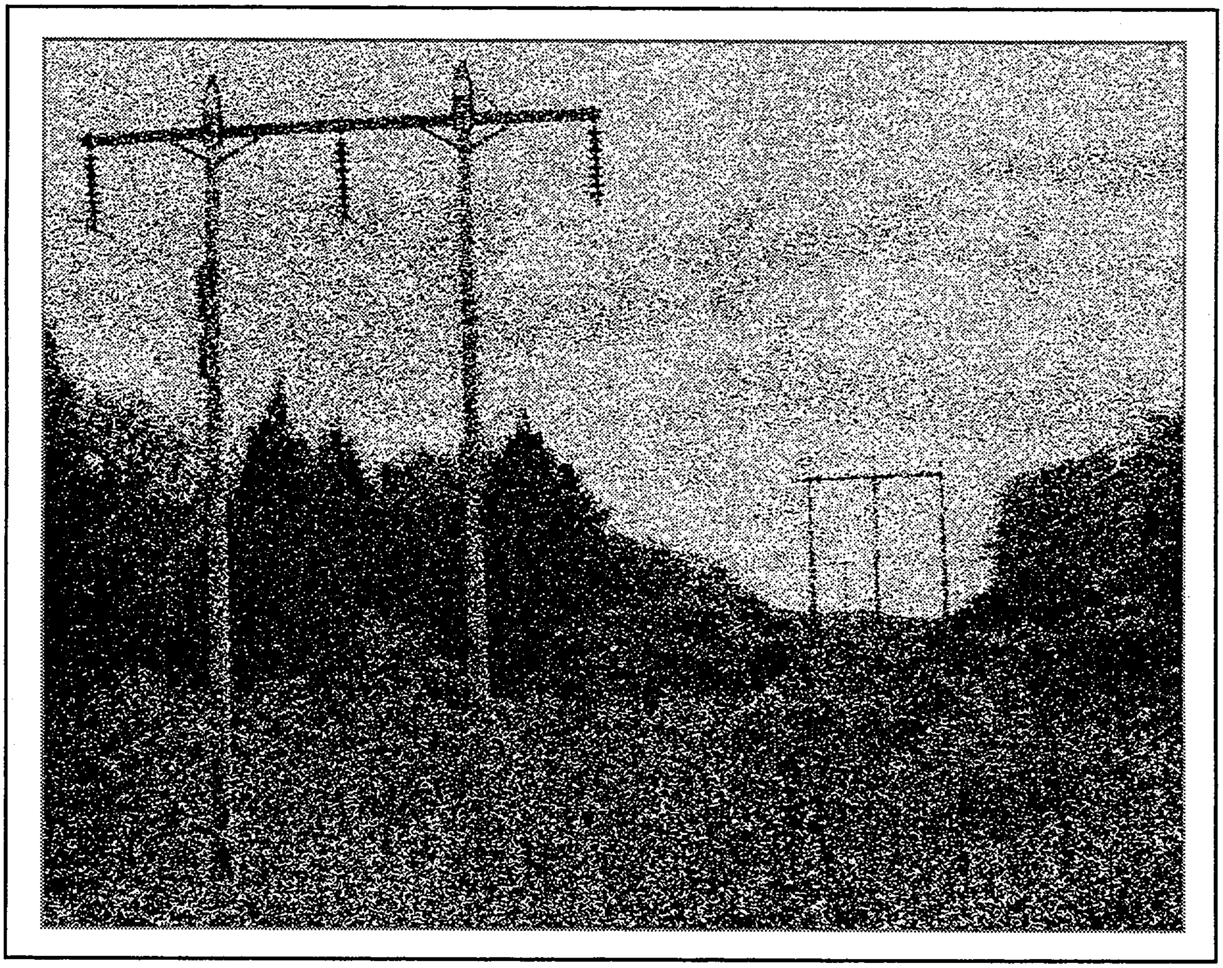
2000 Annual Report



Connecticut Light & Power

The Northeast Utilities System

Directors

David H. Boguslawski
Vice President—
Energy Delivery

Rodney O. Powell
Vice President—Central Region

Officers

David H. Boguslawski
Vice President—Energy Delivery

John B. Keane
Vice President—Generation
Divestiture

Roger C. Zaklukiewicz
Vice President—Transmission and
Distribution

Robert J. Kost
Vice President—Western Region

Rodney O. Powell
Vice President—Central Region

Richard L. Tower
Vice President—Eastern Region

O. Kay Comendul
Secretary

Randy A. Shoop
Treasurer

John P. Stack
Controller

Deborah L. Canyock
Assistant Controller—
Management Information and
Budgeting Services

Lori A. Mahler
Assistant Controller—
Accounting Services

William J. Starr
Assistant Controller—
Taxes

William J. Quinlan
Assistant Secretary

2000 Annual Report

The Connecticut Light and Power Company and Subsidiaries

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FINANCIAL CONDITION

Overview

The Connecticut Light and Power Company's (CL&P or the company), the Northeast Utilities (NU) system's (NU system) largest operating subsidiary, earnings totaled $148.1 million in 2000, compared with a loss of $13.6 million in 1999 and $195.7 million in 1998. The 2000 results represented CL&P's first annual profit since 1995. CL&P benefited from the return to service of the Millstone 2 unit in May 1999 and the strong performance of the Millstone 2 and 3 units in 2000. Millstone 2 operated at a capacity factor of 82 percent in 2000, while Millstone 3 operated at a capacity factor of virtually 100 percent in 2000. However, management projects that CL&P's earnings will decline in 2001 as a result of the expected sale of CL&P's share of the Millstone units, other rate adjustments and the pending resolution of the over-earnings docket. Although CL&P's earnings are expected to decline, its return on equity is not expected to be compromised.

In 2000, CL&P's revenues increased to $2.94 billion, up 20 percent from $2.45 billion in 1999, primarily due to higher wholesale revenues. Revenues were $2.39 billion in 1998. This growth in revenues was offset by a 5 percent retail rate decrease on January 1, 2000, for customers of CL&P.

Consolidated Edison, Inc. Merger

In 2000, NU and Consolidated Edison, Inc. (Con Edison) received most of the approvals needed to complete the merger announced in October 1999. Shareholders from both companies approved the merger in April 2000, and all state regulatory approvals were granted by the end of the year. Additionally, the Federal Energy Regulatory Commission (FERC) approved the merger in May 2000, the Nuclear Regulatory Commission approved the transaction in August 2000, and the United States Department of Justice approved the merger in February 2001. Necessary approval from the Securities and Exchange Commission (SEC) was expected to be received in mid-March 2001.

On February 28, 2001, NU's Board of Trustees requested that Con Edison provide reasonable assurance, in writing, that it intended to comply with the terms of the definitive merger agreement between the two companies. This included assurances that Con Edison would consummate the pending merger at the price set forth in the agreement promptly following the receipt of SEC approval. The original request for assurance was to be received by March 2, 2001, however that date was later extended to March 5, 2001. On March 5, 2001, Con Edison advised NU that it was not willing to close the merger on the agreed terms. NU notified Con Edison that it was treating its refusal to proceed on the terms set forth in the merger agreement as a

repudiation and breach of the merger agreement, and that NU would file suit to obtain the benefits of the transaction as negotiated for NU shareholders. On March 6, 2001, Con Edison filed suit in the U.S. District Court for the Southern District of New York (Southern District), seeking declaratory judgment that NU failed to satisfy conditions precedent under the merger agreement. On March 12, 2001, NU filed suit against Con Edison in the Southern District seeking damages in excess of $1 billion arising from Con Edison's breach of the merger agreement. NU cannot predict the outcome of this matter nor its effect on NU.

Liquidity

CL&P's net cash flows provided by operating activities decreased to $259.9 million in 2000 compared to $299.4 million in 1999 and $364.1 million in 1998. Reductions in depreciation and amortization expense, primarily as a result of industry restructuring resulted in a decrease in net cash flows from operations. Industry restructuring in Connecticut required a retail rate reduction of 5 percent on January 1, 2000, further reducing cash flows from operations. These decreases were offset by a $161.7 million increase in net income for the year ended December 31, 2000, compared with the same periods in 1999 and 1998 which increased cash flows from operating activities. Finally, the payment of taxes which occurred in 2000 related to the 1999 sale of generation assets, also decreased cash flows from operations. Cash flows from operations partially met the payment of CL&P's common and preferred dividends ($79.4 million) and investments in electric utility plant, nuclear fuel and nuclear decommissioning trusts ($269.1 million). The level of common dividends totaled $72 million in 2000, as compared to no common dividends paid in 1999 and 1998. The level of preferred dividends decreased to $7.4 million in 2000, compared with $12.8 million in 1999 and $14.1 million in 1998, reflecting CL&P's ongoing effort to reduce preferred stock outstanding. CL&P currently forecasts construction expenditures ranging from $206 million to $231.1 million for the year 2001.

The transfer of 1,289 megawatts (MW) of hydroelectric generation assets to Northeast Generation Company, an affiliated company, from CL&P and Western Massachusetts Electric Company (WMECO) in March 2000, produced a significant source of cash for CL&P and WMECO. CL&P used this cash to retire long-term debt, preferred stock and to return equity capital to the parent company. Financing activities for 2000 included $578.6 million for the retirement of long-term debt, preferred stock and common stock, compared with $639.8 million for 1999 and $80.7 million in 1998.

In November 2000, CL&P and WMECO reduced their revolving credit agreement to $350 million from $500 million to reflect lower borrowing needs post-restructuring. This agreement was renewed with more favorable terms as a result of the NU system's improving credit profile. In January 2001, Moody's Investors Service and Standard and Poor's upgraded their credit ratings for CL&P primarily as a result of the anticipated sale of the Millstone units and NU's general financial recovery. In February 2001, Fitch IBCA upgraded its credit ratings for CL&P. These upgrades return CL&P's unsecured debt to investment

grade ratings for the first time in five years and will save the NU system in excess of $4.7 million annually in financing costs.

For further information regarding CL&P's borrowing facilities, see Note 2, "Short-Term Debt," to the consolidated financial statements.

In 2001, NU expects to reduce the capitalization of its regulated electric operating companies significantly as a result of continued asset sales and securitization of stranded costs. CL&P expects to receive gross proceeds of $843.2 million as a result of the sale of its ownership interests in the Millstone units to Dominion Resources, Inc. (Dominion). This sale is expected to close as early as the end of March 2001. The cash proceeds are expected to be used to repay subsidiary debt and capital lease obligations and to return equity capital to the parent company.

By the end of 2002, CL&P expects to complete the auction of its share of the Seabrook Station nuclear unit (Seabrook). Cash proceeds will be used to retire debt and to return equity capital to the parent company.

In November 2000, the Connecticut Department of Public Utility Control (DPUC) approved CL&P's request to securitize an amount not to exceed $1.55 billion of approved, eligible stranded costs, primarily related to above-market purchased-power contracts and generation-related regulatory assets. CL&P plans to use approximately $400 million of those proceeds to reduce debt with the remaining proceeds to be used to buydown and buyout above-market purchased-power contracts and to return equity capital to the parent company. However, the Office of Consumer Counsel (OCC) has appealed the securitization order to the Connecticut Superior Court. On March 1, 2001, CL&P and the OCC entered into an agreement to settle this issue. Under the agreement, pending DPUC approval, the OCC agreed to withdraw its appeal of the securitization order and not take any action that would affect the timing and the amount of securitization financing to be undertaken. The DPUC approved the agreement on March 12, 2001. The OCC withdrew its appeal on March 16, 2001. Securitization for CL&P is expected to take place by the end of the first quarter 2001.

Restructuring

As a result of industry restructuring, CL&P stopped supplying power directly to customers in 2000. Instead, CL&P became an energy delivery company, delivering electricity to customers that is produced by other companies and sometimes bought by customers through intermediaries. In 2000, customers in Connecticut had the option of choosing alternative power suppliers or relying on CL&P to acquire the power for them through standard offer service. To date virtually all customers are receiving power through standard offer service. In 1999, under the oversight of the DPUC, CL&P secured four-year fixed-price contracts with three suppliers to provide power to customers who choose standard offer service. CL&P is fully recovering from retail customers the cost of buying power from these three standard offer suppliers and expects to continue recovery through the expiration of the contracts on December 31, 2003. As of January 1, 2000, Select

Energy, Inc. (Select Energy), an affiliated company, became responsible for 50 percent of CL&P's standard offer load for the entire standard offer period, or approximately 2,000 MW annually at peak. Two other unaffiliated suppliers became responsible for the balance of CL&P's standard offer load also for the entire standard offer period.

CL&P continues to generate power through either direct ownership of generating plants, such as Millstone 2 and 3 and Seabrook, or through purchased-power contracts. CL&P sold its share of the capacity associated with Millstone 2 and 3 and Seabrook to Select Energy and five unaffiliated companies. These contracts will expire on December 31, 2001. The revenues generated from these contracts are expected to recover CL&P's share of the nuclear operating costs through the divestiture of the Millstone units.

For further information regarding commitments and contingencies related to restructuring, see Note 9A, "Commitments and Contingencies – Restructuring," to the consolidated financial statements.

Regional Transmission Organization

Pursuant to FERC Order 888 (issued in April 1996), the NU system companies, including CL&P, operate their transmission system under an open access, nondiscriminatory transmission tariff.

In December 1999, the FERC issued an order calling on all transmission owners to voluntarily join Regional Transmission Organizations (RTOs) in order to boost competition in electric markets. In general, each of these organizations would be an independent operator over all transmission facilities, and would perform, among other functions, tariff administration, construction planning and reliability management for the particular regional transmission system. NU's active voting interest in such an organization would be limited to 5 percent under the proposal.

The NU system companies, including CL&P, and other parties have appealed this order. Of primary concern to NU is the ratemaking authority granted to RTOs and its impact on the ability of transmission owners to earn appropriate returns on their transmission investment under the organizational structure and the minimum functions proposed in the order. The NU system companies, including CL&P, were required to participate in a collaborative process established by the FERC beginning in March of 2000. On January 16, 2001, NU along with the Independent System Operator and five other New England transmission owning utilities filed a proposal to establish a New England RTO.

Nuclear Plant Performance and Divestiture

Millstone

The Millstone units completed one of their best years ever in 2000. Millstone 2 operated at a capacity factor of 82 percent in 2000 and completed a refueling outage in early June more than four days ahead of schedule. The 40-day, 21-hour outage set a world record for a refueling that included a full generator rewind. Millstone 3 operated at virtually a 100 percent capacity factor in 2000 and ran for 585 consecutive days before beginning a scheduled refueling outage on February 3, 2001. Millstone 3 is expected to return to service by the end of the first quarter of 2001.

On August 7, 2000, CL&P and certain other joint owners reached an agreement to sell substantially all of the Millstone units, located in Waterford, Connecticut, to Dominion, for approximately $1.3 billion, including approximately $105 million for nuclear fuel. Dominion has also agreed to assume responsibility for decommissioning the three units and NU will transfer to Dominion all funds in the Millstone decommissioning trust. Additionally, NU is obligated to top-off the decommissioning trust if its value does not equal an agreed upon amount at closing. That amount is pursuant to the purchase and sale agreement (PSA) with Dominion, subject to adjustment for delays in the closing of the sale and Millstone 1 not meeting the "cold and dark" condition specified in the PSA.

If the transaction is consummated as proposed, CL&P would receive gross proceeds of approximately $843.2 million on a pretax basis for its respective ownership interest. The proceeds from the sale of this interest will be used to reduce the company's stranded costs under restructuring and the cash proceeds will be used to repay subsidiary debt and capital lease obligations and to return equity capital to the parent company.

In preparation for the divestiture of the Millstone units, it was discovered that two full-length irradiated fuel rods are missing. NU believes that the two rods remain stored in the Millstone 1 spent fuel pool or were shipped in a shielded cask to a facility licensed to accept radioactive material. NU's investigation into the location of the two rods is ongoing. NU is responsible for any potential liabilities, which are not determinable at this time, related to these missing fuel rods.

NU currently expects to close on the sale of Millstone as early as the end of March 2001.

Seabrook

Seabrook operated at a capacity factor of 78 percent in 2000. The unit began a scheduled refueling outage on October 21, 2000. The outage was extended by approximately two months as a result of the need to repair extensive problems with a back-up diesel generator. Seabrook returned to service on January 29, 2001.

On December 15, 2000, NU filed its divestiture plan for Seabrook, including CL&P's 4.06 percent ownership interest, with the New Hampshire Public Utilities Commission and the DPUC. NU hopes to complete the sale in 2002.

Yankee Companies
In 1999, the Vermont Yankee Nuclear Power Corporation (VYNPC) agreed to sell its nuclear generating unit for $22 million to an unaffiliated company. Among other commitments, the acquiring company agreed to assume the obligation to decommission the unit after it is taken out of service, and the owners of VYNPC (including CL&P) agreed to fund their shares of the decommissioning costs up to a negotiated amount. Subsequent to the time that agreement was executed, the original proposed acquiring company increased its purchase price and three other unaffiliated companies have indicated their interest in buying VYNPC's generating unit on terms that have not been disclosed. On February 14, 2001, the Vermont Public Service Board dismissed the acquiring company's petition for approval and VYNPC agreed to work with the Vermont regulators to develop an auction process for the sale of the unit. At present, CL&P expects that the unit will be sold, but the identity of the owner and the terms of sale, including price, future decommissioning obligations and future power purchase obligations, are not known.

Nuclear Decommissioning
In connection with the aforementioned sale of the Millstone units, Dominion has agreed to assume responsibility for decommissioning the Millstone units.

For further information regarding nuclear decommissioning, see Note 10, "Nuclear Decommissioning and Plant Closure Costs," to the consolidated financial statements.

Spent Nuclear Fuel Disposal Costs
The United States Department of Energy (DOE) originally was scheduled to begin accepting delivery of spent nuclear fuel in 1998. However, delays in confirming the suitability of a permanent storage site continually have postponed plans for the DOE's long-term storage and disposal site. Extended delays or a default by the DOE could lead to consideration of costly alternatives. CL&P has the primary responsibility for the interim storage of its spent nuclear fuel prior to divestiture of its nuclear units.

For further information regarding spent nuclear fuel disposal costs, see Note 9D, "Commitments and Contingencies - Spent Nuclear Fuel Disposal Costs," to the consolidated financial statements.

Other Matters

Environmental Matters
CL&P is subject to environmental laws and regulations structured to mitigate or remove the effect of past operations and to improve or maintain the quality of the environment. For further information regarding environmental matters, see Note 9C, "Commitments and

Contingencies – Environmental Matters," to the consolidated financial statements.

Other Commitments and Contingencies
For further information regarding other commitments and contingencies, see Note 9, "Commitments and Contingencies," to the consolidated financial statements.

Forward Looking Statements
This discussion and analysis includes forward looking statements, which are statements of future expectations and not facts including, but not limited to, statements regarding future earnings, refinancings, the use of proceeds from restructuring, and the recovery of operating costs. Words such as *estimates, expects, anticipates, intends, plans,* and similar expressions identify forward looking statements. Actual results or outcomes could differ materially as a result of further actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in historical weather patterns, changes in laws, developments in legal or public policy doctrines, technological developments, and other presently unknown or unforeseen factors.

RESULTS OF OPERATIONS

The components of significant income statement variances for the past two years are provided in the table below.

Income Statement Variances
(Millions of Dollars)

	2000 over/(under) 1999		1999 over/(under) 1998	
	Amount	Percent	Amount	Percent
Operating Revenues	$483	20%	$ 66	3%
Operating Expenses:				
Fuel, purchased and net interchange power	738	80	(143)	(13)
Other operation	(68)	(14)	(41)	(8)
Maintenance	(82)	(38)	(53)	(20)
Depreciation	(76)	(39)	(23)	(10)
Amortization of regulatory assets, net	(350)	(78)	327	(a)
Federal and state income taxes	9	7	134	(a)
Taxes other than income taxes	(37)	(21)	4	3
Gain on sale of utility plant	286	100	(286)	-
Total operating expenses	420	18	(81)	(3)
Operating income	63	36	147	(a)
Other Income:				
Equity in earnings of regional nuclear generating companies	7	(a)	(5)	(76)
Nuclear related costs	39	73	90	63
Other, net	19	73	(20)	(a)
Other income taxes	(6)	(16)	(30)	(45)
Net other income	59	(a)	35	42
Interest charges, net	(40)	(29)	-	-
Net income/(loss)	$162	(a)	$182	93

(a) Percent greater than 100.

Operating Revenues
Operating revenues increased by $483 million or 20 percent in 2000, primarily due to higher wholesale revenues ($510 million), primarily as a result of the sale of the output from Millstone 2 and 3, and the amortization of the gain on the transfer of certain hydroelectric generation assets ($25 million) partially offset by lower retail revenues ($51 million). Retail revenues decreased primarily as a result of a 5 percent retail rate decrease ($108 million), partially offset by higher retail sales ($27 million) and by the impact of Millstone 2 being returned to rate base ($30 million). Retail sales increased by 0.4 percent in 2000.

Operating revenues increased by $66 million or 3 percent in 1999, primarily due to higher wholesale revenues ($72 million). The wholesale revenue increase is primarily due to higher energy sales and related capacity and transmission revenues. Retail revenues decreased primarily due to a retail rate reduction ($55 million) and lower fuel clause revenues ($33 million), partially offset by the impact of Millstone 2 and 3 being returned to CL&P's rate base ($13 million) and higher retail sales ($62 million). Retail kilowatt-hour sales increased by 2.9 percent.

Fuel, Purchased and Net Interchange Power
Fuel, purchased and net interchange power expense increased in 2000, primarily due to the transition, under industry restructuring, of purchasing full requirements for customers from standard offer suppliers, in addition to the remaining fuel costs of the nuclear units and cogenerators.

Fuel, purchased and net interchange power expense decreased in 1999, primarily due to lower replacement power costs due to the return to service of Millstone 2 and 3, partially offset by higher purchased-power costs as a result of a high sales demand.

Other Operation and Maintenance
Other operation and maintenance (O&M) expenses decreased in 2000, primarily due to lower spending at the nuclear units ($56 million), the decommissioning status of Millstone 1 ($14 million), lower expenses due to the sale of certain fossil generation assets ($65 million), and lower administrative and general expenses ($26 million), partially offset by higher customer service expenses ($39 million).

Other O&M expenses decreased in 1999, primarily due to lower costs at the Millstone units ($107 million), lower conservation and load management amortization ($14 million), and lower fossil O&M expenses ($7 million), partially offset by the recognition of environmental insurance proceeds in 1998 ($9 million), higher transmission expenses ($12 million), and higher storm costs ($12 million).

Depreciation
Depreciation expense decreased in 2000, primarily due to the effect of discontinuing Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation," for the generation portion of the business and the resulting reclassification of depreciable nuclear plant balances to regulatory assets ($70

million), the sale of certain fossil generation assets and the transfer of certain hydroelectric generation assets.

Depreciation decreased in 1999 primarily due to the retirement of Millstone 1.

Amortization of Regulatory Assets, Net
Amortization of regulatory assets, net decreased in 2000, primarily due to changes in amortization levels as a result of industry restructuring ($128 million), the amortization in 1999 of the gain on the sale of fossil plants ($286 million), and the completion of the amortization of CL&P's cogeneration deferral in the first quarter of 1999 ($6 million). These decreases were partially offset by higher amortization associated with the reclassified nuclear plant balances ($70 million).

Amortization of regulatory assets, net increased in 1999, primarily due to the increased amortization associated with the gain on the sale of fossil generation assets ($286 million), the amortization of CL&P's Millstone 1 remaining investment ($51 million) and the amortization associated with the reclassified nuclear plant balances transferred to regulatory assets ($19 million). These increases were partially offset by the completion of the amortization of the cogeneration deferral in the first quarter of 1999 ($23 million).

Federal and State Income Taxes
Federal and state income taxes increased in 2000 and 1999, primarily due to higher book taxable income.

Taxes Other Than Income Taxes
Taxes other than income taxes decreased in 2000, primarily due to lower Connecticut gross earnings tax ($18 million) and lower local property taxes ($7 million).

Gain on Sale of Utility Plant
CL&P recorded a gain on the sale of its fossil generation assets in 1999. A corresponding amount of amortization expense was recorded.

Equity Earnings of Regional Nuclear Generating Companies
Equity earnings of regional nuclear generating companies increased in 2000, primarily due to higher earnings from the Connecticut Yankee Atomic Power Company (CYAPC) as a result of a favorable rate settlement.

Equity earnings of regional nuclear generating companies decreased in 1999, primarily due to lower earnings from CYAPC.

Nuclear Related Costs
Nuclear related costs in 2000 are comprised of the settlement of Millstone 3 joint owner litigation, net of insurance proceeds ($9 million) and a settlement with the town of Wallingford ($5 million).

In comparison, nuclear related costs in 1999 are comprised of one-time charges related to the write-off of capital projects as a result of the Connecticut standard offer decision ($11 million), the settlement of Millstone 3 joint owner litigation, net of insurance proceeds ($22

million) and the write-off of Connecticut Municipal Electric Energy Cooperative (CMEEC) nuclear costs ($20 million). Nuclear related costs in 1998 are comprised of a write-off of the Millstone 1 entitlement formerly held by CMEEC ($28 million), and the write-off of an unrecoverable Millstone 1 cost as a result of the February 1999 rate decision ($115 million).

Other, Net
Other, net, increased in 2000, primarily due to the 1999 write-off of stranded costs in relation to the treatment of market-based contracts ($15 million).

Other, net, decreased in 1999, primarily due to the 1999 write-off of stranded costs in relation to the treatment of market-based contracts.

Interest Charges, Net
Interest charges, net, decreased in 2000, primarily due to reacquisitions and retirements of long-term debt in 2000.

The Connecticut Light and Power Company and Subsidiaries

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors
of The Connecticut Light and Power Company:

We have audited the accompanying consolidated balance sheets of The Connecticut Light and Power Company (a Connecticut corporation and a wholly owned subsidiary of Northeast Utilities) and subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, comprehensive income, common stockholder's equity and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The Connecticut Light and Power Company and subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

/s/ ARTHUR ANDERSEN LLP
ARTHUR ANDERSEN LLP

Hartford, Connecticut
January 23, 2001 (except with
respect to the matter discussed
in Note 15, as to which the
date is March 13, 2001)

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

FOR THE YEARS ENDED DECEMBER 31,	2000	1999	1998
	(Thousands of Dollars)		
Operating Revenues	$ 2,935,922	$ 2,452,855	$ 2,386,864
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	1,665,806	927,989	1,070,677
Other	412,230	480,138	520,518
Maintenance	136,141	217,961	271,317
Depreciation	117,305	193,776	216,509
Amortization of regulatory assets, net	97,315	447,776	120,884
Federal and state income taxes	130,994	122,059	(11,642)
Taxes other than income taxes	137,846	174,884	170,347
Gain on sale of utility plant	-	(286,477)	-
Total operating expenses	2,697,637	2,278,106	2,358,610
Operating Income	238,285	174,749	28,254
Other Income/(Loss):			
Equity in earnings of regional nuclear generating companies	8,246	1,506	6,241
Nuclear related costs	(14,099)	(53,031)	(143,239)
Other, net	(7,071)	(25,962)	(6,075)
Minority interest in loss of subsidiary	(9,300)	(9,300)	(9,300)
Income taxes	30,940	36,921	67,127
Other income/(loss), net	8,716	(49,866)	(85,246)
Income/(loss) before interest charges	247,001	124,883	(56,992)
Interest Charges:			
Interest on long-term debt	89,841	127,533	133,192
Other interest	9,025	10,918	5,541
Interest charges, net	98,866	138,451	138,733
Net Income/(Loss)	$ 148,135	$ (13,568)	$ (195,725)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Income/(Loss)	$ 148,135	$ (13,568)	$ (195,725)
Other comprehensive income, net of tax:			
Unrealized gains on securities	90	38	638
Minimum pension liability adjustments	-	-	(260)
Other comprehensive income, net of tax	90	38	378
Comprehensive Income/(Loss)	$ 148,225	$ (13,530)	$ (195,347)

The accompanying notes are an integral part of these financial statements.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AT DECEMBER 31,	2000	1999
	(Thousands of Dollars)	
ASSETS		
Utility Plant, at original cost:		
Electric	$ 5,756,098	$ 5,811,126
Less: Accumulated provision for depreciation	4,210,429	4,234,771
	1,545,669	1,576,355
Construction work in progress	128,835	115,529
Nuclear fuel, net	79,672	80,766
Total net utility plant	1,754,176	1,772,650
Other Property and Investments:		
Nuclear decommissioning trusts, at market	536,912	516,796
Investments in regional nuclear generating companies, at equity	41,395	54,472
Other, at cost	33,708	36,696
	612,015	607,964
Current Assets:		
Cash	5,461	364
Investment in securitizable assets	98,146	107,620
Notes receivable from affiliated companies	38,000	-
Receivables less accumulated provision for uncollectible accounts of $300 in 2000 and 1999	29,245	19,680
Accounts receivable from affiliated companies	103,763	3,390
Fuel, materials and supplies, at average cost	36,332	37,603
Prepayments and other	32,291	35,163
	343,238	203,820
Deferred Charges:		
Regulatory assets	1,835,967	2,564,095
Unamortized debt expense	14,794	16,323
Prepaid pension	170,672	113,465
Other	33,336	19,967
	2,054,769	2,713,850
Total Assets	$ 4,764,198	$ 5,298,284

The accompanying notes are an integral part of these financial statements.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AT DECEMBER 31,	2000	1999
	(Thousands of Dollars)	
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, $10 par value - authorized 24,500,000 shares; 7,584,884 shares outstanding in 2000 and 12,222,930 shares outstanding in 1999	$ 75,849	$ 122,229
Capital surplus, paid in	413,192	665,598
Retained earnings	243,197	153,254
Accumulated other comprehensive income	506	416
Total common stockholder's equity	732,744	941,497
Preferred stock not subject to mandatory redemption	116,200	116,200
Preferred stock subject to mandatory redemption	-	79,789
Long-term debt	1,072,688	1,241,051
Total capitalization	1,921,632	2,378,537
Minority Interest in Consolidated Subsidiary	100,000	100,000
Obligations Under Capital Leases	39,910	50,969
Current Liabilities:		
Notes payable to banks	115,000	90,000
Notes payable to affiliated company	-	11,700
Long-term debt and preferred stock - current portion	160,000	178,755
Obligations under capital leases - current portion	89,959	93,431
Accounts payable	153,944	101,106
Accounts payable to affiliated companies	122,106	3,215
Accrued taxes	32,901	169,214
Accrued interest	13,995	18,640
Other	31,324	26,347
	719,229	692,408
Deferred Credits and Other Long-term Liabilities:		
Accumulated deferred income taxes	977,439	999,473
Accumulated deferred investment tax credits	99,771	107,064
Decommissioning obligation - Millstone 1	580,320	580,320
Deferred contractual obligations	160,590	238,142
Other	165,307	151,371
	1,983,427	2,076,370
Commmitments and Contingencies (Note 9)		
Total Capitalization and Liabilities	$ 4,764,198	$ 5,298,284

The accompanying notes are an integral part of these financial statements.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Common Stock	Capital Surplus, Paid In	Retained Earnings (a)	Accumulated Other Comprehensive Income	Total
	(Thousands of Dollars)				
Balance at January 1, 1998	$122,229	$ 641,333	$ 419,972	$ -	$1,183,534
Net loss for 1998			(195,725)		(195,725)
Cash dividends on preferred stock			(14,139)		(14,139)
Capital stock expenses, net		2,764			2,764
Capital contribution from Northeast Utilities		20,000			20,000
Gain on repurchase of preferred stock		59			59
Other comprehensive income				378	378
Balance at December 31, 1998	122,229	664,156	210,108	378	996,871
Net loss for 1999			(13,568)		(13,568)
Cash dividends on preferred stock			(12,832)		(12,832)
Capital stock expenses, net		1,442			1,442
Allocation of benefits - ESOP			(30,454)		(30,454)
Other comprehensive income				38	38
Balance at December 31, 1999	122,229	665,598	153,254	416	941,497
Net income for 2000			148,135		148,135
Cash dividends on preferred stock			(7,402)		(7,402)
Cash dividends on common stock			(72,014)		(72,014)
Redemption of preferred stock		(749)			(749)
Repurchase of common stock	(46,380)	(253,620)			(300,000)
Capital stock expenses, net		1,963			1,963
Tax benefit for 1993-1999 from reduction of NU parent losses (b)			21,461		21,461
Allocation of benefits - ESOP			(237)		(237)
Other comprehensive income				90	90
Balance at December 31, 2000	$ 75,849	$ 413,192	$ 243,197	$ 506	$ 732,744

(a) The company has no dividend restrictions. However, the company has a 30% common equity test to meet and therefore, at December 31, 2000, cannot pay out approximately $152.9 million in equity.

(b) In June 1999, CL&P paid NU parent $30.5 million for NU shares issued from 1992 through 1998 on behalf of its employees in accordance with NU's 401(k) plan. This transaction resulted in a reduction of the NU parent loss and a tax benefit to CL&P. The amount in 2000 represents the remaining previously unallocated 1993 through 1999 NU parent losses.

The accompanying notes are an integral part of these financial statements.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
(Thousands of Dollars)	2000	1999	1998
Operating Activities:			
Net income/(loss)	$ 148,135	$ (13,568)	$(195,725)
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation	117,305	193,776	216,509
Deferred income taxes and investment tax credits, net	5,672	(140,459)	(65,689)
Amortization of regulatory assets, net	97,315	447,776	120,884
Amortization of recoverable energy costs	4,155	12,702	30,745
Nuclear related costs	14,099	53,031	143,239
Tax benefit for 1993-1999 from reduction of NU parent losses	21,461	-	-
Allocation of ESOP benefits	(237)	(30,454)	-
Gain on sale of utility plant	25,444	(286,477)	-
Net other (uses)/sources of cash	(112,915)	(141,675)	43,297
Changes in working capital:			
Receivables	(109,938)	837	29,914
Fuel, materials and supplies	1,271	34,379	9,896
Accounts payable	171,729	(49,477)	(63,592)
Accrued taxes	(136,313)	149,818	(13,621)
Investments in securitizable assets	9,474	52,633	45,372
Other working capital (excludes cash)	3,204	16,585	62,901
Net cash flows provided by operating activities	259,861	299,427	364,130
Investing Activities:			
Investments in plant:			
Electric utility plant	(208,249)	(180,982)	(132,194)
Nuclear fuel	(35,709)	(26,198)	(8,444)
Net cash flows used for investments in plant	(243,958)	(207,180)	(140,638)
Investment in NU system Money Pool	(38,000)	6,600	(6,600)
Investments in nuclear decommissioning trusts	(25,133)	(54,582)	(54,106)
Other investment activities, net	10,246	(355)	(1,655)
Net proceeds from the transfer/sale of utility plant	686,807	516,912	-
Capital contributions from Northeast Utilities	-	-	20,000
Net cash flows provided by/(used in) investing activities	389,962	261,395	(182,999)
Financing Activities:			
Net increase/(decrease) in short-term debt	13,300	91,700	(86,300)
Reacquisitions and retirements of long-term debt	(179,071)	(620,010)	(45,006)
Reacquisitions and retirements of preferred stock	(99,539)	(19,750)	(35,711)
Repurchase of common shares	(300,000)	-	-
Cash dividends on preferred stock	(7,402)	(12,832)	(14,139)
Cash dividends on common stock	(72,014)	-	-
Net cash flows used in financing activities	(644,726)	(560,892)	(181,156)
Net increase/(decrease) in cash for the period	5,097	(70)	(25)
Cash - beginning of period	364	434	459
Cash - end of period	$ 5,461	$ 364	$ 434
Supplemental Cash Flow Information:			
Cash paid/(refunded) during the year for:			
Interest, net of amounts capitalized	$ 96,735	$ 142,398	$ 110,119
Income taxes	$ 226,380	$ 19,754	$ (46,747)
Increase in obligations:			
Niantic Bay Fuel Trust	$ 6,535	$ 4,752	$ 10,208

The accompanying notes are an integral part of these financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. About The Connecticut Light and Power Company

The Connecticut Light and Power Company (CL&P or the company) along with the Public Service Company of New Hampshire (PSNH), Western Massachusetts Electric Company (WMECO), North Atlantic Energy Corporation (NAEC), and Holyoke Water Power Company (HWP) are the operating companies comprising the Northeast Utilities system (NU system) and are wholly owned by Northeast Utilities (NU). The NU system serves in excess of 30 percent of New England's electric needs and is one of the 25 largest electric utility systems in the country as measured by revenues. The NU system furnishes franchised retail electric service in Connecticut, New Hampshire and western Massachusetts through CL&P, PSNH and WMECO. NAEC sells all of its entitlement to the capacity and output of the Seabrook Station nuclear unit (Seabrook) to PSNH under the terms of two life-of-unit, full cost recovery contracts. HWP, also is engaged in the production and distribution of electric power.

On March 1, 2000, NU completed its acquisition of Yankee Energy System, Inc., the parent company of Yankee Gas Services Company, Connecticut's largest natural gas distribution system.

NU is registered with the Securities and Exchange Commission (SEC) as a holding company under the Public Utility Holding Company Act of 1935 (1935 Act) and the NU system, including CL&P, is subject to provisions of the 1935 Act. Arrangements among the NU system companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the Federal Energy Regulatory Commission (FERC) and/or the SEC. CL&P is subject to further regulation for rates, accounting and other matters by the FERC and the Connecticut Department of Public Utility Control (DPUC).

Several wholly owned subsidiaries of NU provide support services for the NU system companies, including CL&P, and, in some cases, for other New England utilities. Northeast Utilities Service Company (NUSCO) provides centralized accounting, administrative, information resources, engineering, financial, legal, operational, planning, purchasing, and other services to the NU system companies, including CL&P. Northeast Nuclear Energy Company acts as agent for the NU system companies and other New England utilities in operating the Millstone nuclear units. North Atlantic Energy Service Corporation has operational responsibility for Seabrook. In addition, CL&P has established a special purpose subsidiary whose business consists of the purchase and resale of receivables.

B. Presentation

The consolidated financial statements of CL&P include the accounts of all subsidiaries. Intercompany transactions have been eliminated in consolidation.

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

Certain reclassifications of prior years' data have been made to conform with the current year's presentation.

All transactions among affiliated companies are on a recovery of cost basis which may include amounts representing a return on equity and are subject to approval by various federal and state regulatory agencies and the DPUC.

C. New Accounting Standards

Derivative Instruments: Effective January 1, 2001, CL&P adopted Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. SFAS No. 133 requires that derivative instruments be recorded as an asset or liability measured at its fair value and that changes in the fair value of derivative instruments be recognized currently in earnings unless specific hedge accounting criteria are met.

In order to implement SFAS No. 133 by January 1, 2001, NU established a cross-functional project team to identify all derivative instruments, measure the fair value of those derivative instruments, designate and document various hedge relationships, and evaluate the effectiveness of those hedge relationships. NU has completed the process of identifying all derivative instruments and has established appropriate fair value measurements of those derivative instruments in place at January 1, 2001. In addition, for those derivative instruments which are hedging an identified risk, NU has designated and documented all hedging relationships anew.

Management believes the adoption of this new standard will not have a material impact on CL&P's financial position or results of operations.

Transfers of Financial Assets: In September 2000, the Financial Accounting Standards Board (FASB) issued SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities - a Replacement of FASB Statement No. 125." SFAS No. 140 revises the criteria for accounting for securitizations, other financial asset transfers

and collateral and introduces new disclosures, but otherwise carries forward most of the provisions of SFAS No. 125, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," without amendment. SFAS No. 140 is effective for transfers and servicing of financial assets and extinguishments of liabilities occurring after March 31, 2001, and is effective for recognition and reclassification of collateral and for disclosures relating to securitization transactions and collateral for fiscal years ending after December 15, 2000. The adoption of the disclosure requirements under SFAS No. 140 did not have a material impact on CL&P's consolidated financial statements.

Revenue Recognition: In December 1999, the SEC issued Staff Accounting Bulletin (SAB) No. 101, "Revenue Recognition." The adoption of SAB No. 101, as amended, did not have a material impact on CL&P's consolidated financial statements.

D. Investments and Jointly Owned Electric Utility Plant

Regional Nuclear Generating Companies: CL&P owns common stock in four regional nuclear companies (Yankee Companies). CL&P's ownership interests in the Yankee Companies at December 31, 2000 and 1999, which are accounted for on the equity method due to CL&P's ability to exercise significant influence over their operating and financial policies are 34.5 percent of the Connecticut Yankee Atomic Power Company (CYAPC), 24.5 percent of the Yankee Atomic Electric Company (YAEC), 12 percent of the Maine Yankee Atomic Power Company (MYAPC), and 9.5 percent of the Vermont Yankee Nuclear Power Corporation (VYNPC). CL&P's total equity investment in the Yankee Companies at December 31, 2000 and 1999, is $41.4 million and $54.5 million, respectively. Each Yankee Company owns a single nuclear generating unit. However, VYNPC is the only unit still in operation at December 31, 2000.

Millstone: CL&P has an 81 percent joint ownership interest in both Millstone 1, a 660 megawatt (MW) nuclear unit, which is currently in decommissioning status, and Millstone 2, an 870 MW nuclear generating unit. CL&P has a 52.93 percent joint ownership interest in Millstone 3, a 1,154 MW nuclear generating unit. On August 7, 2000, CL&P and certain other joint owners reached an agreement to sell substantially all of the Millstone units to Dominion Resources, Inc. (Dominion) for approximately $1.3 billion, including approximately $105 million for nuclear fuel. NU currently expects to close on the sale of Millstone as early as the end of March 2001.

Seabrook: CL&P has a 4.06 percent joint ownership interest in Seabrook, a 1,148 MW nuclear generating unit. CL&P expects to auction its joint ownership interest in Seabrook, jointly with NAEC, in 2001 with a closing on the sale expected in 2002.

Plant-in-service and the accumulated provision for depreciation for CL&P's share of Millstone 2 and 3 and Seabrook are as follows:

At December 31,	2000	1999
	(Millions of Dollars)	
Plant-in-service		
Millstone 2	$ 779.7	$ 771.7
Millstone 3	1,924.7	1,915.1
Seabrook	174.7	173.9
Accumulated provision for depreciation		
Millstone 2	$ 779.1	$ 743.3
Millstone 3	1,815.0	1,822.8
Seabrook	164.0	165.7

E. Depreciation

The provision for depreciation is calculated using the straight-line method based on estimated remaining useful lives of depreciable utility plant-in-service, adjusted for salvage value and removal costs, as approved by the appropriate regulatory agency where applicable. Except for major facilities, depreciation rates are applied to the average plant-in-service during the period. Major facilities are depreciated from the time they are placed in service. When plant is retired from service, the original cost of the plant, including costs of removal less salvage, is charged to the accumulated provision for depreciation. The costs of closure and removal of nonnuclear facilities are accrued over the life of the plant as a component of depreciation. The depreciation rates for the several classes of electric plant-in-service are equivalent to a composite rate of 3 percent in 2000, 3.3 percent in 1999 and 3.2 percent in 1998.

As a result of discontinuing the application of SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation," for CL&P's generation business in 1999, including CL&P's ownership interest in Seabrook, the company recorded a charge to accumulated depreciation for the nuclear plant in excess of the estimated fair market value at the time in the amount of $1.7 billion and a corresponding regulatory asset was created.

F. Revenues

Revenues are based on authorized rates applied to each customer's use of electricity. In general, rates can be changed only through a formal proceeding before the DPUC. Regulatory commissions also have authority over the terms and conditions of nontraditional rate-making arrangements. At the end of each accounting period, CL&P accrues a revenue estimate for the amount of energy delivered but unbilled.

G. Regulatory Accounting and Assets

The accounting policies of CL&P and the accompanying consolidated financial statements conform to accounting principles generally accepted in the United States applicable

to rate-regulated enterprises and historically reflect the effects of the rate-making process in accordance with SFAS No. 71. As a result of final restructuring orders issued in 1999, CL&P discontinued the application of SFAS No. 71 for the generation portion of its business.

CL&P's transmission and distribution business will continue to be cost-based and management believes the application of SFAS No. 71 continues to be appropriate. Management continues to believe it is probable that CL&P will recover its investments in long-lived assets, including regulatory assets through charges to their transmission and distribution customers generally over periods which end between the years 2015 through 2026, subject to certain adjustments. The majority for CL&P will be recovered through a transition charge over a 12-year period. In addition, all material regulatory assets are earning a return. The components of CL&P's regulatory assets are as follows:

At December 31,	2000	1999
	(Millions of Dollars)	
Recoverable nuclear costs	$1,122.4	$1,781.9
Income taxes, net	371.9	399.5
Unrecovered contractual obligations .	171.8	228.9
Recoverable energy costs, net	85.2	89.5
Other	84.7	64.3
	$1,836.0	$2,564.1

As a result of discontinuing the application of SFAS No. 71 in 1999 for CL&P's generation business, the company reclassified nuclear plant in excess of its estimated fair market value from plant to regulatory assets. As of December 31, 2000 and 1999, excluding the impact of the transfer of generation assets to Northeast Generation Company in 2000, the unamortized balance ($1.35 billion and $1.38 billion, respectively) is classified as recoverable nuclear costs. Also included in that regulatory asset component for 2000 and 1999 are $344.3 million and $401.9 million, respectively, which includes Millstone 1 recoverable nuclear costs relating to the recoverable portion of the undepreciated plant and related assets ($51.2 million and $101.9 million, respectively) and the decommissioning and closure obligation ($293.1 million and $300 million, respectively).

H. Income Taxes

The tax effect of temporary differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income) is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The tax effect of temporary differences, including timing differences accrued under previously approved accounting standards, that give rise to the accumulated deferred tax obligation is as follows:

At December 31,	2000	1999
	(Millions of Dollars)	
Accelerated depreciation and other plant-related differences	$800.0	$845.6
Regulatory assets - income tax gross up	142.6	153.7
Other	34.8	0.2
	$977.4	$999.5

I. Unrecovered Contractual Obligations

Under the terms of contracts with the Yankee Companies, the shareholder-sponsored companies, including CL&P, are responsible for their proportionate share of the remaining costs of the units, including decommissioning. As management expects that CL&P will be allowed to recover these costs from its customers, CL&P has recorded a regulatory asset, with a corresponding obligation, on its consolidated balance sheet.

J. Recoverable Energy Costs

Under the Energy Policy Act of 1992 (Energy Act), CL&P is assessed for its proportionate share of the costs of decontaminating and decommissioning uranium enrichment plants owned by the United States Department of Energy (DOE) (D&D Assessment). The Energy Act requires that regulators treat D&D Assessments as a reasonable and necessary current cost of fuel, to be fully recovered in rates like any other fuel cost. CL&P is currently recovering these costs through rates. As of December 31, 2000 and 1999, CL&P's total D&D Assessment deferrals were $24.1 million and $26.9 million, respectively.

Through December 31, 1999, CL&P had an energy adjustment clause under which fuel prices above or below base-rate levels were charged to or credited to customers. Coincident with the start of restructuring, the energy adjustment clause was terminated. Energy costs deferred and not yet collected under the energy adjustment clause amounted to $61.1 million and $62.6 million at December 31, 2000 and 1999, respectively. This balance is recorded as a generation-related stranded cost and will be recovered through a transition charge mechanism pending final DPUC approval.

2. SHORT-TERM DEBT

Limits: The amount of short-term borrowings that may be incurred by CL&P is subject to periodic approval by either the SEC under the 1935 Act or by state regulators. Currently, SEC authorization allows CL&P to incur total short-term borrowings up to a maximum of $375 million. In addition, the charter of CL&P contains preferred stock provisions restricting the amount of unsecured debt the company may incur. As of December 31, 2000, CL&P's charter permits CL&P to incur $245 million of additional unsecured debt.

Credit Agreement: On November 17, 2000, CL&P and WMECO entered into a 364-day revolving credit facility for $350 million, replacing the previous $500 million facility which was to expire on November 17, 2000. CL&P may draw up to $200 million under the facility which, until the nuclear divestiture, is secured by second mortgages on Millstone 2 and 3. Once CL&P and WMECO receive the proceeds from securitization, the $350 million revolving credit facility will be reduced to $250 million, with a $150 million limit for CL&P. Unless extended, the credit facility will expire on November 16, 2001. At December 31, 2000 and 1999, there were $115 million and $90 million, respectively, in borrowings under these facilities.

Under the aforementioned credit agreement, CL&P may borrow at fixed or variable rates plus an applicable margin based upon certain debt ratings, as rated by the lower of Standard and Poor's or Moody's Investors Service. The weighted average interest rate on CL&P's notes payable to banks outstanding on December 31, 2000 and 1999, was 8.41 percent and 7.69 percent, respectively. Maturities of short-term debt obligations were for periods of three months or less.

This credit agreement provides that CL&P must comply with certain financial and nonfinancial covenants as are customarily included in such agreements, including, but not limited to, common equity ratios and interest coverage ratios. CL&P currently is and expects to remain in compliance with these covenants.

Money Pool: Certain subsidiaries of NU, including CL&P, are members of the Northeast Utilities System Money Pool (Pool). The Pool provides a more efficient use of the cash resources of the NU system and reduces outside short-term borrowings. NUSCO administers the Pool as agent for the member companies. Short-term borrowing needs of the member companies are first met with available funds of other member companies, including funds borrowed by NU parent. NU parent may lend to the Pool but may not borrow. Funds may be withdrawn from or repaid to the Pool at any time without prior notice. Investing and borrowing subsidiaries receive or pay interest based on the average daily federal funds rate. Borrowings based on loans from NU parent, however, bear interest at NU parent's cost and must be repaid based upon the terms of NU parent's original borrowing. At December 31, 2000 and 1999, CL&P had $38 million of lendings to and $11.7 million of

borrowings from the Pool, respectively. The interest rate on lendings to and borrowings from the Pool at December 31, 2000 and 1999, was 5.4 percent and 4.9 percent, respectively.

3. LEASES

CL&P finances its respective shares of nuclear fuel for Millstone 2 and 3 under the Niantic Bay Fuel Trust (NBFT) capital lease agreement. This capital lease agreement has an expiration date of June 1, 2040. At December 31, 2000 and 1999, the present value of CL&P's capital lease obligation to the NBFT was $112.6 million and $127.2 million, respectively. In connection with the planned nuclear divestiture, the NBFT capital lease will be terminated, the nuclear fuel will be transferred to Dominion and the related $180 million Series G Intermediate Term Note Agreement will be extinguished with the divestiture proceeds.

CL&P makes quarterly lease payments for the cost of nuclear fuel consumed in the reactors based on a units-of-production method at rates which reflect estimated kilowatt-hours of energy provided plus financing costs associated with the fuel in the reactors. Upon permanent discharge from the reactors, CL&P's ownership interest in the nuclear fuel transfers to CL&P.

CL&P also has entered into lease agreements, some of which are capital leases, for the use of data processing and office equipment, vehicles, nuclear control room simulators, and office space. The provisions of these lease agreements generally provide for renewal options.

Capital lease rental payments charged to operating expense were $36.3 million in 2000, $10 million in 1999 and $20.5 million in 1998. Interest included in capital lease rental payments was $7.9 million in 2000, $9.4 million in 1999 and $14.1 million in 1998. Operating lease rental payments charged to expense were $9.8 million in 2000, $14.3 million in 1999 and $17.9 million in 1998.

Future minimum rental payments, excluding annual nuclear fuel lease payments and executory costs such as property taxes, state use taxes, insurance, and maintenance, under long-term noncancelable leases, as of December 31, 2000, are as follows:

Year	Capital Leases	Operating Leases
	(Millions of Dollars)	
2001	$ 2.4	$11.5
2002	2.4	10.0
2003	2.4	8.1
2004	2.4	6.6
2005	2.4	5.9
After 2005	27.0	13.4
Future minimum lease payments	39.0	$55.5
Less amount representing interest	21.7	
Present value of future minimum lease payments for other than nuclear fuel	17.3	
Present value of future nuclear fuel lease payments	112.6	
Present value of future minimum lease payments	$129.9	

4. PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION

Details of preferred stock not subject to mandatory redemption are as follows:

Description	December 31, 2000 Redemption Price	Shares Outstanding December 31, 2000	December 31, 2000	December 31, 1999
			(Millions of Dollars)	
$1.90 Series of 1947	$52.50	163,912	$ 8.2	$ 8.2
$2.00 Series of 1947	54.00	336,088	16.8	16.8
$2.04 Series of 1949	52.00	100,000	5.0	5.0
$2.20 Series of 1949	52.50	200,000	10.0	10.0
3.90% Series of 1949	50.50	160,000	8.0	8.0
$2.06 Series E of 1954	51.00	200,000	10.0	10.0
$2.09 Series F of 1955	51.00	100,000	5.0	5.0
4.50% Series of 1956	50.75	104,000	5.2	5.2
4.96% Series of 1958	50.50	100,000	5.0	5.0
4.50% Series of 1963	50.50	160,000	8.0	8.0
5.28% Series of 1967	51.43	200,000	10.0	10.0
$3.24 Series G of 1968	51.84	300,000	15.0	15.0
6.56% Series of 1968	51.44	200,000	10.0	10.0
			$116.2	$116.2

5. LONG-TERM DEBT

Details of long-term debt outstanding are as follows:

At December 31,	2000	1999
	(Millions of Dollars)	
First Mortgage Bonds:		
5 3/4% Series XX due 2000	$ -	$ 159.0
7 7/8% Series A due 2001	160.0	160.0
7 3/4% Series C due 2002	200.0	200.0
7 3/8% Series TT due 2019	-	20.0
8 1/2% Series C due 2024	115.0	115.0
7 7/8% Series D due 2024	140.0	140.0
	615.0	794.0
Pollution Control Notes:		
Variable rate, due 2016-2022	46.4	46.4
Variable rate, tax exempt, due 2028-2031	377.5	377.5
Fees and interest due for spent nuclear fuel disposal costs	194.7	183.4
Other	-	0.2
Less amounts due within one year	160.0	159.0
Unamortized premium and discount, net	(0.9)	(1.4)
Long-term debt, net	$1,072.7	$1,241.1

Long-term debt maturities and cash sinking fund requirements, excluding fees and interest due for spent nuclear fuel disposal costs, on debt outstanding at December 31, 2000, for the years

2001 through 2005 are $160 million, $200 million, and no requirements for 2003, 2004 and 2005, respectively.

Essentially all utility plant of CL&P is subject to the liens of the company's first mortgage bond indenture.

CL&P has secured $315.5 million of pollution control notes with second mortgage liens on Millstone 1, junior to the liens of its first mortgage bond indenture.

CL&P has $62 million of tax-exempt Pollution Control Revenue Bonds with bond insurance secured by first mortgage bonds and a liquidity facility.

The average effective interest rates on the variable-rate pollution control notes ranged from 3.2 percent to 4.9 percent for 2000 and from 2.2 percent to 3.9 percent for 1999.

6. INCOME TAX EXPENSE

The components of the federal and state income tax provisions were charged/(credited) to operations as follows:

For the Years Ended December 31,	2000	1999	1998
	(Millions of Dollars)		
Current income taxes:			
Federal	$ 77.2	$197.7	$ (9.2)
State	17.2	27.9	(3.9)
Total current	94.4	225.6	(13.1)
Deferred income taxes, net:			
Federal	10.6	(113.0)	(34.9)
State	2.4	(20.1)	(17.5)
Total deferred	13.0	(133.1)	(52.4)
Investment tax credits, net	(7.3)	(7.3)	(13.3)
Total income tax expense/(credit)	$100.1	$ 85.2	$(78.8)

The components of total income tax expense/(credit) are classified as follows:

For the Years Ended December 31,	2000	1999	1998
	(Millions of Dollars)		
Income taxes charged to operating expenses	$131.0	$122.1	$(11.7)
Other income taxes	(30.9)	(36.9)	(67.1)
Total income tax expense/(credit)	$100.1	$ 85.2	$(78.8)

Deferred income taxes are comprised of the tax effects of temporary differences as follows:

For the Years Ended December 31,	2000	1999	1998
		(Millions of Dollars)	
Depreciation, leased nuclear fuel, settlement credits and disposal costs	$13.8	$ (9.9)	$ (5.6)
Regulatory deferral	(14.1)	6.2	(36.7)
State net operating loss carryforward	-	7.8	1.1
Regulatory disallowance	-	(24.2)	(18.1)
Sale of fossil generation assets	-	(126.1)	-
Pension accruals	13.6	9.8	8.9
Other	(0.3)	3.3	(2.0)
Deferred income taxes, net	$13.0	$(133.1)	$(52.4)

A reconciliation between income tax expense/(credit) and the expected tax expense/(credit) at 35 percent of pretax income/(loss) is as follows:

For the Years Ended December 31,	2000	1999	1998
		(Millions of Dollars)	
Expected federal income tax	$ 86.9	$25.0	$(96.1)
Tax effect of differences:			
Depreciation	5.8	27.1	20.9
Amortization of regulatory assets	3.6	31.9	22.7
Investment tax credit amortization	(7.3)	(7.3)	(13.3)
State income taxes, net of federal benefit	12.7	5.1	(13.9)
Other, net	(1.6)	3.4	0.9
Total income tax expense/(credit)	$100.1	$85.2	$(78.8)

7. PENSION BENEFITS AND POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

The NU system companies, including CL&P, participate in a uniform noncontributory defined benefit retirement plan covering substantially all regular NU system employees. Benefits are based on years of service and the employees' highest eligible compensation during 60 consecutive months of employment. CL&P's portion of the NU system's total pension credit, part of which was credited to utility plant, was $57.2 million in 2000, $40.3 million in 1999 and $32.6 million in 1998.

Currently, CL&P's policy is to annually fund an amount at least equal to that which will satisfy the requirements of the Employee Retirement Income Security Act and Internal Revenue Code.

The NU system companies, including CL&P, also provide certain health care benefits, primarily medical and dental, and life insurance benefits through a benefit plan to retired employees. These benefits are available for employees retiring from CL&P who have met specified service requirements. For current employees and certain retirees, the total benefit is limited to two times the 1993 per retiree health care cost. These costs are charged to expense over the estimated work life of the employee. CL&P annually funds postretirement costs through external trusts with amounts that have been rate-recovered and which also are tax deductible.

Pension and trust assets are invested primarily in domestic and international equity securities and bonds.

The following table represents information on the plans' benefit obligation, fair value of plan assets, and the respective plans' funded status:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2000	1999	2000	1999
Change in benefit obligation				
Benefit obligation at beginning of year.....	$ (551.9)	$ (562.7)	$(131.9)	$(133.8)
Service cost...............	(9.7)	(11.0)	(1.9)	(2.3)
Interest cost..............	(42.3)	(40.0)	(10.1)	(9.3)
Plan amendment.............	-	(32.5)	-	-
Transfers..................	(4.9)	1.8	-	-
Actuarial (loss)/gain......	(18.9)	58.8	(5.2)	(0.6)
Benefits paid..............	40.4	35.5	12.8	14.1
Settlements and other......	-	(1.8)	-	-
Benefit obligation at end of year..........	$ (587.3)	$ (551.9)	$(136.3)	$(131.9)
Change in plan assets				
Fair value of plan assets at beginning of year.....	$1,037.8	$ 935.7	$ 59.7	$ 53.8
Actual return on plan assets..............	(3.5)	135.8	3.0	6.6
Employer contribution......	-	-	12.5	13.4
Benefits paid..............	(40.4)	(35.5)	(12.8)	(14.1)
Transfers..................	4.9	1.8	-	-
Fair value of plan assets at end of year...........	$ 998.8	$1,037.8	$ 62.4	$ 59.7
Funded status at December 31...........	$ 411.5	$ 485.9	$ (73.9)	$ (72.2)
Unrecognized transition (asset)/obligation.......	(3.7)	(4.6)	88.2	95.5
Unrecognized prior service cost............	30.4	33.1	-	-
Unrecognized net gain......	(267.5)	(400.9)	(14.3)	(23.3)
Prepaid benefit cost	$ 170.7	$ 113.5	$ -	$ -

The following actuarial assumptions were used in calculating the plans' year end funded status:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
	2000	1999	2000	1999
Discount rate..................	7.50%	7.75%	7.50%	7.75%
Compensation/progression rate..	4.50	4.75	4.50	4.75
Health care cost trend rate (a)	N/A	N/A	5.26	5.57

(a) The annual per capita cost of covered health care benefits was assumed to decrease to 4.91 percent by 2001.

The components of net periodic benefit (credit)/cost are:

	For the Years Ended December 31,					
	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	2000	1999	1998	2000	1999	1998
Service cost.....	$ 9.7	$ 11.0	$ 9.8	$ 1.9	$ 2.3	$ 2.0
Interest cost....	42.3	40.0	37.5	10.1	9.3	9.2
Expected return on plan assets.	(88.4)	(78.1)	(68.4)	(4.9)	(4.2)	(3.6)
Amortization of unrecognized net transition (asset)/ obligation......	(0.9)	(0.9)	(0.9)	7.3	7.3	7.4
Amortization of prior service cost............	2.7	2.7	0.3	-	-	-
Amortization of actuarial gain..	(22.6)	(15.0)	(10.9)	-	-	-
Other amortization, net.............	-	-	-	(1.9)	(1.3)	(1.7)
Net periodic benefit (credit)/cost..	$(57.2)	$(40.3)	$(32.6)	$12.5	$13.4	$13.3

For calculating pension and postretirement benefit costs, the following assumptions were used:

	For the Years Ended December 31,					
	Pension Benefits			Postretirement Benefits		
	2000	1999	1998	2000	1999	1998
Discount rate..........	7.75%	7.00%	7.25%	7.75%	7.00%	7.25%
Expected long-term rate of return.......	9.50	9.50	9.50	N/A	N/A	N/A
Compensation/ progression rate.....	4.75	4.25	4.25	4.75	4.25	4.25
Long-term rate of return - Health assets, net of tax.........	N/A	N/A	N/A	7.50	7.50	7.75
Life assets..........	N/A	N/A	N/A	9.50	9.50	9.50

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The effect of changing the assumed health care cost trend rate by one percentage point in each year would have the following effects:

(Millions of Dollars)	One Percentage Point Increase	One Percentage Point Decrease
Effect on total service and interest cost components......	$0.5	$(0.5)
Effect on postretirement benefit obligation...........	$6.2	$(5.9)

The trust holding the health plan assets is subject to federal income taxes.

8. SALE OF CUSTOMER RECEIVABLES

As of December 31, 2000 and 1999, CL&P had sold accounts receivable of $170 million to a third-party purchaser with limited recourse through the CL&P Receivables Corporation (CRC), a wholly owned subsidiary of CL&P. In addition, at December 31, 2000 and 1999, $18.9 million and $22.5 million, respectively, of accounts receivable were designated as collateral under the agreement with the CRC.

Concentrations of credit risk to the purchaser under the company's agreement with respect to the receivables are limited due to CL&P's diverse customer base within its service territory.

9. COMMITMENTS AND CONTINGENCIES

A. Restructuring

The 1999 restructuring orders allowed for securitization of CL&P's nonnuclear regulatory assets and the costs to buyout or buydown the various purchased-power contracts. On November 8, 2000, the DPUC approved CL&P's request to

securitize an amount not to exceed $1.55 billion of approved, eligible stranded costs, primarily related to above-market purchased-power contracts and generation related regulatory assets. However, the Office of Consumer Counsel (OCC) appealed the securitization order to the Connecticut Superior Court and it remains unclear when securitization financing can be undertaken.

B. Nuclear Generation Assets Divestiture

On August 7, 2000, CL&P and certain other joint owners reached an agreement to sell substantially all of the Millstone units, located in Waterford, Connecticut, to Dominion, for approximately $1.3 billion, including approximately $105 million for nuclear fuel. Dominion has also agreed to assume responsibility for decommissioning the three units and NU will transfer to Dominion all funds in the Millstone decommissioning trust. Additionally, NU is obligated to top-off the decommissioning trust if its value does not equal a previously agreed upon level as defined. NU expects to close on the sale of Millstone as early as the end of March 2001.

If the transaction is consummated as proposed, CL&P would receive gross proceeds of approximately $843.2 million on a pretax basis for its respective ownership interest. The proceeds from the sale of this interest will be used to reduce the company's stranded costs under restructuring and the cash proceeds will be used to repay subsidiary debt and capital lease obligations and to return equity capital to the parent company. The DPUC approved the recovery of Millstone-related stranded costs not offset by asset divestiture proceeds. Pursuant to the DPUC order, CL&P will seek recovery of Millstone post-1997 capital additions totaling $50 million. The OCC has appealed CL&P's ability to recover these costs.

C. Environmental Matters

The NU system, including CL&P, is subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of our environment. As such, the NU system, including CL&P, have active environmental auditing and training programs and believe they are substantially in compliance with the current laws and regulations.

However, the normal course of operations may involve activities and substances that expose CL&P to potential liabilities of which management cannot determine the outcome. Additionally, management cannot determine the outcome for liabilities that may be imposed for past acts, even though such past acts may have been lawful at the time they occurred. Management does not believe, however, that this will have a material impact on CL&P's consolidated financial statements.

Based upon currently available information for the estimated remediation costs as of December 31, 2000 and 1999, the liability recorded by CL&P for its estimated environmental remediation costs amounted to $5.2 million and $6.9 million, respectively.

D. Spent Nuclear Fuel Disposal Costs

Under the Nuclear Waste Policy Act of 1982, CL&P must pay the DOE for the disposal of spent nuclear fuel and high-level radioactive waste. The DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. For nuclear fuel used to generate electricity prior to April 7, 1983 (Prior Period Fuel), an accrual has been recorded for the full liability and payment must be made prior to the first delivery of spent fuel to the DOE. Until such payment is made, the outstanding balance will continue to accrue interest at the 3-month treasury bill yield rate. As of December 31, 2000 and 1999, fees due to the DOE for the disposal of Prior Period Fuel were $194.7 million and $183.4 million, respectively, including interest costs of $128.1 million and $116.9 million, respectively.

Fees for nuclear fuel burned on or after April 7, 1983, are billed currently to customers and paid to the DOE on a quarterly basis. CL&P is responsible for fees to be paid for fuel burned until the divestiture of the Millstone and Seabrook nuclear units.

E. Nuclear Insurance Contingencies

Insurance policies covering CL&P's ownership share of the NU system's nuclear facilities have been purchased for the primary cost of repair, replacement or decontamination of utility property, certain extra costs incurred in obtaining replacement power during prolonged accidental outages and the excess cost of repair, replacement or decontamination or premature decommissioning of utility property.

CL&P is subject to retroactive assessments if losses under those policies exceed the accumulated funds available to the insurer. The maximum potential assessments with respect to losses arising during the current policy year for the primary property insurance program, the replacement power policies and the excess property damage policies are $5 million, $2.7 million and $6.1 million, respectively. In addition, insurance has been purchased by the NU system in the aggregate amount of $200 million on an industry basis for coverage of worker claims.

Under certain circumstances, in the event of a nuclear incident at one of the nuclear facilities covered by the federal government's third-party liability indemnification program, the NU system, including CL&P, could be assessed liabilities in proportion to its ownership interest in each

of its nuclear units up to $83.9 million. The NU system's payment of this assessment would be limited to, in proportion to its ownership interest in each of its nuclear units, $10 million in any one year per nuclear unit. In addition, if the sum of all claims and costs from any one nuclear incident exceeds the maximum amount of financial protection, the NU system, including CL&P, would be subject to an additional 5 percent, or $4.2 million, liability, in proportion to its ownership interests in each of its nuclear units. Based upon its ownership interests in the Millstone units and in Seabrook, CL&P's maximum liability, including any additional assessments, would be $192.9 million per incident, of which payments would be limited to $21.9 million per year. In addition, through purchased-power contracts with VYNPC, CL&P would be responsible for up to an additional assessment of $8.4 million per incident, of which payments would be limited to $1 million per year.

CL&P expects to terminate its nuclear insurance upon the divestiture of its nuclear units.

F. Long-Term Contractual Arrangements

Yankee Companies: Under the terms of its agreement, CL&P paid its ownership (or entitlement) shares of costs, which included depreciation, operation and maintenance (O&M) expenses, taxes, the estimated cost of decommissioning, and a return on invested capital. These costs were recorded as purchased-power expenses. CL&P's cost of purchases under its contract with VYNPC amounted to $14.5 million in 2000, $17 million in 1999, and $15.9 million in 1998. VYNPC is in the process of selling its nuclear unit. Upon completion of the sale, this long-term contract will be terminated.

Nonutility Generators (NUGs): CL&P has entered into various arrangements for the purchase of capacity and energy from NUGs. CL&P's total cost of purchases under these arrangements amounted to $308.6 million in 2000, $293.8 million in 1999 and $290.7 million in 1998. The company is in the process of renegotiating the terms of these contracts through either a contract buydown or buyout. CL&P expects any payments to the NUGs as a result of these renegotiations to be recovered from the company's customers.

Hydro-Quebec: Along with other New England utilities, CL&P has entered into an agreement to support transmission and terminal facilities to import electricity from the Hydro-Quebec system in Canada. CL&P is obligated to pay, over a 30-year period ending in 2020, its proportionate share of the annual O&M expenses and capital costs of those facilities.

Estimated Annual Costs: The estimated annual costs of CL&P's significant long-term contractual arrangements, absent the effects of any contract terminations, buydowns or buyouts, are as follows:

	2001	2002	2003	2004	2005
	(Millions of Dollars)				
VYNPC........	$ 16.6	$ 16.9	$ 17.0	$ 18.7	$ 17.6
NUGs.........	292.5	296.2	301.7	283.3	289.2
Hydro-Quebec.	15.9	15.4	14.8	14.2	13.7

10. NUCLEAR DECOMMISSIONING AND PLANT CLOSURE COSTS

Millstone and Seabrook: CL&P's operating nuclear power plants, Millstone 2 and 3 and Seabrook, have service lives that are expected to end during the years 2015 through 2026, and upon retirement, must be decommissioned. Millstone 1's expected service life was to end in 2010, however, in July 1998, restart activities were discontinued and decommissioning of the unit began. In connection with the sale of the Millstone units, Dominion has agreed to assume responsibility for decommissioning. Until the divestiture, CL&P recovers sufficient amounts through its allowed rates related to decommissioning costs.

CL&P's ownership share of the estimated cost of decommissioning Millstone 2 and 3 and Seabrook, in year end 2000 dollars, is $348.8 million, $343.1 million and $23.8 million, respectively. Nuclear decommissioning costs are accrued over the expected service lives of the units and are included in depreciation expense and the accumulated provision for depreciation. Nuclear decommissioning expenses for these units amounted to $24.4 million in 2000, $19.6 million in 1999 and $19.1 million in 1998. Nuclear decommissioning expenses for Millstone 1 were $20.6 million in 2000, $22.8 million in 1999 and $17.3 million in 1998. Through December 31, 2000 and 1999, total decommissioning expenses of $217.8 million and $185.1 million, respectively, have been collected from customers and are reflected in the accumulated provision for depreciation.

External decommissioning trusts have been established for the costs of decommissioning the Millstone units. Payments for CL&P's ownership share of the cost of decommissioning Seabrook are paid to an independent decommissioning financing fund managed by the state of New Hampshire. Funding of the estimated decommissioning costs assumes after-tax earnings on the Millstone and Seabrook decommissioning funds of 5.5 percent and 6.5 percent, respectively.

As of December 31, 2000 and 1999, $191.9 million and $164.2 million, respectively, have been transferred to external decommissioning trusts. Earnings on the decommissioning trusts increase the decommissioning trust balances and the accumulated provisions for depreciation. Unrealized gains and losses associated with the decommissioning trusts also impact the balance of the trusts and the accumulated provisions for depreciation. The fair values of the amounts in the external decommissioning trusts

were $310.1 million and $282.2 million at December 31, 2000 and 1999, respectively. Upon divestiture, balances in the decommissioning trusts will be transferred to the buyer. NU is obligated to top-off the Millstone decommissioning trust if its value does not equal an agreed upon amount at closing, pursuant to the conditions set forth in the purchase and sale agreement.

Yankee Companies: VYNPC owns and operates a nuclear generating unit with a service life that is expected to end in 2012. CL&P's ownership share of estimated costs, in year end 2000 dollars, of decommissioning this unit is $42.9 million. In 1999, VYNPC agreed to sell its nuclear generating unit for $22 million to an unaffiliated company. Among other commitments, the acquiring company agreed to assume the obligation to decommission the unit after it is taken out of service, and the owners of VYNPC (including CL&P) agreed to fund their shares of the decommissioning costs up to a negotiated amount. Subsequent to the time that agreement was executed, the original proposed acquiring company has increased the price it agreed to pay and three other unaffiliated companies have indicated their interest in buying VYNPC's generating unit on terms that have not been disclosed. At present, CL&P expects that the unit will be sold, but the identity of the owner and the terms of sale, including price, future decommissioning obligations and future power purchase obligations, are not known.

As of December 31, 2000 and 1999, CL&P's remaining estimated obligation, including decommissioning for the units owned by CYAPC, YAEC and MYAPC, which have been shut down was $160.6 million and $238.1 million, respectively.

11. MINORITY INTEREST IN CONSOLIDATED SUBSIDIARY

CL&P Capital LP (CL&P LP), a subsidiary of CL&P, previously had issued $100 million of cumulative 9.3 percent Monthly Income Preferred Securities (MIPS), Series A. CL&P has the sole ownership interest in CL&P LP, as a general partner, and is the guarantor of the MIPS securities. Subsequent to the MIPS issuance, CL&P LP loaned the proceeds of the MIPS issuance, along with CL&P's $3.1 million capital contribution, back to CL&P in the form of an unsecured debenture. CL&P consolidates CL&P LP for financial reporting purposes. Upon consolidation, the unsecured debenture is eliminated, and the MIPS securities are accounted for as a minority interest.

12. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Nuclear Decommissioning Trusts: CL&P's portion of the investments held in the NU system companies' nuclear decommissioning trusts were marked-to-market by $83.2 million as of December 31, 2000, and $88.2 million as of December 31, 1999, with corresponding offsets to the accumulated provision for depreciation. The amounts adjusted in 2000 and in 1999 represent cumulative net

unrealized gains. Cumulative gross unrealized holding losses were immaterial for both 2000 and 1999.

Preferred Stock and Long-Term Debt: The fair value of CL&P's fixed-rate securities is based upon the quoted market price for those issues or similar issues. Adjustable rate securities are assumed to have a fair value equal to their carrying value. The carrying amounts of CL&P's financial instruments and the estimated fair values are as follows:

	At December 31, 2000	
(Millions of Dollars)	Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption..............	$116.2	$139.7
Long-term debt - First mortgage bonds...............	615.0	621.6
Other long-term debt...............	618.6	576.4
MIPS	100.0	100.5

	At December 31, 1999	
(Millions of Dollars)	Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption..............	$116.2	$144.9
Preferred stock subject to mandatory redemption.................	99.6	96.8
Long-term debt - First mortgage bonds...............	794.0	805.4
Other long-term debt...............	607.3	564.5
MIPS	100.0	97.3

13. OTHER COMPREHENSIVE INCOME

The accumulated balance for each other comprehensive income item is as follows:

(Thousands of Dollars)	December 31, 1999	Current Period Change	December 31, 2000
Unrealized gains on securities..........	$676	$ 90	$766
Minimum pension liability adjustments...	(260)	-	(260)
Accumulated other comprehensive income....	$416	$ 90	$506

(Thousands of Dollars)	December 31, 1998	Current Period Change	December 31, 1999
Unrealized gains on securities..........	$638	$38	$676
Minimum pension liability adjustments...	(260)	-	(260)
Accumulated other comprehensive income....	$378	$38	$416

The changes in the components of other comprehensive income are reported net of the following income tax effects:

(Thousands of Dollars)	2000	1999	1998
Unrealized gains on securities..........	$(59)	$(26)	$(446)
Minimum pension liability adjustments...	-	-	182
Other comprehensive income.................	$(59)	$(26)	$(264)

14. SEGMENT INFORMATION

Effective January 1, 1999, the NU system companies, including CL&P, adopted SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." The NU system is organized between regulated utilities and competitive energy subsidiaries. CL&P is included in the regulated utilities segment of the NU system and has no other reportable segments.

15. SUBSEQUENT EVENT

Merger Agreement With Consolidated Edison, Inc.: In 2000, NU and Consolidated Edison, Inc. (Con Edison) received most of the approvals needed to complete the merger announced in October 1999. Shareholders from both companies approved the merger in April 2000, and all state regulatory approvals were granted by the end of the year. Additionally, the FERC approved the merger in May 2000, the Nuclear Regulatory Commission approved the transaction in August 2000, and the United States Department of Justice approved the merger in February 2001. Necessary approval from the SEC was expected to be received in mid-March 2001.

On February 28, 2001, NU's Board of Trustees requested that Con Edison provide reasonable assurance, in writing, that it intended to comply with the terms of the definitive merger agreement between the two companies. This included assurances that Con Edison would consummate the pending merger at the price set forth in the agreement promptly following the receipt of SEC approval. The original request for assurance was to be received by March 2, 2001, however that date was later extended to March 5, 2001. On March 5, 2001, Con Edison advised NU that it was not willing to close the merger on the agreed terms. NU notified Con Edison that it was treating its refusal to proceed on the terms set forth in the merger agreement as a repudiation and breach of the merger agreement, and that NU would file suit to obtain the benefits of the transaction as negotiated for NU shareholders. On March 6, 2001, Con Edison filed suit in the U.S. District Court for the Southern District of New York (Southern District), seeking declaratory judgment that NU failed to satisfy conditions precedent under the merger agreement. On March 12, 2001, NU filed suit against Con Edison in the Southern District seeking damages in excess of $1 billion arising from Con Edison's breach of the merger agreement.

The Connecticut Light and Power Company and Subsidiaries

SELECTED CONSOLIDATED FINANCIAL DATA	2000	1999	1998	1997	1996
	(Thousands of Dollars)				
Operating Revenues	$2,935,922	$2,452,855	$2,386,864	$2,465,587	$2,397,460
Operating Income/(Loss)	238,285	174,749	28,254	(7,619)	59,142
Net Income/(Loss)	148,135	(13,568)	(195,725)	(139,597)	(50,868)
Cash Dividends on Common Stock	72,014	-	-	5,989	138,608
Total Assets	4,764,198	5,298,284	6,050,198	6,081,223	6,244,036
Long-Term Debt(a)	1,232,688	1,400,056	2,007,957	2,043,327	2,038,521
Preferred Stock Not Subject to Mandatory Redemption	116,200	116,200	116,200	116,200	116,200
Preferred Stock Subject to Mandatory Redemption (a)	-	99,539	119,289	155,000	155,000
Obligations Under Capital Leases (a)	129,869	144,400	162,884	158,118	155,708

CONSOLIDATED QUARTERLY FINANCIAL DATA (Unaudited)

	Quarter Ended			
2000	March 31	June 30	September 30	December 31
	(Thousands of Dollars)			
Operating Revenues	$747,976	$683,585	$748,143	$756,218
Operating Income	$ 76,021	$ 42,723	$ 51,944	$ 67,597
Net Income	$ 49,643	$ 19,186	$ 27,908	$ 51,398
1999				
Operating Revenues	$606,997	$565,069	$667,349	$613,440
Operating Income	$ 20,412	$ 24,370	$ 51,969	$ 77,998
Net(Loss)/Income	$(13,705)	$ (6,814)	$ 9,873	$ (2,922)

(a) Includes portion due within one year.

The Connecticut Light and Power Company and Subsidiaries

CONSOLIDATED STATISTICS (Unaudited)

	Gross Electric Utility Plant December 31, (Thousands of Dollars)	kWh Sales (Millions)	Average Annual Use Per Residential Customer (kWh)	Electric Customers (Average)	Employees December 31,
2000	$5,964,605	42,179	8,976	1,121,551	2,057
1999	6,007,421	29,317	8,969	1,120,846	2,377
1998	6,345,215	27,356	8,476	1,111,370	2,379
1997	6,639,786	25,766	8,526	1,103,309	2,163
1996	6,512,659	26,043	8,639	1,099,340	2,194

The Connecticut Light and Power Company

First and Refunding Mortgage Bonds

Trustee and Interest Paying Agent
Bankers Trust Company, Corporate Trust
and Agency Group
P.O. Box 318, Church Street Station
New York, NY 10008-0318

Preferred Stock

Transfer Agent, Dividend Disbursing Agent and Registrar
Bank of New York
101 Barclay Street—Floor 12W
New York, NY 01286

2001 Dividend Payment Dates
5.28%, $3.24 Series
January 1, April 1, July 1, and October 1

4.50% (1956), 4.96%, 6.56%
$1.90, $2.00, $2.04, $2.06, $2.09, and $2.20 Series
February 1, May 1, August 1, and November 1

3.90%, 4.50% (1963), Series
March 1, June 1, September 1, and December 1

Monthly Income Preferred Securities

9.30% Cumulative Monthly Income Preferred Securities (MIPS), Series A
2001 Payment Dates
January 31, February 28, April 2, April 30, May 31, July 2, July 31, August 31, October 1, October 31, November 30, December 31

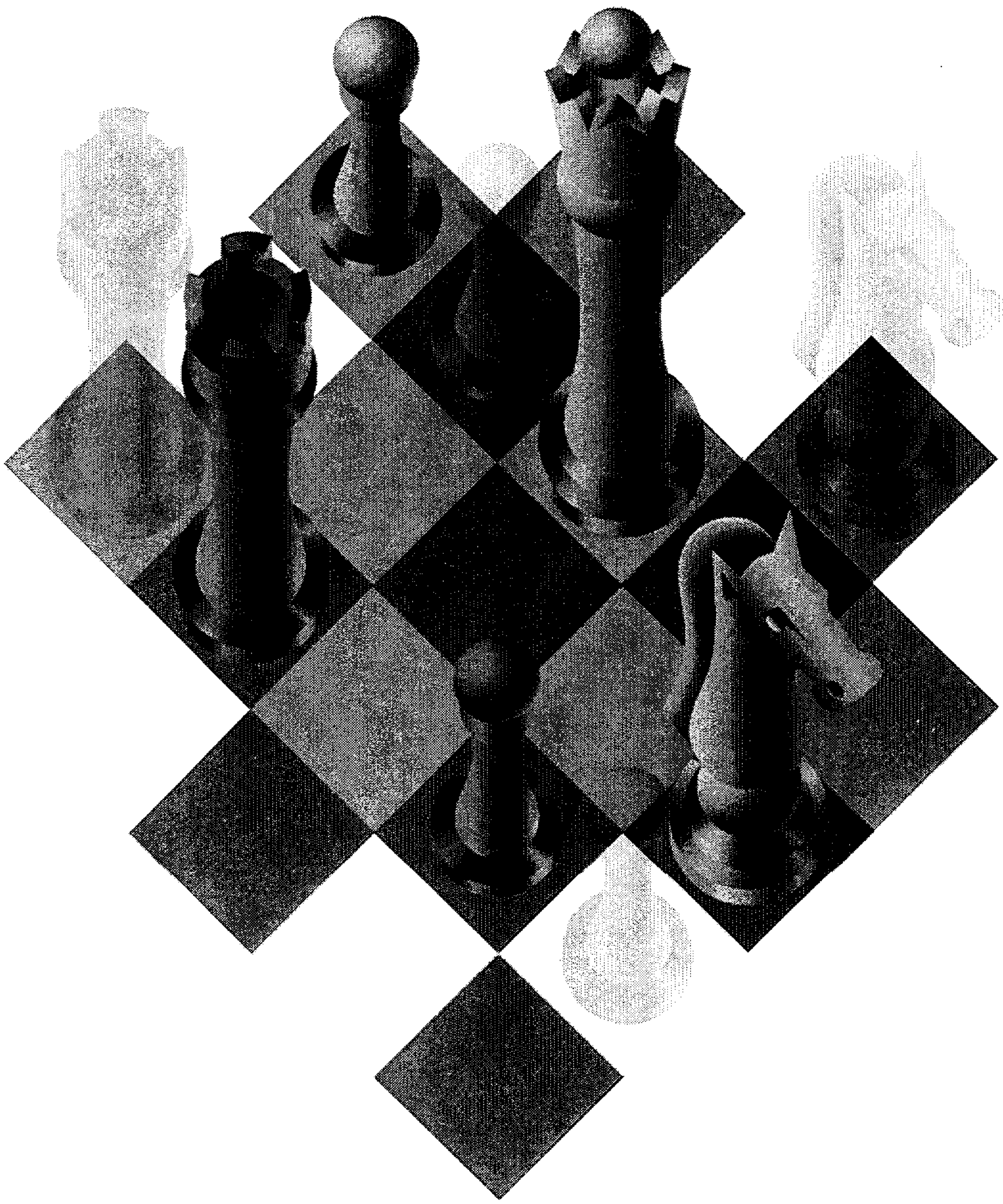
Address General Correspondence in Care of:

Northeast Utilities Service Company
Investor Relations Department
P.O. Box 270
Hartford, CT 06141-0270
Telephone: (860) 665-5000

General Offices
107 Selden Street
Berlin, Connecticut 06037-1616

UIL HOLDINGS CORPORATION

2000 ANNUAL REPORT



Strategic moves-building for growth

UIL at a glance 2000

Corporate Profile

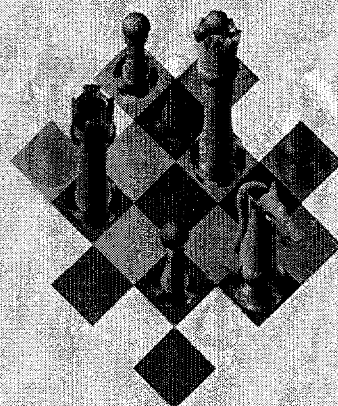
UIL Holdings Corporation is the holding company for The United Illuminating Company (UI) and United Resources Inc. (URI). UI is a New Haven-based regional distribution utility that provides electricity and energy-related services to more than 318,000 customers in municipalities in the Greater New Haven and Greater Bridgeport areas. URI is the umbrella for UIL Holdings' non-regulated business units, including American Payment Systems, Inc. (APS), Xcelecom, Inc., United Capital Investments, Inc. (UCI) and United Bridgeport Energy, Inc. (UBE). APS is the country's largest processor of outsourced utility walk-in payments through a national network of authorized agents. Xcelecom is one of the leading regional providers of tailored electrical and voice-data-video design, construction, system integration and services to customers in the Eastern U.S. UCI and UBE are passive investments of URI.

Financial Profile

(In thousands except per share amounts)	2000	1999	1998
Consolidated Highlights			
Operating Revenues	$880,855	$750,730	$748,091
Net Income	$ 60,757	$ 52,224	$ 45,072
Basic Earnings Per Common Share	$ 4.32	$ 3.71	$ 3.20
Diluted Earnings Per Common Share	$ 4.31	$ 3.71	$ 3.20
Return on Average Common Equity	13.00%	11.45%	9.44%
Book Value Per Common Share	$ 34.03	$ 32.59	$ 31.74
Dividends Declared Per Share	$ 2.88	$ 2.88	$ 2.88
Total Retail Kilowatt-hour Sales	5,653,725	5,652,050	5,452,332

Contents

New Opportunities



Great strategists see new opportunities coming from a long way off. And they move steadily toward them, piece by piece. Throughout the year 2000, UIL made calculated moves across the board to push our plans forward. Where have these moves taken us so far? To markets all across the northeast corridor, and beyond. To a position that's richer in possibilities. To rock-steady performance and results throughout our company. We're no longer a small utility with a limited market and scope. We're a diversified mix of regulated and non-regulated businesses with far-sighted vision and a game plan based on rigorous analysis. As you read through the pages of this year's report, flip back to our past for previous forecasts. If you compare them with today's reality, you'll notice something: Our gains are right in line with our goals. It's all in the strategy. And, of course, the right people making the right moves executing the strategy.

We're growing...

A Fair Price
Enron North America Corp., a wholly-owned subsidiary of Enron Corp., signs on to provide UI's "standard offer" service at a fixed and favorable price, as allowed by Connecticut's electric restructuring law. UI delivers a 10 percent rate reduction from 1996 prices to customers.

More Savings
Our customers see their monthly electric bills drop even more as a 1996 DPUC-approved incentive rate plan returns $19.4 million as a line item credit.

Solid Dividends
The Board of Directors remains upbeat about UIL's financial future. It reaffirms a quarterly dividend of 72 cents per share on common stock.

Reorganization
At a special meeting, our shareowners approve a proposal to reorganize UI, forming a holding company called UIL Holdings Corporation. The plan is also approved by the State Department of Public Utility Control (DPUC), the U.S. Securities and Exchange Commission and the Nuclear Regulatory Commission (NRC).

Station Sold
UI completes a purchase and sales agreement with Quinnipiac Energy LLC transferring ownership of the 75-megawatt English Station. Quinnipiac is a project-specific, limited liability company owned by three local area energy professionals. Upon DEP and Siting Council approval, it will return the station to active duty.

New Acquisitions
UIL's Precision Power Inc. (PPI) acquires The Datastore, Inc. of New Jersey, the first of several major moves this year. PPI adopts the new name "Xcelecom" to reflect its superior capabilities in specialty electrical and voice-data-video system integration services. New acquisitions follow, including The Orlando Diefenderfer Electrical Contractors of Allentown, PA; Johnson Electric of Stratford, CT; McPhee Electric Ltd., and McPhee Utility Power and Signal of Farmington, CT; and JBL Electric, Inc. of Paterson, NJ.

Divestiture
UI's 3.6% investment is valued at $32.5 million in the winning bid of $1.3 billion for the sale of the Millstone nuclear power plant complex. Upon closing in the first half of 2001, the proceeds will be used to reduce debt and improve our capitalization ratio.

Positive Ratings
UI's securities receive a "positive" ratings outlook from Moody's Investors Service, a step up from the former "stable" category. Moody's also assigns a Baa1 issuer rating with a positive outlook for UIL Holdings. Fitch upgrades UI's unsecured debt and secured lease obligations from BBB+ to A-, issuing an implied senior unsecured rating of BBB+ for UIL Holdings. Fitch's rating outlook for both UI and UIL Holdings is "stable."

Energy-Saving Efforts
Through a 13-week joint ad campaign, UI's 318,000 customers and Connecticut Light & Power's 1.1 million customers are urged to call a toll-free number for energy conservation information. UI's Client Relations Center responds to a high volume of customer inquiries.

Internal Efficiency
UI continues a comprehensive three-phase redesign of its support services processes. The expected outcome: savings, efficiencies, and cost-effective, high-value services customized for the corporation and its business units.

Going The Distance
UI's Network Meter Reading Team installs its 200,000th meter in Shelton in late December – a milestone. Once operational, the new system allows the company to read customer meters remotely.

Look at our trajectory

Expect to see signs of continued growth at UIL in the year 2001 – the logical outcome, given all of the resources that fueled our new growth stance last year. For the past three years, earnings have grown at a rate of 14 percent. Long term, we see growth averaging between 8 and 10 percent and sales should rise from $880 million past the billion dollar mark this year. Behind all of those numbers are some dramatic initiatives that took place within our non-regulated companies in 2000.

Nathaniel D. Woodson

Dear Fellow Shareowners:
When major change is part of your strategy, you'd better have a game plan, and a team that can execute the plan to build momentum as well as enter new markets.

Here at UIL Holdings Corporation, both were firmly in place in January 2000 as deregulation finally became a reality in Connecticut. It's my pleasure to report that our preparations paid off just as we expected. There were no obstacles to halt our progress. And no bad news to report as we stood back and surveyed the year.

UIL is now restructured as a holding company. Just as important, we've journeyed far beyond the borders of a "south central Connecticut company" to become nationally known. Our non-regulated companies are now doing business in 45 states because we had the foresight and energy to fuel their growth.

For instance, Xcelecom (formerly Precision Power, Inc.) acquired six additional companies in the year 2000. And American Payment Systems (APS), another non-regulated subsidiary, bought into new technology that's widening its base of business.

At the same time, we made steady gains on the regulated side of our business. Our United Illuminating customers still regard us as their "valued service provider." They've placed their trust in us primarily because we've remained a stable and credible source of energy services. In 1999 we said we were just as committed to them as we are to diversification and growth. Our actions in 2000 said the rest.

Strategic action was, in fact, what made the ground fertile for sustaining our income growth in the year 2000.

Change has had an annealing effect on our company throughout the year. It's proven that leadership, diligence, foresight and focused effort – always our strong suits – are essential survival gear in the new century. We've used them for maximum advantage.

Steady and strong. An ideal place to begin 2001.
We remain convinced that our long-term financial outlook is solid. Earnings were up 16% for 2000 at $4.32 per share. The strong cash flow per share that UIL has maintained in the past continues – making the changes we envision easier to achieve.

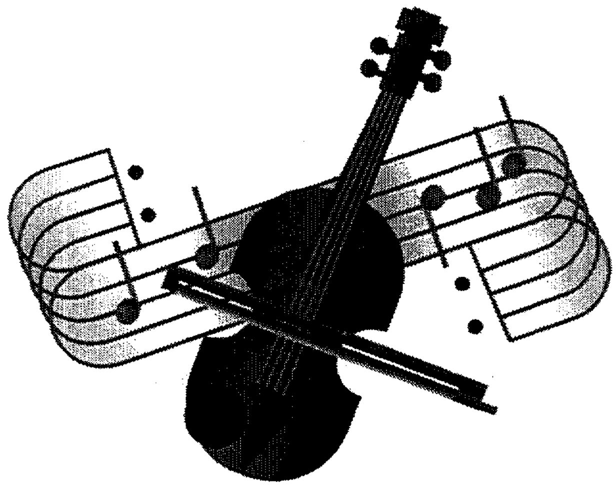
In fact, our financial strength fueled investments in our non-regulated businesses. Because we have access to substantial investment capital, we're able to seed new ventures and spur our existing companies toward greater accomplishments. For most companies our size, that is the grail of economic expansion. And we're already there.

At this writing, UIL stock is yielding a strong dividend of nearly 6%; impressive when you consider that 2000 was a hairpin turn in our industry. In the face of such massive change, we've achieved earnings growth of 14% over the past three years.

We're anticipating continued strong total earnings growth, averaging between 8 and 10 percent over the next several years. Results in 2001 will represent the beginning of a shift in the composition of our earnings as the non-regulated businesses begin to contribute more of our total earnings. At the same time, earnings from the regulated utility will decline due to additional scheduled amortization.

A finely tuned performance

Our strong performance can be credited to many people playing their part to perfection, as well as adept leadership behind the baton. The managerial team we selected over the past two years guided us past the biggest change our industry has ever faced. We've adhered to a carefully orchestrated plan with the discipline that only a professional team can muster. As a result, we've upheld our standards for service, credibility and accessibility, adding another year to a long history of doing what we say we'll do.



Our national footprint is growing.
Some of the best news we can offer shareowners is growth where it matters most: in our non-regulated umbrella company, United Resources Inc. This UIL subsidiary encompasses two non-regulated operating companies: Xcelecom, Inc. and American Payment Systems, Inc., along with our passive investments, United Capital Investments Inc. and United Bridgeport Energy, Inc.

Xcelecom is a now a leading provider of specialty electrical and voice-data-video system integration services to a wide range of commercial, industrial and institutional customers across the northeast. Last year, Xcelecom made six new acquisitions: JBL Electric Inc. and The Datastore, Inc. in New Jersey; Orlando Diefenderfer Electrical Contractors Inc. in Pennsylvania; and McPhee Electric Ltd, McPhee Utility Power and Signal, Ltd. and Johnson Electric Co., Inc.in Connecticut.

As a result, Xcelecom now competes along the I-95 corridor from Washington to Boston -- which currently represents 25% of the nation's commerce. Inroads like this propel us beyond the strict geographical boundaries of a small electric utility to whatever economic vistas we can tap in the future. And, with revenues of $225 million and growing, Xcelecom has the critical mass to compete successfully with anyone.

Our investments in APS have been similarly strategic. Through a nationwide agent system, APS handles payments for utilities customers who prefer to conduct their transactions in person. APS acquired more efficient payment processing technology in 2000 to expand its agent base and better serve the non-contracted payment market. Today, some 6,000 APS agents nationwide assist more than 90 utility clients and a growing number of non-contracted customers. We're now ready to invest in APS strategically in order to increase our non-contracted business and provide additional services to the product mix.

As our national footprint grows, so will the size of our profits over time. And our shareowners won't have long to wait before the results are significant. In two to four years, we estimate that our non-regulated companies will account for more of our total earnings.

High standards with lasting profit potential.
"Slow and steady" may win the race. But at United Illuminating, our regulated business, a steady exterior masks a highly charged corporate attitude and ethic. Delivering electricity and energy-related services to 318,000 customers in the Greater New Haven and Greater Bridgeport areas demands nothing less.

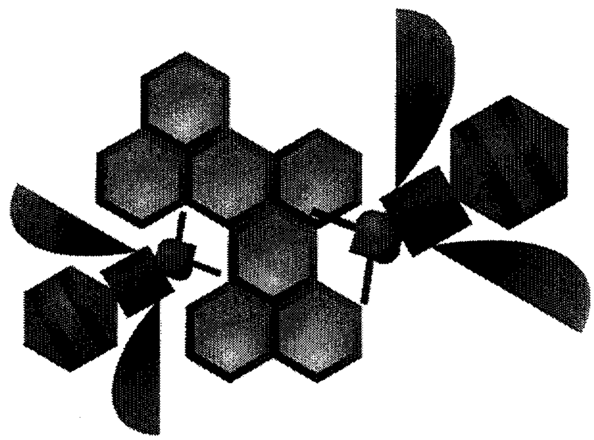
Last year, United Illuminating contributed the lion's share of UIL's earnings, $4.31 per share. In the immediate future UI will remain dominant, but decreasing in proportion to total earnings.

The upbeat responses in our customer surveys confirm UI's high marks for reliability and efficiency. No surprises there. United Illuminating continues to be among best in class for transmission and distribution reliability.

And yet, so much has changed. Currently, a unit of Texas-based Enron Corp. supplies the electric energy for our standard offer customers, eliminating our volume and supply risk. We've con-

Building for growth

UIL has gone beyond the repositioning stage to become a company of many new facets and goals. Through our non-regulated operating companies, we're pushing into new, but related arenas. At Xcelecom, we've forged partnerships in specialty electrical services and voice-data-video system integration services. At American Payment Systems, we've deepened our niche in financial transaction services, generating excitement for novel electronic products. And our search for new growth opportunities isn't over yet.



tinued to pare down our energy generation role by selling off our two investments in jointly owned nuclear power plants. The Millstone plant will change hands in 2001, and by the end of 2002 we expect to sell our interest in the Seabrook plant.

Our sole remaining interest in the energy generation business will be through United Resources' passive investment in Bridgeport Energy LLC, a gas-fired, merchant power plant.

So where does this leave United Illuminating? In a prime position to continue to provide a significant share of UIL earnings along with a higher service standard with direct electronic links between departments. With these links, we can track customer inquiries instantly, streamlining our response. In 2000 we completed customer information system modifications to enable customer choice among energy generation suppliers. And now that our automated network meter reading system is reaching full deployment, we'll virtually eliminate estimated bills. Every bill will be based on actual use. What customers see is truly what they received.

Greater efficiency is not a high-wire act – it is an essential step toward better performance. It assures shareowners that we've invested in digital technology that can enhance profitability, while divesting ourselves of risk. The United Illuminating Company that has emerged is a far more agile enterprise – keeping our service commitments with more speed, accuracy and profitability than ever before.

Investing in where we want to be tomorrow. Right here.

Our venture capital investments through United Capital tell you where we think the future lies. In the year 2000 we made them on the basis of long-term projections for profitability. Our corporate motto is "Do well and do good."

During 2000, we invested funds in a variety of promising local ventures, including Freshnex, an e-commerce company that connects buyers and sellers of perishable foods, and Gemini, a fiber optic infrastructure company.

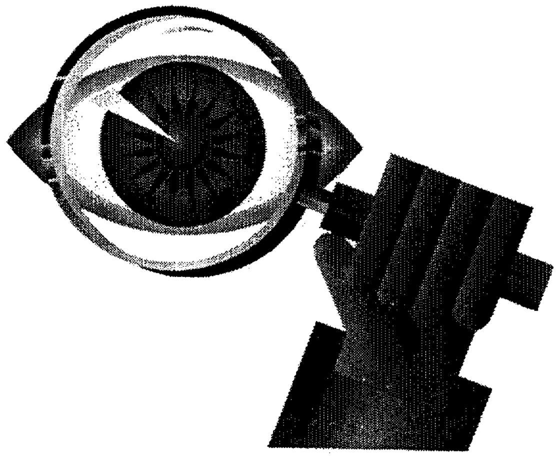
One of the most forward-thinking investments is our 25% ownership share in an underwater merchant electric transmission and fiber optic cable that will connect the New England and New York power pools. Similarly, we have spread our investments over projects in information technologies/communications, medical technology and e-commerce companies in various stages of development.

While these ventures are exciting, we still see endless potential from the windows of our corporate offices in New Haven. Today, in the aftermath of a national growth surge, New Haven continues to attract more biotech and infotech companies than any other city in Connecticut.

Knowing that United Illuminating's future is closely tied to the economic well-being of every community we serve, it's imperative that we invest in them. As we have throughout our history, we actively supported and funded economic development initiatives in the Bridgeport and New Haven areas last year. We also support endeavors that contribute to the social and cultural fabric of our communities. As an example, UIL employees made a personal commitment to our service areas through their

Take a closer look

What makes UIL a dependable financial instrument? Look at the numbers. Earnings per share for 2000 was $4.32, up 16 percent from the year before. UIL stock yielded nearly a 6 percent dividend as we entered the new year – a strong showing for a company that has just emerged from the most challenging transition in our 100-year history. It magnifies and confirms our effort to build new growth ventures on a well-established reputation for stability.



United Way fund drives, raising more than $145,000 – almost 30% more than we contributed the year before. Employee participation was up 3%. Results like this mirror our corporate concern for the greater community.

The desire to give something back has opened doors to a variety of New Haven community efforts. We're proud that UIL plays a significant role on the Governor's Council on Competitiveness and Technology, the Regional Leadership Council, the Regional Growth Partnership, the Governor's New Haven Inner City Business Strategy Initiative, the Bridgeport Regional Business Council and other notable causes.

Our main growth-stimulating factor: the right people.

The future of any organization depends on the right people acting decisively at the right time. Often said, perhaps, but at UIL the words ring true every time we launch a new initiative or complete a new project.

As we continue the re-engineering initiative launched late last year to determine the right level of internal services needed in our regulated company, we recently announced a number of changes to our management structure. Tony Vallillo, a 33-year company veteran, has been named president and chief operating officer of United Illuminating. In completing the transition from a vertically integrated electric utility to a regional distribution company, several of our senior officers also announced their decisions to retire this year. I want to acknowledge and thank Group Vice President Power Supply Jim Crowe, Group Vice President Support Services Al Henricksen, Vice President Corporate Affairs Rita Bowlby, Vice President Planning Steve Goldschmidt and Controller Jim Benjamin for their years of tireless service to UI.

So much within an organization depends on giving people a voice, and last year we used our annual internal Straight Talk Survey to listen more closely. Based on what we heard, and our monthly breakfast meetings with rotating groups of employees, we've overhauled our system for performance evaluation, improved our career development programs and increased our communications effectiveness.

I believe that having the right people with the right skill sets and discipline is the real story behind our new millennium year. We have people who understand their roles fully and have the conviction and commitment to lock their piece of the puzzle into the big picture.

As we continue to build value for our shareowners and begin new ventures within UIL, we will never lose sight of this fact. Outstanding individual performance, multiplied many times throughout our companies, will continue to stimulate growth, opportunity and outstanding results.

We did what we said we would do in 2000. That promise kept, we're moving ahead with our strategy, knowing the way and possessing the means. We anticipate another landmark year, inspired by your confidence, your support and, perhaps most of all, your trust.

Nat Woodson

Nathaniel D. Woodson
Chairman, President and
Chief Executive Officer
March 1, 2001

People Plans Performance

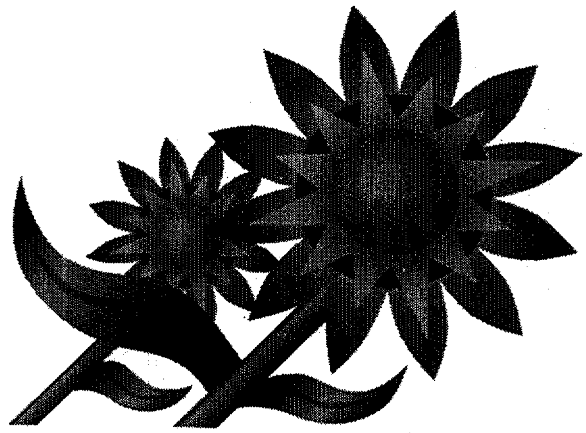
Nathaniel D. Woodson

Robert L. Fiscus

All three determined how the year 2000 would play out at UIL. Nat Woodson (Chairman, President and CEO) and Bob Fiscus (Vice Chairman and Chief Financial Officer) discuss the issues and factors behind them in the pages that follow. What emerges is a multi-dimensional view of our progress and outlook, as well as a forthright portrait of our leadership. Visionary, yet realistic, our key strategists give plenty of supporting evidence for optimism. For everyone with a stake in UIL's future, there are some cogent reasons to stand your ground. And the results speak for themselves.

A sunny outlook

UIL is now a company of boundless energy and opportunity. We're poised for dynamic growth through our well-established energy-related services and our profitable non-regulated companies. Through United Capital Investments we've invested in companies and ventures ranging from advanced information technology to a high-voltage transmission cable that will someday serve New England as an alternate energy supply path. And by attracting more business to our communities, we're spurring their economic revival.



Q **How is UIL different today from a year ago?**

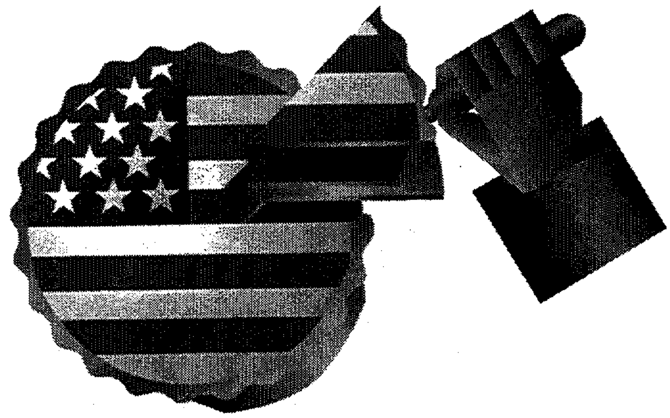
A **Woodson:** The key difference is we're operating in a holding company structure. Before, we were a relatively small utility with some non-regulated subsidiaries. In other words, the line separating our regulated and non-regulated businesses wasn't always clear-cut. Now we're a diversified company, free to grow both the regulated and non-regulated parts of our business separately. That's good news for shareholders, because it will allow us to expand and become more profitable with fewer restrictions. We've moved through the crucial electric restructuring implementation without unexpected twists in the road, validating those decisions we made before implementing our strategy. It bears repeating that we no longer generate energy – we deliver it. Enron now supplies all energy requirements for our standard offer customers. And that allowed us to eliminate our volume and supply risk. On the non-regulated side, we've moved into new geography. American Payment Systems (APS) and Xcelecom (formerly Precision Power Inc.) now have a combined presence covering 45 states. Xcelecom did it by acquiring six additional companies. APS did it by rapidly expanding its agent base via new technology. So UIL is no longer just "that south central Connecticut power company." We have a national footprint with miles and miles of growth potential.

Q **What is the strategy for UIL Holdings overall, as well as the utility and non-regulated businesses?**

A **Woodson:** Our strategy is simple: building for growth and maintaining a strong dividend stream. While all of this building is steadily progressing, we have bedrock for a foundation. Our utility business is consistently profitable because it's extremely well-run. We intend to keep raising the bar of efficiency to make sure this continues. Most of our investments in our non-regulated endeavors are on the right track for producing the desired results. Their national stature is increasing, as are their profits. As we grow, we're diversifying our risk with a mix of regulated and non-regulated ven-

Getting a piece of the pie

In 2000, UIL's non-regulated companies brought the corporation a bigger piece of the nationwide economy. Through aggressive marketing and sales expenditures, APS serves more than 90 utilities and a growing number of non-contracted customers. Xcelecom is growing strong within the I-95 northeast corridor, which comprises 25% of the US economy. Last year, Xcelecom acquired six new companies, enlarging its service area and offerings. Our horizons now encompass the entire nation's economic potential.



tures. So we'll continue along this line of measured, carefully placed investment throughout our company.

Q What distinguishes UIL from other companies in its industry?

A Fiscus: I would say credibility and reality. Plus a conscientious commitment to delivering results. If you take a look at our progress over the past three years, you'll see a sustained growth rate of more than 14 percent. You'll see a dividend yield of 6 percent. What's behind those figures is a sound and realistic investment strategy. While we're investing in non-regulated businesses that take us geographically far from home, we're not straying far from our core. UIL is a company that will continue to grow through solid management of utility distribution and growth in non-regulated businesses that we know and manage well.

Q Realistically, can UIL remain independent in the restructured utility world?

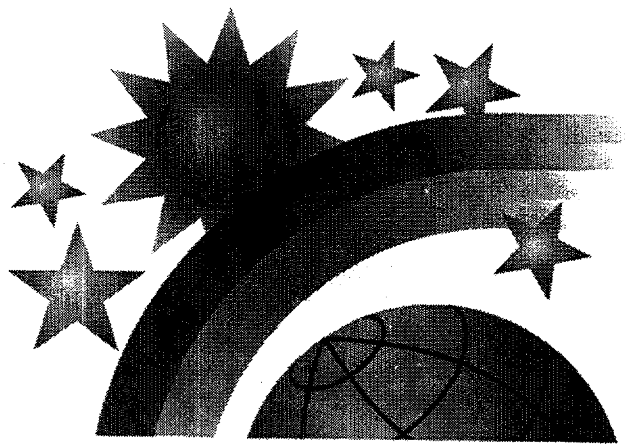
A Fiscus: Consolidation is definitely the trend in our industry. We've always been open to ideas that will improve shareowner value. And while we'll consider any offer that's in the best interests of our shareowners, we have no plans to steer the ship away from a strategy that's already working. To date, we've proven that we can be extremely effective by following our strategy and delivering solid results. Our criterion is 'what works best,' not 'what sounds impressive.'

Q Can you pinpoint UIL's greatest strength?

A Woodson: Unequivocally. Our strength is our people. That isn't a canned answer; it's based on the success of recent internal strategies at UIL. Over the past few years, we've operated with "people, plans and performance" as our corporate call to action. It's led us to recruit an exceptional senior management team. It's prompted us to develop and encourage leadership within our employee ranks as we continue to re-engineer our internal structure. It's delivered near record earnings over the past two years – and growth of 14 percent per year over the past three years. Strong, experienced, capable people working together can push a company

It's been a stellar year

The year 2000 has been a constellation of many accomplishments, turning points, and progressions. We're successfully reengineering our company and reducing our exposure to risk by selling off interests in energy generating plants. At the same time, we've continued to invest in our regulated company, with an eye toward growth as well as firm commitment to our customer base. And we've increased the size of our non-regulated companies' national footprint to include areas that stretch far beyond Connecticut.



forward. Since we took the time to carefully select the right people, we've simply charged forward. I'd call that strength with a lot of energy behind it.

Q How does a small cap company compete for investment dollars in the new economy?

A **Fiscus:** If shareowners are looking for a high total return in the form of a strong dividend and strong earnings growth – then UIL is going to get a thumbs up. And from what I can tell, a lot of investors are looking for the solid results we can deliver, in any economy. They can see where we're heading, that we aren't fickle, and that we're holding our regulated and non-regulated businesses to a high standard for results. Corporate-wide returns will continue to climb and that, in turn, will attract investment capital. We don't have to use risky strategies to end up with terrific results, and this should be very attractive to a growing contingent of investors.

Q How do you envision the UIL of the future?

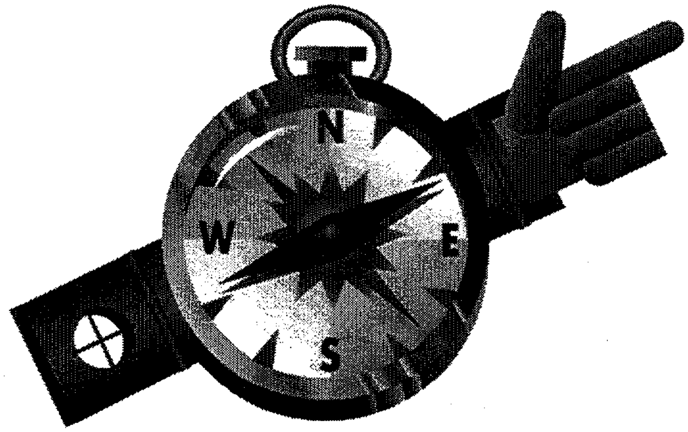
A **Woodson:** I see a well-run diversified company delivering solid financial results. And I see a utility that will live up to its reputation for reliability and value. In those respects, I envision a company that is building on the past with all of the technologies that the future can muster. But if you adjust the telescope to focus on our non-regulated companies, that is where I envision real change. Xcelecom, American Payment Systems, and United Capital will continue to build up capabilities, products and markets. In fact, we fully anticipate that they will contribute more of our total earnings in two to four years.

Q How will the re-engineering effort now underway affect the UIL of the present or future?

A **Fiscus:** Re-engineering is a logical extension of the changes in our industry and company. We sold our generation units, formed a holding company and are now aligning our structure with the emerging size and shape of the new organization.

Stay the course

Where we go from here is not a question mark. It's a goal that we've already surveyed and set forth to accomplish. As we navigate beyond familiar ports, each member of UIL's leadership team goes forward with a complete understanding of their role. We're already familiar with the tasks, the challenges and even the risks. In going forward to achieve ambitious outcomes, we have truly already been there.



Re-engineering has been a company-wide reality check. Which processes really work? Which ones have lost their value? In the face of change, these questions are vital, and we persistently ask them. We've been relentless when it comes to what works and what doesn't. We don't cling to processes that are no longer useful just because they provide pat answers or a desired comfort level. And that's why we've become a much more streamlined and productive company even while all of the changes have been taking place. Remaining static has never been an option, so we've continued to evolve. We've been around long enough to know that staying competitive always involves that element of risk-taking. We either continually reinvent ourselves, or we'll be left behind.

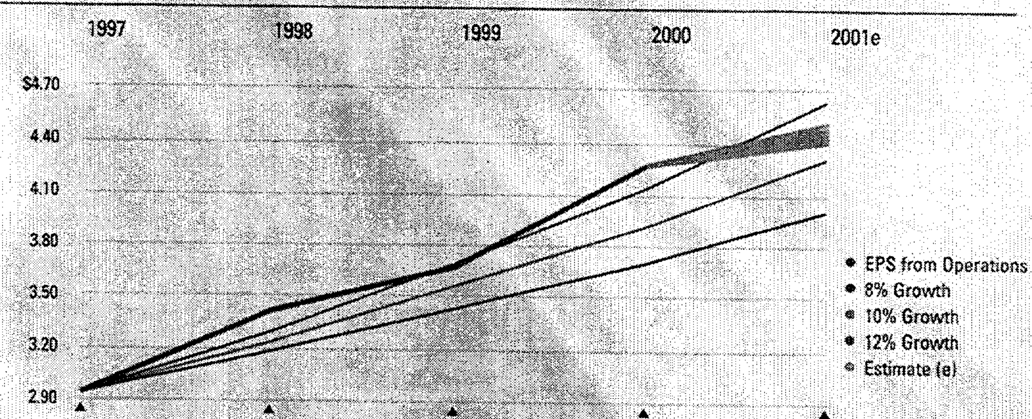
Q **Is the power supply situation in Connecticut different from California? What has UI done to make sure the same thing can't happen here?**

A **Woodson:** There's a big difference, actually. And it has to do with power supply contracts. Under Connecticut and California law, utility companies are required to provide service to customers who elect not to choose an alternate electric supplier. In California, utilities are required to buy this supply on the daily spot market – a highly volatile, risky proposition. In Connecticut, utilities were allowed to negotiate a long-term agreement to supply this service at a fixed price – a much more secure arrangement for all concerned. UI negotiated an agreement with a subsidiary of Enron Corporation of Houston, which today supplies our standard offer customers with all of their electric energy requirements, thus reducing any worries about drastic price fluctuations or sudden energy shortages. And, eliminating our volume and supply risk. Looking forward, we urge our customers and shareholders to support the construction of new electric generation and transmission facilities and expansion of the gas transmission system to increase the capacity of the systems that deliver energy to you.

Financial Section

Earnings per Share from Operations

1997-2000 and Estimated 2001, Compared to 8% to 12% Growth Rates from 1997 Base



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Major Influences on Financial Condition

UIL Holdings' financial condition will continue to be dependent on the level of UI's electric utility retail sales and UI's ability to control expenses, as well as on the performance of the businesses of UIL Holdings' non-regulated subsidiaries. The two primary factors that affect electric utility sales volume are economic conditions and weather. The principal factors affecting the financial condition of APS and Xcelecom are the pace of technological changes, competition and risks related to the management of growth, including, in the case of Xcelecom, acquisition financing and integration.

UIL Holdings' financial status and financing capability will continue to be sensitive to many other factors, including conditions in the securities markets, economic conditions, interest rates, the level of income and cash flow of UIL Holdings' subsidiaries, and legislative and regulatory developments, including the cost of compliance with increasingly stringent environmental legislation and regulations.

On December 31, 1996, the Connecticut Department of Public Utility Control (DPUC) completed a financial and operational review of UI and ordered a five-year incentive regulation plan for the years 1997 through 2001 (the Rate Plan). The Rate Plan accelerates the amortization and recovery of unspecified assets during 1999-2001 if UI's common equity return on regulated utility investment exceeds 10.5% after recording the amortization. UI's authorized return on regulated utility common equity during the period is 11.5%. Earnings above 11.5%, on an annual basis, are utilized one-third for customer price reductions, one-third to increase amortization of assets, and one-third retained as earnings.

The Rate Plan included a provision that it could be reopened and modified upon the enactment of electric utility restructuring legislation in Connecticut. On October 1, 1999, the DPUC issued a decision establishing UI's standard offer customer rates, commencing January 1, 2000, at a level 10% below 1996 rates, as directed by the Restructuring Act described in detail below. These standard offer customer rates supersede the rates that were included in the Rate Plan. The decision also reduced the required amount of accelerated amortization in 2000 and 2001. Under this 1999 decision, all other components of the 1996 Rate Plan are expected to remain in effect through 2001. The Connecticut Office of Consumer Counsel (OCC), the statutory representative of consumer interests in public utility matters, appealed the DPUC's standard offer decision to the Connecticut Superior Court, challenging the DPUC's determination of UI's average prices in 1996 rates from which a 10% reduction is required by the Restructuring Act. On February 22, 2001, the Superior Court dismissed the OCC's appeal from the DPUC's decision; but UI is unable to predict, at this time, whether the OCC will appeal the Superior Court's decision to the Connecticut Appellate Court.

On February 13, 2001, the Connecticut Attorney General and the OCC petitioned the DPUC to initiate a proceeding and hold a hearing concerning the need to decrease UI's rates by reason of UI's having earned a return on regulated common equity more than 1% above the authorized level of 11.5% for at least six consecutive months. UI believes that a hearing would confirm that UI has complied with the DPUC-ordered earnings sharing mechanism in UI's rate plan; and it will contest vigorously any arguments for a rate decrease.

Major Influences on Financial Condition (continued)

In April 1998, Connecticut enacted Public Act 98-28 (the Restructuring Act), a massive and complex statute designed to restructure the State's regulated electric utility industry. As a result of the Restructuring Act, the business of generating and selling electricity directly to consumers has been opened to competition. These business activities are separated from the business of delivering electricity to consumers, also known as the transmission and distribution business. The business of delivering electricity remains with the incumbent franchised utility companies (including UI) which continue to be regulated by the DPUC as Distribution Companies.

Under the Restructuring Act, all of UI's customers are able to choose their power supply providers. Until January 1, 2004, UI is required to offer full "standard offer" electric service, under regulated rates, to all customers who do not choose alternate power supply providers. The standard offer rates must be at least 10% below the average prices in 1996. Under current regulatory provisions, UI's financial condition is not affected materially by whether customers choose alternate suppliers to UI's standard offer electric service.

On December 28, 1999, UI and Enron Power Marketing, Inc. (EPMI) entered into a Wholesale Power Supply Agreement, a PPA Entitlements Transfer Agreement and related agreements documenting a four-year standard offer power supply arrangement and the assumption of all of UI's long-term purchased power agreements, effective January 1, 2000. Under these agreements, EPMI supplies the generation services needed by UI to meet its standard offer obligations for the four-year standard offer period at a fixed price. The agreements with EPMI also include a financially settled contract for differences related to certain call rights of EPMI and put rights of UI with respect to UI's entitlements in Seabrook Unit 1 and in Millstone Unit 3, and UI's provision to EPMI of certain ancillary products and services associated with those nuclear entitlements, which provisions terminate at the earlier of December 31, 2003 or the date that UI sells its nuclear interests. The agreements do not restrict UI's right to sell to third parties UI's ownership interests in those nuclear generation units or the generated energy actually attributable to its ownership interests.

The Restructuring Act requires that UI must attempt to divest its ownership interests in its nuclear-fueled power plants prior to 2004 in order to recover any stranded costs associated with its power plants. On October 1, 1998, in its "unbundling plan" filing with the DPUC under the Restructuring Act, and in other regulatory dockets, UI stated that it plans to divest its nuclear generation ownership interests (17.5% of Seabrook Unit 1 in New Hampshire and 3.685% of Millstone Station Unit 3 in Connecticut) by the end of 2003, in accordance with the Restructuring Act. On April 19, 2000, the DPUC approved UI's plan for divesting its ownership interest in Millstone Unit 3 by participating in an auction process for all three of the generating units at Millstone Station, which was concluded on August 7, 2000, when Dominion Resources, Inc. agreed to purchase Millstone Units 1 and 2, and 93.47% of Millstone Unit 3 for $1.298 billion. The purchase price agreed to for UI's ownership interest in Unit 3, which is subject to adjustments for expenditures and eventualities prior to the date of closing on the sale, is approximately $31 million, exclusive of nuclear fuel. UI's share of the proceeds from the sale of the nuclear fuel inventory at the date of closing on the sale is estimated to be approximately $2.5 million. The sale is scheduled to be consummated on or about April 1, 2001 or as soon thereafter as all requisite regulatory approvals are received. On December 15, 2000, UI and The Connecticut Light and Power Company filed with the DPUC for its approval of their plan to divest their respective interests in Seabrook Unit 1 by an auction process. The DPUC has commenced hearings on this divestiture plan.

Liquidity and Capital Resources

UIL Holdings' capital requirements are presently projected as follows:

(In Millions of Dollars)	2001	2002	2003	2004	2005
Cash on Hand - Beginning of Year(1)	$14.2	$ –	$ –	$ –	$ –
Funds from Operations less Dividends(2)	72.0	79.9	95.8	90.7	95.4
Subtotal	86.2	79.9	95.8	90.7	95.4
Less:					
Capital Expenditures and other Expenditures(2)					
UI	75.6	41.4	31.5	49.5	35.9
URI	18.8	12.9	17.7	10.3	11.9
Total Capital Expenditures	94.4	54.3	49.2	59.8	47.8
Plus:					
Net Cash from Plant Sales	20.2	143.6	–	–	–
Cash Available to pay Debt Maturities and Redemptions	12.0	169.2	46.6	30.9	47.6
Less:					
Maturities and Mandatory Redemptions	–	100.0	100.0	–	4.3
Optional Redemptions	–	128.2	–	–	–
External Financing Requirements (Surplus)(2)	(12.0)	59.0	53.4	(30.9)	(43.3)
Plus:					
Issuance and Sale of Senior Notes	75.0	–	–	–	–
Increase (Decrease) in Short-Term Borrowings	(87.0)	59.0	53.4	(30.9)	(43.3)
Short-Term Borrowings – End of Year	$23.7	$82.7	$136.1	$105.2	$61.9

(1) Excludes $3.3 million Seabrook Unit 1 operating deposit and restricted cash of American Payment Systems, Inc. of $29.9 million.

(2) Funds from Operations less Dividends, Capital Expenditures and External Financing Requirements are estimates based on current earnings and cash flow projections. The estimate of Cash from Plant Sales for 2001 is based on current projections for the Millstone Unit 3 sale anticipated on or about April 1, 2001. The estimate for Cash from Plant Sales for 2002 is based on speculative pricing and other projections for the sale of Seabrook Unit 1, including a sale date in early 2002. All of these estimates are subject to change due to future events and conditions that may be substantially different from those used in developing the projections.

All capital requirements that exceed available cash will have to be provided by external financing. Although there is no commitment to provide such financing from any source of funds, other than a $97.5 million revolving credit agreement with a group of banks, future external financing needs are expected to be satisfied by the issuance of additional short-term and long-term debt. The continued availability of these methods of financing will be dependent on many factors, including conditions in the securities markets, economic conditions, and future income and cash flow.

See "Notes to Consolidated Financial Statements," Note (E) for a discussion of UIL Holdings' short-term credit arrangements.

On September 25, 2000, UI redeemed $50 million of 9 5/8% Preferred Capital Securities, Series A, due 2025, at $25.00 per share, plus accrued dividends to the redemption date of $0.160417 per share. These securities were issued in April 1995 by United Capital Funding Partnership L. P., a Delaware limited partnership that was dissolved following the redemption of the securities.

Liquidity and Capital Resources (continued)

On February 15, 2001, UIL Holdings issued and sold $75,000,000 of Senior Notes to several institutional investors in a private sale. The issue was composed of two series: 7.23% Senior Notes, Series A, due February 15, 2011, in the principal amount of $30,000,000, and 7.38% Senior Notes, Series B, due February 15, 2011, in the principal amount of $45,000,000. Under the Senior Notes, Series A, UIL Holdings is required to prepay the principal amount of $4,285,714 each February 15th, beginning on February 15, 2005 and ending on February 15, 2010. Interest due under the Senior Notes is payable semi-annually on February 15th and August 15th. The net proceeds of the sale were used to repay short-term debt of UIL Holdings.

At December 31, 2000, UIL Holdings had $47.4 million of cash and temporary cash investments, a decrease of $20.9 million from the corresponding balance at December 31, 1999. The components of this decrease, which are detailed in the Consolidated Statement of Cash Flows, are summarized as follows:

(In Millions of Dollars)

Balance, December 31, 1999	$68.3
Net cash provided by operating activities	54.1
Net cash provided by (used in) financing activities:	
– Financing activities, excluding dividend payments	17.1
– Dividend payments	(40.5)
Investment in debt securities	4.8
Cash invested in plant, including nuclear fuel	(56.4)
Net Change in Cash	(20.9)
Balance, December 31, 2000	$47.4

New Accounting Standards

See the discussion included in "Financial Statements and Supplementary Data – Notes to Consolidated Financial Statements – Note (A), Statement of Accounting Policies."

Results of Operations

As a result of the formation of UIL Holdings, all subsidiary results are consolidated. All periods reported herein have been reclassified for consolidated reporting, with no impact on earnings.

2000 vs. 1999

UIL HOLDINGS CORPORATION RESULTS OF OPERATIONS: 2000 vs. 1999

	Year Ended Dec. 31, 2000 (000's)	Year Ended Dec. 31, 1999 (000's)	2000 more (less) than 1999	
			Amount	Percent
OPERATING REVENUE				
United Illuminating	$704,691	$679,975	$ 24,716	4%
United Resources, Inc.	$176,431	$ 71,105	$105,326	148%
Eliminations	$ (267)	$ (350)	$ 83	–
Total Operating Revenue	$880,855	$750,730	$130,125	17%
TOTAL EARNINGS FOR COMMON STOCK	$ 60,757	$ 52,105	$ 8,652	17%
EARNINGS PER SHARE (BASIC)				
United Illuminating	$ 4.25	$ 3.83	$ 0.42	11%
United Resources, Inc.	$ 0.01	$ (0.16)	$ 0.17	–
TOTAL EPS FROM OPERATIONS	$ 4.26	$ 3.67	$ 0.59	16%
EPS from one-time items	$ 0.06	$ 0.04	$ 0.02	–
Dilution	$ (0.01)	–	$ (0.01)	–
TOTAL EPS (DILUTED)	$ 4.31	$ 3.71	$ 0.60	16%

The one-time items recorded in 2000 were:

		EPS
2000 Quarter 3	Proceeds from the Millstone Unit 3 litigation settlement (pre-sharing)	$0.64
	Sharing on Proceeds from the Millstone Unit 3 settlement	(0.43)
	Net	$0.21
2000 Quarter 2	Impairment loss on property in North Haven	$(0.15)

The one-time item recorded in the third quarter of 2000 as Operating revenues - Other was a cash receipt, in the amount of $14.9 million before-tax, in settlement of litigation over costs associated with an extended unplanned shutdown of the Millstone Unit 3 nuclear generating unit in 1996, 1997 and 1998.

The one-time item recorded in 1999 was:

		EPS
1999 Quarter 1	Purchased power expense refund (pre-sharing)	$0.12
	Sharing due to refund	(0.08)
	Net	$0.04

UI RESULTS OF OPERATIONS: 2000 vs. 1999

GENERAL IMPACTS OF CONNECTICUT'S RESTRUCTURING ACT ON UI FINANCIAL REPORTS On April 16, 1999, UI completed the sale of its operating fossil-fueled generating plants that was required by Connecticut's 1998 electric utility industry restructuring legislation (Restructuring Act). On October 1, 1999, the Connecticut Department of Public Utility Control (DPUC) issued its decision establishing UI's standard offer customer rates, commencing January 1, 2000, at a level 10% below 1996 rates (about 6% below 1999 rates), as directed by the Restructuring Act. As a result of these two and other associated events, the "geography" of UI's costs have changed. This particularly relates to regulated retail pricing patterns, wholesale revenue and expense, other operating revenues, retail purchased energy and fossil fuel expenses, operation and maintenance expense, depreciation and property taxes. For example, increased purchased energy expenses in 2000 are more than offset by portions of the decreases in miscellaneous operation and maintenance expense, depreciation and property taxes due to the sale of generating plants.

	Year Ended Dec. 31, 2000 (000's)	Year Ended Dec. 31, 1999 (000's)	2000 more (less) than 1999 Amount	Percent
OPERATING REVENUE				
United Illuminating	$704,691	$679,975	$ 24,716	4%
TOTAL EARNINGS FOR COMMON STOCK	$ 60,575	$ 54,361	$ 6,214	11%
EPS FROM OPERATIONS (BASIC)				
UI excluding Nuclear Production	$ 3.80	N/A	N/A	N/A
Nuclear Production (Note A)	$ 0.45	N/A	N/A	N/A
Total UI EPS from operations	$ 4.25	$ 3.83	$ 0.42	11%
GWH SALES (THOUSANDS OF MWH)	5,654	5,652	2	–%

Note (A): Nuclear Production was included in retail operations in 1999.

Results of Operations (continued)

Overall, retail revenue decreased by $37.2 million in 2000 compared to 1999.

(In Millions of Dollars)	Increase/ (Decrease)
Retail Revenues	
Revenue from:	
Estimate of operating Distribution Division component of "weather corrected" retail sales growth, up 2.1%	$ 4.9
Estimate of operating Distribution Division component of weather effect on retail sales	(10.4)
Estimate of operating Distribution Division component of price reduction	(14.5)
Sharing revenues from operations	4.7
Other retail price reduction, mix of sales and other	(17.6)
TOTAL RETAIL REVENUE FROM OPERATIONS	(32.9)
Sharing revenues from one-time items	(4.3)
TOTAL RETAIL REVENUE	$(37.2)

Wholesale sales margin increased by $48.3 million in 2000 compared to 1999. UI's operating nuclear assets, Seabrook Unit 1 and Millstone Unit 3, supplied power solely to the wholesale market in 2000. Wholesale margin from the Nuclear Division, which was incorporated in retail rates in 1999, was $48.3 million in 2000 and accounted for all of the variance. Overall, the Nuclear Division contributed earnings of $0.45 per share in 2000. This reflects the wholesale sales margin, offset in part by additional maintenance costs resulting from a Seabrook Unit 1 outage extension. The outage extension cost UI about $0.33 per share in 2000.

Other operating revenues increased by $3.3 million in 2000 compared to 1999. Other operating revenues include transmission revenues from the New England Power Pool (NEPOOL), which increased by $4.3 million in 2000 compared to 1999 and were offset by an increase in transmission operation expense. Other revenue items decreased by $1.0 million.

Retail fuel and energy expense increased by $124.7 million in 2000 compared to 1999. UI's operating fossil-fueled generation units were sold on April 16, 1999, and UI receives, and will receive through 2003, electricity to satisfy its standard offer retail customer service requirements through fixed-price purchased power agreements. These costs are recovered through the Generation Service Charge (GSC) portion of UI's unbundled retail customer rates.

UI's operating expenses for operation, maintenance and purchased capacity decreased by $47.2 million in 2000 compared to 1999. The principal components of these expense changes included:

(In Millions of Dollars)	Increase/ (Decrease)
Operating Distribution Division	
Site remediation costs (Note A)	$ (9.3)
1999 fossil generating unit operation and maintenance	(7.5)
Pension and employee benefits costs	(5.2)
NEPOOL transmission expense	3.7
Other transmission	(1.3)
1999 Y2K projects	(2.7)
Other	(5.3)
TOTAL OPERATING DISTRIBUTION DIVISION	(27.6)
NUCLEAR DIVISION (NOTE B)	(4.9)
Competitive Transition Assessment (CTA)	
Purchased capacity (Note C)	(28.5)
Other	0.4
TOTAL CTA	(28.1)
CONSERVATION AND LOAD MANAGEMENT AND RENEWABLE ENERGY (NOTE D)	13.4
Total O&M expense	$(47.2)

Note (A): These costs were incurred in the fourth quarter of 1999 to repair a riparian bulkhead in New Haven and for remediation of environmental conditions at another site.

Note (B): Nuclear Division operation and maintenance expenses are incurred in the business of producing energy for the wholesale market and are reflected in the Nuclear Division results. These expenses decreased by $4.9 million in 2000 compared to 1999, due primarily to the absence of 1999 Millstone Unit 3 refueling outage costs and reductions in base expenses at both Seabrook Unit 1 and Millstone Unit 3 that more than offset the incremental costs associated with the Seabrook Unit 1 2000 outage.

Note (C): UI's wholesale purchased power agreements were assumed by Enron Power Marketing, Inc. (EPMI) as part of an agreement for EPMI to supply the power needed by UI to meet its standard offer retail customer service obligations until the end of the four-year standard offer period (the end of 2003) and the power needed to serve UI's special contract retail customers for the remaining contract terms. UI has created a regulatory asset and noncurrent liability to reflect this agreement, and the regulatory asset is being amortized as part of the Competitive Transition Assessment (CTA). The amortization for 2000 of about $26.8 million is included in the "Amortization of regulatory assets" line of the income statement.

Note (D): Conservation and load management and renewable energy costs are pass-through costs recovered in unbundled retail customer rates.

Other taxes for UI decreased by $4.3 million in 2000 compared to 1999, due in part to the sale of fossil generating units in April 1999.

Depreciation expense for UI decreased by $28.8 million in 2000 compared to 1999. About $24.5 million of this decrease was due to the reclassification of depreciation on nuclear plant stranded assets and other assets from depreciation expense to amortization of regulatory assets within the Competitive Transition Assessment (CTA). The remaining $4.3 million decrease was due primarily to the sale of fossil generating units in 1999.

On December 31, 1996, the DPUC issued an order that implemented a five-year Rate Plan to reduce UI's regulated retail prices and accelerate the recovery of certain "regulatory assets." According to the Rate Plan, under which UI is currently operating, "accelerated" amortization of past regulated utility investments is

Results of Operations (continued)

scheduled for every year that the Rate Plan is in effect, contingent upon UI earning a 10.5% return on regulated utility common equity. Beginning in 2000, these accelerated amortizations are charged to the operating Distribution Division, although they reduce CTA rate base. Additionally, any "sharing" amortization required as a result of the Distribution Division exceeding an 11.5% return on the equity portion of its rate base impacts the Distribution Division earnings but reduces CTA rate base. UI is allowed to earn an 11.5% return, no more and no less, on the equity portion of the CTA rate base that includes all stranded assets. If CTA revenues and various costs included in the CTA do not produce an 11.5% return, then plant amortizations are either accelerated or deferred accordingly. A similar mechanism is in place to deal with Systems Benefits Charges (SBC), but the impact is immaterial. The table below shows the increases and decreases in 2000 compared to 1999 in major amortizations of regulatory assets. The amortizations for the operating Distribution Division impact earnings directly, and the amortizations for the CTA and SBC impact earnings indirectly through changes to rate base.

(In Millions of Dollars)	As Booked	After-tax
Amortization of Regulatory Assets		
Distribution Division:		
Accelerated amortization	$(3.1)	$(4.4)
"Sharing" from operations	(1.7)	(2.9)
"Sharing" from one-time items	2.8	2.4
Deferred Seabrook Return, completed in 1999	(12.6)	(12.6)
Other	1.3	1.0
TOTAL DISTRIBUTION DIVISION	(13.3)	(16.5)
Amortization in CTA and SBC	13.3	13.4
TOTAL AMORTIZATION OF REGULATORY ASSETS	$ 0.0	$(3.1)

Interest charges for UI, including the "Dividend requirement of mandatorily redeemable securities," decreased by $10.1 million in 2000 compared to 1999.

URI RESULTS OF OPERATIONS: 2000 vs. 1999

	Year Ended Dec. 31, 2000 (000's)	Year Ended Dec. 31, 1999 (000's)	2000 more (less) than 1999	
			Amount	Percent
TOTAL OPERATING REVENUE	$176,431	$71,105	$105,326	148%
TOTAL EARNINGS FOR COMMON STOCK	$ 182	$ (2,256)	$ 2,438	–
EPS FROM OPERATIONS (BASIC AND DILUTED)				
Operating Businesses				
American Payment Systems, Inc.	$ 0.15	$ 0.11	$ 0.04	36%
Xcelecom, Inc.	$ 0.15	$ (0.21)	$ 0.36	–
SUBTOTAL	$ 0.30	$ (0.10)	$ 0.40	–
Passive Investments				
United Bridgeport Energy, Inc.	$ (0.19)	$ (0.01)	$ (0.18)	–
United Capital Investments, Inc.	$ 0.11	$ (0.03)	$ 0.14	–
SUBTOTAL	$ (0.08)	$ (0.04)	$ (0.04)	
URI Headquarters (Note A)	$ (0.21)	$ (0.02)	$ (0.19)	
TOTAL NON-REGULATED EPS FROM OPERATIONS	$ 0.01	$ (0.16)	$ 0.17	–

Note (A): Includes financial leveraging, strategic and administrative costs for the holding company of the non-regulated business units.

Overall, the consolidated non-regulated businesses operating under the parent, URI, after corporate parent-allocated interest, earned approximately $0.2 million, or $.01 per share, in 2000, compared to losses of about $2.3 million, or $0.16 per share, in 1999. Operation expenses for the URI businesses, including cost of goods sold, selling and administrative expenses, increased by $94.2 million in 2000 compared to 1999, almost entirely as the result of incorporating acquired companies. Other taxes for URI increased by $0.7 million, reflecting the expansion of these businesses. Depreciation and amortization expense for the URI businesses increased by $1.0 million.

Interest charges for URI increased by a net $6.8 million in 2000, compared to 1999. The results of each of the subsidiaries of URI for 2000, as presented below, reflect the allocation of debt costs from the parent based on a capital structure, including an equity component and an interest rate deemed to be appropriate for that type of business.

URI OPERATING BUSINESSES

AMERICAN PAYMENT SYSTEMS, INC. (APS)   Earnings for APS increased $0.04 per share, or 36%, in 2000 compared to 1999, due primarily to increased transaction volumes. Also, much of APS's field equipment was fully depreciated, resulting in depreciation savings.

XCELECOM, INC.   Earnings for Xcelecom, Inc. increased by $0.36 per share in 2000 compared to 1999, due to the acquisitions completed in 2000 and continuing cost control measures. Operating revenue increased by $103 million to $138 million in 2000.

URI PASSIVE INVESTMENTS

UNITED BRIDGEPORT ENERGY, INC. (UBE)   UBE lost $0.19 per share in 2000, compared to a loss of $0.01 per share in 1999. The increased loss was due to a combination of factors that had adverse impacts on the Bridgeport Energy generating plant: third quarter mild weather that depressed energy sales prices; high gas prices that further reduced margins; mechanical difficulties in the early part of the year that caused an extended shutdown; and a one-time third quarter termination cost of a contractual liability that is expected to benefit UBE's earnings in subsequent years. Fourth quarter 2000 results reflect the recovery of $1.6 million of Installed Capacity (ICAP) revenues, contributing $0.07 per share, based on a power purchaser's agreement to pay in accordance with its power contract terms as a result of a Federal Energy Regulatory Commission (FERC) ruling affirming the value of the ICAP market in New England. However, these ICAP revenues are the subject of an appeal to the FERC by other entities; and the FERC has temporarily stayed its order pending a hearing. See the "Looking Forward" section for more information on the ICAP proceeding and on plans to reduce the risk of the UBE investment.

UNITED CAPITAL INVESTMENTS, INC. (UCI)   UCI earned $0.11 per share in 2000, compared to a $0.03 per share loss in 1999, due to gains on its passive investments.

URI HEADQUARTERS   URI, the holding company for all non-regulated businesses, lost $0.21 per share in 2000 compared to a loss of $0.02 per share in 1999. The results of each of the subsidiaries of URI, as presented above, reflect interest expense on allocated debt from URI, based on a capital structure, including an equity component, and an interest rate deemed to be appropriate for that type of business. Some financial leveraging, and strategic and administrative costs for the subsidiaries of URI, are retained by the parent URI.

Management's Discussion & Analysis of Financial Condition & Results of Operations (continued)

Results of Operations (continued)

1999 vs. 1998

UIL HOLDINGS CORPORATION RESULTS OF OPERATIONS: 1999 vs. 1998

	Year Ended Dec. 31, 1999 (000's)	Year Ended Dec. 31, 1998 (000's)	1999 more (less) than 1998 Amount	Percent
OPERATING REVENUE				
United Illuminating	$679,975	$686,191	$(6,216)	(1)%
United Resources, Inc.	$ 71,105	$ 61,861	$ 9,244	15%
Eliminations	$ (350)	$ 39	$ (389)	–
Total Operating Revenue	$750,730	$748,091	$ 2,639	0.4%
TOTAL EARNINGS FOR COMMON STOCK	$ 52,105	$ 44,892	$ 7,213	16%
EARNINGS PER SHARE (BASIC)				
United Illuminating	$ 3.83	$ 3.49	$ 0.34	10%
United Resources, Inc.	$ (0.16)	$ (0.08)	$ (0.08)	–
TOTAL EPS FROM OPERATIONS	$ 3.67	$ 3.41	$ 0.26	8%
EPS from one-time items	$ 0.04	$ (0.21)	$ 0.25	–
Dilution	–	–	–	–
TOTAL EPS (DILUTED)	$ 3.71	$ 3.20	$ 0.51	16%

The one-time item recorded in 1999 was:

		EPS
1999 Quarter 1	Purchased power expense refund (pre-sharing)	$ 0.12
	Sharing due to refund	(0.08)
	Net	$ 0.04

The one-time items recorded in 1998 were:

		EPS
1998 Quarter 4	Property tax settlement with the City of New Haven, CT	$(0.59)
	Reversal of "sharing" related to property tax settlement	0.29
	Net	$(0.30)
1998 Quarter 3	Refund of prior period transmission charges, with interest	$ 0.14
	"Sharing" due to transmission refund	(0.05)
	Net	$ 0.09

UI RESULTS OF OPERATIONS: 1999 vs. 1998

	Year Ended Dec. 31, 1999 (000's)	Year Ended Dec. 31, 1998 (000's)	1999 more (less) than 1998 Amount	Percent
OPERATING REVENUE				
United Illuminating	$679,975	$686,191	$(6,216)	(1)%
TOTAL EARNINGS FOR COMMON STOCK	$ 54,361	$ 45,993	$ 8,368	18%
EPS FROM OPERATIONS (BASIC)	$ 3.83	$ 3.49	$ 0.34	10%
GWH SALES (THOUSANDS OF MWH)	5,652	5,452	200	4%

Overall, retail revenue increased by $8.0 million in 1999 compared to 1998.

(In Millions of Dollars)	From Operations	From One-time	Total
Retail Sales Margin			
Revenue from:			
Sharing for 1999	$(14.4)	$(3.9)	$(18.3)
Estimate of "real" retail sales growth, up 3.2%	20.2	0	20.2
Estimate of weather effect on retail sales, up 1.1%	7.1	0	7.1
Sales decrease from Yale University cogeneration, (0.6)%	(3.6)	0	(3.6)
Price mix of sales and other	2.6	0	2.6
TOTAL RETAIL REVENUE	$ 11.9	$(3.9)	$ 8.0
REVENUE BASED TAXES	$ (0.6)	$ 0.1	$ (0.5)
Fuel and energy, margin effect:			
Sales increase	$ (4.7)	$ 0	$ (4.7)
Nuclear fuel prices and outage replacement power costs	(0.5)	0	(0.5)
Purchased energy prices	(15.5)	0	(15.5)
TOTAL RETAIL FUEL AND ENERGY	$(20.7)	$ 0	$(20.7)
TOTAL RETAIL SALES MARGIN	$ (9.4)	$(3.8)	$(13.2)

Net wholesale margin (wholesale revenue less wholesale expense) decreased by $10.4 million in 1999 compared to 1998, due to lower wholesale sales. Other operating revenues, which include NEPOOL related transmission revenues, increased by $6.4 million. NEPOOL transmission revenues are recoveries, for the most part, of NEPOOL transmission expense and reflect new accounting requirements implemented by the Federal Energy Regulatory Commission.

Operating expenses for operations, maintenance and purchased capacity charges decreased by $5.7 million in 1999 compared to 1998. The principal components of these expense changes include:

(In Millions of Dollars)	
Capacity expense:	
Connecticut Yankee	$(2.4)
Cogeneration and other purchases (see Note A)	1.8
TOTAL CAPACITY EXPENSE	(0.6)
Other O&M expense:	
Seabrook Unit 1 (refueling outage costs and accruals)	4.1
Millstone Unit 3 (refueling outage costs and accruals)	1.1
Other expenses at nuclear units	(0.8)
Fossil generation unit operating and maintenance costs	(23.1)
NEPOOL transmission expense	3.4
Site remediation costs (see Note B)	7.8
Other miscellaneous, including impact of generation asset sale	2.4
TOTAL O&M EXPENSE	$(5.1)

Note (A): A cogeneration facility was out of service for about a month in the first quarter of 1998 but operated normally in 1999.

Note (B): These costs were incurred to repair a riparian bulkhead in New Haven and for remediation of environmental conditions at another site. No further material expenses are currently anticipated for remediation of these sites.

Depreciation expense decreased by $12.4 million in 1999 compared to 1998, due primarily to the generation asset sale.

Results of Operations (continued)

On December 31, 1996, the Connecticut Department of Public Utility Control issued an order that implemented a five-year Rate Plan to reduce UI's retail prices and accelerate the recovery of certain "regulatory assets." According to the Rate Plan, under which UI is currently operating, "accelerated" amortization of past utility investments is scheduled for every year that the Rate Plan is in effect, contingent upon UI earning a 10.5% return on utility common stock equity. All of the scheduled accelerated amortization for 1998, amounting to $13.1 million before-tax ($8.5 million after-tax), was recorded against earnings from operations in 1998. UI recorded all of the scheduled accelerated amortization for 1999 by amortizing regulatory income tax assets, totaling $12.1 million after-tax ($20 million pre-tax equivalent).

UI can also incur additional accelerated amortization expense as a result of the "sharing" mechanism in the Rate Plan, if UI achieves a return on utility common stock equity above 11.5%, which UI did achieve during the third quarter of 1999. One-time items recorded against the return on utility common stock equity, before UI achieves the 11.5%, are recorded with an appropriate "sharing" effect if UI projects, at that time, that there will be total "sharing" for the year adequate to cover the "sharing" for the one-time item. Such "sharing" amortization was recorded in the first quarter of 1999, in the amount of $1.0 million before-tax ($0.6 million after-tax), as a result of the one-time gain recorded in that quarter. "Sharing" amortization from operations of $10.0 million after-tax ($16.7 million before-tax) was recorded in 1999. "Sharing" amortizations recorded and imputed in the first nine months of 1998 were: $0.5 million before-tax ($0.3 million after-tax) as a result of a one-time item, and $2.1 million before-tax ($1.2 million after-tax) from operations. "Sharing" amortization recorded against earnings from operations in the fourth quarter of 1998 was imputed to be $0.6 million before-tax ($0.3 million after-tax). All of those 1998 "sharing" amortizations were reversed in the fourth quarter of 1998 as a result of the impact of a one-time charge recorded in that quarter.

Interest charges continued on a downward trend, decreasing by $12.8 million for the regulated business in 1999 compared to 1998, partly offset by an increase of $3.5 million in interest charges for non-regulated subsidiaries. Most of the reduction in utility interest charges occurred after the generation asset sale, which was completed on April 16, 1999. On that date, UI used proceeds received from the sale of plant to pay off $205 million of debt.

URI RESULTS OF OPERATIONS: 1999 vs. 1998

	Year Ended Dec. 31, 1999 (000's)	Year Ended Dec. 31, 1998 (000's)	1999 more (less) than 1998 Amount
TOTAL OPERATING REVENUE	$71,105	$61,861	$ 9,244
TOTAL EARNINGS FOR COMMON STOCK	$(2,256)	$ (1,101)	$(1,155)
EPS FROM OPERATIONS (BASIC AND DILUTED)			
Operating Businesses			
American Payment Systems, Inc.	$ 0.11	$ 0.07	$ 0.04
Xcelecom, Inc.	$ (0.21)	$ (0.10)	$ (0.11)
SUBTOTAL	$ (0.10)	$ (0.03)	$ (0.07)
Passive Investments			
United Bridgeport Energy, Inc.	$ (0.01)	N/A	$ (0.01)
United Capital Investments, Inc.	$ (0.03)	$ (0.05)	$ 0.02
SUBTOTAL	$ (0.04)	$ (0.05)	$ 0.01
URI Headquarters (Note A)	$ (0.02)	N/A	$ (0.02)
TOTAL NON-REGULATED EPS FROM OPERATIONS	$ (0.16)	$ (0.08)	$ (0.08)

Note (A): Includes financial leveraging, strategic and administrative costs for the holding company of the non-regulated business units.

Overall, non-regulated businesses, after parent-allocated interest but before income taxes, lost approximately $3.8 million in 1999 compared to losses of about $1.8 million in 1998. American Payment Systems, Inc. (APS) earned approximately $2.6 million (before-tax) in 1999, reflecting an increase of $1.0 million over 1998. Xcelecom, Inc. lost approximately $5.1 million (before-tax) in 1999, compared to a loss of approximately $2.4 million in 1998, reflecting increased infrastructure costs and lower than anticipated contract margins.

On May 11, 1999, United Bridgeport Energy, Inc. (UBE), increased its 4% passive investment in Bridgeport Energy LLC (BE) to 33 1/3%. The second phase of BE's merchant wholesale electric generating project went into commercial operation in July 1999, adding 180 megawatts of generation capacity for a total of 520 megawatts. UBE lost approximately $0.1 million (before-tax) in 1999, as a result of the second quarter shutdown of the first phase generator to allow for construction of the second phase, and additional unscheduled outages and higher gas prices in the fourth quarter of 1999. Other non-regulated subsidiary operations lost approximately $1.2 million in 1999, compared to a similar loss in 1998.

(In Millions of Dollars)	12 mos.ended Dec. 99	12 mos. 99 vs. 98
Summary of Non-regulated Business Unit Pre-tax Income:		
American Payment Systems, Inc.	$ 2.6	$ 1.0
Xcelecom, Inc. (Precision Power, Inc.)	(5.1)	(2.7)
United Bridgeport Energy, Inc.	(0.1)	(0.1)
United Resources, Inc. Capital Projects	(1.2)	–
TOTAL NON-REGULATED BUSINESSES	$(3.8)	$(1.8)

Looking Forward

Certain statements contained herein, regarding matters that are not historical facts, are forward-looking statements (as defined in the Private Securities Litigation Reform Act of 1995). Such forward-looking statements include risks and uncertainties; consequently, actual results may differ materially from those expressed or implied thereby, due to important factors including, but not limited to, general economic conditions, legislative and regulatory changes, demand for electricity and other products and services, changes in accounting principles, policies or guidelines, and other economic, competitive, governmental, and technological factors affecting the operations, markets, products, services and prices of the subsidiaries. Forward-looking statements included herein speak only as of the date hereof and UIL Holdings undertakes no obligation to revise or update such statements to reflect events or circumstances after the date hereof or to reflect the occurrence of unanticipated events or circumstances.

A LOOK AT 2001 UIL Holdings expects that its 2001 earnings will be $4.40-$4.50 per share. This range reflects compound annual growth of about 11% from earnings from operations of $2.93 per share in 1997. The primary reasons for the projected increase in the earnings are: management's commitment to reducing costs while sales increase at its regulated electric utility subsidiary, and its confidence in the ability of its non-regulated subsidiary businesses to execute the strategic growth plans of the various businesses. Further details are explained below.

THE UNITED ILLUMINATING COMPANY (UI)

FIVE-YEAR RATE PLAN On December 31, 1996, the Connecticut Department of Public Utility Control (DPUC) issued an order (the Order) that implemented a five-year regulatory framework (Rate Plan) to reduce UI's regulated retail prices and accelerate the recovery of certain "regulatory assets," beginning with deferred conservation costs. UI has operated under the terms of this Order since January 1, 1997. The Order's schedule of price reductions and accelerated amortizations was based on a DPUC pro-forma financial analysis that

Looking Forward (continued)

anticipated UI would be able to implement such changes and earn an allowed annual return on common equity invested in regulated utility assets of 11.5% over the period 1997 through 2001. The Order established a set formula to share any regulated utility income that would produce a return above the 11.5% level: one-third to be applied to customer price reductions, one-third to be applied to additional amortization of regulatory assets, and one-third to be retained by shareowners (see "Sharing Implementation" below). Regulated utility income for this purpose is inclusive of earnings from operations and one-time items.

SHARING IMPLEMENTATION "Sharing" in 2001 will result only if UI's regulated operating Distribution Division exceeds its allowed return of 11.5% on its portion of regulated utility common equity. Earnings subject to sharing does not include the Competitive Transition Assessment (CTA) and other unbundled utility components. UI is allowed to earn an 11.5% return, no more and no less, on the equity portion of the CTA rate base that includes all stranded assets. The CTA return, therefore, is not subject to "sharing." Distribution Division earnings will not likely exceed the sharing level before the third quarter of 2001. Assuming the sharing level of earnings is exceeded in the third quarter of 2001, then earnings in the third quarter that exceed that level and all positive regulated Distribution Division earnings recorded in the fourth quarter of 2001 will be subject to "sharing."

The framework of the current Rate Plan, including the "sharing" mechanism, is expected to continue at least through 2001. Regulatory decisions during 1999 did not alter UI's allowed return of 11.5% on regulated utility equity, and did not impinge on UI's ability to achieve that return.

UI EARNINGS ESTIMATES FOR 2001 If UI were to earn 11.5% on regulated utility equity, excluding the Nuclear Division, that level of earnings would generate $3.25-$3.35 per share for UIL Holdings.

UI is allowed to earn an 11.5% return on the equity portions of CTA and the Systems Benefits Charge (SBC) rate base (the latter is minimal), no more and no less. For the most part, the regulatory assets that are being recovered through the CTA are being amortized on a straight-line basis. If CTA revenues and expenses produce a return more or less than the allowed return, then deferred accounting or accelerated amortization is used to "true-up" to the allowed return. This true-up adjusts for sales volume fluctuations as well as pricing factors. A similar adjustment, on a much less significant scale, applies to the SBC component.

The generation service, conservation and renewables charges are pass-through charges, based on rates that were set for the standard offer period through 2003. In the case of generation service, UI has contracted with Enron Power Marketing, Inc., a subsidiary of Enron Corp., for all of UI's retail customer standard offer service requirements, through 2003, on a fixed-price basis. This agreement protects UIL Holdings' shareowners and UI's retail customers from the type of market and pricing volatility that is being experienced in California, regardless of demand and volume requirements. The only retail electricity sales volume fluctuations that impact UI's net income are those that apply to the operating Distribution Division component of rates. Thus, a 1% sales volume increase will produce additional sales margin of about $2.4 million in 2001. The Distribution Division was impacted negatively in 2000 by a 0.9% sales decrease, due to mild summer weather.

A mandated increase in Distribution Division accelerated amortization expense, the absence of a significant one-time gain that occurred in 2000, and other 2001 cost increases relative to 2000 would, absent management action, likely prevent Distribution Division earnings from exceeding the 11.5% allowed return level in 2001. However, UI has a major process reengineering effort underway, and expects that effort to produce enough savings in 2001 for it to retain as much as an additional $0.05 per share after sharing.

The Nuclear Division contributed $0.45 per share to UIL Holdings' results for 2000. The scheduled four-week refueling outage for the Seabrook nuclear generating unit that began on October 21, 2000 was extended,

adding six weeks of unscheduled outage in 2000 and an additional four and one-half weeks in 2001. The total negative impact of the refueling outage and the six-week outage extension on the 2000 earnings contribution of the Nuclear Division to UIL Holdings was approximately $0.33 per share. The remaining four and one-half weeks of outage in 2001 should have an impact on 2001 earnings similar to the impact the regularly scheduled 2000 four-week outage had on 2000 earnings. Assuming Seabrook operates normally for the remainder of 2001, the contribution to earnings in 2001 of the Seabrook unit should be about the same as the 2000 earnings. It is possible for earnings to improve slightly from that level if the unit operates at near full capacity as it did in 2000 before the refueling outage began.

UIL Holdings currently expects to complete the sale of its Millstone Unit 3 nuclear generating unit entitlement on or about April 1, 2001. The impact of the sale and a refueling outage scheduled for the first quarter on the earnings of the Nuclear Division in the first quarter of 2001 is expected to be negligible. That unit's impact on 2000 earnings for the Nuclear Division was also immaterial. An estimated impact of the Millstone sale on the CTA is incorporated in UI's earnings projections for 2001.

Overall, UI, including the Nuclear Division, is expected to contribute $3.75-$3.85 to UIL Holdings' earnings per share in 2001.

URI EARNINGS ESTIMATES UIL Holdings' non-regulated businesses, under the parent URI, are expected to earn $0.60-$0.70 per share in 2001.

APS is expected to contribute only about $0.00-$0.05 per share to UIL Holdings in 2001, although its base business is expected to contribute about 15% more than the $0.15 per share earned in 2000. The expected reduction in earnings from the base business reflects anticipated strategic expenses designed to produce future earnings enhancements in the non-contracted payment segment of its business. Management's experience with Xcelecom indicates that incurring short-term strategic expenses to build an appropriate management team and processes that are necessary to grow through acquisitions and product and service enhancements will increase shareowner value in the longer term. Management believes that experience will be equally applicable to APS.

Earnings for Xcelecom increased from a loss of $0.21 per share in 1999 to positive earnings of $0.15 per share in 2000. The acquisitions completed in 2000 and continuing cost control measures are the reasons for the increase. This strategy is expected to produce further earnings increases in 2001, based on a full year's impact of the 2000 acquisitions, and earnings could further improve through additional acquisitions in 2001. Based on past performance and the assumed accomplishment of a portion of its 2001 acquisition plan, Xcelecom is expected to contribute $0.55-$0.60 per share in 2001.

Earnings from URI's passive investments offset by headquarters' costs are expected to contribute $0.00-$0.05 per share in 2001. These investments include United Bridgeport Energy, Inc. (UBE), which is expected to contribute about $0.20 per share in 2001. UBE's expected contribution assumes the favorable outcome of an important pending matter that management is confident will come about, although there can be no assurance that it will occur. The assumption is the anticipated recording of UBE's portion of ICAP revenues in 2001, producing about $0.25 per share for UBE. The Federal Energy Regulatory Commission (FERC), in a ruling in 2000, affirmed the value of the ICAP market in New England, thereby validating a pre-existing contract of Bridgeport Energy for ICAP revenues. However, the FERC ICAP order is the subject of appeal to the FERC by some other entities, and, as a result, the FERC has temporarily stayed its order pending a hearing. DETM may be able to book some ICAP revenues, in spite of the stay, if, as anticipated, the customer continues to pay for its contracted ICAP.

Looking Forward (continued)

As stated previously, as a result of management's continued confidence in the potential of the non-regulated businesses, UIL Holdings is evaluating further investments in this area. Near-term losses could be incurred due to these new growth initiatives, if the potential for future earnings is deemed to warrant such losses.

QUARTERLY EARNINGS PATTERN FOR 2001 The 2001 quarterly earnings pattern for UI is expected to be different than the 2000 pattern. Nuclear Division outages in the first quarter of 2001 will reduce earnings compared to the first quarter of 2000. Higher mandated amortization expense for the Distribution Division will be spread evenly throughout the year, which will further reduce earnings relative to 2000 in the first two quarters of 2001. Since UI is not projecting any significant "sharing" in 2001 at this time, the third and fourth quarters of 2001 should show an improvement compared to the corresponding quarters in 2000. UIL Holdings makes every effort to incorporate such impacts, including the sharing impact, in its earnings estimates as each quarter is reported.

Actual 2001 results may vary depending on changes due to weather, economic conditions, sales mix (the usage pattern of the Distribution Division's retail customers), the ability to control expenses, and other unanticipated events. These factors can change from quarter to quarter.

UIL Holdings' current overall estimate of earnings per share from operations for 2001 is $4.40-$4.50 and the estimates of quarterly results are as follows:

Earnings per share from operations:

Quarter	Estimated 2001 Range*	Actual 2000
1	$0.65 – $0.70	$1.20
2	$1.00 – $1.05	1.41
3	$1.65 – $1.70	1.19
4	$1.05 – $1.10	0.46
		$4.26

*Quarterly range estimates are not additive, that is, adding the low range numbers produces a result that is lower than UIL Holdings' low estimate for the year, and adding the high range numbers produces a result that is higher than UIL Holdings' high estimate for the year. The sums of the low and high range values should not be construed to represent any estimate other than UIL Holdings' annual estimate of $4.40-$4.50 per share. The quarterly range estimates do not add to the total UIL Holdings' range for the year because impacts in one quarter can affect the results of other quarters through the sharing mechanism and through timing of activities.

Report of Independent Accountants

To the Board of Directors and the Shareholders of UIL Holdings Corporation

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, of changes in shareholders' equity and of cash flows present fairly, in all material respects, the financial position of UIL Holdings Corporation and its subsidiaries (the"Company") at December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP

January 22, 2001
New York, NY

Consolidated Statement of Income

For the Years Ended December 31, 2000, 1999 & 1998

(Thousands except per share amounts)	2000	1999	1998
OPERATING REVENUES (NOTE G)			
Utility	$704,691	$679,975	$686,191
Non-regulated businesses	176,164	70,755	61,900
Total Operating Revenues	880,855	750,730	748,091
OPERATING EXPENSES			
Operation			
Fuel and energy	282,153	159,403	151,544
Capacity purchased	4,682	33,873	34,515
Other operation and maintenance	305,316	241,236	237,235
Non-regulated – selling, general and administrative	25,989	15,049	10,401
Depreciation and amortization (Note G)	69,713	97,434	100,619
Taxes – other than income taxes (Note G)	43,056	47,140	64,674
TOTAL	730,909	594,135	598,988
OPERATING INCOME	149,946	156,595	149,103
OTHER INCOME AND (DEDUCTIONS) (NOTE G)	3,339	4,921	2,396
INCOME BEFORE INTEREST CHARGES AND INCOME TAXES	153,285	161,516	151,499
INTEREST CHARGES			
Interest on long-term debt	38,199	42,104	50,129
Interest on Seabrook obligation bonds owned by UI	(6,470)	(6,844)	(7,293)
Dividend requirement of mandatorily redeemable securities	3,529	4,813	4,813
Other interest (Note G)	5,253	4,927	6,496
	40,511	45,000	54,145
Amortization of debt expense and redemption premiums	3,988	2,392	2,511
Net Interest Charges	44,499	47,392	56,656
INCOME BEFORE INCOME TAXES	108,786	114,124	94,843
INCOME TAXES (NOTE F)	48,029	61,900	49,771
NET INCOME	60,757	52,224	45,072
Premium (Discount) on preferred stock redemptions	–	53	(21)
Dividends on preferred stock	–	66	201
INCOME APPLICABLE TO COMMON STOCK	$ 60,757	$ 52,105	$ 44,892
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING – BASIC	14,073	14,052	14,018
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING – DILUTED	14,098	14,055	14,023
EARNINGS PER SHARE OF COMMON STOCK – BASIC	$ 4.32	$ 3.71	$ 3.20
EARNINGS PER SHARE OF COMMON STOCK – DILUTED	$ 4.31	$ 3.71	$ 3.20
CASH DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$ 2.88	$ 2.88	$ 2.88

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

Consolidated Statement of Cash Flows

UIL Holdings Corporation

For the Years Ended December 31, 2000, 1999 & 1998

(Thousands of Dollars)	2000	1999	1998
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$60,757	$ 52,224	$45,072
Adjustments to reconcile net income			
to net cash provided by operating activities:			
Depreciation and amortization	66,068	83,374	88,099
Deferred income taxes	10,435	17,451	3,074
Deferred income taxes-generation asset sale	–	(70,222)	–
Deferred investment tax credits – net	(735)	(467)	(762)
Amortization of nuclear fuel	6,521	8,425	6,892
Allowance for funds used during construction	(2,609)	(2,235)	(468)
CTA and SBC expense deferral	(23,098)	–	–
Amortization of deferred return	–	12,586	12,586
Changes in:			
Accounts receivable – net	(49,693)	8,749	(14,889)
Fuel, materials and supplies	(457)	(1,202)	(14,466)
Prepayments	181	4,368	(4,027)
Accounts payable	34,143	2,025	(9,782)
Interest accrued	95	(1,770)	(63)
Taxes accrued	1,275	(6,446)	4,849
Other assets and liabilities	(1,565)	(8,387)	(4,062)
Total Adjustments	40,561	46,249	66,981
NET CASH PROVIDED BY OPERATING ACTIVITIES	101,318	98,473	112,053
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuances of:			
Common stock	517	1,157	4,923
Long-term debt	–	25,000	199,636
Notes payable	93,568	(69,761)	49,141
Securities redeemed and retired:			
Preferred stock	–	(4,299)	(52)
Company-obligated mandatorily redeemable securities of subsidiary holding solely parent debentures	(50,000)	–	–
Long-term debt	(26,609)	(218,008)	(222,348)
(Premium) discount on preferred stock redemptions	–	(53)	21
Expenses of issuances	–	(550)	(1,600)
Lease obligations	(376)	(348)	(339)
Dividends			
Preferred stock	–	(116)	(202)
Common stock	(40,517)	(40,450)	(40,285)
NET CASH USED IN FINANCING ACTIVITIES	(23,417)	(307,428)	(11,105)
CASH FLOWS FROM INVESTING ACTIVITIES			
Acquisition of business, net of cash acquired	(49,371)	–	–
Investment in non-regulated businesses	–	(88,489)	–
Net cash received from sale of generation assets	–	270,590	–
Plant expenditures, including nuclear fuel	(54,191)	(34,772)	(38,040)
Investment in debt securities	4,778	5,447	8,528
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	(98,784)	152,776	(29,512)
CASH AND TEMPORARY CASH INVESTMENTS:			
NET CHANGE FOR THE PERIOD	(20,883)	(56,179)	71,436
BALANCE AT BEGINNING OF PERIOD	68,322	124,501	53,065
BALANCE AT END OF PERIOD	47,439	68,322	124,501
LESS: RESTRICTED CASH	33,202	29,223	26,812
BALANCE: UNRESTRICTED CASH AND TEMPORARY CASH INVESTMENTS	$14,237	$ 39,099	$97,689
CASH PAID DURING THE PERIOD FOR:			
Interest (net of amount capitalized)	$35,252	$ 40,020	$51,481
Income taxes	$36,900	$121,450	$42,450

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

Consolidated Balance Sheet

UIL Holdings Corporation

Assets

December 31, 2000 and 1999

(Thousands of Dollars)	2000	1999
CURRENT ASSETS		
Unrestricted cash and temporary cash investments	$ 14,237	$ 39,099
Restricted cash	33,202	29,223
Accounts receivable, less allowance for doubtful accounts of $ 2,569 and $ 2,308	190,159	109,669
Unbilled revenues	36,694	29,787
Materials and supplies, at average cost	10,938	9,259
Prepayments	2,875	3,056
Other	201	33
TOTAL	288,306	220,126
OTHER PROPERTY AND INVESTMENTS		
Investment in United Bridgeport Energy facility	90,284	83,494
Nuclear decommissioning trust fund assets	32,844	28,255
Other	7,862	11,918
	130,990	123,667
PROPERTY, PLANT AND EQUIPMENT AT ORIGINAL COST		
In service	962,485	1,031,601
Less, accumulated provision for depreciation	466,635	548,765
	495,850	482,836
Construction work in progress	30,267	25,708
Nuclear fuel	24,536	21,101
Net Property, Plant and Equipment	550,653	529,645
REGULATORY ASSETS (future amounts due from customers through the ratemaking process)		
Nuclear plant investments-above market	497,829	518,268
Income taxes due principally to book-tax differences	123,043	166,965
Long-term purchase power contracts-above market	128,328	144,406
Connecticut Yankee	24,272	37,013
Unamortized redemption costs	22,293	22,314
Other	44,628	21,019
TOTAL	840,393	909,985
DEFERRED CHARGES		
Goodwill	51,508	4,827
Unamortized debt issuance expenses	5,477	8,688
Other	1,227	1,272
TOTAL	58,212	14,787
TOTAL ASSETS	$1,868,554	$1,798,210

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

Consolidated Balance Sheet

Liabilities & Capitalization

December 31, 2000 and 1999

(Thousands of Dollars)	2000	1999
CURRENT LIABILITIES		
Notes payable	$ 110,699	$ 17,131
Current portion of long-term debt	–	25,000
Accounts payable	149,146	105,289
Dividends payable	10,135	10,125
Taxes accrued	3,845	2,570
Interest accrued	8,528	8,433
Obligations under capital leases	405	375
Other accrued liabilities	73,762	39,421
TOTAL	356,520	208,344
NONCURRENT LIABILITIES		
Purchase power contract obligation	128,328	144,406
Nuclear decommissioning obligation	32,844	28,255
Connecticut Yankee contract obligation	17,157	27,056
Pensions accrued	1,705	19,026
Obligations under capital leases	15,725	16,131
Other	12,727	12,261
TOTAL	208,486	247,135
DEFERRED INCOME TAXES (future tax liabilities owed to taxing authorities)	252,809	264,223
REGULATORY LIABILITIES (future amounts owed to customers through the ratemaking process)		
Accumulated deferred investment tax credits	14,422	15,157
Deferred gains on sale of property	15,978	15,901
Customer refund	17,976	18,381
Other	1,097	2,543
TOTAL	49,473	51,982
CAPITALIZATION (NOTE B)		
Long-term debt		
Long-term debt	604,856	605,641
Investment in Seabrook obligation bonds	(82,635)	(87,413)
Net long-term debt	522,221	518,228
Company-obligated mandatorily redeemable securities of subsidiary holding solely parent company debentures	–	50,000
Common stock equity		
Common stock (no par value, 14,076,697 and 14,062,502 shares outstanding in 2000 and 1999)	291,342	292,006
Paid-in capital	2,483	2,253
Capital stock expense	(2,170)	(2,170)
Unearned employee stock ownership plan equity	(8,310)	(9,261)
Retained earnings	195,700	175,470
	479,045	458,298
TOTAL CAPITALIZATION	1,001,266	1,026,526
COMMITMENTS AND CONTINGENCIES (NOTE L)	–	–
TOTAL LIABILITIES AND CAPITALIZATION	$1,868,554	$1,798,210

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

Consolidated Statement of Changes in Shareholders' Equity

UIL Holdings Corporation

December 31, 2000, 1999 & 1998 (Dollar amounts in Thousands)	Common Stock Shares[a]	Common Stock Amount	Preferred Stock Shares[b]	Preferred Stock Amount	Paid-in Capital	Capital Stock Expense	Unearned ESOP Equity	Retained Earnings	Total
Balance as of December 31, 1997	13,907,824	$288,730	43,509	$4,351	$1,349	($2,182)	($11,160)	$159,344	$440,432
Net income for 1998								45,072	45,072
Cash dividends on common stock – $2.88 per share								(40,389)	(40,389)
Cash dividends on preferred stock								(201)	(201)
Issuance of 98,798 shares common stock – no par value	98,798	3,276			459				3,735
Allocation of benefits – ESOP	27,940				238		950		1,188
Repurchase and cancellation of preferred stock			(524)	(52)					(52)
Discount on preferred stock repurchase								21	21
Balance as of December 31, 1998	14,034,562	292,006	42,985	4,299	2,046	(2,182)	(10,210)	163,847	449,806
Net income for 1999								52,224	52,224
Cash dividends on common stock – $2.88 per share								(40,470)	(40,470)
Cash dividends on preferred stock								(66)	(66)
Allocation of benefits – ESOP	27,940				207		949		1,156
Repurchase and cancellation of preferred stock			(42,985)	(4,299)		12		(12)	(4,299)
Premium on preferred stock repurchase								(53)	(53)
Balance as of December 31, 1999	14,062,502	292,006	0	0	2,253	(2,170)	(9,261)	175,470	458,298
Net income for 2000								60,757	60,757
Cash dividends on common stock – $2.88 per share								(40,527)	(40,527)
Issuance of 4,616 shares common stock – no par value	4,616	163			32				195
Retirement of 18,361 shares common stock – no par value	(18,361)	(827)							(827)
Allocation of benefits – ESOP	27,940				198		951		1,149
Balance as of December 31, 2000	14,076,697	$291,342	0	$0	$2,483	($2,170)	($8,310)	$195,700	$479,045

(a) There were 30,000,000 shares authorized in 2000, 1999 and 1998

(b) There were 5,000,000 shares authorized in 2000 and 1,119,612 shares authorized in 1999 and 1998

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

UIL Holdings Corporation (UIL Holdings) is the parent holding company for The United Illuminating Company (UI) and United Resources, Inc (URI) and is not itself an operating company. This holding company structure became effective on July 20, 2000 as a result of the corporate restructuring of UI and its direct and indirect non-regulated subsidiaries. All of UI's interests in all of its direct and indirect non-regulated subsidiaries have been transferred to UIL Holdings and, to the extent new businesses are subsequently acquired or commenced, UIL Holdings expects they will be financed and owned by UIL Holdings. UIL Holdings is an exempt public utility holding company under the provisions of the Public Utility Holding Company Act of 1935.

UI is a regulated operating electric public utility established in 1899. It is engaged principally in the purchase, transmission, distribution and sale of electricity for residential, commercial and industrial purposes in a service area of about 335 square miles in the southwestern part of the State of Connecticut. The population of this area is approximately 704,000, which represents approximately 21% of the population of the State. The service area, largely urban and suburban in character, includes the principal cities of Bridgeport (population approximately 137,000) and New Haven (population approximately 124,000) and their surrounding areas. Situated in the service area are retail trade and service centers, as well as large and small industries producing a wide variety of products, including helicopters and other transportation equipment, electrical equipment, chemicals and pharmaceuticals. Of UI's 2000 retail electric revenues, approximately 42% were derived from residential sales, 40% from commercial sales, 16% from industrial sales and 2% from other sales.

URI serves as the parent company for UIL Holdings' four non-regulated businesses, each of which is wholly owned. American Payment Systems, Inc. (APS) manages a national network of agents for the processing of bill payments made by customers of UI and other companies. APS is one of the largest vendors in the nation for walk-in payment of utility bills and already services approximately 25% of the market. Xcelecom, Inc. (formerly known as Precision Power, Inc.) and its subsidiaries provide specialty electrical and voice-data-video integrated solutions in regional markets of the Northeastern United States. A third subsidiary, United Capital Investments, Inc., and its subsidiaries invest in business ventures that are expected to earn above-average returns. URI's fourth subsidiary, United Bridgeport Energy, Inc., owns, as a passive investor, 33 1/3 % of a merchant wholesale electric generating facility that is co-owned and operated by a unit of Duke Energy and is located in Bridgeport, Connecticut.

The consolidated financial statements of UIL Holdings and its wholly-owned direct subsidiaries, UI and URI, have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). UIL Holdings' Consolidated Financial Statements include the accounts of UIL Holdings and its wholly-owned subsidiaries, UI and URI. UIL Holdings' prior period consolidated financial statements have been prepared from UI's prior period consolidated financial statements, except that amounts have been reclassified to reflect UIL Holdings' structure.

(A) Statement of Accounting Policies

ACCOUNTING RECORDS The accounting records for UI are maintained in accordance with the uniform systems of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and the Connecticut Department of Public Utility Control (DPUC).

The accounting records of UIL Holdings' non-regulated subsidiaries are maintained in conformity with generally accepted accounting principles.

PRESENTATION The consolidated financial statements include the accounts of UIL Holdings and its wholly-owned subsidiaries, UI and URI. Intercompany accounts and transactions have been eliminated in consolidation.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to use estimates and assumptions that affect the reported

(A) Statement of Accounting Policies (continued)

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. Actual results could differ from those estimates.

Certain amounts previously reported have been reclassified to conform with current year presentation.

REGULATORY ACCOUNTING Generally accepted accounting principles for regulated entities in the United States of America allow UI to give accounting recognition to the actions of regulatory authorities in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." In accordance with SFAS No. 71, UI has deferred recognition of costs (a regulatory asset) or has recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations relieved in the future through the ratemaking process. In addition to the Regulatory Assets and Liabilities separately identified on the Consolidated Balance Sheet, there are other regulatory assets and liabilities such as conservation and load management costs and certain deferred tax liabilities. UI also has obligations under long-term power contracts, the recovery of which is subject to regulation. If UI, 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 are not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71.

The Restructuring Act enacted in Connecticut in 1998 provides for UI to recover previously deferred costs through ongoing assessments to be included in future regulated service rates. See Note (C), "Rate-Related Regulatory Proceedings" for a discussion of the nature, amount and timing of recovery of UI's stranded costs associated with the generation portion of its assets and operations, as well as a discussion of the regulatory decisions that provide for such recovery. Based on these regulatory decisions, the sale of UI's fossil-generation assets and the planned divestiture of its nuclear generation ownership interests by the end of 2003, on December 31, 1999 UI discontinued applying SFAS No. 71 to the generation portion of its assets and operations. However, based on the recovery mechanism that allows recovery of all of its stranded costs through its standard offer rates, UI was not required to take any write-offs in connection with this event. UI expects to continue to meet the criteria for application of SFAS No. 71 for the remaining portion of its assets and operations for the foreseeable future. If a change in accounting were to occur to the non-generation portion of UI's operations, it could have a material adverse effect on UI's earnings and retained earnings in that year and could have a material adverse effect on UI's ongoing financial condition as well.

PROPERTY, PLANT AND EQUIPMENT The cost of additions to property, plant and equipment and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC) in the case of utility plant. The cost of current repairs and minor replacements is charged to appropriate operating expense accounts. The original cost of property, plant and equipment retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation.

UIL Holdings' property, plant and equipment as of December 31, 2000 and 1999 was comprised as follows:

(In Thousands)	2000	1999
Utility:		
Nuclear Production	$269,750	$ 271,012
Transmission	152,218	148,419
Distribution	430,620	415,892
General	44,246	46,578
Future use plant	642	30,167
Other	28,499	94,997
Subtotal	925,975	1,007,065
Non-regulated business units	36,510	24,536
	$962,485	$1,031,601

See Note (C), "Rate-related Regulatory Proceedings" for a discussion of the sale by the Company of its two operating fossil-fueled generating stations and the regulatory decisions allowing for recovery of stranded costs, including the above-market investment in nuclear generating units.

DEPRECIATION Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis, using estimated service lives determined by independent engineers. One-half year's depreciation is taken in the year of addition and disposition of utility plant, except in the case of major operating units on which depreciation commences in the month they are placed in service and ceases in the month they are removed from service. The aggregate annual provisions for depreciation for the years 2000, 1999 and 1998 were approximately 3.05%, 3.29% and 3.45%, respectively, of the original cost of depreciable property.

INCOME TAXES In accordance with Statement of Financial Accounting Standards (SFAS) No. 109, "Accounting for Income Taxes," UIL Holdings has provided deferred taxes for all temporary book-tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted future tax rates that are anticipated to be in effect when the temporary differences reverse. In accordance with generally accepted accounting principles for regulated industries, UI has established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences.

For ratemaking purposes, UI normalizes all investment tax credits (ITC) related to recoverable plant investments except for the ITC related to Seabrook Unit 1, which was taken into income in accordance with provisions of a 1990 DPUC retail rate decision.

REVENUES Regulated utility revenues for UI are based on authorized rates applied to each customer's use of electricity. These rates are approved by the DPUC and can be changed only through formal proceedings. At the end of each accounting period, the estimated amount of revenues (less related expenses and applicable taxes) for services rendered but not billed is accrued.

Revenues from construction contracts entered into by Xcelecom, Inc., a wholly-owned subsidiary of URI, are recognized on a percentage-of-completion method. Under this method, revenue is recognized based on the percentage of costs incurred and accrued to date to the estimated total cost to complete these contracts.

CASH AND TEMPORARY CASH INVESTMENTS For cash flow purposes, UIL Holdings considers all highly liquid debt instruments with a maturity of three months or less at the date of purchase to be cash and temporary cash investments.

(A) Statement of Accounting Policies (continued)

NEW ACCOUNTING STANDARDS The Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." This statement, which will become effective for UIL Holdings in the first quarter of 2001, establishes accounting and reporting standards for derivative instruments and for hedging activities. It requires entities to recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. The accounting for the changes in the fair value of a derivative (gains and losses) would depend on the intended use and designation of the derivative. UI has a contract with a power marketer that includes a financially settled contract for differences related to certain call rights of the power marketer and put rights of UI with respect to UI's entitlements in Seabrook Unit 1 and Millstone Unit 3. This contract will terminate at the earlier of December 31, 2003 or the date that UI sells its interest in these units. Application of the new accounting standard will require the recognition of UI's future obligation for financial settlements under this contract. As of December 31, 2000, UI's estimated future obligation for financial settlements under this contract is approximately $18 million. This future obligation has been estimated using assumptions regarding the future market price for power, the operations of the units, and the projected future sale dates for UI's interest in these units. If actual market prices, the operations of the units, and the actual dates of sale differ significantly from these assumptions, the actual amount paid for financial settlement of this contract will vary significantly from this estimate. However, since the costs of this contract are considered in the annual reconciliation of the Competitive Transition Assessment, there is currently no income statement effect. The adoption of this accounting statement will not have any impact on UIL Holdings' results of operations and is not expected to have a material impact on UIL Holdings' financial condition.

(B) Capitalization

UIL Holdings had 14,321,177 shares of its common stock, no par value, outstanding at December 31, 2000 and 14,334,922 shares of its common stock, no par value, outstanding at December 31, 1999, of which 244,480 shares and 272,420 shares were unallocated shares held by UI's 401(k)/Employee Stock Ownership Plan (KSOP) and not recognized as outstanding for accounting purposes as of December 31, 2000 and 1999, respectively.

UI has entered into an arrangement under which it loaned $11.5 million to the KSOP. The trustee for the KSOP used the funds to purchase shares of UI common stock in open market transactions. On July 20, 2000, effective with the formation of the holding company structure, unallocated shares held by the KSOP were converted into shares of UIL Holdings' common stock. The shares will be allocated to employees' KSOP accounts, as the loan is repaid, to cover a portion of the required KSOP contributions. The loan will be repaid by the KSOP over a twelve-year period, using employer contributions and UIL Holdings' dividends paid on the unallocated shares of the stock held by the KSOP. As of December 31, 2000, 244,480 shares, with a fair market value of $12.2 million, had been purchased by the KSOP and had not been committed to be released or allocated to KSOP participants.

In 1990, UI's Board of Directors and the shareowners approved a stock option plan for officers and key employees of UI. Effective with the formation of the holding company structure on July 20, 2000, all outstanding options were converted into options to purchase an equivalent number of shares of UIL Holdings' common stock. Options to purchase 3,500 shares of stock at an exercise price of $30 per share, 7,800 shares of stock at an exercise price of $39.5625 per share, and 5,000 shares of stock at an exercise price of $42.375 per share have been granted and remained outstanding at December 31, 2000. None of these options were exercised during 2000.

On March 22, 1999, UI's Board of Directors approved a stock option plan for directors, officers and key employees of UI. The plan provides for the awarding of options to purchase up to 650,000 shares of UI's common stock over periods of from one to ten years following the dates when the options are granted. The exercise price of each option cannot be less than the market value of the stock on the date of the grant. On June 28, 1999, UI's shareowners approved the plan. Effective with the formation of the holding company structure on July 20,

2000, all outstanding options were converted into options to purchase an equivalent number of shares of UIL Holdings' common stock. Options to purchase 6,300 shares of stock at an exercise price of $43.50 per share, 121,925 shares of stock at an exercise price of $43.21875 per share, 183,800 shares of stock at an exercise price of $39.40625 per share, 2,170 shares of stock at an exercise price of $53.1250, 382 shares of stock at an exercise price of $52.6875, 1,000 shares of stock at an exercise price of $50.3125, 407 shares of stock at an exercise price of $53.0625 and 446 shares at an exercise price of $48.40625 have been granted and remained outstanding at December 31, 2000. Options to purchase 9,075 shares of stock at an exercise price of $43.21875 were exercised during the twelve months ended December 31, 2000.

Stock option transactions for 2000, 1999 and 1998 are as follows:

	2000		1999		1998	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance – Beginning of Year	16,300	$38.37	16,300	$38.37	115,098	$33.90
Granted	334,605	$41.15	–	–	–	–
Forfeited	(9,100)	$40.59	–	–	–	–
Exercised	(9,075)	$43.22	–	–	(98,798)	$33.16
Balance – End of Year	332,730	$41.00	16,300	$38.37	16,300	$38.37
Exercisable at End of Year	58,730	$41.58	16,300	$38.37	16,300	$38.37

If compensation expense had been recorded for the stock option plan based on the fair value method as opposed to the intrinsic value method applied by UIL Holdings, net income and earnings per share for 2000 would have been as follows:

	2000
Net income	
As reported	$60,757
Pro forma	$60,490
Earnings per share-Basic	
As reported	$ 4.32
Pro forma	$ 4.30
Earnings per share-Diluted	
As reported	$ 4.31
Pro forma	$ 4.29

The fair value of stock options granted has been estimated on the date of grant using the Black-Scholes option-pricing model using the following assumptions:

	2000
Risk-free interest rate	5.08%
Expected volatility	16.51%
Expected lives	9.09 years
Expected dividend yield	6.13%

The weighted average fair value of options granted during 2000 was $3.16. As of December 31, 2000, the weighted average remaining contractual life for those options outstanding is 8.4 years.

On February 23, 1998, UI's Board of Directors granted 80,000 "phantom" stock options to Nathaniel D. Woodson upon his appointment as President of UI. Effective with the formation of the holding company structure on July 20, 2000, all outstanding phantom stock options were converted to UIL Holdings' phantom stock options. On each of the first five anniversaries of the grant date, 16,000 phantom stock options become exercisable and can be exercised at any time within Mr. Woodson's period of employment with UI by means of UI

(B) Capitalization (continued)

paying him the difference between the prevailing market price for each share of UIL Holdings' common stock and the phantom stock option price of $45.16 per share. At ten years after the grant date any unexercised phantom stock options will expire. At December 31, 2000, 32,000 phantom stock options were exercisable. During 2000, $282,000 was recognized as expense with regard to these phantom stock options.

RETAINED EARNINGS RESTRICTION The indenture under which UI has issued $200 million principal amount of Notes places limitations on UI relative to the payment of cash dividends on its common stock, which is wholly-owned by UIL Holdings, and the purchase or redemption of said common stock. Retained earnings in the amount of $117.9 million were free from such limitations at December 31, 2000.

COMPANY-OBLIGATED MANDATORILY REDEEMABLE SECURITIES OF SUBSIDIARY HOLDING SOLELY PARENT DEBENTURES

On September 25, 2000, UI redeemed $50 million of 9 5/8% Preferred Capital Securities, Series A, due 2025, at $25.00 per share, plus accrued dividends to the redemption date of $0.160417 per share. These securities were issued in April 1995 by United Capital Funding Partnership L. P., a Delaware limited partnership (United Capital).

United Capital was a special purpose limited partnership in which UI owned all of the general partner interests. Its only asset was $50 million of 9 5/8% Junior Subordinated Deferrable Interest Debentures, Series A, due April 30, 2025, issued by UI in 1995, which were repaid by UI in conjunction with United Capital's redemption of its 9 5/8% Preferred Capital Securities, Series A, due 2025. United Capital was dissolved following its redemption of these securities.

LONG-TERM DEBT

(In Thousands) December 31,	2000	1999
OTHER LONG-TERM DEBT		
Pollution Control Revenue Bonds:		
4.35%, 1996 Series, due June 26, 2026 (1)	$ 7,500	$ 7,500
8%, 1989 Series A, due December 1, 2014	–	25,000
5 7/8%, 1993 Series, due October 1, 2033	64,460	64,460
Pollution Control Refunding Revenue Bonds:		
4.35%, 1997 Series, due July 30, 2027 (2)	27,500	27,500
4.55%, 1997 Series, due July 30, 2027 (1)	71,000	71,000
5.40%, 1999 Series, due December 1, 2029 (3)	25,000	25,000
Notes:		
6.25%, 1998 Series I, due December 15, 2002	100,000	100,000
6.00%, 1998 Series J, due December 15, 2003	100,000	100,000
Obligation under the Seabrook Unit 1 sale/leaseback agreement	209,565	210,424
	605,025	630,884
Unamortized debt discount less premium	(169)	(243)
	604,856	630,641
Less:		
Current portion included in Current Liabilities	–	25,000
Investment-Seabrook Lease Obligation Bonds	82,635	87,413
Total Long-Term Debt	$522,221	$518,228

(1) The interest rate for these Bonds was fixed on February 1, 1999 for the five-year period ending January 31, 2004. Prior to February 1, 1999, the interest rate was variable.

(2) The interest rate for these Bonds was fixed on February 1, 1999 for the three-year period ending January 31, 2002. Prior to February 1, 1999, the interest rate was variable.

(3) The interest rate for these Bonds was fixed on December 16, 1999 for the three-year period ending December 1, 2002.

On February 15, 2001, UIL Holdings issued and sold $75,000,000 of Senior Notes to several institutional investors in a private sale. The issue was composed of two series: 7.23% Senior Notes, Series A, due February 15, 2011, in the principal amount of $30,000,000, and 7.38% Senior Notes, Series B, due February 15, 2011, in the principal amount of $45,000,000. Under the Senior Notes, Series A, UIL Holdings is required to prepay the principal amount of $4,285,714 each February 15th, beginning on February 15, 2005 and ending on February 15, 2010. Interest due under the Senior Notes is payable semi-annually on February 15th and August 15th. The net proceeds of the sale were used to repay short-term debt of UIL Holdings.

The expenses to issue long-term debt are deferred and amortized over the life of the respective debt issue.

Maturities and mandatory redemptions/repayments are set forth below:

(In Thousands)	2001	2002	2003	2004	2005
Maturities	$ –	$100,000	$100,000	$ –	$4,286

(C) Rate-Related Regulatory Proceedings

On December 31, 1996, the Connecticut Department of Public Utility Control (DPUC) completed a financial and operational review of UI and ordered a five-year incentive regulation plan for the years 1997 through 2001 (the Rate Plan). The Rate Plan accelerates the amortization and recovery of unspecified assets during 1999-2001 if UI's common equity return on regulated utility investment exceeds 10.5% after recording the amortization. UI's authorized return on regulated utility common equity during the period is 11.5%. Earnings above 11.5%, on an annual basis, are utilized one-third for customer price reductions, one-third to increase amortization of assets, and one-third retained as earnings.

The Rate Plan included a provision that it could be reopened and modified upon the enactment of electric utility restructuring legislation in Connecticut. On October 1, 1999, the DPUC issued a decision establishing UI's standard offer customer rates, commencing January 1, 2000, at a level 10% below 1996 rates, as directed by the Restructuring Act described in detail below. These standard offer customer rates supersede the rates that were included in the Rate Plan. The decision also reduced the required amount of accelerated amortization in 2000 and 2001. Under this 1999 decision, all other components of the 1996 Rate Plan are expected to remain in effect through 2001. The Connecticut Office of Consumer Counsel (OCC), the statutory representative of consumer interests in public utility matters, appealed the DPUC's standard offer decision to the Connecticut Superior Court, challenging the DPUC's determination of UI's average prices in 1996 rates from which a 10% reduction is required by the Restructuring Act. On February 22, 2001, the Superior Court dismissed the OCC's appeal from the DPUC's decision; but UI is unable to predict, at this time, whether the OCC will appeal from the Superior Court's decision to the Connecticut Appellate Court.

On February 13, 2001, the Connecticut Attorney General and the OCC petitioned the DPUC to initiate a proceeding and hold a hearing concerning the need to decrease UI's rates by reason of UI' s having earned a return on regulated common equity more than 1% above the authorized level of 11.5% for at least six consecutive months. UI believes that a hearing would confirm that UI has complied with the DPUC-ordered earnings sharing mechanism in UI's rate plan; and it will contest vigorously any arguments for a rate decrease.

In April 1998, Connecticut enacted Public Act 98-28 (the Restructuring Act), a massive and complex statute designed to restructure the State's regulated electric utility industry. As a result of the Restructuring Act, the business of generating and selling electricity directly to consumers has been opened to competition. These business activities are separated from the business of delivering electricity to consumers, also known as the

(C) Rate-Related Regulatory Proceedings (continued)

transmission and distribution business. The business of delivering electricity remains with the incumbent franchised utility companies (including UI) which continue to be regulated by the DPUC as Distribution Companies. Since mid-1999, Distribution Companies have been required to separate on consumers' bills the electricity generation services component from the charge for delivering the electricity and all other charges.

A major component of the Restructuring Act is the collection, by Distribution Companies, of a "competitive transition assessment," a "systems benefits charge," an "energy conservation and load management program charge" and a "renewable energy investment charge." The competitive transition assessment represents costs that have been reasonably incurred by, or will be incurred by, Distribution Companies to meet their public service obligations as electric companies, and that will likely not otherwise be recoverable in a competitive generation and supply market. These costs include above-market long-term purchased power contract obligations, regulatory asset recovery and above-market investments in power plants (so-called stranded costs). The systems benefits charge represents public policy costs, such as generation decommissioning and displaced worker protection costs. Beginning in 2000, a Distribution Company has been required to collect the competitive transition assessment, the systems benefits charge, the energy conservation and load management program charge and the renewable energy investment charge from all Distribution Company customers.

Under the Restructuring Act, all of UI's customers are able to choose their power supply providers. Until January 1, 2004, UI is required to offer full "standard offer" electric service, under regulated rates, to all customers who do not choose alternate power supply providers. The standard offer rates must be at least 10% below the average prices in 1996. The standard offer rates must include the price of generation, transmission and distribution services, the competitive transition assessment, the systems benefits charge and the conservation and renewable energy charges. Under current regulatory provisions, UI's financial condition is not affected materially by whether customers choose alternate suppliers to UI's standard offer electric service.

On December 28, 1999, UI and Enron Power Marketing, Inc. (EPMI) entered into a Wholesale Power Supply Agreement, a PPA Entitlements Transfer Agreement and related agreements documenting a four-year standard offer power supply arrangement and the assumption of all of UI's long-term purchased power agreements, effective January 1, 2000. Under these agreements, EPMI supplies the generation services needed by UI to meet its standard offer obligations for the four-year standard offer period at a fixed price. The agreements with EPMI also include a financially settled contract for differences related to certain call rights of EPMI and put rights of UI with respect to UI's entitlements in Seabrook Unit 1 and in Millstone Unit 3, and UI's provision to EPMI of certain ancillary products and services associated with those nuclear entitlements, which provisions terminate at the earlier of December 31, 2003 or the date that UI sells its nuclear interests. The agreements do not restrict UI's right to sell to third parties UI's ownership interests in those nuclear generation units or the generated energy actually attributable to its ownership interests.

The Restructuring Act requires that, in order for a Distribution Company to recover any stranded costs associated with its power plants, its fossil-fueled plants must be sold prior to 2000, with any net excess proceeds used to mitigate its recoverable stranded costs, and UI must attempt to divest its ownership interests in its nuclear-fueled power plants prior to 2004.

On April 16, 1999, UI sold both of its operating fossil-fueled generating stations, Bridgeport Harbor Station and New Haven Harbor Station, to Wisvest Corporation, a non-utility subsidiary of Wisconsin Energy Corporation based in Milwaukee, Wisconsin. UI realized a book gain from the sale proceeds net of taxes and plant investment. However, this gain was offset by a writedown of other above-market generation costs, such as regulated plant costs and tax-related regulatory assets or other costs related to the restructuring transition, such that there was no net income effect of the sale. Net cash proceeds from the sale were approximately $165 million.

On August 17, 2000, UI sold English Station (a deactivated non-nuclear generating station, bordering the Mill River in New Haven) to Quinnipiac Energy LLC (QE), a privately-owned independent power producer. QE intends to reactivate the generating units at the station. Under the terms of the transaction, UI has retained a permanent right of occupancy on and over the station property for UI's existing New Haven harbor transmission line towers and cables. QE will complete the bulkhead replacement project that UI has commenced to preserve and protect the station property; and QE will assume responsibility for any and all environmental liability associated with UI's prior ownership and operation of the station. UI has agreed to pay for the cost of completing the bulkhead replacement project and has funded 61% (approximately $1.2 million) of the environmental remediation costs that will be incurred by QE under Connecticut's Transfer Act as a result of QE's acquisition of the station. UI has also paid QE $4.25 million for QE's assumption of the remaining Transfer Act remediation costs and any and all environmental liability associated with UI's prior ownership and operation of the station.

On October 1, 1998, in its "unbundling plan" filing with the DPUC under the Restructuring Act, and in other regulatory dockets, UI stated that it plans to divest its nuclear generation ownership and leasehold interests (17.5% of Seabrook Unit 1 in New Hampshire and 3.685% of Millstone Station Unit 3 in Connecticut) by the end of 2003, in accordance with the Restructuring Act. On April 19, 2000, the DPUC approved UI's plan for divesting its ownership interest in Millstone Unit 3 by participating in an auction process for all three of the generating units at Millstone Station, which was concluded on August 7, 2000, when Dominion Resources, Inc. agreed to purchase Millstone Units 1 and 2, and 93.47% of Millstone Unit 3 for $1.298 billion. The purchase price agreed to for UI's ownership interest in Unit 3, which is subject to adjustments for expenditures and eventualities prior to the date of closing on the sale, is approximately $31 million, exclusive of nuclear fuel. UI's share of the proceeds from the sale of the nuclear fuel inventory at the date of closing on the sale is estimated to be approximately $2.5 million. The sale is scheduled to be consummated on or about April 1, 2001 or as soon thereafter as all requisite regulatory approvals are received. On December 15, 2000, UI and The Connecticut Light and Power Company filed with the DPUC for its approval of their plan to divest their respective interests in Seabrook Unit 1 by an auction process. The DPUC has commenced hearings on this divestiture plan.

The 1999 DPUC decision establishing UI's standard offer rates authorized UI to recover $801 million of stranded costs through its rate structure.

Based on the decisions in the regulatory proceedings described above, the sale of UI's fossil-generation assets and the planned divestiture of its nuclear generation ownership interests by the end of 2003, UI ceased applying SFAS No. 71 to the generation portion of its assets and operations as of December 31, 1999. Based on the favorable DPUC decisions that allow full recovery, through UI's rates, of all historically incurred stranded costs, UI did not record any write-offs in connection with this event.

(D) Accounting for Phase-in Plan

UI phased into rate base its allowable investment in Seabrook Unit 1, amounting to $640 million, during the period January 1, 1990 to January 1, 1994. In conjunction with this phase-in plan, UI was allowed to record a deferred return on the portion of allowable investment excluded from rate base during the phase-in period. UI amortized the net-of-tax accumulated deferred return of $62.9 million over the five-year period that ended on December 31, 1999.

(E) Short-Term Credit Arrangements

On June 26, 2000, UI entered into a Money Market Loan arrangement with Chase Manhattan Bank. On September 29, 2000, this arrangement was transferred to UIL Holdings. This is an uncommitted short-term borrowing arrangement under which Chase Manhattan Bank may make loans to UIL Holdings for fixed maturities from one day up to six months. Chase Securities, Inc. acts as an agent and sells the loans to investors. The fixed interest rates on the loans are determined based on conditions in the financial markets at the time of each loan. As of December 31, 2000, UIL Holdings had loans totaling $59 million outstanding under this arrangement.

(E) Short-Term Credit Arrangements (continued)

UI's $60 million revolving credit agreement with a group of banks was terminated on August 3, 2000. UI had no short-term borrowings outstanding under this facility at that time.

UIL Holdings has a revolving credit agreement with the same group of banks, which extends to August 2, 2001. The borrowing limit of this facility is $97.5 million. The facility permits UIL Holdings to borrow funds at a fluctuating interest rate determined by the prime lending market in New York, and also permits UIL Holdings to borrow money for fixed periods of time specified by UIL Holdings at fixed interest rates determined by the Eurodollar interbank market in London. If a material adverse change in the business, operations, affairs, assets or condition, financial or otherwise, or prospects of UIL Holdings and its subsidiaries, on a consolidated basis, should occur, the banks may decline to lend additional money to UIL Holdings under this revolving credit agreement, although borrowings outstanding at the time of such an occurrence would not then become due and payable. As of December 31, 2000, UIL Holdings had $50 million in short-term borrowings outstanding under this facility.

The revolving credit agreement described above requires that UIL Holdings (i) maintain a ratio of consolidated debt to consolidated capital, as of the last day of each March, June, September and December, of not greater than 0.65 to 1.00; and (ii) shall not cause to exist debt of UIL Holdings (excluding debt of its subsidiaries) to exceed $175 million in the aggregate principal amount outstanding at any time. As of December 31, 2000, UIL Holdings' consolidated debt to consolidated capital ratio was 0.58 and its aggregate principal debt outstanding (excluding debt of its subsidiaries) was $173.7 million (including intercompany loans to UIL Holdings).

Information with respect to short-term borrowings under the UIL Holdings' Money Market Loan arrangement and revolving credit agreement and the UI revolving credit agreement is as follows:

(In Thousands)	2000	1999	1998
Maximum aggregate principal amount of short-term borrowings outstanding at any month-end	$114,000	$80,000	$130,000
Average aggregate short-term borrowings outstanding during the year*	$ 42,511	$45,300	$115,753
Weighted average interest rate*	7.2%	5.5%	6.1%
Principal amounts outstanding at year-end	$109,000	$17,000	$ 80,000
Annualized interest rate on principal amounts outstanding at year-end	7.6%	7.0%	5.7%

*Average short-term borrowings represent the sum of daily borrowings outstanding, weighted for the number of days outstanding and divided by the number of days in the period. The weighted average interest rate is determined by dividing interest expense by the amount of average borrowings. Fees of approximately $386,000, $291,000 and $381,000 paid during 2000, 1999 and 1998, respectively, are excluded from the calculation of the weighted average interest rate.

(F) Income Taxes

(In Thousands)	2000	1999	1998
Income tax expense consists of:			
INCOME TAX PROVISIONS:			
Current			
Federal	$31,650	$91,247	$36,774
State	6,679	23,891	10,685
Total current	38,329	115,138	47,459
Deferred			
Federal	9,152	(39,767)	2,964
State	1,283	(13,004)	110
Total deferred	10,435	(52,771)	3,074
Investment tax credits	(735)	(467)	(762)
TOTAL INCOME TAX EXPENSE	$48,029	$61,900	$49,771
INCOME TAX COMPONENTS CHARGED AS FOLLOWS:			
Operating expenses	$52,298	$65,042	$52,862
Nonoperating tax expense	(4,269)	(3,142)	(3,091)
TOTAL INCOME TAX EXPENSE	$48,029	$61,900	$49,771
The following table details the components of the deferred income taxes:			
Gain on sale of utility property	$ –	($70,573)	($697)
Seabrook sale/leaseback transaction	(2,599)	(69)	304
Pension benefits	6,878	4,192	3,463
Accelerated depreciation	(3,006)	4,996	5,449
Tax depreciation on unrecoverable plant investment	235	5,902	6,291
Unit overhaul and replacement power costs	326	1,523	(1,157)
Conservation and load management	(107)	(2,181)	(8,026)
Displaced worker protection costs	(909)	2,329	–
Bond redemption costs	(585)	(1,014)	(1,039)
Cancelled nuclear project	(467)	(467)	(467)
Restructuring costs	1,132	490	–
Regulatory deferrals	9,210	–	–
Other – net	327	2,101	(1,047)
DEFERRED INCOME TAXES – NET	$10,435	($52,771)	$ 3,074

(F) Income Taxes (continued)

Total income taxes differ from the amounts computed by applying the federal statutory tax rate to income before taxes. The reasons for the differences are as follows:

(In Thousands)	2000		1999		1998	
	Pre-Tax	Tax	Pre-Tax	Tax	Pre-Tax	Tax
Computed tax at federal statutory rate		$ 38,075		$ 39,943		$33,195
Increases (reductions) resulting from:						
Deferred return-Seabrook Unit 1	–	–	12,586	4,405	12,586	4,405
ITC taken into income	(735)	(735)	(468)	(468)	(762)	(762)
Allowance for equity funds used during construction	(1,149)	(402)	(575)	(201)	(13)	(5)
Fossil plant decommissioning reserve	(13)	(4)	(262)	(92)	(723)	(253)
Amortization of regulatory asset	41,236	14,433	22,635	7,922	–	–
Book depreciation in excess of non-normalized tax depreciation	(10,185)	(3,565)	16,155	5,654	22,789	7,976
State income taxes, net of federal income tax benefits	7,962	5,176	10,887	7,076	10,795	7,017
Other items – net	(14,140)	(4,949)	(6,683)	(2,339)	(5,149)	(1,802)
Total income tax expense		$ 48,029		$ 61,900		$49,771
Book income before income taxes		$108,786		$114,124		$94,843
Effective income tax rates		44.1%		54.2%		52.5%

At December 31, 2000, UIL Holdings had deferred tax liabilities for taxable temporary differences of $339 million and deferred tax assets for deductible temporary differences of $86 million, resulting in a net deferred tax liability of $253 million. Significant components of deferred tax liabilities and assets were as follows: tax liabilities on book/tax plant basis differences and on the cumulative amount of income taxes on temporary differences previously flowed through to ratepayers, $194 million; tax liabilities on normalization of book/tax depreciation timing differences, $122 million and tax assets on the disallowance of plant costs, $35 million.

(G) Supplementary Information

(In Thousands)	2000	1999	1998
OPERATING REVENUES			
Utility			
Retail	$ 602,347	$ 639,596	$ 631,607
Wholesale	67,990	24,334	44,948
Proceeds from Millstone Unit 3 settlement	14,960	–	–
Other	19,394	16,045	9,636
Non-regulated business unit revenues			
American Payment Systems	37,940	35,595	33,746
Xcelecom	138,267	35,423	28,115
Other/Eliminations	(43)	(263)	39
Total Operating Revenues	$ 880,855	$ 750,730	$ 748,091
SALES BY CLASS(MEGAWATT-HOURS) – UNAUDITED			
Retail			
Residential	2,056,366	2,053,927	1,924,724
Commercial	2,403,212	2,388,240	2,324,507
Industrial	1,146,295	1,161,856	1,154,935
Other	47,852	48,027	48,166
	5,653,725	5,652,050	5,452,332
Wholesale	2,237,805	1,009,866	1,551,109
Total Sales by Class	7,891,530	6,661,916	7,003,441
DEPRECIATION AND AMORTIZATION			
Utility property, plant, and equipment	$ 24,575	$ 53,347	$ 67,143
Nonutility property-unregulated	4,717	3,689	4,052
Accelerated conservation and load management costs	–	–	13,086
Amortization of nuclear plant regulatory assets	2,851	22,636	–
Amortization of purchase power contracts	26,744	–	–
Amortization of other regulatory assets	5,668	–	–
Amortization of cancelled plant	1,172	1,172	1,172
Amortization of deferred return	–	12,586	12,586
Nuclear decommissioning	3,986	4,004	2,580
Total Depreciation and Amortization	$ 69,713	$ 97,434	$ 100,619
TAXES – OTHER THAN INCOME TAXES			
Charged to:			
Operating:			
State gross earnings	$ 23,715	$ 24,518	$ 24,039
Local real estate and personal property (1)	13,939	17,745	35,088
Payroll taxes	5,402	4,877	5,547
	43,056	47,140	64,674
Nonoperating and other accounts	654	598	510
Total Taxes - other than income taxes	$ 43,710	$ 47,738	$ 65,184
OTHER INCOME AND (DEDUCTIONS) – NET			
Interest income	$ 1,723	$ 1,801	$ 3,181
Allowance for funds used during construction	2,609	2,235	468
Equity earnings from Connecticut Yankee	1,913	36	854
Miscellaneous other income and (deductions) - net	(2,906)	849	(2,107)
Total Other Income and (Deductions) – net	$ 3,339	$ 4,921	$ 2,396
OTHER INTEREST CHARGES			
Notes Payable	$ 3,078	$ 2,662	$ 5,050
Other	2,175	2,265	1,446
Total Other Interest Charges	$ 5,253	$ 4,927	$ 6,496

(1) 1998 includes $14,025 charge for property tax settlement

(H) Pension and Other Benefits

UI's qualified pension plan, which is based on the highest three years of pay, covers substantially all of its employees, the employees of APS, and certain management employees of URI and Xcelecom. UI also has a non-qualified supplemental plan for certain executives and a non-qualified retiree only plan for certain early retirement benefits. The net pension credit to income for these plans for 2000, 1999 and 1998 was $14.7 million, $8.0 million, and $5.1 million, respectively.

Funding policy for the qualified plan is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the plan. In 1998, $2.6 million was contributed for 1998 funding requirements. No contributions were made in 1999. In 2000, $2.5 million was contributed for 1999 funding requirements. UI has established a supplemental retirement benefit trust and through this trust purchased life insurance policies on the officers of UI to fund the future liability under the supplemental plan. The cash surrender value of these policies is shown as an investment on the Consolidated Balance Sheet.

In addition to providing pension benefits, UI also provides other postretirement benefits (OPEB), consisting principally of health care and life insurance benefits, for retired employees and their dependents. Employees whose sum of age and years of service at time of retirement is equal to or greater than 85 (or who are 62 with at least 20 years of service) are eligible for benefits partially subsidized by UI. The amount of benefits subsidized by UI is determined by age and years of service at retirement.

For funding purposes, UI established a Voluntary Employees' Benefit Association Trust (VEBA) to fund OPEB for UI's union employees. Approximately 45% of UI's employees are represented by Local 470-1, Utility Workers Union of America, AFL-CIO, for collective bargaining purposes. UI established a 401(h) account in connection with the qualified pension plan to fund OPEB for UI's non-union employees who retire on or after January 1, 1994. The funding policy assumes contributions to these trust funds to be the total OPEB expense calculated under SFAS No. 106, adjusted to reflect a share of amounts expensed as a result of voluntary early retirement programs minus pay-as-you-go benefit payments for pre-January 1, 1994 non-union retirees, allocated in a manner that minimizes current income tax liability, without exceeding maximum tax deductible limits. In accordance with this policy, UI did not make contributions to the union VEBA in 2000, 1999 and 1998. UI contributed $0.2 million to the 401(h) account in 2000. UI did not make a contribution to the 401(h) account in 1999 and contributed $0.9 million to the 401(h) account in 1998. Plan assets for both the union VEBA and 401(h) account consist primarily of equity and fixed-income securities.

The following table represents the plans' beginning benefit obligation balance reconciled to the ending benefit obligation balance, beginning fair value of plan assets balance reconciled to the ending fair value of plan assets balance and the respective funded status reconciled to the Consolidated Balance Sheet.

	Pension Benefits		Other Post-retirement Benefits	
(In Thousands) At December 31,	2000	1999	2000	1999
CHANGE IN BENEFIT OBLIGATION				
Benefit obligation at beginning of year	$232,392	$280,746	$31,591	$40,229
Service cost	4,052	5,334	442	549
Interest cost	16,669	17,470	2,336	2,276
Amendments	8,698	994	–	1,364
Actuarial (gain) loss	(6,476)	(34,672)	910	(9,322)
Benefits paid (including expenses)	(21,495)	(18,979)	(2,569)	(1,935)
Acquisition/(Divestiture)	–	(18,500)	–	(1,570)
Benefit obligation at end of year	$233,840	$232,393	$32,710	$31,591
CHANGE IN PLAN ASSETS				
Fair value of plan assets at beginning of year	$277,987	$268,684	$20,681	$23,203
Actual return on plan assets	(12,109)	39,757	1,615	555
Employer contributions	2,657	2,525	807	208
Benefits paid (including expenses)	(21,495)	(18,979)	(2,569)	(1,935)
Acquisition/(Divestiture)	–	(14,000)	–	(1,350)
Fair value of plan assets at end of year	$247,040	$277,987	$20,534	$20,681
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ (13,200)	$ (45,594)	$12,176	$10,910
Unrecognized prior service cost	(11,553)	(3,731)	(280)	(291)
Unrecognized transition asset	4,741	5,552	(12,345)	(13,435)
Unrecognized net gain (loss) from past experience	21,717	62,799	5,464	7,674
Accrued benefit obligation	$ 1,705	$ 19,026	$ 5,015	$ 4,858

	Pension Benefits		Other Post-retirement Benefits	
At December 31,	2000	1999	2000	1999
The following actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate	7.50%	7.50%	7.50%	7.50%
Average wage increase	4.50%	4.50%	4.50%	4.50%
Health care cost trend rate	N/A	N/A	5.50%	5.50%

(H) Pension and Other Benefits (continued)

The components of net periodic benefit cost are:

(In Thousands) For the Year Ended December 31,	Pension Benefits 2000	Pension Benefits 1999	Other Post-retirement Benefits 2000	Other Post-retirement Benefits 1999
Components of net periodic benefit cost:				
Service cost	$ 4,052	$ 5,334	$ 442	$ 549
Interest cost	16,669	17,470	2,336	2,276
Expected return on plan assets	(29,735)	(28,677)	(2,227)	(2,463)
Amortization of:				
Prior service costs	876	537	11	11
Transition obligation (asset)	(1,054)	(1,097)	1,089	1,169
Actuarial (gain) loss	(5,471)	(1,527)	(687)	(801)
Settlements (curtailments)	–	–	–	–
Net periodic benefit cost	($14,663)	($7,960)	$ 964	$ 741

For the Year Ended December 31,	Pension Benefits 2000	Pension Benefits 1999	Other Post-retirement Benefits 2000	Other Post-retirement Benefits 1999
The following actuarial assumptions were used in calculating net periodic benefit cost:				
Discount rate	7.50%	6.75%	7.50%	6.75%
Average wage increase	4.50%	4.50%	4.50%	4.50%
Return on plan assets	11.00%	11.00%	11.00%	11.00%
Health care cost trend rate	N/A	N/A	5.50%	5.50%

A one percentage point change in the assumed health care cost trend rate would have the following effects:

(In Thousands)	1% Increase	1% Decrease
Aggregate service and interest cost components	$ 354	$ (290)
Accumulated postretirement benefit obligation	$3,412	$(2,858)

UI has a 401(k)/Employee Stock Ownership Plan (KSOP) in which substantially all of its employees, the employees of APS, and certain management employees of URI and Xcelecom are eligible to participate. The KSOP enables employees to defer receipt of up to 15% of their compensation and to invest such funds in a number of investment alternatives. Matching contributions are made to the KSOP, in the form of UIL Holdings' common stock, based on each employee's salary deferrals in the KSOP. The matching contribution currently equals fifty cents for each dollar of the employee's compensation deferred, but is not more than 3 3/8% of the employee's annual salary. Matching contributions to the KSOP during 2000, 1999 and 1998 were $1.8 million, $1.5 million and $1.7 million, respectively.

UIL Holdings pays dividends on the shares of stock in the KSOP to the participant and UIL Holdings receives a tax deduction for the dividends paid. Contributions are made to the KSOP equal to 25% of the dividends paid to each participant. Annual contributions during 2000, 1999 and 1998 were $293,000, $319,000 and $270,000, respectively.

(I) Jointly Owned Plant

At December 31, 2000, UI had the following interests in jointly owned plants:

(In Millions Except Share Amounts)	Ownership/ Leasehold Share	Plant Investment(1)	Accumulated Depreciation
Seabrook Unit 1	17.5 %	$654	$179
Millstone Unit 3	3.685	136	69

(1) Of the plant investment amounts, $456 million for Seabrook Unit 1 and $62 million for Millstone Unit 3 are reflected on the consolidated balance sheet as regulatory assets.

UI's share of the operating costs of jointly owned plants is included in the appropriate expense captions in the Consolidated Statement of Income.

(J) Unamortized Cancelled Nuclear Project

From December 1984 through December 1992, UI had been recovering its investment in Seabrook Unit 2, a partially constructed nuclear generating unit that was cancelled in 1984, over a regulatory approved ten-year period without a return on its unamortized investment. In the 1992 rate decision, the DPUC adopted a proposal by UI to write off its remaining investment in Seabrook Unit 2, beginning January 1, 1993, over a 24-year period, corresponding with the flowback of certain Connecticut Corporation Business Tax (CCBT) credits. Such decision will allow UI to retain the Seabrook Unit 2/CCBT amounts for ratemaking purposes, with the accumulated CCBT credits not deducted from rate base during the 24-year period of amortization in recognition of a longer period of time for amortization of the Seabrook Unit 2 balance. As a result of reducing its remaining unamortized investment in Seabrook Unit 2 with proceeds from the sale of certain Seabrook Unit 2 equipment, UI expects to completely amortize its unamortized investment in the year 2007.

(K) Lease Obligations

UIL Holdings has lease arrangements for data processing equipment, office equipment, vehicles and office space, including the lease of a distribution service facility, which is recognized as a capital lease. The gross amount of assets recorded under capital leases and the related obligations of those leases as of December 31, 2000 are recorded on the Consolidated Balance Sheet.

Future minimum lease payments under capital leases, excluding the Seabrook sale/leaseback transaction, which is being treated as a long-term financing, are estimated to be as follows:

(In Thousands)	
2001	$ 1,696
2002	1,696
2003	1,696
2004	16,000
2005	–
After 2005	–
Total minimum capital lease payments	21,088
Less: Amount representing interest	4,958
Present value of minimum capital lease payments	$16,130

Capitalization of leases on UI's books has no impact on income, since the sum of the amortization of a leased asset and the interest on the lease obligation equals the rental expense allowed for ratemaking purposes.

(K) Lease Obligations (continued)

Operating leases, which are charged to operating expense, consist principally of lease of office space and facilities and a wide variety of equipment. The most significant operating lease is that of UI's corporate headquarters. The future minimum lease payments under these operating leases is estimated to be as follows:

(In Thousands)	
2001	$ 8,550
2002	9,781
2003	10,504
2004	10,655
2005	11,443
2006 – after	71,965
Total	$122,898

Rental payments charged to operating expenses in 2000, 1999 and 1998, including rental payments for its corporate headquarters, were $11.3 million, $11.0 million and $11.7 million, respectively.

(L) Commitments and Contingencies

CAPITAL EXPENDITURE PROGRAM (UNAUDITED) UIL Holdings' 2001-2005 estimated capital expenditure program, excluding UI's allowance for funds used during construction, is presently budgeted as follows:

(In Thousands)	2001	2002	2003	2004	2005	Total
UI						
Distribution and Transmission	$67,167	$41,427	$31,455	$49,457	$35,903	$225,409
Nuclear Generation (1)	2,829	–	–	–	–	2,829
Nuclear Fuel (1)	5,569	–	–	–	–	5,569
Total UI	75,565	41,427	31,455	49,457	35,903	233,807
URI						
Xcelecom	5,333	7,337	12,906	6,677	8,130	40,383
American Payment Systems	3,364	5,063	4,800	3,627	3,719	20,573
United Capital Investments	10,155	516	–	–	–	10,671
Total URI	18,852	12,916	17,706	10,304	11,849	71,627
Total UIL Holdings	$94,417	$54,343	$49,161	$59,761	$47,752	$305,434

(1) Assumes that the sale of UI's interest in Millstone Unit 3 and Seabrook Unit 1 will be completed by April 1, 2001 and December 31, 2001, respectively.

NUCLEAR INSURANCE CONTINGENCIES The Price-Anderson Act, currently extended through August 1, 2002, limits public liability resulting from a single incident at a nuclear power plant. The first $200 million of liability coverage is provided by purchasing the maximum amount of commercially available insurance. Additional liability coverage will be provided by an assessment of up to $83.9 million per incident, levied on each of the nuclear units licensed to operate in the United States, subject to a maximum assessment of $10 million per incident per nuclear unit in any year. In addition, if the sum of all public liability claims and legal costs resulting from any nuclear incident exceeds the maximum amount of financial protection, each reactor operator can be assessed an additional 5% of $83.9 million, or $4.2 million. The maximum assessment is adjusted at least every five years to reflect the impact of inflation. With respect to each of the two operating nuclear generating units in which UI has an interest, UI will be obligated to pay its ownership and/or leasehold share of any statutory assessment resulting from a nuclear incident at any nuclear generating unit. Based on its interests in these nuclear generating units, UI estimates its maximum liability would be $17.8 million per incident. However, any assessment would be limited to $2.1 million per incident per year.

The Nuclear Regulatory Commission requires each operating nuclear generating unit to obtain property insurance coverage in a minimum amount of $1.06 billion and to establish a system of prioritized use of the insurance proceeds in the event of a nuclear incident. The system requires that the first $1.06 billion of insurance proceeds be used to stabilize the nuclear reactor to prevent any significant risk to public health and safety and then for decontamination and cleanup operations. Only following completion of these tasks would the balance, if any, of the segregated insurance proceeds become available to the unit's owners. For each of the two operating nuclear generating units in which UI has an interest, UI is required to pay its ownership and/or leasehold share of the cost of purchasing such insurance. Although each of these units has purchased $2.75 billion of property insurance coverage, representing the limits of coverage currently available from conventional nuclear insurance pools, the cost of a nuclear incident could exceed available insurance proceeds. Under those circumstances, the nuclear insurance pools that provide this coverage may levy assessments against the insured owner companies if pool losses exceed the accumulated funds available to the pool. The maximum potential assessments against UI with respect to losses occurring during current policy years are approximately $2.4 million.

OTHER COMMITMENTS AND CONTINGENCIES

• CONNECTICUT YANKEE On December 4, 1996, the Board of Directors of the Connecticut Yankee Atomic Power Company (Connecticut Yankee) voted unanimously to retire the Connecticut Yankee nuclear plant (the Connecticut Yankee Unit) from commercial operation. UI has a 9.5% stock ownership share in Connecticut Yankee. The power purchase contract under which UI had purchased its 9.5% entitlement to the Connecticut Yankee Unit's power output permits Connecticut Yankee to recover 9.5% of all of its costs from UI. In December of 1996, Connecticut Yankee filed decommissioning cost estimates and amendments to the power contracts with its owners with the Federal Energy Regulatory Commission (FERC). Based on regulatory precedent, this filing requested confirmation that Connecticut Yankee will continue to collect from its owners its decommissioning costs, the unrecovered investment in the Connecticut Yankee Unit and other costs associated with the permanent shutdown of the Connecticut Yankee Unit. On April 7, 2000, Connecticut Yankee reached a settlement agreement with the DPUC and the Connecticut Office of Consumer Counsel (two of the intervenors in the FERC proceeding). This agreement was submitted to the FERC, which approved it in all respects on July 26, 2000; and it became effective on August 1, 2000. The agreement allows Connecticut Yankee to earn a return on equity of 6% and stipulates a new decommissioning cost estimate for the Connecticut Yankee Unit for purposes of FERC-approved decommissioning cost collections by Connecticut Yankee through the power contracts with the unit's owners.

UI's estimate of its remaining share of Connecticut Yankee costs, including decommissioning, less return of investment (approximately $7.1 million) and return on investment (approximately $1.6 million) at December 31, 2000, is approximately $17.2 million. This estimate, which is subject to ongoing review and revision, has been recorded as an obligation and a regulatory asset on the Consolidated Balance Sheet.

• HYDRO-QUEBEC UI is a participant in the Hydro-Quebec transmission intertie facility linking New England and Quebec, Canada. Phase I of this facility, which became operational in 1986 and in which UI has a 5.45% participating share, has a 690 megawatt equivalent generation capacity value; and Phase II, in which UI has a 5.45% participating share, increased the equivalent generation capacity value of the intertie from 690 megawatts to a maximum of 2000 megawatts in 1991. UI is obligated to furnish a guarantee for its participating share of the debt financing for the Phase II facility. As of December 31, 2000, UI's guarantee liability for this debt was approximately $5.6 million.

(L) Commitments and Contingencies (continued)

• LONG ISLAND CABLE PROJECT United Capital Investments (UCI), an indirect wholly-owned subsidiary of UIL Holdings, has a 25% interest in a merchant electric transmission line project that proposes to install, own and operate a 330-megawatt transmission line connecting Connecticut and Long Island under Long Island Sound. UCI is obligated to furnish a direct guarantee by means of a letter of credit for its participating share of the debt financing of the project. Under separate agreement, UIL Holdings is an indirect guarantor of the obligation of UCI. As of December 31, 2000, UCI's guarantee liability for this debt was approximately $7.7 million.

• ENVIRONMENTAL CONCERNS In complying with existing environmental statutes and regulations and further developments in areas of environmental concern, including legislation and studies in the fields of water quality, hazardous waste handling and disposal, toxic substances, and electric and magnetic fields, UIL Holdings may incur substantial capital expenditures for equipment modifications and additions, monitoring equipment and recording devices, and it may incur additional operating expenses. The total amount of these expenditures is not now determinable.

• SITE DECONTAMINATION, DEMOLITION AND REMEDIATION COSTS UI has estimated that the total cost of decontaminating and demolishing its Steel Point Station and completing requisite environmental remediation of the site will be approximately $11.3 million, of which approximately $8.7 million had been incurred as of December 31, 2000, and that the value of the property following remediation will not exceed $6.0 million. As a result of a 1992 DPUC retail rate decision, beginning January 1, 1993, UI has been recovering through retail rates $1.075 million of the remediation costs per year. The remediation costs, property value and recovery from customers will be subject to true-up in UI's next retail rate proceeding based on actual remediation costs and actual gain on UI's disposition of the property.

UI has begun replacing the bulkhead surrounding a site, bordering the Mill River in New Haven, that contains transmission facilities and deactivated generation facilities, at an estimated cost of $13.5 million. Of this amount, $4.2 million represents the portion of the costs to protect UI's transmission facilities and will be capitalized as plant in service. The remaining estimated cost of $9.3 million was expensed in 1999. UI has conveyed to an unaffiliated entity, Quinnipiac Energy LLC (QE), this entire site, reserving to UI permanent easements for the operation of its transmission facilities on the site. QE will complete the bulkhead replacement project at UI's expense. UI has also funded 61% (approximately $1.2 million) of the environmental remediation costs that will be incurred by QE to bring the site into compliance with applicable Connecticut minimum standards. QE intends to reactivate the generation facilities on the site as a merchant electric generating plant.

As described at Note (C), "Rate-Related Regulatory Proceedings," UI closed on the sale of its Bridgeport Harbor Station and New Haven Harbor Station generating plants in compliance with Connecticut's electric utility industry restructuring legislation on April 16, 1999. Environmental assessments performed in connection with the marketing of these plants indicate that substantial remediation expenditures will be required in order to bring the plant sites into compliance with applicable Connecticut minimum standards. The purchaser of the plants has agreed to undertake and pay for the major portion of this remediation. However, UI will be responsible for remediation of the portions of the plant sites that have been retained by it.

(M) Nuclear Fuel Disposal and Nuclear Plant Decommissioning

Costs associated with nuclear plant operations include amounts for disposal of nuclear wastes, including spent fuel, and for the ultimate decommissioning of the plants. Under the Nuclear Waste Policy Act of 1982, the federal Department of Energy (DOE) is required to design, license, construct and operate a permanent repository for high level radioactive wastes and spent nuclear fuel. The Act requires the DOE to provide for the disposal of spent nuclear fuel and high level radioactive waste from commercial nuclear plants through contracts with the owners and generators of such waste; and the DOE has established disposal fees that are being paid

to the federal government by electric utilities owning or operating nuclear generating units. In return for payment of the prescribed fees, the federal government was required to take title to and dispose of the utilities' high level wastes and spent nuclear fuel beginning no later than January 1998. However, the DOE has announced that its first high level waste repository will not be in operation earlier than 2010, and possibly not earlier than 2013, and that, absent a repository, the DOE has no statutory obligation to begin taking high level wastes and spent nuclear fuel for disposal by January 1998. However, numerous utilities and states have obtained a judicial declaration that the DOE has a statutory responsibility to take title to and dispose of high level wastes and spent nuclear fuel beginning in January 1998, and that the contracts between the DOE and the plant owners and generators of such waste will provide a potentially adequate remedy to owners and generators in monetary damages for breach of the contracts. The DOE is contesting these judicial declarations; and it is unclear at this time whether the United States Congress will enact legislation to address spent fuel/high level waste disposal issues.

Until the federal government begins receiving such materials, nuclear generating units will need to retain high level wastes and spent nuclear fuel on-site or make other provisions for their storage. Storage facilities for the Connecticut Yankee Unit are deemed adequate, and storage facilities for Millstone Unit 3 are expected to be adequate for the projected life of the unit. Storage facilities for Seabrook Unit 1 are expected to be adequate until at least 2010. Fuel consolidation and compaction technologies are being considered for Seabrook Unit 1 and may provide adequate storage capability for the projected life of the unit. In addition, other licensed technologies, such as dry storage casks, may satisfy spent nuclear fuel storage requirements.

Disposal costs for low-level radioactive wastes (LLW) that result from operation or decommissioning of nuclear generating units decreased in 1999, as a result of negotiations between the generators of such wastes and the owners of licensed disposal facilities. Currently, the Chem Nuclear LLW facility at Barnwell, South Carolina, is open to the Connecticut Yankee Unit, Millstone Unit 3, and Seabrook Unit 1 for disposal of LLW. The Envirocare LLW facility at Clive, Utah, is also open to these generating units for portions of their LLW. All three units have contracts in place for LLW disposal at these disposal facilities.

Because access to a LLW disposal facility may be interrupted at any time, Seabrook Unit 1 and Millstone Unit 3 have storage plans that will allow on-site retention of LLW for at least five years in the event that disposal is interrupted. The Connecticut Yankee Unit, which has been retired from commercial operation, has a similar storage program, although disposal of its LLW is taking place in connection with its decommissioning.

The State of New Hampshire has not met deadlines for compliance with the Low-Level Radioactive Waste Policy Act and has stated that the state is unsuitable for a LLW disposal facility. New Hampshire is pursuing other options for out-of-state disposal of LLW. Connecticut, New Jersey and South Carolina have formed the Atlantic Compact, which should ensure that the Connecticut Yankee Unit and Millstone Unit 3 will have access to the Chem Nuclear LLW facility at Barnwell, South Carolina, through the end of their decommissioning.

NRC licensing requirements and restrictions are also applicable to the decommissioning of nuclear generating units at the end of their service lives, and the NRC has adopted comprehensive regulations concerning decommissioning planning, timing, funding and environmental reviews. UI and the other owners of the nuclear generating units in which UI has interests estimate decommissioning costs for the units and attempt to recover sufficient amounts through their allowed electric rates, together with earnings on the investment of funds so recovered, to cover expected decommissioning costs. Changes in NRC requirements or technology, as well as inflation, can increase estimated decommissioning costs.

(M) Nuclear Fuel Disposal and Nuclear Plant Decommissioning (continued)

New Hampshire has enacted a law requiring the creation of a government-managed fund to finance the decommissioning of nuclear generating units in that state. The New Hampshire Nuclear Decommissioning Financing Committee (NDFC) has established $609.3 million (in 2001 dollars) as the decommissioning cost estimate for Seabrook Unit 1, of which UI's share would be approximately $107 million. This estimate assumes the prompt removal and dismantling of the unit at the end of its estimated 36-year energy producing life. Monthly decommissioning payments are being made to the state-managed decommissioning trust fund. UI's share of the decommissioning payments made during 2000 was $3.4 million. UI's share of the fund at December 31, 2000 was approximately $24.2 million.

Connecticut has enacted a law requiring the operators of nuclear generating units to file periodically with the DPUC their plans for financing the decommissioning of the units in that state. The current decommissioning cost estimate for Millstone Unit 3 is $648 million (in 2001 dollars), of which UI's share would be approximately $24 million. This estimate assumes the prompt removal and dismantling of the unit at the end of its estimated 40-year energy producing life. Monthly decommissioning payments, based on these cost estimates, are being made to a decommissioning trust fund managed by Northeast Utilities (NU). UI's share of the Millstone Unit 3 decommissioning payments made during 2000 was $0.6 million. UI's share of the fund at December 31, 2000 was approximately $8.6 million. The current decommissioning cost estimate for the Connecticut Yankee Unit, assuming the prompt removal and dismantling of the unit, is $393 million, of which UI's share would be $37 million. Through December 31, 2000, $244 million has been expended for decommissioning. The projected remaining decommissioning cost is $149 million, of which UI's share would be $14 million. The decommissioning trust fund for the Connecticut Yankee Unit is also managed by NU. For UI's 9.5% equity ownership in Connecticut Yankee, decommissioning costs of $2.4 million were funded by UI during 2000, and UI's share of the fund at December 31, 2000 was $16 million.

The Financial Accounting Standards Board (FASB) expects to issue a revised exposure draft related to the accounting for the closure and removal costs of long-lived assets, including nuclear plant decommissioning. If the proposed accounting standard were adopted, it may result in higher annual provisions for decommissioning to be recognized earlier in the operating life of nuclear units and an accelerated recognition of the decommissioning obligation. The FASB will be deliberating this issue, and the resulting final pronouncement is not expected to be effective prior to 2002.

(N) Fair Value of Financial Instruments

The estimated fair values of the Company's financial instruments are as follows:

(In Thousands)	2000		1999	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Unrestricted cash and temporary cash investments	$ 14,237	$ 14,237	$ 39,099	$ 39,099
Long-term debt (1)(2)(3)	$395,460	$384,838	$420,217	$399,767

(1) Excludes the obligation under the Seabrook Unit 1 sale/leaseback agreement.

(2) The fair market value of UIL Holdings' long-term debt is estimated by brokers based on market conditions at December 31, 2000 and 1999, respectively.

(3) See Note (B), "Capitalization – Long-Term Debt."

(O) Quarterly Financial Data (Unaudited)

Selected quarterly financial data for 2000 and 1999 are set forth below:

(In Thousands, Except Per Share Amounts)

Quarter	Operating Revenues (1)	Operating Income (1)	Net Income	Earnings per Share of Common Stock (2) Basic	Diluted
2000					
First Quarter	$204,240	$38,099	$16,865	$1.20	$1.20
Second Quarter	194,804	43,389	17,796	1.26	1.26
Third Quarter	247,054	49,961	19,707	1.40	1.40
Fourth Quarter	234,757	18,497	6,389	.46	.46
1999					
First Quarter	$181,184	$38,012	$ 9,901	$ .70	$ .70
Second Quarter	175,897	39,054	13,986	.99	.99
Third Quarter	220,527	59,358	24,997	1.78	1.78
Fourth Quarter	173,122	20,171	3,340	.24	.24

(1) Operating revenues and operating income for the 1999 quarterly periods have been restated to reflect the presentation on the Consolidated Statement of Income.

(2) Based on weighted average number of shares outstanding each quarter.

(P) Segment Information

UIL Holdings has two reportable operating segments, UI, its regulated electric utility business engaged in the transmission, distribution and sale of electricity, and Xcelecom, Inc., its non-regulated, wholly-owned subsidiary, which provides specialized contracting services in the electrical, communications and data network infrastructure industries. Revenues from inter-segment transactions are not material, and all of UIL Holdings' revenues are derived in the United States.

The following table reconciles certain segment information with that provided in UIL Holdings' consolidated financial statements. In the table, Other includes the information for the remainder of UIL Holdings' unregulated businesses and inter-segment eliminations.

(In Thousands)	2000	1999	1998
REVENUES FROM EXTERNAL CUSTOMERS			
Regulated Utility	$704,691	$ 679,975	$ 686,191
Xcelecom – Unregulated business	138,267	35,423	28,115
Other	37,897	35,332	33,785
Total UIL Holdings	$880,855	$ 750,730	$ 748,091

	2000	1999	1998
INCOME (LOSS) BEFORE INCOME TAXES			
Regulated Utility	$108,039	$ 117,902	$ 96,710
Xcelecom – Unregulated business	3,944	(4,805)	(2,366)
Other	(3,197)	1,027	499
Total UIL Holdings	$108,786	$ 114,124	$ 94,843

(In Thousands) At December 31	2000	1999
TOTAL ASSETS		
Regulated Utility	$1,602,327	$1,809,451
Xcelecom – Unregulated business	136,951	24,215
Other	129,276	(35,456)
Total UIL Holdings	$1,868,554	$1,798,210

Market for UIL Holdings' Common Equity and Related Stockholders Matters

On July 20, 2000, as a result of a corporate restructuring of UI and its direct and indirect subsidiaries into a holding company system, UI became a wholly-owned subsidiary of UIL Holdings and each share of UI's issued and outstanding Common Stock was automatically converted into a share of UIL Holdings Common Stock. This Common Stock has traded on the New York Stock Exchange since 1971. The high and low sale prices during 2000 and 1999 were as follows:

	2000 Sale Price		1999 Sale Price	
	High	Low	High	Low
First Quarter	52 1/8	38 1/8	52 11/16	41 7/8
Second Quarter	47 3/8	39 5/8	44 11/16	39 5/16
Third Quarter	55 1/8	44 3/16	50 11/16	43 1/8
Fourth Quarter	52 3/16	43 3/8	53 3/16	47 15/16

UI and UIL Holdings have paid quarterly dividends on the Common Stock since 1900. The quarterly dividends declared by UI in 1999 and by UI and UIL Holdings in 2000 were at a rate of 72 cents per share.

As of December 31, 2000, there were 12,592 Common Stock shareowners of record.

Financial and Stock Data (Note)

INCOME AND DIVIDEND DATA

Year	Pretax (fed.) Net Income $ mil	Balance for Common $ mil	Basic Earnings per Share $	Diluted Earnings per Share $	Dividend Declared Share $	Payout Ratio %	Yield on Average Price %
1996	74	41	2.88	2.87	2.88	100.0	8.1
1997	72	43	3.10	3.09	2.88	92.9	8.2
1998	84	45	3.20	3.20	2.88	90.0	6.0
1999	103	52	3.71	3.71	2.88	77.6	6.2
2000	101	61	4.32	4.31	2.88	66.7	6.2
5 Yr. Avg.	87	48	3.44	3.44	2.88	85.4	6.9

COMMON SHARE DATA

Year	Closing Price Range			Price Earnings Ratio		
	$ High	$ Low	$ End	High	Low	Close
1996	39 3/4	31 3/8	31 3/8	13.8	10.9	10.9
1997	45 15/16	24 1/2	45 15/16	14.8	7.9	14.8
1998	53 3/4	42 5/8	51 1/2	16.8	13.3	16.1
1999	53 3/16	39 5/16	51 3/8	14.3	10.6	13.9
2000	55 1/8	38 1/8	49 3/4	12.8	8.8	11.5
5 Yr. Avg.	49 9/16	35 3/16	46	14.5	10.3	13.4

COMMON SHARE DATA (Cont'd)

Quarter ended	Closing Market Price $									Trading Volume in Thousands		
	2000			1999			1998					
	High	Low	End	High	Low	End	High	Low	End	2000	1999	1998
3/31	52 1/8	38 1/8	39 1/4	52 11/16	41 7/8	41 15/16	48 9/16	42 5/8	48 3/8	2,645	1,698	2,847
6/30	47 3/8	39 5/8	43 3/4	44 11/16	39 5/16	42 7/16	51 15/16	46 15/16	50 5/8	2,061	3,034	2,631
9/30	55 1/8	44 3/16	51 7/16	50 11/16	43 1/8	48 3/8	53 9/16	49	52 1/4	2,184	2,784	2,183
12/31	52 3/16	43 3/8	49 3/4	53 3/16	47 15/16	51 3/8	53 3/4	48 1/16	51 1/2	2,518	1,663	1,382

QUARTERLY FINANCIAL INFORMATION

Quarter ended	Pretax (fed.) Net Income $ mil.			Basic Earnings per Share $			Dividends Paid per Share $		
	2000	1999	1998	2000	1999	1998	2000	1999	1998
3/31	28	22	18	1.20	0.70	0.64	0.72	0.72	0.72
6/30	30	26	16	1.26	0.99	0.60	0.72	0.72	0.72
9/30	33	45	45	1.40	1.78	1.87	0.72	0.72	0.72
12/31	10	10	5	0.46	0.24	0.10	0.72	0.72	0.72

(fed.) = Federal

Note: Certain data for the years 1996-1998 has been restated.

Selected Financial Data

	2000	1999	1998	1997	1996
FINANCIAL RESULTS OF OPERATION (THOUSANDS)					
Sales of electricity					
Utility					
Retail					
Residential	$ 252,730	$ 271,605	$ 262,974	$ 259,325	$ 266,068
Commercial	242,075	256,246	254,765	248,490	264,111
Industrial	96,955	100,437	102,201	102,763	109,032
Other	10,587	11,308	11,667	11,755	11,903
Total Retail	602,347	639,596	631,607	622,333	651,114
Wholesale	67,990	24,334	44,948	82,871	72,844
Other operating revenues	34,354	16,045	9,636	3,825	3,300
Nonregulated businesses	176,164	70,755	61,900	38,040	22,151
Total operating revenues	880,855	750,730	748,091	747,069	749,409
Fuel and interchange energy -net					
Retail -own load	262,252	134,851	116,769	109,542	95,359
Wholesale	19,901	24,552	34,775	73,124	65,158
Capacity purchased-net	4,682	33,873	34,515	39,976	46,830
Depreciation	33,278	61,040	86,861 (1)	77,745 (1)	68,211
Amortization of regulatory assets	36,435	36,394	13,758	13,758	13,758
Other operating expenses, excluding tax expense	331,305	256,285	247,636	236,253	243,454
Gross earnings tax	23,715	24,518	24,039	23,571	26,804
Other non-income taxes	19,341	22,622	40,635 (2)	28,922	30,382
Total operating expenses, excluding income taxes	730,909	594,135	598,988	602,891	589,956
AFUDC	2,609	2,235	468	1,575	2,375
Other non-operating income(loss)	730	2,686	1,928	1,898	(4,482)
Interest expense					
Long-term debt - net	31,729	35,260	42,836	56,158	65,046
Dividend requirement of mandatorily redeemable securities	3,529	4,813	4,813	4,813	4,813
Other	9,241	7,319	9,007	6,068	4,721
Total	44,499	47,392	56,656	67,039	74,580
Income tax expense					
Operating income tax	52,298	65,042	52,862	39,281	49,277
Non-operating income tax	(4,269)	(3,142)	(3,091)	(2,126)	(5,556)
Total	48,029	61,900	49,771	37,155	43,721
Net income	60,757	52,224	45,072	43,457	39,045
Premium (Discount) on preferred stock redemption	–	53	(21)	(48)	(1,840)
Preferred and preference stock dividends	–	66	201	205	330
Income applicable to common stock	$ 60,757	$ 52,105	$ 44,892	$ 43,300	$ 40,555
Operating income	$ 149,946	$ 156,595	$ 149,103	$ 144,178	$ 159,453
FINANCIAL CONDITION (THOUSANDS)					
Current assets	$ 288,306	$ 220,126	$ 305,189	$ 204,474	$ 199,097
Other property and investments (4)	155,526	144,768	49,549	47,706	39,240
Property, Plant and Equipment – net	495,850	482,836 (3)	1,181,053	1,232,909	1,268,157
Construction work in progress	30,267	25,708	33,695	25,448	40,998
Deferred charges and regulatory assets	898,605	924,772 (3)	371,674	408,993	449,150
Total Assets	$1,868,554	$1,798,210	$1,941,160	$1,919,530	$1,996,642
Current portion of long-term debt	$ –	$ 25,000	$ 66,202	$ 100,000	$ 69,900
Other current liabilities	245,821	166,213	172,830	175,340	166,138
Noncurrent liabilities	208,486	247,135	111,848	121,746	140,704
Deferred income tax liabilities and other	302,282	316,205	339,072	349,591	355,326
Long-term debt excluding current portion	522,221	518,228	664,510	644,670	759,680
Notes payable	110,699	17,131	86,892	37,751	10,965
Preferred, preference stock and company-obligated mandatorily redeemable securities of subsidiaries holding solely parent debentures	–	50,000	54,299	54,351	54,461
Common stock equity	479,045	458,298	445,507	436,081	439,468
Total Liabilities and Capitalization	$1,868,554	$1,798,210	$1,941,160	$1,919,530	$1,996,642

(1) Includes the before-tax effect of charges for additional amortization of conservation & load management costs: $13.1 million in 1998 and $6.6 million in 1997.

(2) Includes the effect of charges of $14.0 million, before-tax, associated with property tax settlement.

(3) Reflects reclassification of $518.3 million of nuclear assets from plant in service to regulatory asset.

(4) Includes an investment of $90.3 million and $83.5 million in a generation facility as of December 31, 2000 and 1999, respectively.

	2000	1999	1998	1997	1996
COMMON STOCK DATA					
Average number of shares outstanding	14,073,168	14,052,091	14,017,644	13,975,802	14,100,806
Number of shares outstanding at year-end	14,076,697	14,062,502	14,034,562	13,907,824	14,101,291
Earnings per share (average) – basic	$ 4.32	$ 3.71	$ 3.20	$ 3.10	$ 2.88
Earnings per share (average) – diluted	$ 4.31	$ 3.71	$ 3.20	$ 3.09	$ 2.87
Book value per share	$ 34.03	$ 32.59	$ 31.74	$ 31.35	$ 31.16
Average return on equity					
Total	13.00%	11.45%	9.44%	10.45%	9.20%
Utility	13.50%	14.00%	11.43%	11.54%	11.51%
Dividends declared per share	$ 2.88	$ 2.88	$ 2.88	$ 2.88	$ 2.88
Market Price:					
High	$ 55.125	$ 53.188	$ 53.750	$ 45.938	$ 39.750
Low	$ 38.125	$ 39.313	$ 42.625	$ 24.500	$ 31.375
Year-end	$ 49.750	$ 51.375	$ 51.500	$ 45.938	$ 31.375
Net cash provided by operating activities, less dividends ($000's)	$ 60,801	$ 57,907	$ 71,566	$ 132,189	$ 120,624
Capital expenditures, excluding AFUDC	$ 56,401	$ 34,772	$ 38,040	$ 33,436	$ 47,174
OTHER FINANCIAL AND STATISTICAL DATA					
Sales by class (MWh's)					
Residential	2,056,366	2,053,927	1,924,724	1,899,2840	1,895,804
Commercial	2,403,212	2,388,240	2,324,507	2,248,974	2,263,056
Industrial	1,146,295	1,161,856	1,154,935	1,168,470	1,143,410
Other	47,852	48,027	48,166	48,619	48,388
Total	5,653,725	5,652,050	5,452,332	5,365,347	5,350,658
Number of retail customers by class (average)					
Residential	284,955	282,986	281,591	280,283	279,024
Commercial	29,776	29,757	29,468	29,228	28,666
Industrial	1,725	1,746	1,752	1,697	1,652
Other	1,207	1,185	1,172	1,163	1,141
Total	317,663	315,674	313,983	312,371	310,483
Revenue per kilowatt hour by class (cents)					
Residential	12.29	13.22	13.66	13.65	14.03
Commercial	10.07	10.73	10.96	11.05	11.67
Industrial	8.46	8.64	8.85	8.79	9.54
Average large industrial customers time of use rate (cents)	8.06	8.21	8.16	8.12	8.26
Revenues – retail sales ($000's)					
Base	$ 620,486	$ 655,327	$ 629,446	$ 620,636	$ 643,344
Base rate adjustments	(18,139)	(15,731)	2,161	1,697	7,770
Total	$ 602,347	$ 639,596	$ 631,607	$ 622,333	$ 651,114
Revenues – retail sales per kWh (cents)					
Base	10.97	11.59	11.54	11.57	12.02
Base rate adjustments	(0.32)	(0.28)	0.04	0.03	0.15
Total	10.65	11.31	11.58	11.60	12.17
Number of employees at year-end	2,277	1,239	1,193	1,175	1,287
Total utility employees payroll($000's)	$ 59,276	$ 66,155	$ 65,294	$ 68,640	$ 69,276

Executive Officers & Board of Directors

Executive Officers

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Vice Chairman of the Board of Directors & Chief Financial Officer

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Yale Law School

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Chairman of the Board of Directors,
President and Chief Executive Officer,
UIL Holdings Corporation

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American Stock Transfer & Trust Company
59 Maiden Lane
New York, NY 10038

Send Certificates for Transfer and Address Changes to:

American Stock Transfer & Trust Company
59 Maiden Lane
New York, NY 10038

Annual Meeting Date

UIL Holdings Corporation's Annual Meeting will be held at: Quinnipiac University
275 Mount Carmel Ave.
Hamden, CT
on Wednesday May 16, 2001
beginning at 10:00 a.m.

Dividend Reinvestment & Direct Stock Purchase and Sale Plan

Investors interested in obtaining information regarding the benefits of participating in Investors Choice, a Dividend Reinvestment & Direct Stock Purchase and Sale Plan for UIL Holdings Corporation's common stock, may write to:

American Stock Transfer & Trust Company
59 Maiden Lane
New York, NY 10038

Investor Relations Hotline

For information on UIL's earnings, news releases, media articles and dividend information, including ex-dividend dates and dividend payment dates, call:
From within the New Haven area:
(203) 499.3333 or
From outside the New Haven area:
(800) 7.CALL UI (722.5584)

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UIL

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