PSNH PUBLIC SERVICE
Company of New Hampshire

SEABROOK STATION
Engineering Office:
1671 Worcester Road
Framingham, Massachusetts 01701
(617) - 872 - 8100

July 27, 1983
SBN- 540
T.F. B3.1.5

United States Nuclear Regulatory Commission
Washington, DC 20555

Attention: Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation

References: (a) Construction Permits CPPR-135 and CPPR-136, Docket Nos. 50-443 and 50-444

Subject: Submittal of 1982 Annual Financial Reports

Dear Sir:

Pursuant to 10CFR50.71(b), we have enclosed one copy of the 1982 Annual Financial Reports of each of the Seabrook Station Joint Owners. A listing of the Joint Owners is also enclosed.

Please contact me should you require additional information or copies of the Financial Reports.

Very truly yours,

YANKEE ATOMIC ELECTRIC COMPANY

David A. Maidrand

John DeVincentis for
Project Manager

ALL/bal

Enclosure

cc: Atomic Safety and Licensing Board Service List

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JOINT OWNERS

Public Service of New Hampshire

The United Illuminating Company

Massachusetts Municipal Wholesale Electric Company

New England Power Company

Central Maine Power Company

The Connecticut Light and Power Company

Commonwealth Electric Company

Montaup Electric Company

Bangor Hydro-Electric Company

New Hampshire Electric Cooperative, Inc.

Central Vermont Public Service Corporation

Maine Public Service Company

Fitchburg Gas & Electric Light Company

Vermont Electric Cooperative, Inc.

Taunton Municipal Lighting Plant Commission

Hudson Light and Power Department

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549
FORM 10-K

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

For the fiscal year ended December 31, 1982. Commission file number 1-5324

NORTHEAST UTILITIES
(Exact name of registrant as specified in its charter)

MASSACHUSETTS	04-2147929
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification Number)

174 Brush Hill Avenue, West Springfield, Massachusetts	01089
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (413) 785-5871

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

Title of each class	Name of each exchange on which registered
Common Shares, $5.00 par value	New York Stock Exchange, Inc.

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

None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes X No ____

State the aggregate market value of the voting stock held by nonaffiliates of the registrant.

Aggregate market value: $1,138,091,962, based on a closing sales price of $12 5/8 per share on March 1, 1983.

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

Class	Outstanding at March 1, 1983
Common Shares, $5.00 par value	90,145,898 shares

Documents incorporated by reference:

Portions of the Proxy Statement dated March 26, 1983 are incorporated by reference into Part III.

NORTHEAST UTILITIES

1982 Form 10-K Annual Report

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PART I

Item 1. Business

NORTHEAST UTILITIES

PART I

Item 1. Business

THE COMPANY

Northeast Utilities (the Company) is the parent company of the Northeast Utilities system (the System). It is not itself an operating company. Through three of the Company's wholly owned subsidiaries -- The Connecticut Light and Power Company (CL&P), Western Massachusetts Electric Company (WMECO) and Holyoke Water Power Company (HWP) -- the System furnishes electric service in most of Connecticut (excluding New Haven and Bridgeport and several smaller cities and towns) and in western Massachusetts. The System companies' retail electric service territories cover approximately 5,877 square miles in 208 cities and towns in Connecticut and Massachusetts with an estimated total population of 2.74 million. CL&P also furnishes retail gas service in portions of Connecticut. Its eleven separate gas service areas, not fully interconnected, cover approximately 1,321 square miles in 51 cities and towns in Connecticut with an estimated population of 1.22 million.

On June 30, 1982, two of the System companies -- The Hartford Electric Light Company (HELCO) and CL&P's subsidiary The Connecticut Gas Company (Conn Gas) -- were merged into CL&P. Unless otherwise indicated, all CL&P information in this report for periods before June 30, 1982 incorporates information about HELCO and Conn Gas as if the mergers had already taken place; financial information about CL&P has been restated to reflect the mergers.

Other wholly owned subsidiaries of the Company provide substantial support services to the System companies. Northeast Utilities Service Company (the Service Company) supplies centralized accounting, administrative, data processing, engineering, financial, legal, operational, planning, purchasing and other services to the System companies. Northeast Nuclear Energy Company (NNECO) acts as agent for System companies in constructing and operating nuclear generating facilities. The Rocky River Realty Company and The Quinnehtuk Company are both real estate companies.

The System is operated on an integrated basis, under which the directors and the principal officers of each operating subsidiary are (with some exceptions) the same.

RATES

General

CL&P's retail electric and gas rate schedules are subject to the jurisdiction of the Connecticut Department of Public Utility Control (DPUC). WMECO's retail electric rate schedules are subject to the jurisdiction of the Massachusetts Department of Public Utilities (DPU). HWP's contracts with industrial customers are filed with the DPU for information purposes, but the rates charged are not subject to the DPU's jurisdiction. CL&P's, WMECO's and HWP's wholesale electric rates are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).

Connecticut Retail Rates

Connecticut law provides that increased rates may not be put into effect without the prior approval of the DPUC, which has 150 days to act upon a proposed rate increase. If the DPUC does not act within that period, the proposed rates may be put into effect subject to refund. Interim rate increases, subject to refund, may be approved by the DPUC after a public hearing if they are found to be necessary to prevent substantial and material deterioration of the financial condition, or the adequacy and reliability of service, of a utility. Under Connecticut law, the DPUC is required to conduct a complete review and investigation of, and to hold a public hearing on, the financial and operating results of each electric and gas utility at least once every two years to determine whether an increase or decrease in the level of the utility's rates is required. The review may, and in the case of CL&P in recent years always has been, combined with a regular rate case.

In recent rate decisions the DPUC has approved accounting principles and rate-making practices that improve CL&P's ability to recover its costs through rates. Certain adjustments to historical test year data are permitted to reflect many of the conditions anticipated by CL&P during the first year amended rate schedules are to be in effect, including an allowance for the impact of inflation on the test year's operation and maintenance expenses, increased rate base and projected capitalization. Current DPUC practices also permit CL&P to accrue an allowance for funds used during construction (AFUDC) on a net-of-income tax basis and to normalize tax timing differences.

On December 14, 1982, the DPUC issued its decision in CL&P's 1982 retail rate case, granting CL&P annual retail electric and gas revenue increases aggregating approximately \$101.1 million, or 6.8 percent (\$78.6 million, or 6.2 percent, for electric revenues and \$22.5 million, or 10.2 percent, for gas revenues). The total increase granted was 79.5 percent of CL&P's amended request. The DPUC authorized a 16.4 percent return on common equity in

the rate base, which is 0.3 percent higher than the 16.1 percent return previously allowed, but 1.1 percent below the 17.5 percent requested by CL&P. On December 21, 1982 the DPUC approved revised rates reflecting the increased revenues; the revised rates are being charged with respect to service rendered to electric and gas customers on and after December 22, 1982.

In its decision the DPUC found that it is in the public interest and in the best interests of customers and shareholders that the construction of a third nuclear electric generating unit at the System's Millstone Point plant (Millstone 3) be continued. The current construction cost estimate for Millstone 3 of $3.54 billion (including AFUDC) and the estimated in-service date of May, 1986, were found to be reasonable. The DPUC also found that abandonment of Millstone 3 would likely result in higher electricity costs for customers as well as greater financial and investment risk for the Company. The DPUC also found that the cost of electricity generated by Millstone 3 over its projected useful life will likely be lower than the cost of energy from alternative sources over the same period, although such costs in the early years would be higher than replacement oil costs. Additional information about Millstone 3 is found in many sections of this report. For detailed information, see "Construction and Financing Program -- Construction -- Millstone 3".

CL&P expects that it will be necessary to apply to the DPUC for additional rate relief in 1983, but the amount of rate relief to be requested and the time of application have not been determined.

Massachusetts Retail Rates

Massachusetts law allows the DPU to suspend a proposed rate increase for up to six months. If the DPU does not act within the suspension period, the proposed rates may be put into effect. Interim rate increases, subject to refund, may be approved by the DPU after a public hearing if they are found necessary to avoid "probable, immediate and irreparable harm" to the business of the utility or to the interests of the customers or if they relate to known and measurable expenses which, based on DPU precedent, would not be an issue in the main proceeding.

Under present rate making standards, the DPU allows few adjustments to historic test year expenses to reflect the conditions anticipated by a company during the first year amended rate schedules are to be in effect. The principal adjustments that are permitted are inflation adjustments to historic test year non-fuel operation and maintenance expense. Rate base and capital structure are based on test year-end levels adjusted for known and measurable changes. Because the DPU does not accept many forward-looking adjustments, WMECO does not fully recover increasing costs through rates.

Current DPU practices permit WMECO to accrue AFUDC on a net-of-income tax basis and to normalize tax timing differences.

On November 13, 1981 WMECO filed with the DPU an application for approval of amended rate schedules. As subsequently revised, WMECO's request

sought increases of annual revenues aggregating approximately $24 million. The DPU issued an order on May 28, 1982 granting rate relief of approximately $4.3 million. The DPU authorized a 17 percent return on common equity in rate base, which is 1 percent higher than the 16 percent return previously allowed but 2 percent below the 19 percent requested by WMECO. On July 28, 1982 the DPU issued an order denying WMECO's Motion for Reconsideration, but allowing an additional $127,000 in rate relief to reflect some of the calculation errors WMECO sought to be corrected by its Motion for Recalculation. As revised, the total amount of the increase was only 18 percent of the amount WMECO had requested.

See "Item 3. Legal Proceedings" for a description of legal and administrative proceedings involving CL&P and WMECO, which relate to a portion of the DPU's orders concerning the System's generation and transmission agreement.

On October 15, 1982 WMECO filed an application with the DPU for approval of amended rate schedules reflecting increases of annual revenues aggregating approximately $24.1 million. WMECO also filed a petition for interim rate relief of $5.3 million. Each request was suspended for six months. If approved, the permanent rates would become effective May 1, 1983. Hearings on the permanent rate application are expected to end in early March, 1983. A decision on the request for interim relief is pending.

Fuel Adjustment Clauses

The System companies have fuel adjustment clauses applicable to their retail and wholesale electric rates, and CL&P has a purchased gas adjustment clause applicable to its retail gas rates.

In Connecticut, administrative proceedings are required by the DPUC each month to approve the charges proposed for the following month under retail fossil fuel adjustment clauses and purchased gas adjustment clauses. Monthly fossil fuel and gas adjustment charges are also subject to retroactive review and appropriate adjustment by the DPUC each quarter after full public hearings. The Connecticut clauses do not fully track changes in fossil fuel and purchased gas costs, but the DPUC allows CL&P to recover through future rates differences in actual fossil fuel and purchased gas expenses and the amounts currently recovered from customers through fuel adjustment clauses.

CL&P's retail rate schedules also include a nuclear generation utilization adjustment clause. This clause levels the effect on fuel costs caused by variations from a 70 percent composite nuclear generation capacity factor for the nuclear units in which CL&P has entitlements. See "Electric Operations -- Nuclear Generation -- General". The 70 percent composite capacity factor is used as a baseline because it is the capacity factor used in setting base rates. For the twelve-month period ending July 31 of each year, the amount of any additional fuel cost savings or any additional fuel cost expense resulting from the actual capacity factor for that period being above or below 70 percent will be either refunded to or collected from customers over

the following eleven months. However, the clause does not automatically permit collection from customers to the extent that the factor is less than 55 percent in the twelve-month period. For the period August 1, 1981 to July 31, 1982, the composite nuclear generation capacity factor was 74.1 percent, resulting in fuel cost savings of $20.6 million above the base level. That amount is being returned to customers by reducing their monthly bills through July 31, 1983. In the previous year, the composite nuclear generation capacity factor was 57.3 percent. Additional fuel costs of $51.7 million below the base level were incurred in that year; under the clause, that amount was collected from customers over the subsequent twelve months. For the five months ended December 31, 1982, the factor was 69.2 percent.

In Massachusetts the DPU must hold public hearings before permitting quarterly adjustments in WMECO's retail fuel adjustment clause. All fuel costs are collected on a current basis by means of a forecasted quarterly fuel clause. Legislation enacted in 1981 added to the existing quarterly fuel clause mechanism a performance program related to fuel procurement and use. The legislation also permits a penalty for failure to meet fuel procurement and use performance goals set for each utility. The DPU has established performance goals for WMECO for the period June, 1982 through May, 1983. All fuel clause revenues collected in Massachusetts are subject to potential refund, pending the DPU's examination of WMECO's actual performance. On January 20, 1983 WMECO appealed the DPU's order setting performance goals to the Massachusetts Supreme Judicial Court, challenging the DPU's authority to set performance standards for generating plants that are not wholly owned or operated by WMECO. The Court's decision is not expected until late 1983. While it continues to question the DPU's authority to set procurement standards for all System plants, WMECO is currently operating within the present performance standards and management believes that the likelihood of a significant refund of fuel clause revenues is remote.

Oil Conservation Adjustment

To assist in financing the cost of converting HWP's oil-burning Mt. Tom station to coal-burning (see "Construction and Financing Program -- Construction -- Oil Reduction Efforts"), the System companies developed an oil conservation adjustment (OCA) rate mechanism. The OCA permits two-thirds of the fuel cost savings per kilowatthour (presently calculated as of the date of initial conversion) to be collected through rates and retained by the utility company until the full cost of conversion is paid. With the approval of the FERC, the DPUC and the DPU, the System companies have incorporated the OCA in their current retail and wholesale rates. Collection of OCA revenues began in December, 1981 and will continue for approximately three years.

Wholesale Rates

CL&P has three municipal and one investor-owned wholesale electric customers. On December 30, 1982, the FERC accepted and approved agreements among CL&P and its wholesale customers reflecting a settlement of all aspects

of the R-3, R-4, W-1 and W-2 wholesale rate cases pending at FERC and in the courts. Those cases have been terminated under the settlement. The customers will receive an annual aggregate revenue reduction of $500,000 in the level of the existing W-1 rate, which became effective May 17, 1982, and an annual aggregate revenue reduction of $500,000 in the level of the W-2 rate which will become effective on July 1, 1983. The customers have withdrawn or waived their rights to prosecute several pending and potential claims. No adjustments were made to the R-3 and R-4 rates, which were charged from 1976 to 1982.

On December 3 and 6, 1982, WMECO filed rate schedule changes with the FERC for an annual increase totalling $900,000 in wholesale rates charged its three municipal and three investor-owned utility customers. All of the customers concurred in the requested increase. On January 18, 1983, the FERC accepted the filing and permitted it to become effective as of November 1, 1982, as agreed to by the parties. In the filing, WMECO agreed not to seek to make effective any subsequent increase in its wholesale rates before July 1, 1983.

See "Item 3. Legal Proceedings" for a description of legal and administrative proceedings involving CL&P and WMECO, which relate to a portion of the DPU's order concerning the System's generation and transmission agreement, and antitrust litigation with certain of CL&P's wholesale customers.

CONSTRUCTION AND FINANCING PROGRAM

Construction

General

The System companies have substantial financial commitments for their construction programs for the next several years, principally to complete Millstone 3. The System's construction program expenditures, including AFUDC, in the period 1983 through 1987 are estimated to be as follows:

	1983	1984	1985	1986	1987
		(Thousands of Dollars)			
Electric Plant					
Production	$539,943	$535,530	$359,484	$168,935	$ 50,854
Substations and Transmission Lines ...	24,934	26,559	14,055	8,648	19,233
Distribution Operations.	49,848	53,353	56,348	60,737	65,236
General	15,714	11,127	4,851	4,984	5,310
Gas Plant	21,632	16,972	15,978	15,883	16,928
TOTAL	$652,071	$643,541	$450,716	$259,187	$157,561

The data shown above, and other data in this report, are presented on the assumption that the System companies will retain their present interests in Millstone 3 and the Seabrook project. See "Millstone 3" and "Seabrook", below.

The 1983 and 1984 construction programs include approximately $3.6 million and $0.5 million respectively, for environmental control facilities.

Millstone 3

CL&P and WMECO are the lead participants responsible for constructing and operating Millstone 3, a 1,150 MW pressurized water reactor nuclear electric generating unit under construction in Waterford, Connecticut. Millstone 3 is scheduled for completion in May, 1986. CL&P and WMECO's present collective share is 65 percent of the unit (representing 747.5 MW), of which CL&P owns 52.65 percent (605.5 MW) and WMECO owns 12.35 percent (142 MW).

On September 7, 1982, CL&P and WMECO announced the completion of a detailed review of the cost of constructing Millstone 3. On the basis of that review, the total estimated cost of the unit, including AFUDC, has increased to approximately $3.54 billion. The previous cost estimate was approximately $2.6 billion, based on a review completed in December, 1980. The May, 1986 scheduled in-service date remained unchanged. The approximate aggregate cost of CL&P's and WMECO's joint ownership interest in the unit is now estimated at $2.3 billion, compared with the previous estimate of $1.69 billion.

New and revised regulatory requirements, such as those in the areas of seismic and fire protection, are responsible for approximately 60 percent of the increased costs. Other major causes of the increase are an increase to 9.25 percent, net-of-tax and compounded semi-annually, in the AFUDC rate estimate used after 1982, design modifications resulting from industry experience, revisions to escalation predictions and changes in assumed tax rates.

As of December 31, 1982 CL&P and WMECO had invested approximately $1.071 billion in Millstone 3, including AFUDC of $246.3 million. Their construction expenditures for the unit, including AFUDC, are estimated to be approximately $4[illegible]4.4 million in 1983, $444.1 million in 1984, $298.5 million in 1985, and $103.1 million in 1986. At December 31, 1982 construction of the project was approximately 60 percent complete. The Company expects that construction will be substantially completed by the end of 1984, with pre-operational testing and initial fuel loading taking place in 1985.

Although it cannot assure that the current estimate of the cost of completing Millstone 3 will not be exceeded, management of the Company believes that the current estimate is reasonable. Engineering, material purchasing and construction are at advanced stages, reducing the likelihood of major changes which could significantly alter the ultimate cost of constructing the unit. In the opinion of management, there are also fewer adverse outside factors at present that are likely to increase the ultimate cost, because inflation rates and borrowing rates have fallen and are projected to remain lower than in recent years, and because the rate at which the Nuclear Regulatory Commission (NRC) has published new regulations affecting the cost of constructing nuclear units has slowed. Nevertheless, many factors that are outside the Company's control, such as changes in the regulatory climate, delays or other difficulties occurring in the licensing process, extended labor stoppages, higher borrowing costs and higher inflation rates, could cause the cost of constructing Millstone 3 to increase and could delay completion of the unit.

CL&P and WMECO were parties to contracts expiring on December 31, 1982 for the sale of interests representing an aggregate of 49.6 megawatts of Millstone 3 to four other utility systems. On the basis of their recent reviews of the estimated cost of constructing Millstone 3 and their power supply needs, three of the utility systems permitted their contracts to lapse. These three utilities had been committed to purchase an aggregate of 42.7 megawatts. The fourth utility system has extended its contract through June 30, 1983, but has reduced its commitment from 6.9 megawatts to 1.73 megawatts. CL&P and WMECO intend to continue their efforts to reduce their ownership interests in Millstone 3.

A municipal utility holding a 0.365 percent joint ownership interest in Millstone 3 has advised the Company that it is unable to make further payments for its share of the cost of constructing the unit. CL&P and WMECO are reviewing the actions available to them.

Seabrook

CL&P has a 4.05985 percent joint ownership interest in the Seabrook nuclear electric generating plant (two units with a rated capacity of 1,150 MW each) under construction at a site in Seabrook, New Hampshire. Public Service Company of New Hampshire (PSNH) is the lead participant responsible for constructing and scheduling Seabrook Units 1 and 2. On November 30, 1982, PSNH reported the completion of a review of the estimated cost and scheduling of the units. PSNH estimated that Unit 1 would be completed in December, 1984 and Unit 2 would be completed in March, 1987, at a total cost of $5.12 billion,

including AFUDC at PSNH's rate. Subsequently it was decided to reduce 1983 construction to a level that would result in a further deferral of Unit 2's completion date to July, 1987. PSNH estimates that this additional deferral will result in additional costs of approximately $122 million, including AFUDC at PSNH's rate. The two units were previously expected to be completed in February, 1984 and May, 1986, respectively, at a cost of $3.56 billion.

PSNH attributed the higher cost estimate to such items as increased material and labor requirements, increased design and engineering complexities, increased quality assurance requirements, added costs due to deferral of some work on the units in 1980 and 1981, additional financing costs, and corrections to the previous estimate. PSNH reported that the delayed completion date estimates reflect progress that has been slower than planned, primarily because of increased labor requirements resulting largely from engineering changes.

CL&P's actual expenditures, including AFUDC but excluding nuclear fuel, for the Seabrook project through December 31, 1982 were approximately $95.1 million. On the basis of the two recent revisions by PSNH, CL&P estimates that its share of the costs would increase from approximately $133.9 million to approximately $211.5 million, an increase of $77.6 million (57.9 percent). Its construction expenditures for the Seabrook units, including AFUDC, are estimated to be $37.4 million in 1983, $33.0 million in 1984, $20.7 million in 1985, $18.3 million in 1986 and $7.0 million in 1987.

PSNH has been experiencing difficulties in financing its construction program. If PSNH's financing program or the financing programs of other participants cannot be carried out, the construction and in-service dates for one or both of the Seabrook units might be deferred further, or construction of one or both of the units might be suspended until such financial problems are resolved. Any such deferral or suspension, or delay for any reason, would increase substantially the estimated cost of completing the Seabrook project.

An independent engineering firm has been engaged by PSNH to review and confirm PSNH's recent cost and scheduling estimates. CL&P is receiving periodic interim reports from the consultant, but CL&P has not conducted an independent review of PSNH's construction and schedule estimates and is not able to assure that both units will be completed at the estimated times and costs.

In 1982 the New Hampshire Public Utilities Commission (NHPUC) attempted to prohibit PSNH from using the proceeds of financings for the construction of Seabrook Unit 2 until completion of Unit 1 or a reduction of PSNH's ownership interest in the Seabrook project from approximately 35 percent to 28 percent, a level which the NHPUC believed was more consistent with PSNH's financing capabilities. PSNH's offer to other utilities of portions of its interest in the project received no substantial responses. Upon appeal of the NHPUC's order prohibiting such use, the New Hampshire Supreme Court, in a three-to-two decision, vacated the NHPUC's order, concluding that the NHPUC does not have the authority to impose such a prohibition on financings.

Other proceedings, before the NHPUC and before other governmental bodies in New Hampshire and elsewhere, involve questions about the need to

complete one or both units and the ability of PSNH and other participants to finance their interests in the project. CL&P has not independently examined PSNH's and other participants' abilities to finance their respective shares of the units.

Oil Reduction Efforts

The System has developed a comprehensive energy conservation and supply plan entitled the "Northeast Utilities Conservation Program for the 1980s and 1990s" (NU 80s/90s). The major goals of NU 80s/90s are to reduce the System's oil dependence and to assist customers to take cost effective conservation actions. The customer conservation elements of the program are intended to make customers aware of conservation's potential, to inform them about preferred technical and economic means of conservation, and to provide them with selected conservation services.

A specific goal of NU 80s/90s is to cut the System's use of oil in the generation of electricity. The principal actions which were proposed to meet the System's oil-reduction targets are the following:

- Placing Millstone 3 in service by 1986, as scheduled, while retaining a substantial part of the System's present ownership;

- Adding hydroelectric capacity, including imported sources, and encouraging customer-owned cogeneration and small power production, including refuse-derived and hydroelectric energy; and

- Converting the most suitable System oil burning units to coal, provided that such conversion is cost-effective and can be financed by the System.

While reduction of the use of oil for generating electricity remains a specific goal of the System, occurrences since NU 80s/90s was developed in early 1981 have adversely affected the System's ability to implement an aggressive coal conversion effort. As a result, NU 80s/90s' specific target of reducing the percentage of oil used in generation to ten percent by 1987 cannot be met, although substantial reductions are still contemplated.

Restrictive environmental standards, the delay that results from uncertainty in regulatory and environmental standards and lower oil price projections all contribute to likely increases in the estimated costs of converting suitable oil burning units to coal and reductions in the expected cost benefits from conversion.

Significant uncertainty has been created in Connecticut by a recent preliminary decision of a Connecticut Department of Environmental Protection hearing officer in a case involving an unaffiliated utility company. If upheld, the decision would require emissions from a converted coal burning plant to meet the very restrictive standards imposed by the federal government

on new emission sources. The cost of meeting new source standards at CL&P's Norwalk Harbor or Devon sites would in the Company's judgment be prohibitive, if they could be met at all.

In the current economic and regulatory climate, therefore, the Company has decided that it will complete the conversion of HWP's 148 MW Mt. Tom Station in Holyoke, Massachusetts, as described below, that it will continue its technical studies for the conversion of up to an additional seven units, but that it will not begin the actual conversion of any more units until the required environmental standards are more favorable and certain and the cost-effectiveness of conversion can be more assured. The System's construction program includes only funds for Mt. Tom Station and studies.

The first phase of converting Mt. Tom Station was completed in December, 1981, when coal burning began. Before coal could be burned, modifications to existing environmental protection and control equipment, waste water and ash disposal systems, and coal handling and coal burning facilities were necessary. The cost of these initial modifications was approximately $15 million, exclusive of AFUDC. More extensive modifications needed to meet final environmental requirements will be effected during a second phase, which could extend until February, 1984. During the second phase the unit is operating under a delayed compliance order (DCO) issued by the federal Environmental Protection Agency (EPA) under the Clean Air Act. The DCO permits state emission standards to be exceeded temporarily while new air pollution control equipment is installed at the plant. The total cost of converting Mt. Tom Station is estimated at $40 million. The initial financing for conversion of Mt. Tom Station is being provided by a $12 million pollution control revenue bond issued by the City of Holyoke, Massachusetts, and a $28 million revolving credit loan agreement between HWP and a syndicate of banks. These borrowings are being repaid through the use of the OCA mechanism described in "Rates".

In addition to completing Millstone 3, the significant oil reduction energy supply actions other than conversion of Mt. Tom Station involve importing hydroelectric power from Canada, adding some hydroelectric capacity in the System's service area, and cooperating with cogenerators and small power producers.

In January, 1982, CL&P, WMECO and HWP entered into agreements with other New England utility companies which will finance, construct and own the United States portion of a 450 kV direct current transmission circuit between New England and Quebec, Canada. The project would initially provide approximately 690 MW of capacity for importing electricity generated in Canadian hydroelectric plants. By the end of February, 1983, most of the material regulatory approvals necessary for construction to begin had been obtained. The DPU approved WMECO's participation in the project in December 1982. The DPUC approved CL&P's participation in the project on March 1, 1983. HWP's participation does not require state regulatory approval. The line is expected to be completed by November, 1986. Under the agreements, the System companies will be responsible for their share (expected to be 23.6 percent) of the annual costs associated with the United States portion of the interconnection when the line is completed, and they will be entitled to use their proportional shares

of the line's capacity to transfer power to and from Quebec. The System expects that, in addition to reducing oil consumption, the project will make cost savings available to customers by enabling the System to purchase surplus, lower cost Canadian power. Cost savings will also be achieved by permitting the "banking" of energy in Canada during off-peak hours in New England, while making equivalent amounts of energy available to New England during peak hours.

HWP is constructing Hadley Falls Unit No. 2, a 15 MW hydroelectric facility in Holyoke, Massachusetts. Through December 31, 1982, HWP had expended $10.7 million on the unit. The project is scheduled for completion in November, 1983, at a total cost of approximately $21.4 million.

CL&P also proposes to cooperate with a private developer in a project under which the private developer would construct a 6 MW hydroelectric facility on the Housatonic River between Derby and Shelton, Connecticut. The facility is expected to cost approximately $12 million; financing for the project is to be provided by the private developer. An application with respect to that project was filed with the FERC in February, 1983. An application for that site had previously been filed by a competing developer. Regulatory approval for the project in which CL&P is involved is not assured.

In its December, 1982 CL&P retail rate decision, the DPUC ordered CL&P to prepare an "aggressive" hydroelectric development program. Such a program would compel CL&P to reconsider its standards for evaluating the cost effectiveness of developing additional capacity sources. The economic justification for hydroelectric projects under such a program will require cost recovery over a significantly longer period than CL&P has previously used for economic studies.

CL&P is cooperating with the Connecticut Resource Recovery Authority (CRRA) in a study of the technical and financial feasibility of a refuse recovery and burning project at CL&P's South Meadow (Hartford) Station to use solid wastes from a number of mid-Connecticut municipalities as a fuel source for generating electricity. If the project is found to be feasible, modification of the South Meadow facilities could be accomplished by approximately 1986. The CRRA would provide most of the financing for the project. It would build and own refuse receiving, processing and storage facilities on land leased to it by CL&P. It would also build and own the boilers and ancillary equipment for production of steam at the generating plant. CL&P would rehabilitate its existing steam turbine generators, operate the boiler and generation facilities, and purchase all or a portion of the steam when it is available. The project, which might also burn coal as a supplemental fuel, would have capacity of approximately 65 MW. CL&P's participation in the project would be subject to DPUC approval.

Financing Nuclear Fuel

The System's nuclear fuel requirements are for its two operating nuclear units, Millstone Unit Nos. 1 and 2 (Millstone 1 and 2) and for the three nuclear units under construction in which the System has interests, Millstone 3 and the two Seabrook units. The requirements for the Millstone units are financed through a third party trust financing described below. All nuclear fuel for CL&P's share of the Seabrook units is owned and financed directly by CL&P. For the period 1983-1987, CL&P's share of the cost of nuclear fuel for the Seabrook units is estimated at $12.5 million, including AFUDC.

In February, 1982, CL&P and WMECO entered into arrangements under which a trust (the Niantic Bay Fuel Trust, or "NBFT") will own and finance the nuclear fuel for Millstone 1 and 2 and the System's share of the nuclear fuel for Millstone 3. NBFT finances such fuel from the time uranium is acquired, during the offsite processing stages and through its use in the units' reactors. NBFT obtains funds from bank loans, the sale of commercial paper backed by a bank letter of credit and the sale of intermediate term notes. The fuel will be leased to CL&P and WMECO by the trust while it is used in the reactors, and will be transferred to CL&P and WMECO when it is discharged from the reactors. CL&P and WMECO are severally obligated to make quarterly lease payments, to pay all expenses incurred by NBFT in connection with the fuel and the financing arrangements, to purchase the fuel under certain circumstances and to indemnify all the parties to the transactions.

The trust arrangements presently allow up to $230 million to be financed by NBFT through January, 1987 with bank loans and letter-of-credit-backed commercial paper. After that date, the arrangements with the banks will continue in effect from year to year unless terminated voluntarily by CL&P and WMECO or unless terminated, in whole or in part, by the banks upon four years' prior notice. The arrangements with the banks also allow up to $300 million in aggregate principal amount of intermediate term notes to be sold by NBFT. Through December 31, 1982, NBFT had issued $125 million of intermediate term notes. The amount of credit available to CL&P and WMECO through NBFT is increased by the amount of any intermediate term notes which are sold.

During 1982, NBFT acquired the fuel being processed for Millstone 1 and 2 and the System's share of the fuel being processed for Millstone 3. Before it was acquired by NBFT, the fuel in process for Millstone 1 and 2 had been financed on behalf of CL&P and WMECO by another fuel trust which owned the fuel until it was placed in a reactor. Fuel in the Millstone 1 and 2 reactors had been financed by NNECO, a subsidiary of the Company, through bank borrowings, issuing secured notes and receiving capital contributions or advances from the Company.

On December 1, 1982, the fuel in the Millstone 1 and 2 reactors was acquired by NBFT. Proceeds of approximately $109 million were received by NNECO and were used primarily to retire $65 million of NNECO's secured notes and to make a $30 million dividend payment to the Company.

As of December 31, 1982, NBFT's investment in nuclear fuel for all three Millstone units was approximately $267.0 million, which consists of $96.4 million of fuel being processed for Millstone 1 and 2, $66.3 million of fuel being processed for Millstone 3 and $104.3 million of fuel in the Millstone 1 and 2 reactors.

Nuclear fuel costs are being recovered through rates as the fuel is consumed in reactors.

Financing

1982

In 1982 the System companies realized aggregate gross proceeds, before underwriting commissions and costs of issuance, of approximately $311 million by issuing and selling common shares, preferred stock and first mortgage bonds. In addition, the System companies entered into revolving credit and trust financing arrangements, described below, under which up to approximately $1.0 billion can be made available to the System companies. These financings were undertaken to support the construction and nuclear fuel requirements described above and to meet approximately $237 million of 1982 debt maturities and cash sinking fund requirements.

The Company issued and sold eight million common shares in a public offering in May, realizing net proceeds of approximately $82.8 million. The Company also realized approximately $25 million in 1982 through the sale of approximately 2.5 million shares under its dividend reinvestment and common share purchase plan. HELCO issued and sold $20 million principal amount of eight year first mortgage bonds in February at an interest rate of 17.6 percent per annum and $40 million principal amount of ten year first mortgage bonds in May at an interest rate of 15 5/8 percent per annum; CL&P assumed these bonds and all other outstanding HELCO bonds on June 30, 1982, in connection with its merger with HELCO. CL&P issued and sold $100 million principal amount of thirty year first mortgage bonds in October at an interest rate of 15 percent per annum and issued and sold, for $40 million, 800,000 shares of preferred stock in June at a dividend rate of 15.04 percent per annum. The Company made capital contributions of $110 million to CL&P, $10 million to WMECO and $3 million to HWP in 1982. The bulk of those funds were provided by the $82.8 million proceeds of the Company's public offering of eight million shares in May, with the balance coming from the sale of shares under the Company's dividend reinvestment and common share purchase plan and a $30 million dividend from NNECO to the Company.

In February, 1982, CL&P and WMECO completed the new nuclear fuel financing arrangements described above under "Financing Nuclear Fuel". In October CL&P and WMECO revised a $140 million revolving credit and term loan agreement to reduce borrowing costs, extend maturities and increase the maximum amount that could be borrowed to $200 million. In November CL&P entered into a two-year $50 million floating rate Eurodollar loan agreement.

In March, 1982 CL&P and WMECO entered into a construction trust arrangement to provide advance commitments to assist them to finance their shares of the cost of constructing Millstone 3. The financing involved the establishment of a special purpose trust. The trust was given a lien, junior to the liens of CL&P's, HELCO's and WMECO's first mortgage indentures, on the companies' interests in Millstone 3 in exchange for the construction trust's agreement to make loans to the companies and to reimburse the companies for a significant portion of their Millstone 3 expenditures as they are incurred. The trust's obligations are initially limited to $400 million. The trust will meet its obligations by issuing up to $200 million of letter-of-credit-backed commercial paper and issuing up to an additional $200 million of term notes to participating banks. Once Millstone 3 is in service, but beginning no later than 1988, the trust obligations are to be repaid over a four-year period. The companies are also obligated to pay all expenses incurred by the trust in connection with the financing arrangements, to repay the borrowings before their normal maturity in certain circumstances, and to indemnify all parties to the transactions. As of December 31, 1982, the trust had provided $96 million and $39 million of financing for CL&P and WMECO, respectively.

Requirements

In addition to financing the construction requirements described under "Construction", the System companies are obligated to meet $205 million of long-term debt maturities and cash sinking fund requirements in 1983 through 1987. In 1983, long-term debt maturity and cash sinking fund requirements will be $18 million.

In 1983 the construction program expenditures of $652 million, the nuclear fuel requirements of $2 million for CL&P's share of fuel for the Seabrook station, and the long-term debt maturity and cash sinking fund requirements of $18 million are expected to produce aggregate capital requirements of $672 million. The System companies propose to finance their 1983 requirements through a combination of internally generated and external funds, with external funds expected to provide approximately three-fourths.

1983

The Company expects to offer approximately six million additional common shares to the public in 1983. These shares would be in addition to those issued under its dividend reinvestment and common share purchase plan. CL&P expects to issue and sell approximately $130 million principal amount of intermediate term or long-term debt securities and approximately $45 million (900,000 shares) of its $50 par value per share preferred stock in 1983. WMECO expects to issue and sell approximately $50 million (500,000 shares) of its $100 par value per share preferred stock in 1983. The Company expects to make additional open account advances or capital contributions in 1983 to System companies in amounts up to $90 million in the aggregate, primarily to CL&P (up to $60 million) and WMECO (up to $30 million).

In lieu of one or more conventional first mortgage bond issues, CL&P might borrow up to $75 million in 1983 in a Eurobond financing that would be effected through a special finance subsidiary. The subsidiary would issue its own debentures in the Eurobond market (i.e., outside the United States of America) and would relend the net proceeds of the debenture issue to CL&P. CL&P would guarantee its subsidiary's obligations. CL&P is also considering entering into an floating rate Eurodollar intermediate term loan arrangement for up to $75 million coupled with an "interest rate swap" arrangement. The objective of such an arrangement is to convert the floating rate term loan obligation into a fixed rate obligation having a lower effective interest cost than a comparable first mortgage bond issue. Whether a Eurobond issue, a term loan and interest rate swap transaction or a conventional first mortgage bond issue will be effected by CL&P will be evaluated at the proposed time of issue in the light of prevailing interest rates and market conditions.

The amount and kind of each issue of securities, and the timing of the securities issues have not been definitively determined.

Financing Limitations

The amounts of short-term borrowings which may be incurred by the Company, CL&P, WMECO, HWP and NNECO are subject to periodic approval by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935. Short-term or other unsecured borrowings are also restricted, in the case of CL&P and WMECO, by the preferred stock provisions of their charters, and in the case of the Company, WMECO and HWP, by loan agreements. The amounts of such restrictions and the amounts of outstanding short-term borrowings are set forth below for the Company, CL&P, WMECO, HWP and NNECO as of December 31, 1982:

	Restrictions		Outstanding at 12/31/82		
	SEC Authorization	Preferred Stock and Loan Limitations*	Commercial Paper	Short-Term Bank Loans**	Total Short-Term Debt Outstanding
	(Thousands of Dollars)		(Thousands of Dollars)		
Company	$100,000	$298,000	- 0 -	$ 10,000	$ 10,000
CL&P	410,000	571,000	$ 25,775	8,800	34,575
WMECO	85,000	89,000	11,950	1,000	12,950
HWP	28,000	41,000	- 0 -	- 0 -	- 0 -
NNECO	80,000	NONE	- 0 -	- 0 -	- 0 -
TOTAL	$703,000	$999,000	$ 37,725	$ 19,800	$ 57,525

[see footnotes, next page]

* While not restricting the amount of short-term debt which CL&P or WMECO may incur, several other loan agreements under which CL&P and WMECO are borrowers provide that the lender is not required to make additional loans if the borrower does not meet specified financial ratios. Compliance with such ratios normally requires, in effect, that the borrower's debt (as defined in each agreement) not exceed specified percentages of total capitalization (as defined).

** See note 5 to the consolidated financial statements for information about credit lines available to System companies.

The indentures securing the outstanding first mortgage bonds of CL&P and WMECO provide that additional bonds may not be issued, except for certain refunding purposes, unless earnings (as defined in each indenture, and before income taxes) are at least twice the pro forma annual interest charges on outstanding bonds and certain prior lien obligations (including outstanding HELCO bonds in the case of CL&P) and the bonds to be issued. CL&P's first mortgage indenture contains a second test that must be met before additional bonds may be issued, namely that CL&P's earnings (as defined, and after deducting income taxes) are at least 1 3/4 times the pro forma annual interest charges on outstanding bonds and certain prior lien obligations (including outstanding HELCO bonds) and the bonds to be issued. The preferred stock provisions of CL&P and WMECO also prohibit the issuance of additional preferred stock unless earnings (as defined) are at least one and one-half times the pro forma annual interest charges on indebtedness and the annual dividend requirements on preferred stock that will be outstanding after the additional stock is issued.

On the basis of the indenture and preferred stock formulas, the coverages for the years ended December 31, 1980, 1981, and 1982 were, based on the amounts outstanding as of the end of such periods, as follows:

	CL&P			WMECO	
	Bond Coverage		Preferred Stock	Bond	Preferred Stock
	2.00 Test	1.75 Test	Coverage	Coverage	Coverage
December 31, 1980	2.20	1.77	1.31	2.23	1.25
December 31, 1981	2.38	1.90	1.46	2.46	1.56
December 31, 1982	2.83	2.19	1.73	2.66	1.63

As part of the merger of HELCO into CL&P, the outstanding preferred stock of HELCO became preferred stock of CL&P. The new CL&P preferred stock has the same dividend rates, sinking funds, liquidation preferences and other relative rights and preferences as the HELCO shares for which they were substituted. The outstanding HELCO bonds were assumed by CL&P, and the HELCO indenture was closed to the issuance of additional bonds. Any subsequent bond issues, including any refunding of outstanding HELCO bond issues, will be effected under the CL&P indenture.

The System companies' ability to meet their financial requirements depends heavily on the adequacy of future earnings, and, therefore, on their ability to obtain adequate and timely rate relief. Since a substantial portion of the subsidiaries' earnings in the period before Millstone 3 and the Seabrook units are placed in rate base is expected to consist of AFUDC, a noncash item, the extent to which the companies must issue senior securities to meet cash requirements is increased. Generally prevailing interest rates and other conditions in the capital markets, and the market appraisal of the System companies' securities, including the Company's common shares, also affect the System companies' ability to carry out their financing plans. If the System companies were to encounter difficulty in financing their present requirements, they would be forced to consider further deferrals or abandonments of projects in their respective construction programs and further reductions of their ownership interests in generating units, operating or under construction.

ELECTRIC OPERATIONS

Distribution and Load

System operating companies own and operate a fully-integrated electric utility business. System companies' retail electric service territories cover approximately 5,877 square miles and have an estimated total population of 2.74 million. The companies furnish retail electric service in 208 cities and towns in Connecticut and Massachusetts.

System operating companies furnish firm wholesale electric service to eight municipal electric systems and four investor-owned electric systems. Three Connecticut municipal electric systems that had previously been firm wholesale customers of CL&P have been served since late 1981 by the Connecticut Municipal Electric Energy Cooperative (CMEEC). CL&P has sold CMEEC life-of-unit rights to capacity from 24 of CL&P's own generating units, and from CL&P's interests in ten jointly-owned generating units. These contracts involve capacity comparable to that previously used by CL&P to serve the municipal systems now served by CMEEC. The contracts do not affect CL&P's ownership interests in the generating units.

The City of Springfield, Massachusetts, is studying the possibility of forming a municipal electric department and acquiring WMECO's facilities in the city. Springfield is the largest city in WMECO's service territory.

About 86 percent of the System's consolidated operating revenues for 1982 came from electric operations. Electric revenues for 1982 were derived 42 percent from residential customers, 32 percent from commercial customers, 21 percent from industrial customers, 3 percent from wholesale customers and the balance from others. The components of electric revenues were not materially different in 1981.

Through March 1, 1983 the all-time maximum demand on the System was 4,126,600 kilowatts, which occurred on January 12, 1981. This figure includes slightly more than 100,000 kilowatts of demand from CMEEC's members. Since October 1, 1981, maximum demand has been computed without CMEEC's requirements. The generating capacity of the System's generating plants (including the System companies' entitlements in regional nuclear generating companies) was 6,373,400 kilowatts at the time of the peak. The System was selling 388,900 kilowatts of capacity from its plants to other utilities at that time. System capacity which is in excess of System needs is offered for sale to other utilities.

During 1982, System energy requirements were met 57 percent by nuclear units, 32 percent by oil burning units, seven percent by coal burning units, and four percent by hydroelectric units. By comparison, during 1981, System energy requirements were met 54 percent by nuclear units, 42 percent by oil burning units, one percent by coal burning units, and three percent by hydroelectric units.

A goal of the System is to promote conservation measures that will help contain the growth in the demand for electricity. The System's March, 1983 load forecast estimates that total energy requirements over the next ten years will grow at an annual compound rate of 1.5 percent, which approximates the load growth target set forth in NU 80s/90s more than two years ago. The Company believes that the lack of significant load growth experienced in the past three years, and the decline of 1.9 percent in the System's kilowatthour sales from 1981 to 1982 (excluding sales to CMEEC for the first nine months of 1981), result in large measure from poor economic conditions and unusually moderate weather in the region, and that these do not represent long-term trends that should be expected to continue. See "Construction and Financing Program -- Construction -- Oil Reduction Efforts" for information about the System's conservation and load growth plans.

The Company expects that the System will be able to meet currently projected customer electricity loads with its existing operating units reliably until at least the early 1990s. It expects that the addition of Millstone 3 and the two Seabrook units would provide the System with the additional capacity necessary to meet projected loads until the late 1990s. Decisions about capacity additions to meet needs for later periods are expected to be made in the mid-1980s.

Generation and Transmission

System operating companies and most other New England utilities with electric generating facilities are parties to the New England Power Pool (NEPOOL) Agreement. Under the NEPOOL Agreement the region's generation and transmission facilities are planned and operated as part of a regional New England bulk power system. System transmission lines form part of a New England transmission system linking System generating plants with one another and with the facilities of other utilities in the northeastern United States and Canada. The generating facilities of all participants are operated as a single system through the New England Power Exchange, a central dispatch facility. The NEPOOL Agreement provides for a determination of the generating capacity responsibilities of participants and certain transmission rights and responsibilities. Pool dispatch results in substantial purchases and sales of electric energy by pool participants, including the System companies, at prices determined in accordance with the NEPOOL Agreement.

The System companies pool their electric production costs and the costs of their principal transmission facilities. This arrangement makes unit bulk power costs of the System companies substantially uniform.

Fossil Fuels

Oil

Oil-fired generation produced approximately 32 percent of the electricity provided to the System's customers in 1982, compared with 42 percent in 1981. These figures represent the use of approximately 12.5 million barrels of oil in 1982, down from 16.6 million barrels in 1981. In 1982, approximately 10.5 million barrels of fuel oil were consumed by the System's own stations in the generation of electricity, down approximately 20 percent from the 13 million barrels used in 1981.

The System companies were able to obtain their full oil requirements in 1982. The average 1982 price paid for fuel oil was about 11 percent below the 1981 level. Currently, the prices for the System's fuel oil are running slightly below 1982 levels, reflecting a surplus of conventional fuel oil. Very low sulfur fuel oils, such as the 0.5 percent sulfur content oil burned at CL&P's Middletown Station, command a price premium over other fuels and have limited availability in the market place.

The System's fuel oil storage capacity is approximately three million barrels. The inventory is generally sufficient for 45 days of operation.

The bulk of the System's oil requirements is purchased under contracts from three large independent oil companies. The contracts expire annually but may be extended from year to year by mutual agreement.

Coal

The first major coal purchases for the System in ten years were begun in August, 1981 to meet the December oil-to-coal conversion date at the Mt. Tom Station. See "Construction and Financing Program -- Construction -- Oil Reduction Efforts." The quality of coal currently being used at Mt. Tom Station is very high in heat value and low in ash content in order to minimize the particulate emissions during the interim period required for the Company to design and install a more efficient precipitator.

Mt. Tom Station consumed 404,000 tons of 1.5 percent sulfur content coal in 1982 at an average delivered price of $63.50 per ton. On the basis of fuel cost per unit of heat energy delivered, the 1.5 percent sulfur content coal which is now burned at Mt. Tom Station currently costs about 50 percent less than the 2.2 percent sulfur content oil it is replacing. Coal of this sulfur grade is readily available; current prices are running below those which were in effect in 1982. All of the coal purchased for the Mt. Tom Station is on a "spot" basis and nine vendors have supplied coal to date. Following the installation of a more efficient precipitator at the station in the summer of 1983, HWP will re-examine its arrangements for coal supply for the station.

The Company believes that the availability of transportation and coal supplies is adequate to meet HWP's requirements for Mt. Tom Station.

Nuclear Generation

General

Together CL&P and WMECO own 100 percent of Millstone 1 and 2, as tenants in common. Their respective ownership interests are 81 percent and 19 percent.

CL&P and WMECO have agreements with other New England utilities covering their joint ownership as tenants in common of Millstone 3. CL&P is a party to such an agreement with respect to its interest in the Seabrook units. The agreements all provide for pro rata sharing of the construction and operating costs and the electrical output of each unit by the owners, as well as associated transmission costs.

CL&P and WMECO own stock in four regional nuclear generating companies (the Yankee companies) whose other stockholders are all New England electric utilities. Each Yankee company owns and operates a single nuclear generating unit. The stockholder-sponsors of a Yankee company are responsible for proportionate shares of the operating costs of the Yankee company, and are entitled to proportionate shares of the electrical output. The relative rights and obligations with respect to the Yankee companies are approximately proportionate to the stockholders' percentage stockholdings, but vary slightly to reflect arrangements under which non-stockholder electric utilities have contractual rights to some of the output of particular units. The Yankee

companies and CL&P's and WMECO's stock ownership percentages in each are set forth below:

	CL&P	WMECO	System
Connecticut Yankee Atomic Power Company (CYAPC)	34.5%	9.5%	44%
Maine Yankee Atomic Power Company (MYAPC)	12.0%	3.0%	15%
Vermont Yankee Nuclear Power Corporation (VYNPC)	9.5%	2.5%	12%
Yankee Atomic Electric Company (YAEC)	24.5%	7.0%	31.5%

CL&P and WMECO are obligated, within specified limits, to provide their percentages of such additional equity capital as may be necessary for the Yankee companies. The shareholders of VYNPC have guaranteed their pro rata shares of a $40 million nuclear fuel financing. CL&P's and WMECO's guaranties in this financing aggregate $4.8 million, plus indemnity obligations. Shareholders of CYAPC have guaranteed their pro rata shares of $50 million principal amount of 17 percent sinking fund debentures and up to $50 million of borrowings that may be made under a revolving credit agreement. CL&P's and WMECO's shares of the guaranties in these financings aggregate $44 million.

The Company believes that the Yankee companies will require additional external financing in the next several years to finance construction expenditures and nuclear fuel or for other purposes. Although the ways in which each Yankee company will attempt to finance these expenditures have not been finally determined, the Company expects that the System companies may be asked to provide additional equity capital and/or other types of direct or indirect financial support for one or more Yankee companies.

Operations

The System companies have interests in six operating nuclear units, Millstone 1 and 2 and the four units owned and operated by the Yankee companies. The System operates the Connecticut Yankee unit on behalf of the owners of CYAPC.

In 1982 Millstone 1 operated at a 70.7 percent capacity factor. (A capacity factor is a ratio which compares a unit's actual generating output for a period with the unit's maximum potential output if it had operated at its design limits for every hour in the period.) The unit was out of service for ten weeks beginning in September, 1982 for scheduled refueling and maintenance. During the shutdown, turbine modifications were made to permit the unit to return to full capability; it had been operating at reduced capability since the unit incurred turbine damage in mid-1981. Millstone 1 is not scheduled to shut down again for refueling and maintenance until 1984.

Millstone 2 operated at a 66.2 percent capacity factor in 1982. The unit was out of service for an extended refueling and maintenance outage which began in December, 1981 and was completed in March, 1982. A pitting corrosion problem affecting steam generator tubes was identified during the outage. Approximately 700 tubes with defects greater than 40 percent of wall thickness (out of more than 17,000 tubes in the unit) were plugged with removable mechanical plugs. The problem was determined to be an operational problem rather than a safety problem. The unit returned to service at 100 percent of its capacity. Detailed analyses to determine the specific causes of the pitting phenomena are underway. The cost and effectiveness of proposed corrective measures, including chemical cleaning, tube sleeving, and sludge lancing, are currently being evaluated. Millstone 2 is scheduled for a sixteen week refueling and maintenance outage beginning in May, 1983. A substantial amount of tube sleeving is scheduled to be performed during the outage.

The Connecticut Yankee, Maine Yankee, Vermont Yankee and Yankee Atomic units operated in 1982 at capacity factors of 89.0 percent, 62.0 percent, 90.3 percent and 57.3 percent, respectively. As of December 31, 1982, the Connecticut Yankee unit had, since it began operations in 1968, generated more than 62 billion kilowatthours of electricity, which the Company believes is more than any other nuclear generating unit in the world has produced.

The Maine Yankee and Yankee Atomic units completed scheduled refueling and maintenance outages in 1982; the next scheduled outage for each unit is in 1984. During its 1982 refueling outage, the Yankee Atomic unit underwent extensive turbine repairs, which restored it to full capability after approximately two years of reduced capacity operations. The Connecticut Yankee unit was shut down on January 22, 1983 for a planned seven-week refueling and maintenance period. The Vermont Yankee unit is scheduled to be taken out of service on March 5, 1983 for refueling and maintenance.

As holders of licenses to construct or operate nuclear reactors, CL&P, WMECO and NNECO are subject to the jurisdiction of the Nuclear Regulatory Commission (NRC). The NRC has broad jurisdiction over the design, construction and operation of nuclear generating stations, including matters of public health and safety, financial qualifications, antitrust considerations and environmental impact.

The NRC regularly conducts generic reviews of technical issues, a number of which may affect the nuclear plants in which System companies have interests. These issues include seismic design standards for nuclear plants located in the Eastern United States, a probabilistic risk assessment program to measure the likelihood and effects of severe accidents at operating nuclear plants, the possibility that neutron bombardment may adversely affect the reactor pressure vessels of operating pressurized water reactors, the ability of safety related equipment to function properly under accident conditions, post-accident measures for controlling hydrogen, a program to evaluate the ability of operating plants to meet current licensing requirements and other issues. At the present time, the outcome of the NRC's reviews of these issues, and the ways in which the different nuclear plants in which System companies

have interests may be affected, cannot be determined. The cost of complying with any new requirements which may result from these reviews cannot be estimated at this time, but such costs may be substantial.

It is anticipated that additional changes in nuclear plant construction, including further backfitting of existing plants, and in nuclear plant operations might be required by the NRC. The System companies' actions and changes in NRC requirements might also result in increases in the capital expenditures and operating costs associated with the nuclear plants in which they have entitlements. Some equipment modifications have required and may in the future require shutdowns or deratings of the plants which would not otherwise be necessary, which would result in additional costs for replacement power. The amounts of increased capital expenditures and operating costs, including costs of replacement power, may be substantial but cannot reasonably be estimated at this time.

Modifications of emergency response planning and notification systems for nuclear plants, including those made to date, are expected to result in total expenditures of $9.4 million for the Connecticut Yankee unit (of which the System's share is 44 percent) and $7.5 million for Millstone 1 and 2. In addition, recently proposed NRC supplemental guidelines relating to emergency response facilities could, if adopted, require additional expenditures of up to $10 million for the Connecticut Yankee unit and up to $20 million for Millstone 1 and 2.

The NRC has evaluated nuclear power plant fire protection requirements and has established regulations on the subject. The System companies joined with five other utilities in requesting judicial review of the validity of those regulations and certain of the specific requirements. A decision rendered by the United States Court of Appeals for the District of Columbia Circuit on March 16, 1982 upheld the validity of the NRC's regulations. The United States Supreme Court has declined to review the Court of Appeals' decision. The System companies have filed with the NRC exemption requests with respect to certain requirements of the NRC's regulations. The Company estimates that the cost of meeting the new fire protection requirements, if all pending exemption requests are granted, will be approximately $20 million for the Connecticut Yankee, Millstone 1 and Millstone 2 plants, together, and, if all exemption requests are denied, approximately $220 million. These estimates assume that the work can be accomplished during normally scheduled refueling outages and therefore do not include any costs associated with replacement power. The NRC's action on pending exemption requests is expected in the first half of 1983.

Following the 1979 Three Mile Island accident, numerous class actions and several individual actions were filed in the U.S. District Court for the Middle District of Pennsylvania and elsewhere, seeking damages as a result of that accident. If the provisions of the Price-Anderson Act are held to apply to the accident, and if total third party damage awards resulting from the accident exceed the private insurance pool coverage of $160 million, then the System companies would be required to pay their share of the excess. The

System companies' share would be a maximum of $5 million for each of the two operating Millstone units, plus their pro rata share of a maximum of $5 million for each of the other operating nuclear units in which they have an ownership interest. See note 8 to the consolidated financial statements for information about the System's insurance arrangements relating to liability, property damage and the cost of replacement power resulting from nuclear incidents.

See "Regulatory and Environmental Requirements and Proceedings -- NRC Nuclear Plant Licensing" for information about licensing matters which affect the System's nuclear units.

Nuclear Fuel

To the extent indicated below, there are outstanding contracts for uranium concentrates and conversion, enrichment and fabrication for the System's existing and planned units, and the other units in which System companies are participating, which cover the units' requirements through the following years:

	Uranium Concentrates	Conversion to Hexafluoride	Enrichment	Fabrication
Connecticut Yankee	1986	1986	1995	1986
*Maine Yankee	1987	1995	2002	1991
*Vermont Yankee	1990	1995	2001	1984
*Yankee Atomic	1983	1995	2001	1993
*Seabrook Unit No. 1	1984	1987	2009	1990
*Seabrook Unit No. 2	1984	1987	2011	1990
Millstone 1	1987	1988	2001	1992
Millstone 2	1986	1987	2001	1987
Millstone 3	1990	1988	2014	1993

* The information in the table for these units has been furnished to the Company by the utility company having responsibility for operation of the unit.

The System expects that uranium concentrates and related services for periods not covered by existing contracts will be available, although their availability might require that suppliers develop additional capacity.

Waste Disposal and 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. The System companies reflect in their nuclear fuel expense the spent fuel disposal costs estimated by the U.S. Department of Energy (DOE). This provision for spent fuel disposal has been accepted by the

DPUC and the DPU in rate case or fuel adjustment decisions and is reflected in the wholesale fuel adjustment charges. Such provisions, which reflect increases over previous levels, also include amortization and recovery in rates, over a ten-year period, of previously unrecovered estimated disposal costs of accumulated spent nuclear fuel.

On January 7, 1983 the President of the United States signed into law the Nuclear Waste Policy Act of 1982. Under this Act the Federal government is required to design, license, construct and operate a permanent repository for high level radioactive wastes and spent nuclear fuel. The Federal government will also establish a fee to be paid to the government by electric utilities owning or operating nuclear generating units. The fee has been initially set at 1.0 mil per kilowatthour for nuclear generation after April 7, 1983. The fee for previously burned fuel will be at a comparable rate for the electric utility industry as a whole, but the charge for each utility has not yet been definitely determined. In return for the fee, the Federal government, beginning not later than January 31, 1998, will take title to and dispose of the utilities' high level wastes and spent nuclear fuel. Under the Act the NRC may not renew a license for any person to use a production facility unless that person, by June 30, 1983, enters into a contract with the Federal government for disposal of its high level wastes and spent nuclear fuel.

Until the Federal government begins receiving such materials in accordance with the Nuclear Waste Policy Act, operating nuclear generating plants will need to retain high level wastes and spent fuel on-site or make some other provisions for their storage until that time. The storage facilities for Connecticut Yankee and the Millstone units, including facilities currently under construction at Millstone 3, are expected to be adequate until the time when the Act requires a Federal repository facility to be available. MYAPC and YAEC will require additional storage capacity on site by the mid-1980s; each is examining ways of increasing the density of fuel storage within its present facility. The Company has been advised by VYNPC that it expects that its storage capacity to be adequate until at least 1989; VYNPC's plans for storage beyond that date are not known.

Disposal costs for low level radioactive wastes that result from normal operation of the System's nuclear units have increased significantly in recent years despite reduced volumes of such wastes, and are expected to continue to rise. The cost increases are functions of increased packaging and transportation costs, and higher fees from the disposal facilities. Pursuant to the Low Level Radioactive Waste Policy Act of 1981, the states in which present disposal facilities are located (South Carolina, Nevada and Washington) will be allowed to prohibit shipments of low level wastes from states which have not entered into regional compacts by 1986. There is no assurance that wastes from nuclear units in which System companies have interests can be sent to the present facilities or that new sites will be available and willing to accept low level wastes from such nuclear units by that date.

If storage or waste repository facilities for spent fuel or low level wastes, or both, are not available when required, the System may incur substantial additional costs in developing alternate arrangements.

The System companies estimate decommissioning costs for their nuclear units on the basis of immediate and complete dismantlement of those units at their retirement. The estimated decommissioning costs on this basis for Millstone 1 and 2 and Connecticut Yankee are in the range of $80 to $100 million per unit, in current dollars. These estimates are reviewed and updated regularly to reflect inflation and changes in decommissioning requirements and technology. Changes in requirements or technology, or adoption of a decommissioning method other than immediate dismantlement, could increase these estimates further. CL&P and WMECO attempt to recover sufficient amounts through their allowed revenues to cover their expected decommissioning costs. Although allowances for decommissioning have increased significantly in recent years, full rate recovery of the projected costs of decommissioning will require ratepayers in future years to increase their payments in order to offset the effects of insufficient rate recoveries in previous years. Only the portion of presently estimated total decommissioning costs that has been accepted by regulatory agencies is reflected in the financial statements of the Company.

VYAPC is not currently collecting funds for decommissioning from its sponsors but is proposing to start such collections in 1983. YAEC, MYAPC and CYAPC have been collecting revenues for decommissioning, and each has increased the amount of their collections in 1982. The Company expects that all Yankee companies will be increasing their decommissioning charges in future years.

GAS OPERATIONS

CL&P furnishes retail gas service in eleven separate service areas, not fully interconnected, that cover approximately 1,321 square miles in 51 cities and towns in Connecticut with an estimated population of 1.22 million. About 13 percent of the System's consolidated operating revenues for 1982 came from gas operations. Gas revenues in 1982 were derived 42 percent from residential customers, 26 percent from commercial customers, 31 percent from industrial customers and the balance from others. The components of gas revenues were not materially different in 1981.

Pipeline gas provided 93.1 percent of CL&P's 1982 requirements. Liquified natural gas (LNG) provided 4.8 percent and propane provided the remainder. System gas requirements for 1983 are expected to be met approximately 92.8 percent by pipeline gas, 4.1 percent by LNG and the balance by propane. Pipeline gas is purchased under long-term contracts with Algonquin Gas Transmission Company (approximately 60 percent) and Tennessee Gas Pipeline Company (approximately 40 percent) at rates subject to the jurisdiction of the FERC.

The System's gas supplies have been adequate in recent years, and did not require any service interruptions, even during the unusually cold periods in January, 1982. Through March 1, 1983, the System's peak day sendout was on January 18, 1982, when CL&P distributed 206,783 million British thermal units of gas. CL&P anticipates that gas supplies will be adequate through at least the 1986-87 heating season.

Suppliers of pipeline gas have periodically obtained rate increases for their gas deliveries and have additional requests for rate increases pending before the FERC. Increases in purchased gas costs are by far the most significant factors in increased operating costs for gas service. CL&P has an adjustment clause in its retail gas rate schedules under which billings to customers reflect changed gas costs.

The price of most natural gas produced in the United States is controlled pursuant to the Natural Gas Policy Act of 1978. The price controls are to expire under that Act with respect to an estimated 60 percent of domestically produced gas on January 1, 1985. Proposed changes to the Act to accelerate or defer further the effective date of the end of price controls, and to expand or restrict the nature of gas production subject to price controls, are being actively advocated by industry groups, consumer groups and others with substantial but often conflicting interests in the matter. The ultimate resolution of the price control issue is expected to have substantial implications for the price and supply of natural gas, but the effects cannot be known at present.

CL&P is undertaking a long-term program of improving its gas distribution system. It installed 22,000 linear feet of gas main in Stamford, Connecticut, in 1982 as part of an extensive distribution rehabilitation program in that city. Approximately 20,000 linear feet of main were replaced in the towns of Shelton, Derby, Ansonia and Monroe, Connecticut. In addition, two separate service areas (Waterbury and Shelton) were connected in late 1981 to increase the system's reliability by allowing for exchange of gas purchased from two different gas pipeline companies.

CL&P, along with thirteen other gas companies in New England, New York, and New Jersey, has made arrangements to receive a ten-year supply of natural gas from TransCanada Pipelines Limited (TransCanada), a Canadian corporation. To facilitate their dealings with TransCanada, the participants have organized Boundary Gas, Inc. to purchase gas from TransCanada and to resell gas to the participants. CL&P has a 5.11 percent stock ownership interest in Boundary Gas, which entitles and obligates it to purchase a proportionate share of the natural gas that Boundary Gas is expected to purchase from TransCanada.

For TransCanada to deliver gas to the United States it must construct major pipeline facilities to connect with United States facilities in upper New York State. In addition to the pipeline facilities to be built by TransCanada, additional transportation facilities within the United States are necessary. Some facilities are needed to connect TransCanada's facilities with those of

Tennessee Gas Pipeline Company at the United States-Canadian border near Niagara Falls, New York. Other facilities are needed to augment the capacity of existing Tennessee facilities through which gas is transported to gas distribution companies in the northeastern United States. All such facilities are expected to be completed in late 1984 if timely regulatory approvals are received and if Tennessee Gas Pipeline Company is able to arrange suitable financing for the projects.

The TransCanada arrangements require approval of Canada's National Energy Board, which began hearings in March, 1982. On January 27, 1983 the Canadian National Energy Board approved the sale of about 92 million cubic feet of gas per day for all Boundary Gas participants, of which CL&P's share would be about 4.8 million cubic feet per day. This is about half the amount requested and would represent about five percent of CL&P's total gas supplies during 1985, the anticipated first full year of purchases. The FERC and the Economic Regulatory Administration (ERA) of the DOE must also approve the project. In August, 1982 the ERA issued an order conditionally authorizing Boundary Gas' importation of gas from Canada. Hearings on the FERC application began in December, 1982; a decision is expected by the fall of 1983. Receipt of all necessary approvals for the Boundary Gas project is therefore not assured.

After a sale agreement under which CL&P would have sold its gas properties to another utility terminated in 1979, CL&P undertook studies to determine whether to retain or dispose of its gas properties. It has concluded that the gas properties should be retained. The SEC has opposed retention of both gas and electric properties by companies subject to the Public Utility Holding Company Act of 1935. See "Regulatory and Environmental Requirements and Proceedings -- Public Utility Regulation" for information about possible amendment or repeal of that law.

REGULATORY AND ENVIRONMENTAL REQUIREMENTS AND PROCEEDINGS

Public Utility Regulation

The Company is registered with the SEC as a holding company under the Public Utility Holding Company Act of 1935 (the 1935 Act). Under the 1935 Act, the SEC has jurisdiction over the Company and its subsidiaries with respect to, among other things, securities issues, sales and acquisitions of securities and utility assets, intercompany loans, services performed by and for associated companies, accounts and records, involvement in non-utility operations, and dividends. The 1935 Act has been the subject of proposed legislation that would repeal or substantially modify the law. Whether the 1935 Act will be repealed or substantially amended, and whether regulation of the System companies would be materially reduced or modified, is not known.

CL&P is subject to regulation by the DPUC, which has jurisdiction, among other things, over retail rates, accounting procedures, certain

dispositions of property and plant, mergers and consolidations, securities issues, standards of service, management efficiency, and construction and operation of generation, transmission and distribution facilities. WMECO is also subject to the jurisdiction of the DPUC with respect to its activities in Connecticut and securities issues.

WMECO is subject to regulation by the DPU, which has jurisdiction over retail rates, accounting procedures, quality of service, contracts for the purchase of electricity, mergers, securities issues and other matters. HWP is subject to regulation by the DPU with respect to certain contracts and quality of service. The Company and its subsidiaries are subject to the general supervision of the DPU with respect to all dealings with WMECO and HWP.

CL&P is subject to the jurisdiction of the NHPUC for limited purposes in connection with its ownership interest in the Seabrook units.

CL&P, WMECO and HWP are public utilities under Part II of the Federal Power Act and are subject to regulation by the FERC with respect to, among other things, interconnection and coordination of facilities, wholesale rates and accounting procedures.

The System incurs substantial capital expenditures and operating expenses to comply with environmental, energy, licensing and other regulatory requirements, including those described in the following subsections, and it expects to incur additional costs to meet further developments in these and other areas of regulation. Because of the continually changing nature of regulations affecting the System, the total amount of these costs is not now determinable. Compliance with existing and proposed regulations also affects the time needed to complete new facilities or to modify present facilities, and it affects System companies' rates, sales, revenues and net income, all in ways that may be substantial but are not readily calculable.

Environmental Impact Requirements

The National Environmental Policy Act of 1969 (NEPA) requires that detailed statements of the environmental effects of major federal actions be prepared by federal agencies. Major federal actions can include licenses or permits issued to the System by the FERC, the NRC and other federal agencies for construction or operation of generation and transmission facilities. NEPA requires that federal licensing agencies make an independent environmental evaluation of the proposed action.

Massachusetts law requires all state agencies to determine the environmental impact of any construction proposed by private companies requiring state permits, funding or participation. Massachusetts state agencies are required to make "a finding that all feasible measures have been taken to avoid or minimize impact" of such construction. In certain instances Massachusetts law also requires the preparation and dissemination among various state agencies of environmental impact reports pertaining to the proposed construction.

NRC Nuclear Plant Licensing

Millstone 2 and the Yankee Atomic, Connecticut Yankee, Maine Yankee and Vermont Yankee units have full term (typically 40 years from the date a construction permit is issued for the unit) full power operating licenses. An application for a full term full power operating license for Millstone 1, which is operating under a provisional license, is pending before the NRC. A construction permit for Millstone 3 was issued by the NRC in August 1974 and expires December 30, 1985. An application for a full term full power operating license for Millstone 3 was filed with the NRC on October 29, 1982. It is expected that an operating license will be obtained or that the construction permit will be extended before the current expiration date.

NRC construction permits for Seabrook Units 1 and 2 were issued in 1976. An application for an operating license for the Seabrook plant was docketed by the NRC in October, 1981. It is expected that evidentiary hearings on the operating license application, which will be contested, will not commence before the Spring of 1983. The construction and licensing of these units has been subjected to lengthy delays associated with administrative proceedings, numerous lawsuits, financial constraints, work stoppages and demonstrations at the construction site. See "Construction and Financing Program -- Construction -- Seabrook" for further information about Seabrook.

In April, 1982, the U.S. Court of Appeals for the District of Columbia Circuit invalidated the NRC's generic rule on the environmental effects of the uranium fuel cycle in the case of Natural Resources Defense Council v. NRC. This rule has been used by the NRC since 1974 in connection with the licensing of nuclear power plants in order to comply with the requirements of NEPA. The U.S. Supreme Court has agreed to review this case; it is expected that oral arguments will be heard in April, 1983. Although the decision has not yet become effective, it raises questions with respect to many construction permits and operating licenses issued by the NRC, including permits and licenses for plants in which the System companies have an interest.

The time required to construct major generating facilities and to obtain required licenses and regulatory approvals compels electric utilities (including System companies) to make substantial investments in facilities before final licenses and approvals are received. Completion of each of the three nuclear generating units now under construction in which the System companies are participating depends, among other things, on obtaining necessary regulatory approvals, permits and sufficient financing. If any of the units were canceled due to future developments, System companies would apply to appropriate regulatory authorities for approval to amortize their shares of total costs over a future period and to recover the costs through their rates. Although they have been allowed to amortize and recover through rates part of the costs of previously cancelled nuclear units, the System companies cannot predict whether and to what extent such recovery would be permitted.

The effect of the licensing matters described in this section on operating nuclear units and on units under construction cannot accurately be

predicted. In some circumstances, they could require modifications, reductions in authorized power levels or shutdowns of operating units. They could also require modification of units under construction, or they could delay or prevent their construction. Any of these effects could have a substantial adverse effect on the System companies.

Water Quality Requirements

The federal Clean Water Act (CWA) provides that every "point source" discharger of pollutants into navigable waters must obtain a National Pollutant Discharge Elimination System (NPDES) permit specifying the allowable quantity and characteristics of its effluent. To obtain an NPDES permit, a discharger must meet technology-based effluent standards and must also demonstrate that its effluent will not cause a violation of established standards for the quality of the receiving waters.

The initial NPDES permits for System thermal generating plants expired in 1979. New permits were issued for System plants in Massachusetts in January, 1980 but expired October 1, 1980. Pending receipt of a new permit, for which an application has been submitted, WMECO's West Springfield station is being operated in accordance with the expired permit. A permit was issued in December, 1981 for HWP's Mt. Tom Station, in connection with its conversion to coal burning. New permits have been obtained for System plants in Connecticut. These permits will expire in January, 1985, except for the permit for the Millstone units, which expires in July, 1985. The permits may be reopened to reflect more stringent requirements proposed by the EPA. Compliance with NPDES requirements has necessitated substantial expenditures and may require further expenditures in the future.

The applicability of NPDES permit requirements to hydroelectric facilities is unresolved and is the subject of litigation in which the System companies have intervened. The United States Court of Appeals for the District of Columbia Circuit has ruled in the case of National Wildlife Federation v. Gorsuch that the EPA has authority to determine that dams do not require NPDES permits. System companies have not obtained NPDES permits for their hydroelectric facilities.

The CWA requires the DEP in Connecticut and the EPA and the Department of Environmental Quality Engineering (DEQE) in Massachusetts to approve the intake structure design and thermal discharge of generating plants. All System plants have received these approvals.

On November 19, 1982 the EPA published its final effluent guidelines for the steam electric generating industry. The major impact on System generating units is expected to be from more stringent controls on the discharge of chlorine. Augmented chemical waste treatment facilities for the System's generating plants may be required to comply with the guidelines.

The CWA's ultimate cost impact on the System cannot be estimated because of uncertainties such as the impact of the newly promulgated effluent

guidelines. Additional modifications, in some cases extensive and involving substantial cost, may ultimately be required for one or more of the System's generating facilities.

Air Quality Requirements

Under the federal Clean Air Act, the EPA has promulgated national ambient air quality standards for certain air pollutants, including sulfur oxides, particulate matter and nitrogen oxides. With some exceptions, the EPA has approved a Connecticut implementation plan proposed by the DEP, and a Massachusetts plan proposed by the DEQE, for the achievement, maintenance and enforcement of these standards.

In November 1981 the DEP revised its air quality regulations. The regulations now permit CL&P to burn 1.0 percent sulfur oil at all but one of its oil-fired generating stations in Connecticut. CL&P must continue to burn 0.5 percent sulfur oil at its Middletown Station. The revised regulations could also permit the burning of coal with a sulfur content of up to 0.7 percent at CL&P's plants, or up to 1.0 percent if a discretionary permit were obtained; however, see "Construction and Financing Program -- Construction -- Oil Reduction Efforts" for information about a recent DEP proceeding which could have adverse consequences for coal burning at CL&P's plants.

The Massachusetts air quality regulations permit HWP to burn 1.5 percent sulfur coal at Mt. Tom Station. WMECO's West Springfield Station has burned 2.2 percent sulfur oil since 1977. The results of recent air quality modeling tests indicated that a reduction of the sulfur content in the oil burned at that station would be necessary under certain weather conditions to satisfy air quality requirements in the Springfield area. The units are currently burning 1.0 percent sulfur oil as required by the DEQE while WMECO explores ways of meeting air quality standards with the use of the less expensive 2.2 percent sulfur oil.

EPA, Connecticut and Massachusetts regulations also include other air quality standards, emission standards and monitoring, and testing and reporting requirements which apply to the System's generating stations. They require that new or modified fossil fuel-fired electric generating units operate within stringent emission limits, and meet all applicable state and federal air quality standards and regulations. These regulations could hinder or possibly preclude coal conversion projects or the construction of new or modification of other existing fossil units in the System's service area.

Toxic Substances and Hazardous Waste Regulations

Under the federal Toxic Substances Control Act of 1976 (TSCA), the EPA has issued regulations which control the use and disposal of polychlorinated biphenyls (PCBs). PCBs had been widely used as insulating fluids in many electric utility transformers and capacitors manufactured before TSCA prohibited any further manufacture of such PCB equipment. The System companies have taken numerous steps to comply with these regulations and have

incurred increased costs for disposal of used fluids and equipment that are subject to the regulations. One disposal measure involves the System's burning of some waste oil with a low level of PCB contamination (between 50 and 500 parts per million) as supplemental fuel at CL&P's Middletown Station Unit No. 3. The EPA and DEP have approved this disposal method. In several related legal actions in 1981, the City of Middletown, Connecticut, challenged the System's method of disposing of low level PCB contaminated oil; one such action is currently on appeal before the Connecticut Supreme Court. In response to these local concerns, independent studies were conducted which concluded that there was no evidence that burning this waste oil would present a hazard to human health or the environment.

Fluids with a concentration of PCBs higher than 500 parts per million, and materials (such as electrical capacitors) that contain such fluids, must be disposed of through burning in high temperature incinerators approved by the EPA. Three such incinerators owned and operated by unaffiliated companies, located outside the System's service territories, have been approved. Solid wastes containing PCBs must be disposed of in secured chemical waste landfills.

EPA regulations issued in 1982 require utilities to phase out the use of certain PCB capacitors by 1986. The System expects to incur additional costs in connection with PCB disposal, but costs other than for phasing out capacitors are not expected to be material.

Under the federal Resource Conservation and Recovery Act of 1976 (RCRA), the generation, transportation, storage, treatment and disposal of hazardous wastes are subject to EPA regulations. Massachusetts and Connecticut have issued state regulations that parallel RCRA regulations but are more stringent. The notifications and applications required by the present regulations have been made. The procedures by which System companies handle, store, treat and dispose of hazardous waste products have been revised, where necessary, to comply with these regulations.

FERC Hydro Project Licensing

System operating companies hold licenses granted under Part I of the Federal Power Act for the operation and maintenance of seven existing hydroelectric projects, the Northfield, Turners Falls, Gardners Falls, Hadley Falls, Scotland, Housatonic and Falls Village projects. The FERC has held that no license is required for four other existing projects, the Chicopee River, Taftville, Robertsville and Tunnel projects. A license application for the Derby-Shelton project described under "Construction and Financing Program -- Construction -- Oil Reduction Efforts", is pending before the FERC. The licensing of two other projects, involving units which had previously been retired but which have recently been restored and reactivated, is under review.

Federal Power Act licenses may be issued for terms of fifty years or less as determined by the FERC. Any hydroelectric project so licensed is subject to recapture by the United States or licensing to others, after

expiration of the license, upon payment to the licensee of the lesser of fair value or the net investment in the project plus severance damages less certain amounts earned by the licensee in excess of a reasonable rate of return. Licenses are customarily conditioned on the licensee's development of recreational and other nonpower uses at each licensed plant. Conditions may be imposed with respect to low flow augmentation of streams and fish passage facilities.

On December 28, 1982 the FERC ruled that the Holyoke (Mass.) Gas and Electric Department (the Department) will not be issued a preliminary permit to study the feasibility of installing additional hydroelectric capacity at the Hadley Falls project on the Connecticut River because HWP has a license to the potential power at the site. In its decision, however, the FERC ordered HWP to study the economic feasibility of installing capacity at the project in addition to the capacity to be provided by the unit described under "Construction and Financing Program -- Construction -- Oil Reduction Efforts". The Department has asked the FERC to reconsider its order.

SEGMENTS OF BUSINESS

Information about the Company's business segments is given in note 9 to the consolidated financial statements, which are included in Appendix A to this report.

EMPLOYEES

The officers of the Company receive their remuneration from the Service Company or other System companies, not from the Company. The Company has no employees. As of December 31, 1982, the Company's subsidiaries had approximately 8,700 regular employees on their payrolls. CL&P, WMECO and HWP have union agreements covering approximately 2,500 employees. All the union agreements expire in 1984.

Item 2. Properties

The physical properties of the System are owned or leased by subsidiaries of the Company.

CL&P's properties are subject to the liens of CL&P's first mortgage indentures and with respect to properties formerly owned by HELCO, to the lien of HELCO's first mortgage indenture. WMECO's and HWP's physical properties are subject to the liens of their respective first mortgage indentures. In addition, CL&P's and WMECO's interest in Millstone 3 and Millstone 1 are subject to second liens in favor of the trustee of the Millstone Construction Trust (in the case of Millstone 3) and lenders under term loan agreements (in the case of Millstone 1).

From January 1, 1978 through December 31, 1982, the System companies made gross property additions and betterments to utility plant, excluding nuclear fuel, aggregating $1,565,958,000 and retired or sold properties having an aggregate cost of $201,792,000, resulting in net additions during that period of $1,364,166,000.

Electric Properties

As of December 31, 1982, the System operating companies had 50 transmission substations with an aggregate capacity of 17,663,375 kVA and 366 distribution substations with an aggregate capacity of 8,288,757 kVA. Their transmission systems included 450 circuit miles of overhead 345 kV lines, 1,463 circuit miles of overhead 115 kV lines, 40 cable miles of 138 kV submarine cable, 113 cable miles of underground 115 kV cable and 152 circuit miles of 69 kV overhead lines. The distribution systems included 20,677 pole miles of overhead lines and 842 conduit bank miles of underground lines. The System operating companies had in service 233,215 line transformers with an aggregate capacity of 9,818,565 KVA.

As of December 31, 1982, the electric generating plants of the System operating companies and the System companies' entitlements from the generating plants of the four Yankee regional nuclear generating companies were as follows:

Name, Owner, Town, Location	Type	Year Installed	Total Generating Plant: Name Plate Rating (Kilowatts)	Total Generating Plant: Claimed Capability (Kilowatts) (Winter Ratings)	Northeast (a) Utilities' Entitlements (Kilowatts) (Winter Ratings)
System Generating Plants					
Millstone Plant (CL&P & WMECO)	Nuclear	1970	661,500	660,000	637,064
(Waterford-Long Island Sound)		1975	909,900	868,500	838,319
			1,571,400	1,528,500	1,475,383
Northfield Plant (CL&P & WMECO) (Northfield and Erving - Connecticut River)	Pumped Storage	1972-1973	846,000	1,000,000	988,256
Middletown Plant (CL&P)	Steam	1954-1973	836,896	833,000	800,745
(Middletown - Connecticut River)	Gas Turbine	1966	18,594	- (c)	- (c)
			855,490	833,000	800,745
Montville Plant (CL&P)	Steam	1954-1971	489,900	492,000	472,949
(Montville - Thames River)	2 Diesels	1967	5,500	5,500	5,288
			495,400	497,500	478,237
Devon Plant (CL&P)	Steam	1942-1958	429,000	463,000	454,558
(Milford - Housatonic River)	Gas Turbine	1966	16,320	18,700	17,976
			445,320	481,700	472,534
Norwalk Harbor Plant (CL&P)	Steam	1960-1963	326,400	338,000	324,913
(Norwalk - Long Island Sound)	Gas Turbine	1966	16,320	17,000	16,342
			342,720	355,000	341,255
West Springfield Plant (WMECO)	Steam	1949-1957	209,636	211,300	211,300
(West Springfield - Connecticut River)	Gas Turbine	1968	18,594	22,000	22,000
			228,230	233,300	233,300
South Meadow Plant (CL&P) (Hartford - Connecticut River)	4 Gas Turbines	1970	167,400	196,000	196,000
Mt. Tom Plant (HWP) (Holyoke - Connecticut River)	Steam	1960	136,000	148,000	92,000
Turners Falls Plant (WMECO) (Montague - Connecticut River)	Hydro	1905-1917	55,520	58,000	58,000
Shepaug Plant (CL&P) (Southbury - Housatonic River)	Hydro	1955	37,200	47,000	44,255
Rocky River Plant (CL&P) (New Milford - Housatonic River)	Pumped Storage	1928-1952	31,000	29,000	29,000
Cobble Mountain Plant (WMECO) (b) (Granville - Westfield Little River)	Hydro	1930	33,000	32,500	32,500

Name, Owner, Town, Location	Type	Year Installed	Total Generating Plant Name Plate Rating (Kilowatts)	Clamied Capability (Kilowatts)	Northeast (a) Utilities' Entitlements (Kilowatts)
				(Winter Ratings)	
Stevenson Plant (CL&P) (Monroe - Housatonic River)	Hydro	1919-1936	30,500	28,700	28,700
18 Small Hydro Plants			66,256	69,100	65,020
9 Gas Turbine Plants			211,908	242,200	242,200
Total System Generating Plants			5,553,344	5,779,500	5,577,385
Regional Nuclear Generating Plants (d)					
Connecticut Yankee Atomic Power Company (Haddam, Connecticut)	Nuclear	1968	264,132	247,181	247,181
Maine Yankee Atomic Power Company (Wiscasset, Maine)	Nuclear	1972	109,111	107,907	107,907
Vermont Yankee Nuclear Power Corporation (Vernon, Vermont)	Nuclear	1972	60,796	54,996	54,996
Yankee Atomic Electric Company (Rowe, Massachusetts)	Nuclear	1961	58,275	53,453	53,453
Total Regional Nuclear Generating Plants			492,314	463,537	463,537
Total Generating Plants			6,045,658	6,243,037	6,040,922

(a) Northeast Utilities' Entitlements (Kilowatts) ratings are shown net of the following life-of-unit contracts:

- The Connecticut Municipal Electric Energy Cooperative (CMEEC) Agreement under which CMEEC has rights to specific percentages of the total claimed capability of various generating units within the NU system.

- HWP sells approximately 56,000 KW of the capacity (37.8% of the output) of its Mt. Tom plant to the New England Power Company (NEPCO) under a contract that terminates in 1990, unless NEPCO exercises its right to extend the contract for an additional ten years.

(b) The Cobble Mountain plant is leased from the City of Springfield.

(c) Middletown Gas Turbine unit is expected back in service by mid 1983. The unit's winter capability at that time is expected to be 22,000 KW with an NU Entitlement of 21,100 KW.

(d) Represents Northeast Utilities' entitlements in the generating plants of the four Yankee regional nuclear generating companies.

Gas Properties

As of December 31, 1982, CL&P, the only operating subsidiary of the Company supplying retail gas service, had nine propane plants, three permanent LNG plants and leased space in two other large LNG storage facilities, nine gas storage holders with a total capacity of approximately 8,197 Mcf, 2,265 miles of gas distribution mains and approximately 6 miles of gas transmission mains. See "Operations - Gas" under "Item 1. Business".

Franchises

The Company's operating subsidiaries hold numerous franchises in the territories served by them.

CL&P

Subject to the power of alteration, amendment or repeal by the General Assembly of Connecticut and subject to certain approvals, permits and consents of public authority and others prescribed by statute, CL&P has, subject to certain exceptions not deemed material, valid franchises free from burdensome restrictions to sell electricity and gas in the respective areas in which it is now supplying such service.

In addition to the right to sell electricity and gas as set forth above, the franchises of CL&P include, among others, rights and powers to manufacture, generate, purchase, transmit and distribute electricity and gas, to sell electricity and gas at wholesale to other utility companies and municipalities and to erect and maintain certain facilities on public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. The franchises of CL&P include the power of eminent domain.

NNECO

Subject to the power of alteration, amendment or repeal by the General Assembly of Connecticut and subject to certain approvals, permits and consents of public authority and others prescribed by statute, NNECO has a valid franchise free from burdensome restrictions to sell electricity to utility companies doing an electric business in Connecticut and other states.

In addition to the right to sell electricity as set forth above, the franchise of NNECO includes, among others, rights and powers to manufacture, generate and transmit electricity, and to erect and maintain facilities on public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law.

WMECO

WMECO is authorized by its charter to conduct its electric business in the territories served by it, and has locations in the public highways for transmission and distribution lines. Such locations are granted pursuant to the laws of Massachusetts by the Department of Public Works

of Massachusetts or local municipal authorities and are of unlimited duration, but the rights thereby granted are not vested. Such locations are for specific lines only, and for extensions of lines in public highways further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. In addition, WMECO has been granted easements for its lines in the Massachusetts Turnpike by the Massachusetts Turnpike Authority.

HWP and Holyoke Power and Electric Company (HP&E)

HWP and its wholly owned subsidiary HP&E are authorized by their charters to conduct their businesses in the territories served by them. HWP's electric business is subject to the restriction that sales be made by written contract in amounts of not less than 100 horsepower except for municipal customers in the counties of Hampden or Hampshire, Massachusetts and except for customers who occupy property in which HWP has a financial interest, by ownership or purchase money mortgage. HWP also has certain dam and canal and related rights, all subject to such consents and approvals of public authorities and others as may be required by law. The two companies have locations in the public highways for their transmission and distribution lines. Such locations are granted pursuant to the laws of Massachusetts by the Department of Public Works of Massachusetts or local municipal authorities and are of unlimited duration, but the rights thereby granted are not vested. Such locations are for specific lines only and for extensions of lines in public highways further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. The companies have no other utility franchises.

Item 3. Legal Proceedings

The United States District Court for the District of Connecticut has before it an antitrust action involving two price-squeeze claims brought against the Company, CL&P and Northeast Utilities Service Company by three municipal customers of CL&P (Wallingford, East Norwalk and South Norwalk). The price-squeeze claims were remanded to the District Court in an October 13, 1981 decision by the United States Court of Appeals for the Second Circuit. The Court of Appeals denied the remaining antitrust claims of the municipal customers.

On August 24, 1982 WMECO filed an appeal with the Massachusetts Supreme Judicial Court challenging a May 28, 1982 order of the DPU to file an amendment of the System's generation and transmission agreement (the NUG&T) with the FERC and to prepare and file with the DPU a report on alternative allocation methodologies for the NUG&T. The NUG&T is the contract among the system companies that provides the basis for planning their bulk power supply system on a one-system basis. A decision by the Court with respect to the DPU's jurisdiction is not expected until late 1983.

Although the appeal of the DPU decision is still being pursued, WMECO filed the ordered allocation study with the DPU on October 15, 1982 and filed an amendment of the NUG&T with the FERC on November 9, 1982. The FERC amendment proposes, as ordered by the DPU, a change in the return on common equity portion of the NUG&T. In the FERC filing, WMECO preserved its arguments that the DPU does not have jurisdiction over the NUG&T.

While the proposed amendment of the NUG&T may, if approved by the FERC, shift expenses among the operating companies, there would be no revenue change for the System as a whole. Whether a shift of expenses between companies would affect decisions on a state regulatory level in the future is presently unknown.

The following sections of "Item 1. Business" discuss additional legal proceedings: "Construction and Financing Program -- Construction -- Seabrook" for information about proceedings relating to the Seabrook nuclear electric generating units in which CL&P has an ownership interest; "Rates" for information about rate and fuel adjustment clause proceedings; "Regulatory and Environmental Requirements and Proceedings" for information about litigation over NRC licensing regulation, litigation over the System's plans for PCB disposal, and litigation over NPDES permit requirements, and "Electric Operations -- Nuclear Generation -- Operations" for information about possible contingent liabilities of CL&P and WMECO for damages resulting from the TMI accident and litigation concerning NRC fire protection regulations.

Item 4. Submission of Matters to a Vote of Security Holders (Fourth Quarter 1982)

NONE

PART II

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

The Company declared and paid quarterly dividends of $0.295 in 1981 and $0.32 in 1982. On January 25, 1983, the Board of Trustees declared a dividend of $0.345 per share, payable on March 31, 1983 to holders of record on March 1, 1983. The declaration of future dividends may vary depending on capital requirements and income as well as financial and other conditions existing at the time.

Information with respect to dividend restrictions is contained in Note (b) of the "Notes to the Consolidated Statements of Capitalization" on page 37 and additional information with respect to common shares is contained under the caption "Common Share Information" on page 54 of the Company's Annual Report to Shareholders, portions of which are attached to this report as Appendix A.

Item 6. Selected Consolidated Financial Data

This information is contained on page 50 of the Company's Annual Report to Shareholders, portions of which are attached to this report as Appendix A.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

This information is contained on pages 15 through 25 of the Company's Annual Report to Shareholders, portions of which are attached to this report as Appendix A.

Item 8. Financial Statements and Supplementary Data

The following consolidated financial statements of the Company and its subsidiaries are included on pages 30 through 49 and page 54 in the Company's Annual Report to Shareholders, portions of which are attached to this report as Appendix A.

Company Report

Auditors' Report

Consolidated Statements of Income for the years ended December 31, 1982, 1981 and 1980

Consolidated Statements of Sources of Funds for Gross Property Additions for the years ended December 31, 1982, 1981 and 1980

Consolidated Balance Sheets at December 31, 1982 and 1981

Consolidated Statements of Capitalization at December 31, 1982 and 1981

Consolidated Statements of Common Shareholders' Equity for the years ended December 31, 1982, 1981 and 1980

Notes to Consolidated Financial Statements

Consolidated Statements of Quarterly Financial Data

Item 9. Disagreements on Accounting and Financial Disclosure

NONE

PART III

Item 10. Directors and Executive Officers of the Registrant

Incorporated herein by reference is the definitive proxy statement for solicitation of proxies by the Company's Board of Trustees, which will be dated March 26, 1983 and filed with the Commission pursuant to Rule 14a-6 under the Securities Exchange Act of 1934 (the Act).

Item 11. Management Remuneration and Transactions

Incorporated herein by reference is the definitive proxy statement for solicitation of proxies by the Company's Board of Trustees, which will be dated March 26, 1983 and filed with the Commission pursuant to Rule 14a-6 under the Act.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Incorporated herein by reference is the definitive proxy statement for solicitation of proxies by the Company's Board of Trustees, which will be dated March 26, 1983 and filed with the Commission pursuant to Rule 14a-6 under the Act.

Item 13. Certain Relationships and Related Transactions

Incorporated herein by reference is the definitive proxy statement for solicitation of proxies by the Company's Board of Trustees, which will be dated March 26, 1983 and filed with the Commission pursuant to Rule 14a-6 under the Act.

PART IV

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) 1. Financial Statements:

The Auditors' Report and consolidated financial statements of the Company and its subsidiaries included in the Annual Report to Shareholders are listed in Item 8.

The following additional financial information is filed herewith:

Report of Independent Public Accountants on Schedules

Consent of Independent Public Accountants

2. Schedules:

V. Utility Plant (including Intangibles and excluding Nuclear Fuel), Consolidated - years ended December 31, 1982, 1981 and 1980

V. Nuclear Fuel, Consolidated - years ended December 31, 1982, 1981 and 1980

VI. Accumulated Provision for Depreciation of Utility Plant, Consolidated - years ended December 31, 1982, 1981 and 1980

VIII. Reserves, Consolidated - years ended December 31, 1982, 1981 and 1980

IX. Short-Term Borrowings, Consolidated - years ended December 31, 1982, 1981 and 1980

X. Supplementary Income Statement Information - years ended December 31, 1982, 1981 and 1980

All other schedules of the Company for which provision is made in the applicable regulations of the Securities and Exchange Commission are not required under the related instructions or are not applicable, and therefore have been omitted.

EXHIBITS

Each document described below is incorporated by reference to the files of the Securities and Exchange Commission, unless the reference to the document is indicated by an asterisk.

Exhibit Number	Description

2 Certificate of Merger

2.1 Certificate of Merger dated June 30, 1982 setting forth the plan of merger between CL&P and HELCO. (Exhibit 2.1, September 30, 1982 Form 10-Q File No. 1-5324)

2.2 Certificate of Merger dated June 30, 1982, setting forth the plan of merger between CL&P and Conn. Gas. (Exhibit 2.2, September 30, 1982 Form 10-Q, File No. 1-5324)

3 Declaration of Trust

3.1 Declaration of Trust of Northeast Utilities as amended through April 25, 1978. (Exhibit 3.1, File No. 2-72538)

4 Instruments defining the rights of security holders, including indentures

4.1 Northeast Utilities

4.1.1 Loan Agreement dated as of June 1, 1976 between Northeast Utilities and the Equitable Life Assurance Society of the United States. (Exhibit 4.1, File No. 2-72538)

4.2 The Connecticut Light and Power Company

4.2.1 Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, Trustee, dated as of May 1, 1921. (Exhibit B-2, File No. 2-2477)

4.2.2 Collateral Indenture and Supplemental Indenture thereto, dated as of May 1, 1921. (Exhibits B-3 and B-4, File No. 2-2477)

4.2.3 September 1, 1936. (Exhibit B-12, File No. 2-2477)

4.2.4 October 20, 1936. (Exhibit B-13, File No. 2-2477)

4.2.5 August 31, 1944. (Exhibit B-18, File No. 2-5460)

4.2.6 September 1, 1944. (Exhibit B-19, File No. 2-5460)

4.2.7 May 1, 1945. (Exhibit B-20, File No. 2-5907)

4.2.8 October 1, 1945. (Exhibit B-21, File No. 2-5907)

4.2.9 November 1, 1949. (Exhibit B-22, File No. 2-8171)

4.2.10 December 1, 1952. (Exhibit B-23, File No. 2-10949)

4.2.11 December 1, 1955. (Exhibit B-24, File No. 2-13032)

4.2.12 January 1, 1958. (Exhibit B-25, File No. 2-14688)

4.2.13 February 1, 1960. (Exhibit B-26, File No. 2-16004)

4.2.14 April 1, 1961. (Exhibit 4.14, File No. 2-60806)

4.2.15 September 1, 1963. (Exhibit 4.15, File No. 2-60806)

4.2.16 April 1, 1967. (Exhibit 4.16, File No. 2-60806)

4.2.17 May 1, 1967. (Exhibit 4.17, File No. 2-60806)

4.2.18 January 1, 1968. (Exhibit 4.18, File No. 2-60806)

4.2.19 October 1, 1968. (Exhibit 4.19, File No. 2-60806)

4.2.20 December 1, 1969. (Exhibit 4.20, File No. 2-60806)

4.2.21 January 1, 1970. (Exhibit 4.21, File No. 2-60806)

4.2.22 October 1, 1970. (Exhibit 4.22, File No. 2-60806)

4.2.23 December 1, 1971. (Exhibit 4.23, File No. 2-60806)

4.2.24 August 1, 1972. (Exhibit 4.24, File No. 2-60806)

4.2.25 April 1, 1973. (Exhibit 4.25, File No. 2-60806)

4.2.26 March 1, 1974. (Exhibit 4.26, File No. 2-60806)

4.2.27 February 1, 1975. (Exhibit 4.27, File No. 2-60806)

4.2.28 September 1, 1975. (Exhibit 4.28, File No. 2-60806)

4.2.29 May 1, 1977. (Exhibit 4.29, File No. 2-60806)

4.2.30 March 1, 1978. (Exhibit 2.30, File No. 2-68807)

4.2.31 September 1, 1980. (Exhibit 4.31, File No. 2-73795)

4.2.32 October 1, 1981. (Exhibit 4.32, File No. 2-79235)

4.2.33 June 30, 1982. (Exhibit 4.33, File No. 2-79235)

4.2.34 October 1, 1982. (Exhibit 4, September 30, 1982, Form 10-Q, File No. 1-5324)

4.3 The Hartford Electric Light Company

4.3.1 Trust Indenture dated as of July 1, 1947 between HELCO and Old Colony Trust Company, Trustee. (Exhibit B-1, File No. 2-8085)

Supplemental Indentures thereto dated as of:

4.3.2 March 15, 1952. (Exhibit B-4, File No. 2-10496)

4.3.3 September 1, 1952. (Exhibit B-5, File No. 2-10496)

4.3.4 April 2, 1956. (Exhibit C-4, File No. 2-13660)

4.3.5 July 1, 1957. (Exhibit C-5, File No. 2-13660)

4.3.6 January 1, 1958. (Exhibit B-3-a, File No. 2-14429)

4.3.7 October 1, 1958. (Exhibit A-3-a, File No. 2-21154)

4.3.8 October 1, 1959. (Exhibit A-3-b, File No. 2-21154)

4.3.9 April 1, 1963. (Exhibit 3.9, File No. 2-60876)

4.3.10 December 1, 1964. (Exhibit 3.10, File No. 2-60876)

4.3.11 February 1, 1967. (Exhibit 4.19, File No. 2-26021)

4.3.12 First Mortgage Indenture and Deed of Trust dated as of January 1, 1958 between HELCO and Old Colony Trust Company, Trustee. (Exhibit B-4, File No. 2-14429)

Supplemental Indentures thereto dated as of:

4.3.13 October 1, 1958. (Exhibit A-4-a, File No. 2-21154)

4.3.14 April 1, 1963. (Exhibit 3.14, File No. 2-60876)

4.3.15 December 1, 1964. (Exhibit 3.15, File No. 2-60876)

4.3.16 February 1, 1967. (Exhibit 4.24, File No. 2-26021)

4.3.17 April 1, 1967. (Exhibit 3.17, File No. 2-60876)

4.3.18 February 1, 1968. (Exhibit 3.18, File No. 2-60876)

4.3.19 November 1, 1968. (Exhibit 3.19, File No. 2-60876)

4.3.20 December 1, 1969. (Exhibit 3.20, File No. 2-60876)

4.3.21 May 1, 1970. (Exhibit 3.21, File No. 2-60876)

4.3.22 December 1, 1971. (Exhibit 3.22, File No. 2-60876)

4.3.23 June 1, 1972. (Exhibit 3.23, File No. 2-60876)

4.3.24 May 1, 1973. (Exhibit 3.24, File No. 2-60876)

4.3.25 April 1, 1974. (Exhibit 3.25, File No. 2-60876)

4.3.26 January 1, 1975. (Exhibit 3.26, File No. 2-60876)

4.3.27 October 1, 1975. (Exhibit 3.27, File No. 2-60876)

4.3.28 April 1, 1978. (Exhibit 3.3.28, 1980 Form 10-K, File No. 1-5324)

4.3.29 March 1, 1980. (Exhibit 3.3.29, 1980 Form 10-K, File No. 1-5324)

4.3.30 December 1, 1981. (Exhibit 3.3.30, 1981 Form 10-K File No. 1-5324)

*4.3.31 May 1, 1982.

*4.3.32 June 30, 1982 (Twentieth and Twenty-first Supplemental Indentures)

4.4 Western Massachusetts Electric Company

4.4.1 First Mortgage Indenture and Deed of Trust between WMECO and Old Colony Trust Company, Trustee, dated as of August 1, 1954. (Exhibit 4(b), File No. 2-11114)

Supplemental Indentures dated as of:

4.4.2 October 1, 1954. (Exhibit 4(b) 1.2, File No. 2-11114)

4.4.3 April 1, 1957. (Exhibit 2.7, File No. 2-13136)

4.4.4 May 1, 1962. (Exhibit 2.8, File No. 2-20196)

4.4.5 March 1, 1967. (Exhibit 2.5, File No. 2-68808)

4.4.6 March 1, 1968. (Exhibit 2.6, File No. 2-68808)

4.4.7 December 1, 1968. (Exhibit 2.7, File No. 2-68808)

4.4.8 June 1, 1970. (Exhibit 2.8, File No. 2-68808)

4.4.9 July 1, 1972. (Exhibit 2.9, File No. 2-68808)

4.4.10 July 1, 1973. (Exhibit 2.10, File No. 2-68808)

4.4.11 April 1, 1974. (Exhibit 2.11, File No. 2-68808)

4.4.12 January 1, 1975. (Exhibit 2.12, File No. 2-68808)

4.4.13 November 1, 1976. (Exhibit 2.13, File No. 2-68808)

4.4.14 September 1, 1980. (Exhibit 4.14, File No. 2-71694)

4.4.15 May 1, 1981. (Exhibit 3.3.30, 1981 Form 10-K File No. 1-5324)

4.5 Holyoke Water Power Company--First Mortgage Indenture and Deed of Trust between HWP and Old Colony Trust Company, Trustee, dated as of June 1, 1958. (Exhibit 3.5, 1980 Form 10-K, File No. 1-5324)

10 Material Contracts

10.1 Stockholder Agreement dated as of July 1, 1964 among the stockholders of Connecticut Yankee Atomic Power Company. (Exhibit 13.1, File No. 2-22958)

10.2 Power Contract dated as of July 1, 1964 between Connecticut Yankee Atomic Power Company and CL&P, HELCO and WMECO. (Exhibit 13.2, File No. 2-22958)

10.2.1 Form of supplementary Power Contract dated as of March 1, 1978 between Connecticut Yankee Atomic Power Company and each of CL&P, HELCO and WMECO. (Exhibit 10.2.1, 1980 Form 10-K, File No. 1-5324)

10.2.2 Form of amendment to Supplementary Power Contract dated as of August 1, 1980 between Connecticut Yankee Atomic Power Company and each of CL&P, HELCO and WMECO. (Exhibit 10.2.2, 1980 Form 10-K, File No. 1-5324)

10.3 Capital Funds Agreement dated as of September 1, 1964 between Connecticut Yankee Atomic Power Company and CL&P, HELCO and WMECO. (Exhibit 13.3, File No. 2-22958)

10.3.1 Five Year Capital Contribution Agreement dated as November 1, 1980 among the stockholders of Connecticut Yankee Atomic Power Company. (Exhibit 10.3.1, 1980 Form 10-K, File No. 1-5224)

10.4 Stockholder Agreement dated December 10, 1958 between Yankee Atomic Electric Company and CL&P, HELCO and WMECO. (Exhibit 10.4, 1980 Form 10-K, File No. 1-5324)

10.5 Power Contract as amended through April 30, 1975 between Yankee Atomic Electric Company and CL&P, HELCO and WMECO. (Exhibit 5.8, File No. 2-57327)

10.6 Millstone Plant Agreement dated as of June 30, 1966 among CL&P, HELCO, WMECO and The Millstone Point Company. (Exhibit 13.6, File No. 2-26021)

10.6.1 Supplement to Millstone Plant Agreement dated as of December 1, 1967 by and among CL&P, HELCO, WMECO and The Millstone Point Company. (Exhibit 7.10, File No. 2-60806)

10.6.2 Supplement to Millstone Plant Agreement dated as of December 1, 1972 by and among CL&P, HELCO, WMECO and The Millstone Point Company. (Exhibit 7.11, File No. 2-60806)

10.7 Capital Funds Agreement dated as of May 20, 1968 between Maine Yankee Atomic Power Company and CL&P, HELCO and WMECO. (Exhibit 4.13, File No. 2-30018)

10.8 Power Contract dated as of May 20, 1968 between Maine Yankee Atomic Power Company and CL&P, HELCO and WMECO. (Exhibit 4.14, File No. 2-30018)

10.9 Stockholder Agreement dated as of May 20, 1968 among stockholders of Maine Yankee Atomic Power Company. (Exhibit 4.15, File No. 2-30018)

10.10 Capital Funds Agreement dated as of February 1, 1968 between Vermont Yankee Nuclear Power Corporation and CL&P, HELCO and WMECO. (Exhibit 4.16, File No. 2-30018)

10.10.1 Amendment to Capital Funds Agreement dated as of March 12, 1968 between Vermont Yankee Nuclear Power Corporation and CL&P, HELCO and WMECO. (Exhibit 4.17, File No. 2-30018)

10.11 Power Contract dated as of February 1, 1968 between Vermont Yankee Nuclear Power Corporation and CL&P, HELCO and WMECO. (Exhibit 4.18, File No. 2-30018)

10.11.1 Amendment to Power Contract dated as of June 1, 1972 between Vermont Yankee Nuclear Power Corporation and CL&P, HELCO and WMECO. (Exhibit 5.22, File No. 2-47038)

10.12 Sponsor Agreement dated as of July 1, 1968 among the sponsors of Vermont Yankee Nuclear Power Corporation. (Exhibit 4.16, File No. 2-30285)

10.13 Form of Service Contract dated as of July 1, 1966 between each affiliated company of the System and the Service Company. (Exhibit 10.15, 1980 Form 10-K, File No. 1-5324)

10.13.1 Form of Renewal of Service Contract dated as of January 1 in each year. (Exhibit 10.15.1, 1980 Form 10-K, File No. 1-5324)

10.14 Agreement for joint ownership, construction and operation of New Hampshire nuclear generating units dated as of May 1, 1973. (Exhibit 13-57, File No. 2-48966)

10.14.1 Amendments to Exhibit 10.14 dated May 24, 1974, June 21, 1974 and September 25, 1974. (Exhibit 5.15, File No. 2-51999)

10.14.2 Amendments to Exhibit 10.14 dated October 25, 1974 and January 31, 1975. (Exhibit 5.23, File No. 2-54646)

10.14.3 Sixth Amendment to Exhibit 10.14 dated as of April 18, 1979. (Exhibit 5.4.3, File No. 2-64294)

10.14.4 Seventh Amendment to Exhibit 10.14 dated as of April 18, 1979. (Exhibit 5.4.4, File No. 2-64294)

10.14.5 Eighth Amendment to Exhibit 10.14 dated as of April 25, 1979. (Exhibit 5.4.5, File No. 2-64815)

10.14.6 Ninth Amendment to Exhibit 10.14 dated as of June 8, 1979. (Exhibit 5.4.6, File No. 2-64815)

10.14.7 Tenth Amendment to Exhibit 10.14 dated as of October 10, 1979. (Exhibit 5.4.2, File No. 2-66334)

10.14.8 Eleventh Amendment to Exhibit 10.14 dated as of December 15, 1979. (Exhibit 5.4.8, File No. 2-66492)

10.14.9 Twelfth Amendment to Exhibit 10.14 dated as of June 16, 1980. (Exhibit 5.4.9, File No. 2-68168)

10.14.10 Thirteenth Amendment to Exhibit 10.14 dated as of December 31, 1980. (Exhibit 10.6, File No. 2-70579)

10.15 Memorandum of Understanding between CL&P, HELCO, Holyoke Power and Electric Company, HWP and WMECO dated as of June 1, 1970 with respect to pooling of generation and transmission. (Exhibit 13.32, File No. 2-38177)

*10.15.1 Amendment to Memorandum of Understanding between CL&P, HELCO, Holyoke Power and Electric Company, HWP and WMECO dated as of February 2, 1982 with respect to pooling of generation and transmission.

10.16 New England Power Pool Agreement effective as of November 1, 1971 as amended. (Exhibit 7.44, File No. 260806)

10.17 Participation Agreement dated June 20, 1969 between Maine Electric Power Company, Inc., CL&P, WMECO, HELCO and HWP. (Exhibit 10.22, 1980 Form 10-K, File No. 1-5324)

10.17.1 Supplement amending Participation Agreement dated as of June 24, 1970. (Exhibit 10.22.1, 1980 Form 10-K, File No. 1-5324)

10.17.2 Second Supplement to Participation Agreement dated as of December 1, 1971. (Exhibit 10.22.2, 1980 Form 10-K, File No. 1-5324)

10.17.3 Amendment to Unit Participation Agreement dated as of December 11, 1980. (Exhibit 10.22, 1981 Form 10-K, File No. 1-5324)

10.18 Sharing Agreement dated as of September 1, 1973 with respect to 1979 Connecticut nuclear generating unit. (Exhibit 6.43, File No. 2-50142)

10.18.1 Amendment dated August 1, 1974 to Sharing Agreement--1979 Connecticut Nuclear Unit. (Exhibit 5.45, File No. 2-52392)

10.18.2 Amendment dated December, 1975 to Sharing Agreement--1979 Connecticut Nuclear Unit. (Exhibit 7.47, File No. 2-60806)

10.19 Agreement Among Participants in Nuclear Units for Temporary Reallocation of Capacity in Event of Delay in Units. (Exhibit 6.45, File No. 2-50142)

10.19.1 Agreement Among Participants in Nuclear Units for Sharing of Additional Capacity Made Necessary by Delay in Units. (Exhibit 6.46, File No. 2-50142)

10.20 Lease dated as of July 1, 1970 between CL&P and The Rocky River Realty Company. (Exhibit 13.34, File No. 2-38177)

10.21 Agreement dated October 14, 1957 by and among WMECO, Holyoke Power and Electric Company, HWP and Old Colony Trust Company. (Exhibit 13.11, File No. 2-14830)

10.22 Gas Sales Contract applicable to CD-6 rates between Conn. Gas and Tennessee Gas Pipeline Company, dated December 13, 1978. (Exhibit 10.32, 1980 Form 10-K, File No. 1-5324)

10.23 Service Agreement dated January 9, 1979 applicable to rate schedule F-1 between Algonquin Gas Transmission Company and Conn. Gas. (Exhibit 10.36, 1980 Form 10-K, File No. 1-5324)

10.24 Service Agreement dated January 9, 1979 applicable to rate schedule W-S-1 between Algonquin Gas Transmission Company and Conn. Gas. (Exhibit 10.37, 1980 Form 10-K, File No. 1-5324)

10.25 Service Agreement dated January 9, 1979 applicable to rate schedule SNG-1 between Conn. Gas and Algonquin Transmission Company. (Exhibit 10.38, 1980 Form 10-K, File No. 1-5324)

10.26 Storage Service Transportation contract dated May 26, 1981 between Tennessee Gas Pipeline Company and Conn Gas. (Exhibit 10.39, 1981 Form 10-K, File No. 1-5324)

10.27 Service Agreement between Algonquin LNG, Inc. and Conn Gas dated February 29, 1980 which provides for storage of

120,000 bbls. of LNG in Algonquin's Providence, Rhode Island LNG storage tank. (Exhibit 10.40, 1981 Form 10-K, File No. 1-5324)

10.27.1 Underground Storage Agreement (Rate Schedule SS-1) dated as of May 21, 1981 between Penn-York Storage Corporation and Conn Gas which provides for underground storage of gas owned by Conn Gas. (Exhibit 10.40.1, 1981 Form 10-K, File No. 1-5324)

10.28 Memorandum of Agreement among Boundary Gas, Inc., Conn. Gas and other utilities, dated October 6, 1980. (Exhibit 10.42, 1980 Form 10-K, File No. 1-5324)

10.29 Precedent Agreement between TransCanada Pipelines Limited and Boundary Gas, Inc., dated October 14, 1980. (Exhibit 10.43, 1980 Form 10-K, File No. 1-5324)

10.30 Service Contract dated as of March 1, 1977 between CL&P and HELCO. (Exhibit 10.45, 1980 Form 10-K, File No. 1-5324)

10.30.1 Form of Annual Renewal of Service Contract. (Exhibit 10.45.1, 1980 Form 10-K, File No. 1-5324)

10.31 Extra Expense Insurance Policy issued by Nuclear Electric Insurance Limited with respect to the Millstone nuclear generating units, commencing September 15, 1981. (Exhibit 10.46, 1981 Form 10-K, File No. 1-5324)

10.31.1 Excess Property Insurance Policy issued by Nuclear Electric Insurance Limited with respect to the Millstone nuclear generating units. (Exhibit 10.46.1, 1981 Form 10-K, File No. 1-5324)

10.32 Extra Expense Insurance Policy issued by Nuclear Electric Insurance Limited with respect to the Connecticut Yankee nuclear generating plant, commencing September 15, 1981. (Exhibit 10.47, 1981 Form 10-K, File No. 1-5324)

10.32.1 Excess Property Insurance Policy issued by Nuclear Electric Insurance Limited with respect to the Connecticut Yankee nuclear generating unit. (Exhibit 10.47.1, 1981 Form 10-K, File No. 1-5324)

10.33 Fuel oil purchase agreement between Amerada Hess Corporation and the Service Company dated December 24, 1970. (Exhibit 10.48, 1980 Form 10-K, File No. 1-5324)

10.34 Supplement to fuel oil purchase agreement between Amerada Hess Corporation and the Service Company dated February 22, 1977. (Exhibit 10.49, 1980 Form 10-K, File No. 1-5324)

10.35 Trust Agreement dated January 4, 1982, between The Connecticut Bank and Trust Company, as Trustor, and Bankers Trust Company, as Trustee, and CL&P, HELCO and WMECO. (Exhibit 10.54, 1981 Form 10-K, File No. 1-5324)

10.35.1 Nuclear Fuel Lease Agreement dated as of January 4, 1982, between Bankers Trust Company, Trustee, as Lessor, and CL&P, HELCO and WMECO, as Lessees. (Exhibit 10.54.1, 1981 Form 10-K, File No. 1-5324)

10.36 Phase I New Hampshire Transmission Line Support Agreement, dated as of December 1, 1981. (Exhibit 10.55, 1981 Form 10-K, File No. 1-5324)

10.36.1 Phase I Vermont Transmission Line Support Agreement, dated as of December 1, 1981. (Exhibit 10.55.1, 1981 Form 10-K, File No. 1-5324)

10.36.2 Phase I Terminal Facility Support Agreement, dated as of December 1, 1981. (Exhibit 10.55.2, 1981 Form 10-K, File No. 1-5324)

10.36.3 Agreement with respect to Use of Quebec interconnection, dated as of December 1, 1981. (Exhibit 10.55.3, 1981 Form 10-K, File No. 1-5324)

10.36.4 Millstone Construction Trust - $200,000,000 Credit Agreement dated as of March 15, 1982. (Exhibit 10.1, March 31, 1982, Form 10-Q, File No. 1-5324)

10.36.5 Millstone Construction Trust - $200,000,000 Revolving Credit Agreement dated as of March 15, 1982 (Exhibit 10.2, March 31, 1982, Form 10-Q, File No. 1-5324)

The registrant undertakes to file with the Commission upon request any instrument with respect to long-term debt of the registrant and its subsidiaries, not filed herewith, as to which the total amount of securities authorized thereunder does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis.

*13 Annual Report to Shareholders

*22 Subsidiaries of the Registrant

(b) Reports on Form 8-K - The Company filed a report on Form 8-K as of December 29, 1982 regarding the decision by the DPUC to grant CL&P annual retail electric and gas rate increases of approximately $101.1 million.

SIGNATURE

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

NORTHEAST UTILITIES
(Registrant)

Date March 8, 1983

By /s/ Lelan F. Sillin, Jr.
Lelan F. Sillin, Jr.
Chairman and Chief Executive Officer

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

Date March 8, 1983

By /s/ Lelan F. Sillin, Jr.
Lelan F. Sillin, Jr.
Trustee, Chairman and Chief Executive Officer

Date March 8, 1983

By /s/ William B. Ellis
William B. Ellis
Trustee, President and Chief Operating Officer

Date March 8, 1983

By /s/ E. James Ferland
E. James Ferland
Vice President and Chief Financial Officer

Date March 8, 1983

By /s/ George D. Uhl
George D. Uhl
Controller and Chief Accounting Officer

Date March 8, 1983

By /s/ William O. Bailey
William O. Bailey
Trustee

Date March 8, 1983

By /s/ Edward B. Bates
Edward B. Bates
Trustee

Date March 8, 1983

By /s/ John McP. Collins
John McP. Collins
Trustee

Date March 8, 1983

By /s/ Donald W. Davis
Donald W. Davis
Trustee

Date__________	By__________ Richard B. Haskell Trustee
Date March 8, 1983	By /s/ Eugene D. Jones Eugene D. Jones Trustee
Date March 8, 1983	By /s/ Elizabeth T. Kennan Elizabeth T. Kennan Trustee
Date March 8, 1983	By /s/ Chester W. Kitchings Chester W. Kitchings Trustee
Date March 8, 1983	By /s/ Denham C. Lunt, Jr. Denham C. Lunt, Jr. Trustee
Date March 8, 1983	By /s/ Burke Marshall Burke Marshall Trustee
Date March 8, 1983	By /s/ William J. Pape, II William J. Pape, II Trustee
Date March 8, 1983	By /s/ Norman C. Rasmussen Norman C. Rasmussen Trustee
Date March 8, 1983	By /s/ Albert E. Steiger, Jr. Albert E. Steiger, Jr. Trustee
Date__________	By__________ Donald C. Switzer Trustee

NORTHEAST UTILITIES AND SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS

The Company Report and Auditors' Report are located on pages 30 and 31, respectively, of the Company's Annual Report to Shareholders, portions of which are attached to this report as Appendix A.

Consolidated Financial Statements are located on pages 32 to 49 of the Company's Annual Report to Shareholders, portions of which are attached to this report as Appendix A.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS ON SCHEDULES

In connection with our examinations of the financial statements included in Northeast Utilities' Annual Report to Shareholders and incorporated by reference in this Form 10-K, we have also examined the supplemental schedules listed in the accompanying index. Our examinations were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplemental schedules are presented for purposes of complying with the Securities and Exchange Commission's rules and regulations under the Securities Exchange Act of 1934 and are not otherwise a required part of the basic financial statements. The supplemental schedules have been subjected to the auditing procedures applied in the examinations of the basic financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

ARTHUR ANDERSEN & CO.

Hartford, Connecticut,
February 18, 1983.

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation by reference of our reports dated February 18, 1983 appearing, or incorporated by reference, in Northeast Utilities' annual report on Form 10-K for the year ended December 31, 1982, into Post-effective Amendment No. 1 to the Company's Form S-16 on Form S-3 Registration Statement No. 2-74611.

ARTHUR ANDERSEN & CO.

Hartford, Connecticut,
March 8, 1983

NORTHEAST UTILITIES AND SUBSIDIARIES
UTILITY PLANT (INCLUDING INTANGIBLES AND EXCLUDING NUCLEAR FUEL)
YEAR ENDED DECEMBER 31, 1982
(Thousands of Dollars)

COL. A Classification	COL. B Balance at beginning of period	COL. C Additions at cost	COL. D Retirements	COL. E Other Changes-Add (Deduct)-Describe	COL. F Balance at close of period
Utility Plant in Service					
Electric	$2,913,820	$132,379	$15,519	$ (98)(f) 11 (c) 167 (b) 295 (d)	$3,031,055
Gas	198,197	25,665	1,418	(9)(f)	222,435
Other	32,925	821	1,845	(295)(d) (114)(f)	31,492
Construction Work in Progress					
Electric	878,087	338,057 (a)	-	(103)(f) (8,530)(e)	1,207,511
Gas	6,995	(3,577)(a)	-	-	3,418
Other	8,996	4,006 (a)	-	(353)(f)	12,649
Utility Plant Held for Future Use					
Electric	8,984	13	3	(2,000)(f) (167)(b)	6,827
Gas	25	-	-	-	25
Other	3,034	18	20	(598)(f)	2,434
TOTAL	$4,051,063	$497,382	$18,805	$(11,794)	$4,517,846

(a) Net increase (decrease) during the year.
(b) Transfer between Utility Plant in Service and Utility Plant Held for Future Use.
(c) Adjustment of prior year retirement.
(d) Transfer between Utility Plant in Service Electric and Utility Plant in Service Other.
(e) Transfer between Construction Work in Progress and Nuclear Fuel.
(f) Transfer between Utility Plant Accounts and Non-Utility Plant Accounts.

NORTHEAST UTILITIES AND SUBSIDIARIES
UTILITY PLANT (INCLUDING INTANGIBLES AND EXCLUDING NUCLEAR FUEL)
YEAR ENDED DECEMBER 31, 1981
(Thousands of Dollars)

COL. A Classification	COL. B Balance at beginning of period	COL. C Additions at cost	COL. D Retirements	COL. E Other Changes-Add (Deduct)-Describe	COL. F Balance at close of period
Utility Plant in Service					
Electric	$2,756,140	$181,637	$23,678	$ (429)(b) 119 (d) (37)(e) 68 (c)	$2,913,820
Gas	180,251	19,083	1,137	-	198,197
Other	31,547	1,365	24	37 (e)	32,925
Construction Work in Progress					
Electric	712,646	172,662 (a)	-	(5,215)(f) (2,006)(g)	878,087
Gas	5,009	1,986 (a)	-	-	6,995
Other	10,270	(363)(a)	-	(911)(h)	8,996
Utility Plant Held for Future Use					
Electric	7,051	2,001	-	(68)(c)	8,984
Gas	25	-	-	-	25
Other	218	2,816	-	-	3,034
TOTAL	$3,703,157	$381,187	$24,839	$(8,442)	$4,051,063

(a) Net increase (decrease) during the year.
(b) Transfer between Utility Plant in Service and Nonutility Property.
(c) Transfer between Utility Plant in Service and Utility Plant Held for Future Use.
(d) Adjustment of prior year retirement.
(e) Transfer between Utility Plant in Service Electric and Other.
(f) Sale of a portion of CL&P's interest in the Seabrook nuclear project.
(g) Canceled Nuclear Project.
(h) Transfer between Construction Work in Progress and Nonutility Property.

NORTHEAST UTILITIES AND SUBSIDIARIES
UTILITY PLANT (INCLUDING INTANGIBLES AND EXCLUDING NUCLEAR FUEL)
YEAR ENDED DECEMBER 31, 1980
(Thousands of Dollars)

COL. A Classification	COL. B Balance at beginning of period	COL. C Additions at cost	COL. D Retirements	COL. E Other Changes-Add (Deduct)-Describe	COL. F Balance at close of period
Utility Plant in Service					
Electric	$2,682,232	$ 87,055	$13,170	$ (123)(b) 147 (c) (1)(f)	$2,756,140
Gas	163,933	18,305	1,983	(7)(f) 3 (b)	180,251
Other	32,045	525	231	(792)(d)	31,547
Construction Work in Progress					
Electric	568,460	170,152(a)	-	(22)(e) (25,944)(h)	712,646
Gas	3,411	1,598(a)	-	-	5,009
Other	5,570	3,908(a)	-	792 (d)	10,270
Utility Plant Held for Future Use					
Electric	6,072	860	-	(4)(g) 123 (b)	7,051
Gas	28	-	-	(3)(b)	25
Other	218	-	-	-	218
TOTAL	$3,461,969	$282,403	$15,384	$(25,831)	$3,703,157

(a) Net increase during the year.
(b) Transfer between Utility Plant in Service and Utility Plant Held for Future Use.
(c) Adjustment of prior year retirement.
(d) Transfer between Utility Plant in Service to Construction Work in Progress in order to comply with the Securities and Exchange Commission Regulations.
(e) Sale of substation.
(f) Transfer between Utility Plant in Service and Nonutility Property.
(g) Transfer between Nonutility Plant and Utility Plant Held for Future Use.
(h) Canceled Nuclear Project.

NORTHEAST UTILITIES AND SUBSIDIARIES
NUCLEAR FUEL
YEAR ENDED DECEMBER 31, 1982
(Thousands of Dollars)

COL. A Classification	COL. B Balance at beginning of period	COL. C Additions at cost	COL. D Retirements	COL. E Other Changes-Add (Deduct)-Describe	COL. F Balance at close of period
Nuclear fuel in process of refinement, conversion, enrichment and fabrication	$ 98,544	$36,450	$ -	$ (65,629)(e) (79,026)(b) 9,661 (g)	$ -
Nuclear fuel materials and assemblies - stock account	56,213	70	-	814 (b) (55,877)(e) (1,220)(g)	-
Nuclear fuel assemblies in reactor	140,823	-	-	40,235 (b) (181,058)(e)	-
Spent nuclear fuel	85,350	-	-	37,977 (b) (123,327)(e)	-
Accumulated provision for amortization of nuclear fuel assemblies	(191,005)	-	-	(48,509)(a) (2,291)(c) 204 (d) 195,491 (e) 46,021 (f) 89 (g)	-
TOTAL NUCLEAR FUEL	$ 189,925	$36,520	$ -	$(226,445)	$ -

(a) Amortization of nuclear fuel assemblies and nuclear fuel disposal costs charged to expense.
(b) Transfers between nuclear fuel accounts.
(c) Combustion Engineering transfer credits.
(d) End of cycle adjustment.
(e) Sale of nuclear fuel to a third party trust.
(f) Transfer of nuclear fuel disposal costs and related credits to accumulated provision for depreciation.
(g) Transfer of nuclear fuel and related credits to Construction Work in Progress.

NORTHEAST UTILITIES AND SUBSIDIARIES
NUCLEAR FUEL
YEAR ENDED DECEMBER 31, 1981
(Thousands of Dollars)

COL. A Classification	COL. B Balance at beginning of period	COL. C Additions at cost	COL. D Retirements	COL. E Other Changes-Add (Deduct)-Describe	COL. F Balance at close of period
Nuclear fuel in process of refinement, conversion, enrichment and fabrication	$ 70,925	$31,991	$ -	$ (420)(e) (3,952)(b)	$ 98,544
Nuclear fuel materials and assemblies - stock account	31,644	45,031	-	(20,462)(b)	56,213
Nuclear fuel assemblies in reactor	130,409	-	-	10,414 (b)	140,823
Spent nuclear fuel	71,350	-	-	14,000 (b)	85,350
Accumulated provision for amortization of nuclear fuel assemblies	(150,787)	-	-	(39,465)(a) (991)(c) 238 (d)	(191,005)
TOTAL NUCLEAR FUEL	$153,541	$77,022	$ -	$(40,638)	$189,925

(a) Amortization of nuclear fuel assemblies and nuclear fuel disposal costs charged to expense. Excludes $163,000 which represents a portion of the net positive salvage authorized by the State Regulatory Commission to be recovered through rates over a four-year period.
(b) Transfers between nuclear fuel accounts.
(c) Combustion Engineering transfer credits.
(d) End of cycle adjustment.
(e) During 1981, CL&P sold a portion of its ownership in the Seabrook plant and the related nuclear fuel in process.

NORTHEAST UTILITIES AND SUBSIDIARIES
NUCLEAR FUEL
YEAR ENDED DECEMBER 31, 1980
(Thousands of Dollars)

COL. A Classification	COL. B Balance at beginning of period	COL. C Additions at cost	COL. D Retirements	COL. E Other Changes-Add (Deduct)-Describe	COL. F Balance at close of period
Nuclear fuel in process of refinement, conversion, enrichment and fabrication	$ 54,186	$57,289	$ -	$(40,550)(b)	$ 70,925
Nuclear fuel materials and assemblies - stock account	13,021	10,002	-	8,621 (b)	31,644
Nuclear fuel assemblies in reactor	108,928	-	-	21,481 (b)	130,409
Spent nuclear fuel	60,902	-	-	10,448 (b)	71,350
Accumulated provision for amortization of nuclear fuel assemblies	(119,881)	-	-	(30,413)(a) (619)(c) 126 (d)	(150,787)
TOTAL NUCLEAR FUEL	$117,156	$67,291	$ -	$(30,906)	$153,541

(a) Amortization of nuclear fuel assemblies and nuclear fuel disposal costs charged to expense. Excludes $435,000 which represents a portion of the net positive salvage authorized by the State Regulatory Commission to be recovered through rates over a four-year period.
(b) Transfers between nuclear fuel accounts.
(c) Combustion Engineering transfer credits.
(d) End of cycle adjustment.

Schedule V

NORTHEAST UTILITIES AND SUBSIDIARIES
ACCUMULATED PROVISION FOR DEPRECIATION OF UTILITY PLANT
YEAR ENDED DECEMBER 31, 1982
(Thousands of Dollars)

COL. A Description	COL. B Balance at beginning of period	COL. C Additions Charged to Costs and Expenses	COL. D Retirements	COL. E Other Changes-Add (Deduct)-Describe	COL. F Balance at close of period
ACCUMULATED PROVISION FOR DEPRECIATION OF UTILITY PLANT					
Electric	$861,258	$ 99,879	$17,988	$ 105 (a) 46,021 (b)	$ 989,275
Gas	38,258	5,803	1,999	494 (a)	42,556
Other	13,435	735	1,705	247 (a)	12,712
Total	$912,951	$106,417	$21,692	$46,867	$1,044,543

(a) Depreciation charged to Transportation Clearing, Fuel Stock and Other Accounts.
(b) Transfer between accumulated provision for depreciation and nuclear fuel.

NORTHEAST UTILITIES AND SUBSIDIARIES
ACCUMULATED PROVISION FOR DEPRECIATION OF UTILITY PLANT
YEAR ENDED DECEMBER 31, 1981
(Thousands of Dollars)

COL. A Description	COL. B Balance at beginning of period	COL. C Additions Charged to Costs and Expenses	COL. D Retirements	COL. E Other Changes- Add (Deduct)- Describe	COL. F Balance at close of period
ACCUMULATED PROVISION FOR DEPRECIATION OF UTILITY PLANT					
Electric	$788,433	$ 96,547	$24,071	$ 349 (a)	$861,258
Gas	34,253	5,400	1,463	68 (a)	38,258
Other	11,784	854	62	859 (a)	13,435
Total	$834,470	$102,801	$25,596	$1,276	$912,951

(a) Depreciation charged to Transportation Clearing, Fuel Stock and Other Accounts.

NORTHEAST UTILITIES AND SUBSIDIARIES
ACCUMULATED PROVISION FOR DEPRECIATION OF UTILITY PLANT
YEAR ENDED DECEMBER 31, 1980
(Thousands of Dollars)

COL. A	COL. B	COL. C	COL. D	COL. E	COL. F
Description	Balance at beginning of period	Additions Charged to Costs and Expenses	Retirements	Other Changes-Add (Deduct)-Describe	Balance at close of period
ACCUMULATED PROVISION FOR DEPRECIATION OF UTILITY PLANT					
Electric	$712,106	$90,626	$14,875	$ 576 (a)	$788,433
Gas	31,118	5,011	2,004	128 (a)	34,253
Other	10,697	629	88	546 (b)	11,784
Total	$753,921	$96,266	$16,967	$1,250	$834,470

(a) Depreciation charged to Transportation and Fuel Stock Clearing Accounts.
(b) Depreciation charged to other accounts.

NORTHEAST UTILITIES AND SUBSIDIARIES
RESERVES
YEAR ENDED DECEMBER 31, 1982
(Thousands of Dollars)

COL. A	COL. B	COL. C		COL. D	COL. E
		Additions			
		(1)	(2)		
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions-Describe	Balance at End of Period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$4,920	$13,899	$ -	$10,765 (a)	$8,054
RESERVES NOT APPLIED AGAINST ASSETS:					
Injuries and damages (b)	$2,320	$ 2,242	$ -	$ 2,010 (c)	$2,552
Medical insurance (e)	1,881	14,695	-	13,961 (d)	2,615
TOTAL	$4,201	$16,937	$ -	$15,971	$5,167

(a) Amounts charged off as uncollectible after deducting customers' deposits and recoveries of accounts previously charged off.
(b) Provided to cover claims for injuries to employees, for workmen's compensation and for bodily injury to others and property damage.
(c) Principally payments f r various injuries and damages and expenses in connection therewith.
(d) Principally payments for various employee medical expenses and expenses in connection therewith.
(e) Provided to cover claims for employee medical insurance.

NORTHEAST UTILITIES AND SUBSIDIARIES
RESERVES
YEAR ENDED DECEMBER 31, 1981
(Thousands of Dollars)

COL. A	COL. B	COL. C		COL. D	COL. E
		Additions			
		(1)	(2)		
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts-Describe	Deductions-Describe	Balance at End of Period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$3,772	$ 8,677	$ -	$ 7,529 (a)	$4,920
RESERVES NOT APPLIED AGAINST ASSETS:					
Injuries and damages (b)	$2,125	$ 1,981	$ -	$ 1,786 (c)	$2,320
Medical insurance (e)	1,883	12,145	-	12,147 (d)	1,881
TOTAL	$4,008	$14,126	$ -	$13,933	$4,201

(a) Amounts charged off as uncollectible after deducting customers' deposits and recoveries of accounts previously charged off.
(b) Provided to cover claims for injuries to employees, for workmen's compensation and for bodily injury to others and property damage.
(c) Principally payments for various injuries and damages and expenses in connection therewith.
(d) Principally payments for various employee medical expenses and expenses in connection therewith.
(e) Provided to cover claims for employee medical insurance.

NORTHEAST UTILITIES AND SUBSIDIARIES
RESERVES
YEAR ENDED DECEMBER 31, 1980
(Thousands of Dollars)

COL. A	COL. B	COL. C		COL. D	COL. E
		Additions			
		(1)	(2)		
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts-Describe	Deductions-Describe	Balance at End of Period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$3,451	$ 5,938	$ -	$ 5,617 (a)	$3,772
RESERVES NOT APPLIED AGAINST ASSETS:					
Injuries and damages (b)	$2,022	$ 1,993	$ -	$ 1,890 (c)	$2,125
Medical insurance (e)	1,636	9,871	-	9,624 (d)	1,883
TOTAL	$3,658	$11,864	$ -	$11,514	$4,008

(a) Amounts charged off as uncollectible after deducting customers' deposits and recoveries of accounts previously charged off.
(b) Provided to cover claims for injuries to employees, for workmen's compensation and for bodily injury to others and property damage.
(c) Principally payments for various injuries and damages and expenses in connection therewith.
(d) Principally payments for various employee medical expenses and expenses in connection therewith.
(e) Provided to cover claims for employee medical insurance.

Schedule VIII

NORTHEAST UTILITIES AND SUBSIDIARIES

SHORT-TERM BORROWINGS
(Dollar Amounts in Thousands)

Column A Category of aggregate short-term borrowings	Column B Balance at end of period	Column C(a) Weighted average interest rate at end of period	Column D Maximum amount outstanding during the period	Column E (b) Average amount outstanding during the period	Column F(c) Weighted average interest rate during the period
December 31, 1982					
Notes Payable to Banks	$ 19,800	9.2%	$155,350	$ 73,620	16.8%
Commercial Paper	37,725	9.3	290,400	117,065	14.0
December 31, 1981					
Notes Payable to Banks	$ 79,500	13.3%	$240,850	$107,956	20.0%
Commercial Paper	146,135	13.0	258,375	182,205	17.2
December 31, 1980					
Notes Payable to Banks	$168,850	21.2%	$193,350	$ 64,540	16.6%
Commercial Paper	168,476	19.6	202,956	151,084	14.6

(a) Includes commitment fees and excludes the effect of compensating balances.
(b) Average daily balance during the period.
(c) Based on the daily amounts outstanding including commitment fees and excluding the effect of compensating balances.

Schedule X

NORTHEAST UTILITIES AND SUBSIDIARIES
SUPPLEMENTARY INCOME STATEMENT INFORMATION
YEARS ENDED DECEMBER 31, 1982, 1981, and 1980
(Thousands of Dollars)

Column A	Column B		
Item	Charged To Costs And Expenses		
	1982	1981	1980
Taxes, other than income taxes charged to expense:			
State gross receipts	$ 73,484	$ 65,229	$ 52,537
Real and personal property	54,631	55,976	53,276
Payroll and other	12,179	10,750	8,496
Total	$140,294	$131,955	$114,309

Items other than those disclosed above have been omitted because either they are not applicable, the required information has been presented in the consolidated financial statements or notes thereto, or such amounts are less than 1 percent of total revenues.

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

This section is management's assessment of the company's financial condition and the principal factors which have an impact on the results of operations. This discussion should be read in conjunction with the company's consolidated financial statements and footnotes.

FINANCIAL CONDITION

More responsible rate regulation in Connecticut and at the federal level has allowed the company to improve its financial condition. Company earnings per common share rose from $1.29 in 1981 to $1.76 in 1982, a 36 percent increase. The company's capital structure has improved with the equity ratio increasing from 31.8 percent of total capitalization at the end of 1981 to 33.5 percent at the end of 1982. The ratio between market price and book value per common share rose from 71 percent on December 31, 1981 to 94 percent on December 31, 1982. Dividends paid in 1982 were increased to $1.28 per share, reflecting an 8 percent increase from the 1981 level of $1.18 per share. These accomplishments were made during a year when the company had the highest cash requirements in its history for debt maturities and construction expenditures.

Because Connecticut revenues amount to approximately 85 percent of the company's total revenues, continuation of an improved regulatory environment in Connecticut is the key to the company eventually regaining financial strength. In light of the significant construction expenditure requirements in the near future, responsible regulation will be required if the company is to be able to balance the interests of both ratepayers and shareholders.

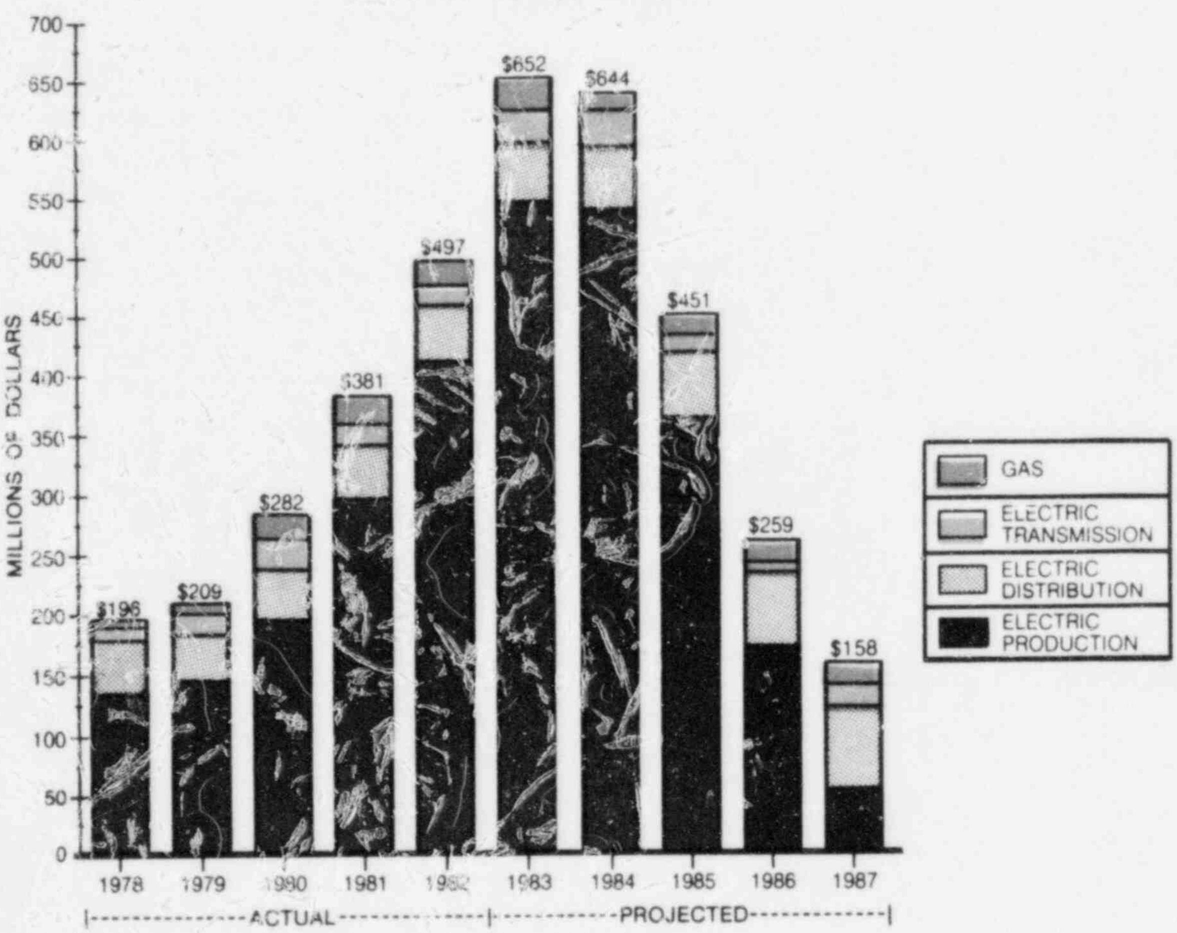
Construction Program

The construction of the Millstone 3 nuclear unit is the most significant item in the company's construction program, representing approximately 64 percent of the system's total planned capital expenditures for the period 1983 through 1986, the planned in-service date of the

unit. These expenditures include a 1982 revision to the Millstone 3 construction cost estimate, which increased the estimated cost of The Connecticut Light and Power Company's (CL&P) and Western Massachusetts Electric Company's (WMECO) current 65 percent ownership interest (representing 747.5 MW) from $1.7 billion to $2.3 billion. The construction of the unit is now approximately 60 percent complete. In a December 1982 rate case decision, the Connecticut Department of Public Utility Control (DPUC) found that "it is in the public interest and in the best interest of the customers and shareholders of CL&P that this project [Millstone 3] be continued."

The construction program also includes CL&P's 4.1 percent interest in two nuclear units under construction in Seabrook, New Hampshire. Based upon a 1982 revised cost estimate and construction schedule, the estimated final cost of CL&P's ownership interest in the Seabrook units was increased from $134 million to $212 million and the scheduled in-service dates for units 1 and 2 were

Construction Expenditures



delayed from February 1984 and May 1986 to December 1984 and July 1987, respectively.

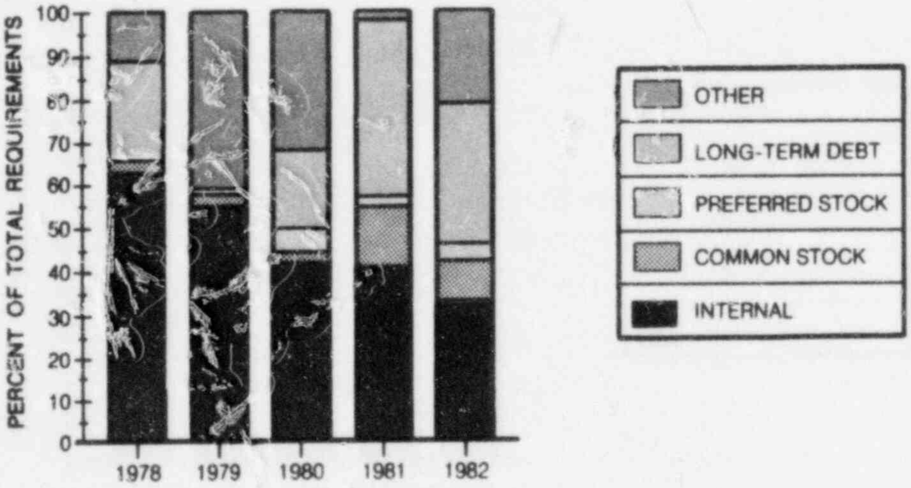
Construction expenditures, including an allowance for funds used during construction (AFUDC) but excluding nuclear fuel, for the period 1978 to 1982 and projected construction expenditures through 1987, are illustrated in the preceding chart. Annual construction expenditures will peak in 1983 and 1984 and will decline during the period through 1986 when Millstone 3 is scheduled to be placed in service.

Financing

The system companies finance their requirements in excess of internally generated funds through short-term and intermediate-term borrowings, construction and nuclear fuel financing trusts, the sale of first mortgage bonds and preferred stock, leasing agreements and receipt of capital contributions or advances from the parent company. In addition to construction and nuclear fuel requirements, the system companies are obligated to spend $205 million in 1983 through 1987 to meet debt maturities and cash sinking-fund requirements.

Internal cash generation has not been sufficient to fund the system companies' entire construction program. Therefore, external financing has supplied a major portion of the program's requirements and will continue to do so until Millstone 3 is placed in service. The following chart illustrates the relative percentages of all sources of funds for the five-year period from 1978 to 1982.

Sources Of Funds



During 1982, the company was able to meet its financing requirements through various financing vehicles. The company sold eight million common shares in a public offering and approximately two and one-half million shares through its Dividend Reinvestment and Common Share Purchase Plan. These sales resulted in net proceeds to the company of $83 million and $25 million, respectively. In addition, the system companies realized net proceeds of $197 million from the issue and sale of first mortgage bonds and preferred stock during 1982.

In March 1982, CL&P and WMECO entered into a construction trust agreement to finance a portion of the Millstone 3 construction expenditures. The primary purpose of the construction trust is to allow CL&P and WMECO to defer the issuance of large amounts of debt and equity securities until Millstone 3 is in service and the companies begin to receive increased cash flow benefits as a result of its inclusion in rate base. As of December 31, 1982, the companies had $135 million outstanding, including interest, under this agreement.

CL&P and WMECO entered into a nuclear fuel trust agreement, the Niantic Bay Fuel Trust (NBFT), in February 1982. The trust owns and finances the nuclear fuel for Millstone 1 and 2 and the companies' ownership share of the nuclear fuel for Millstone 3, and leases it to CL&P and WMECO while it is used in the reactors. As of December 31, 1982, the trust's investment in nuclear fuel was $267 million. It is anticipated that NBFT will provide the necessary financing for CL&P's and WMECO's nuclear fuel requirements for the Millstone units.

In November 1982, CL&P and WMECO increased the limit on a revolving credit/term loan agreement entered into during 1980 by $60 million to a new level of $200 million, and CL&P entered into a two-year $50 million floating-rate Eurodollar revolving credit agreement. There were no borrowings under either of these agreements during 1982. In addition, the system companies have $48 million of credit lines with various banks. These agreements provide the system companies another source of external financing.

To assist in raising required capital in a cost-effective manner, CL&P is prepared to use, when appropriate, additional financing vehicles. CL&P is considering the issuance of bonds in the Eurobond market for up to $75 million. It is also considering

entering into a floating-rate Eurodollar intermediate-term loan arrangement for up to $75 million, coupled with an "interest rate swap" arrangement. The objective of such an arrangement is to convert the floating-rate term loan obligation into a fixed-rate obligation having a lower effective interest cost than a comparable first mortgage bond issue. Whether a Eurobond issue, a term loan and interest rate swap transaction or a conventional first mortgage bond issue will be effected by CL&P will be evaluated in light of prevailing interest rates and market conditions.

In 1983, the company expects to sell additional common shares to the general public and through the Dividend Reinvestment and Common Share Purchase Plan, primarily to finance the company's equity contributions to its subsidiaries. The company's subsidiaries also intend to issue additional long-term debt and preferred stock and to utilize further the present construction and nuclear fuel trust agreements.

The company has a targeted capital structure of 40 percent common equity, 12 percent preferred stock and 48 percent long-term debt. Management believes that such a capital structure will improve bond ratings and financing flexibility. The company's common equity ratio of 33.5 percent at December 31, 1982 is low by utility industry standards and has been a factor in the downgradings of CL&P's and WMECO's bond ratings. Some improvement in the capital structure occurred as a result of the common stock sale in 1982.

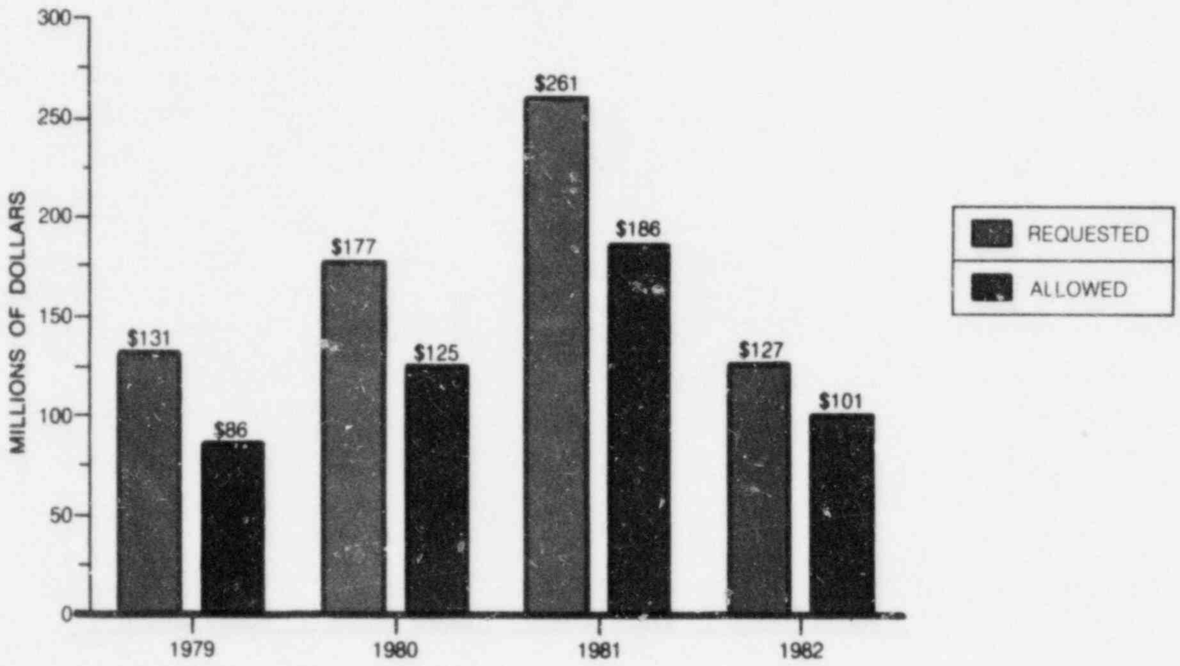
Rate Matters

Adequate and timely rate relief remains the key to improving the system's operating results, increasing internal cash generation and assuring the ability to enter the capital markets at a reasonable cost. Therefore, the system companies will continue to file applications, when appropriate, for needed rate relief in both their wholesale and retail jurisdictions.

The company is encouraged by improvements made in Connecticut regulatory treatment, including the recognition of the effects of inflation on operating costs.

During 1982, the DPUC granted CL&P $101.1 million in additional annual revenues, or 79.5 percent of the amount requested. A December 1981 Connecticut rate case decision allowed CL&P to adopt a change in its fuel recovery procedures to provide for the collection of substantially all fuel costs from retail customers, thereby, rectifying an inequity that previously existed. The following chart presents a comparison of Connecticut retail rate increases requested versus allowed. The decisions since 1979 are of major significance because they have provided a signal to the financial community that the regulatory climate in Connecticut is improving its response to prevailing economic conditions.

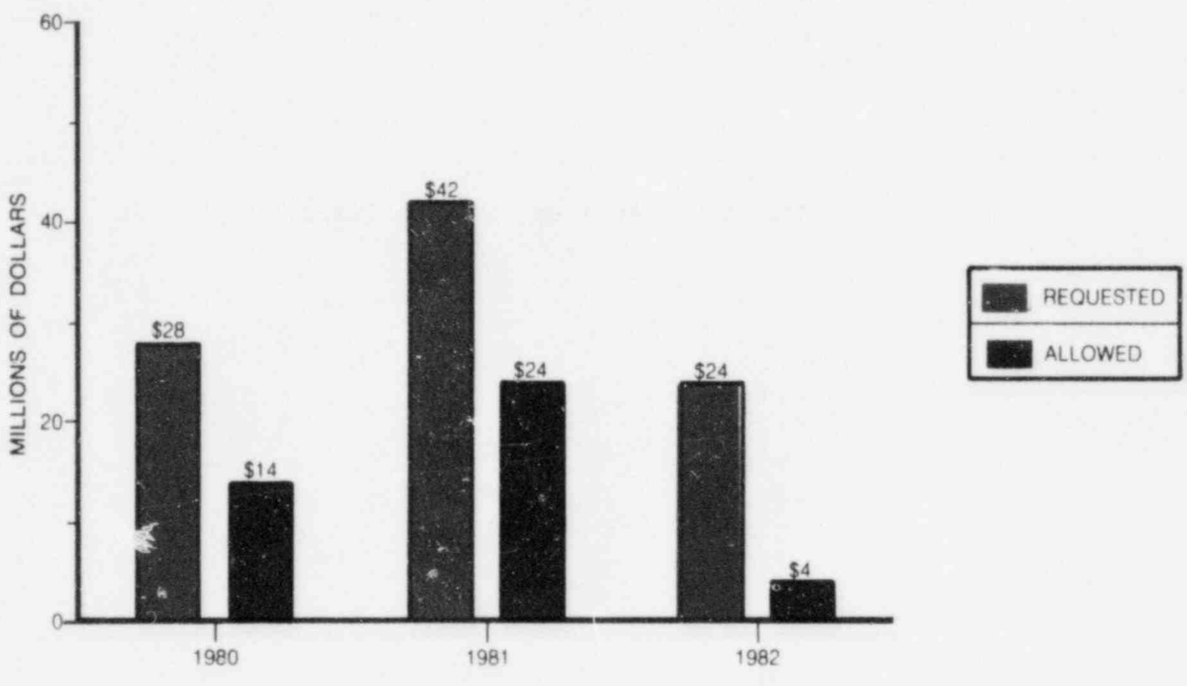
Connecticut Retail Rate Increases
Requested versus Allowed



Effective May 1982, the Federal Energy Regulatory Commission (FERC), approved a settlement between CL&P and its wholesale customers allowing $5.7 million in additional annual revenues. CL&P has also received approval from FERC of a settlement with its wholesale customers to increase its wholesale rates by an additional $2.3 million annually, effective July 1, 1983.

The company, however, is becoming increasingly concerned about the lack of responsiveness on the part of the Massachusetts Department of Public Utilities (DPU). Recent DPU ratemaking policies have not provided WMECO an opportunity to earn allowed returns. During 1982, the DPU granted only $4.4 million in additional annual revenues, or 18 percent of the amount sought. The following chart illustrates a comparison of Massachusetts retail rate increases requested versus allowed.

Massachusetts Retail Rate Increases
Requested versus Allowed



Note: There were no Massachusetts retail rate decisions issued to WMECO during 1979

In October 1982, WMECO filed an application with the DPU for an increase in electric retail rates, requesting immediate interim rate relief of $5.3 million and permanent rate relief of $24.1 million. Decisions on both requests are pending at this time.

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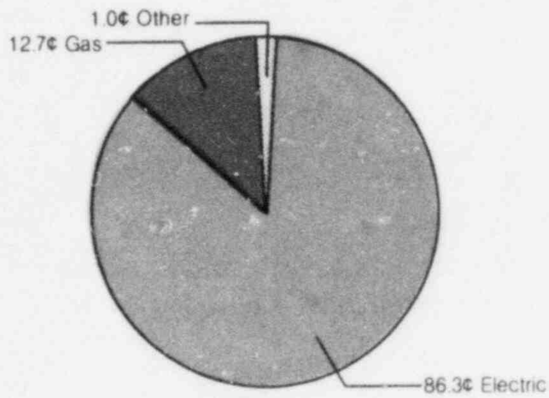
RESULTS OF OPERATIONS

The principal factors affecting the company's results of operations can be put into perspective by presenting the major components included in the results of operations. The following charts, indicating where the company's 1982 revenue dollar came from and went, illustrate both the respective size of our electric and gas operations and the magnitude of the various expenses the company incurs.

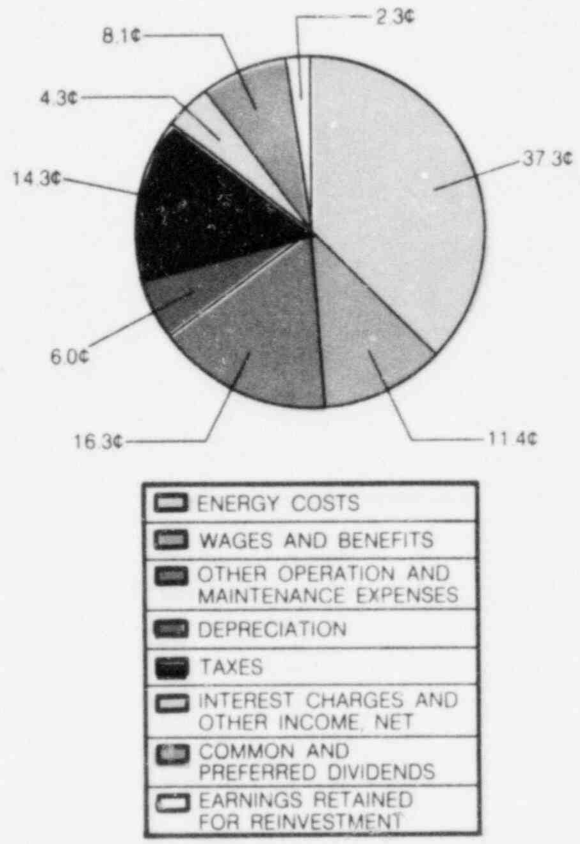
1982 Revenue Dollar
(cents per dollar of revenues)

Where It Came From



	Electric	Gas
Residential	35.9¢	5.3¢
Commercial	27.2¢	3.3¢
Industrial	17.8¢	4.0¢
Wholesale	2.7¢	—
Streetlighting and Miscellaneous	2.7¢	0.1¢
Total	86.3¢	12.7¢

Where It Went



Operating Revenues

Operating revenues increased $108.2 million from 1981 to 1982 and $330.5 million in 1981 compared to 1980. The components of the change in operating revenues for the past two years were as follows:

	Increase/(Decrease)	
	1982 vs. 1981	1981 vs. 1980
	(Thousands of Dollars)	
Rate increases	$199,226	$128,430
Fuel cost recoveries	(63,282)	186,498
Sales increases (decreases)	(20,649)	14,879
Other	(7,132)	705
Total revenue increase	$108,163	$330,512

The retail rate increases granted were the major causes of revenue increases in 1982 and provided a substantial portion of the total 1981 increase.

Fuel cost recovery revenues decreased in 1982 because of the decline in oil prices during the year. By comparison, oil prices increased rapidly in early 1981 so that fuel cost recovery revenues in 1981 contributed more than half of the overall revenue increase from 1980. The average cost of oil to the system companies was approximately $30 per barrel in 1982, compared to $33 in 1981 and $27 in 1980.

A decrease of 1.9 percent in electric sales and less than 1 percent in gas sales during 1982 can be attributed to the effects of weak economic conditions, continued customer conservation efforts, together with more moderate weather conditions. Electric sales increased less than 1 percent and gas sales increased 5.4 percent during 1981.

Electric and Gas Energy Expenses

Electric energy expenses decreased $99.0 million in 1982 as compared to 1981 as a result of several contributing factors. Fossil fuel prices drifted downward during most of 1982 and, at the same time, the system companies' sales decreased by 1.9 percent. In addition, 1982 includes a full year of generation from the Mt. Tom station, which began burning coal in December 1981. Electric energy expenses increased $171.2 million during 1981 as compared to 1980 primarily because of increased fossil fuel prices.

Gas energy expenses increased $36.0 million in 1982 as compared to 1981 and $22.3 million in 1981 as compared to 1980. These increases are primarily a result of increased gas prices.

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased $83.0 million in 1982 compared to 1981 and increased $57.8 million in 1981 as compared to 1980. Inflation contributed to these increased expenses because of its impact on payroll, materials and supplies, and employee benefits. In addition, Nuclear Regulatory Commission directives and higher nuclear outage costs increased other operation and maintenance expenses during 1982 and 1981.

Despite increased nuclear operation and maintenance expenses, nuclear units continue to offer substantial savings over oil-fired units. During 1982, nuclear energy spared the use of approximately 22.2 million barrels of oil and resulted in a savings of $316.7 million to our customers through a reduction in other fuel costs. In addition, the capacity factors of the nuclear units the system companies own and operate, or in which they have entitlements, continue to be above average as compared to the total United States nuclear power industry.

Income Taxes

Federal and state income taxes increased $45.7 million in 1982 as compared to 1981. The current income tax increase of $12.3 million can be attributed to an increase in taxable income. Deferred income taxes increased $33.4 million in 1982 primarily as a result of an increase in investment tax credit normalization. Federal and state income taxes increased $18.7 million in 1981 as compared to 1980. This increase was primarily caused by higher current income taxes of $14.0 million resulting from an increase in taxable income.

Allowance for Funds Used During Construction

Allowance for funds used during construction, which represents the estimated cost of capital invested in construction work in progress (CWIP), increased $14.4 million in 1982 and $22.8 million in 1981. These increases were caused by higher average CWIP balances, attributed primarily to the Millstone 3 construction project. The increase in AFUDC during 1982 was partially reduced as a result of nuclear fuel being financed by the nuclear fuel trust. A 1986 in-service date is planned for Millstone 3 and at that time, under current regulatory practice, the unit investment would be transferred from CWIP to plant in-service and AFUDC would be significantly reduced.

Interest Charges

Interest charges decreased $13.2 million during 1982 as compared to 1981 as a result of several contributing factors. The system companies reduced their short-term debt balance significantly by issuing long-term debt and equity securities, and using trust financing agreements. In addition, the system companies benefited from a reduction in short-term interest rates. Interest charges were also reduced in 1982 because financing costs for most nuclear fuel requirements are now incurred by the nuclear fuel trust and recorded in fuel expense by the company when the nuclear fuel is burned. In contrast, during 1981 an increase in short-term borrowings, new long-term and intermediate-term debt issues, and higher interest rates contributed to a $62.8 million increase in interest expense.

Impact of Inflation

As previously indicated, the company is impacted by the effects of inflation and has attempted to quantify this impact as prescribed by the Financial Accounting Standards Board in Statement of Financial Accounting Standards No. 33, "Financial Reporting and Changing Prices." See Note 10, "Impact of Changing Prices," of Notes to Consolidated Financial Statements for a discussion on the impact of inflation on the company.

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COMPANY REPORT

The consolidated financial statements of Northeast Utilities and subsidiaries and other sections of this Annual Report were prepared by the company. These financial statements, which were examined by Arthur Andersen & Co., were prepared in accordance with generally accepted accounting principles using estimates and judgment, where required, giving consideration to materiality.

The company maintains a system of internal accounting controls that is supported by an organization of trained management personnel, policies and procedures, and a comprehensive program of internal audits. The company has endeavored to establish an environment which encourages the maintenance of high standards of conduct in all of its business activities. Written procedures manuals and established training programs communicate to the company's employees their internal control responsibilities as well as the company's policies and procedures prohibiting conflicts of interest. All supervisors are required to review internal control procedures under their jurisdiction and annually to make written representations as to the adequacy of the system of internal controls and its implementation. The company requires annual written representations from all management employees on possible conflicts of interest. Management reviews and acts upon all questions of the adequacy of the internal control process and possible conflicts of interest.

The Audit Committee of the Board of Trustees is composed entirely of outside trustees. This committee meets periodically with management, the internal auditors, and the independent auditors to review the activities of each and to discuss auditing, financial reporting, and the adequacy of internal accounting controls.

Because of inherent limitations in any system of internal accounting controls, errors or irregularities may occur and not be detected. The company concludes, however, that it has established an internal control environment which meets high standards and believes that its system of internal accounting controls provides reasonable assurance that its assets are safeguarded from loss or unauthorized use and that its financial records, which are the basis for the preparation of all financial statements, are reliable.

AUDITORS' REPORT

To the Board of Trustees and Shareholders
of Northeast Utilities:

We have examined the consolidated balance sheets and consolidated statements of capitalization of Northeast Utilities (a Massachusetts trust) and subsidiaries as of December 31, 1982, and 1981, and the related consolidated statements of income, common shareholders' equity and sources of funds for gross property additions for each of the three years in the period ended December 31, 1982. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the financial statements referred to above present fairly the financial position of Northeast Utilities and subsidiaries as of December 31, 1982, and 1981, and the results of their operations and the sources of funds for gross property additions for each of the three years in the period ended December 31, 1982, in conformity with generally accepted accounting principles applied on a consistent basis subsequent to the change (with which we concur) in accounting for the allowance for funds used during construction as described in Note 1 of Notes to Consolidated Financial Statements.

ARTHUR ANDERSEN & CO.

Hartford, Connecticut,
February 18, 1983.

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	1982	1981	1980
	(Thousands of Dollars, except share information)		
Operating Revenues	$1,763,220	$1,655,057	$1,324,545
Operating Expenses:			
Operation —			
Fuel	464,654	511,776	420,138
Purchased and interchange power, net	46,022	97,915	18,385
Gas purchased for resale	147,637	111,651	89,366
Other	378,358	322,973	267,853
Maintenance	109,721	82,152	79,476
Depreciation	106,417	102,801	96,266
Federal and state income taxes (Note 4)	113,712	67,552	46,835
Taxes other than income taxes	140,031	131,458	113,959
Total operating expenses	1,506,552	1,428,278	1,132,278
Operating Income	256,668	226,779	192,267
Other Income:			
Allowance for equity funds used during construction	52,096	32,658	26,070
Equity in earnings of regional nuclear generating companies	8,570	6,148	3,692
Other, net	(1,994)	(2,999)	1,667
Income taxes applicable to other income — credit	37,898	37,705	22,433
Net other income	96,570	73,512	53,862
Income before interest charges	353,238	300,291	246,129
Interest Charges:			
Interest on long-term debt	175,866	158,883	120,588
Other interest	31,679	61,824	37,302
Allowance for borrowed funds used during construction, net of the income tax effect of $35,139,000 in 1982, $35,361,000 in 1981 and $22,144,000 in 1980	(37,081)	(42,146)	(25,960)
Total interest charges	170,464	178,561	131,930
Income after interest charges	182,774	121,730	114,199
Preferred Dividends of Subsidiaries	31,532	26,612	25,447
Net Income	$ 151,242	$ 95,118	$ 88,752
Earnings Per Common Share	$ 1.76	$ 1.29	$ 1.31
Common Shares Outstanding (average)	85,777,230	73,783,201	67,555,006

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

Northeast Utilities and Subsidiaries

CONSOLIDATED STATEMENTS OF SOURCES OF FUNDS FOR GROSS PROPERTY ADDITIONS

For the Years Ended December 31,	1982	1981	1980
		(Thousands of Dollars)	
Funds Generated From Operations:			
Net Income	$151,242	$ 95,118	$ 88,752
Principal noncash items:			
Depreciation and nuclear fuel amortization	154,722	142,191	126,988
Deferred income taxes, net	50,989	17,329	25,842
Amortization of deferred charges and other noncash items	8,995	1,327	4,441
Amortization of energy adjustment clauses	47,808	33,876	7,584
Allowance for equity funds used during construction	(52,096)	(32,658)	(26,070)
Total funds from operations	361,660	257,183	227,537
Less: Cash dividends paid on common shares	110,650	87,064	74,311
Net funds generated from operations	251,010	170,119	153,226
Funds Obtained From Financing:			
Proceeds from issuance of:			
Common shares	107,843	88,257	14,047
Preferred stock	38,054	14,453	24,680
Long-term debt	362,198	262,489	98,035
Proceeds from the sale of nuclear fuel to a third party trust (Note 6)	230,400	—	—
Increase (decrease) in short-term debt	(168,110)	(111,691)	169,436
Increase (decrease) in nuclear fuel payable	(26,900)	4,600	175
Total	543,485	258,108	306,373
Less: Reacquisitions and retirements of long-term debt and preferred stock	274,641	7,778	30,147
Net funds from financing	268,844	250,330	276,226
Other Sources (Uses) of Funds:			
Decrease (increase) in net current assets (excluding short-term debt, long-term debt due within one year, preferred stock to be redeemed within one year and nuclear fuel payable):			
Cash and special deposits	19,823	(6,471)	(15,014)
Receivables and accrued utility revenues	(14,345)	3,890	(101,417)
Fuel, materials and supplies	(3,961)	(20,948)	(4,110)
Accounts payable	(53,984)	18,130	85,232
Accrued taxes	17,503	21,371	(26)
Other, net	(2,930)	7,745	1,949
Net change	(37,894)	23,717	(33,386)
Sale of utility plant	—	5,636	—
Deferred unusual operating expense	—	(10,949)	(4,034)
Energy adjustment clauses, net	2,886	(11,700)	(70,294)
Other, net	(3,040)	(1,602)	1,886
Net other sources (uses) of funds	(38,048)	5,102	(105,828)
Total Funds For Construction From Above Sources	481,806	425,551	323,624
Allowance For Equity Funds Used During Construction	52,096	32,658	26,070
GROSS PROPERTY ADDITIONS	$533,902	$458,209	$349,694
Composition of Gross Property Additions:			
Electric and other utility plant	$475,294	$360,118	$262,500
Gas utility plant	22,088	21,069	19,903
Nuclear fuel	36,520	77,022	67,291
Total	$533,902	$458,209	$349,694

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

CONSOLIDATED BALANCE SHEETS

At December 31,	1982	1981
	(Thousands of Dollars)	
Assets		
Utility Plant, at original cost:		
Electric	$3,037,882	$2,922,804
Gas	222,460	198,222
Other	33,926	35,959
	3,294,268	3,156,985
Less: Accumulated provision for depreciation	1,044,543	912,951
	2,249,725	2,244,034
Construction work in progress (Note 8)	1,223,578	894,078
Nuclear fuel, net of amortization (Note 6)	—	189,925
Total net utility plant	3,473,303	3,328,037
Other Property and Investments:		
Investments in regional nuclear generating companies, at equity	55,504	49,639
Other, at cost	15,996	21,296
	71,500	70,935
Current Assets:		
Cash and special deposits	4,177	24,000
Receivables, less accumulated provision for uncollectible accounts of $8,054,000 in 1982 and $4,920,000 in 1981	196,127	184,715
Accrued utility revenues	78,495	75,562
Fuel, materials and supplies, at average cost	130,021	126,060
Recoverable energy costs	—	35,768
Current portion of accumulated deferred income taxes	6,168	—
Prepayments and other	7,689	7,813
	422,677	453,918
Deferred Charges:		
Unamortized debt expense	5,317	3,864
Energy adjustment clauses, net	6,295	14,164
Canceled nuclear project (Note 3)	14,397	21,468
Deferred unusual operating expense (Note 3)	10,089	14,301
Other	25,061	18,894
	61,159	72,691
Total Assets	$4,028,639	$3,925,581

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

Northeast Utilities and Subsidiaries

CONSOLIDATED BALANCE SHEETS

At December 31,	1982	1981
	(Thousands of Dollars)	
Capitalization and Liabilities		
Capitalization: (See consolidated statements of capitalization)		
Common shareholders' equity	$1,159,698	$1,013,205
Preferred stock not subject to mandatory redemption	291,195	291,200
Preferred stock subject to mandatory redemption	103,893	65,401
Long-term debt	1,894,542	1,608,272
Total capitalization	3,449,328	2,978,078
Current Liabilities:		
Notes payable to banks (Note 5)	19,800	79,500
Commercial paper (Note 5)	37,725	146,135
Long-term debt due within one year	15,499	210,215
Preferred stock to be redeemed within one year	568	1,200
Nuclear fuel payable	—	26,900
Accounts payable	123,859	177,843
Accrued taxes	90,181	72,678
Refundable energy costs	10,783	—
Current portion of accumulated deferred income taxes	—	13,824
Accrued interest	40,790	44,962
Other	12,834	14,514
	352,039	787,771
Deferred Credits:		
Accumulated deferred income taxes	81,935	78,807
Accumulated deferred investment tax credits	128,845	66,798
Other	16,492	14,127
	227,272	159,732
Commitments and Contingencies (Note 8)		
Total Capitalization and Liabilities	$4,028,639	$3,925,581

The accompanying notes are an integral part of these financial statements

Northeast Utilities and Subsidiaries

CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31			1982	1981
			(Thousands of Dollars)	
Common Shareholders' Equity:				
Common shares, $5.00 par value—authorized 130,000,000 shares in 1982 and 100,000,000 shares in 1981; outstanding 89,497,740 shares in 1982 and 79,001,844 shares in 1981 (a)			$ 447,489	$ 395,009
Capital surplus, paid in			307,586	254,165
Retained earnings (b)			404,623	364,031
Total Common Shareholders' Equity			1,159,698	1,013,205
Cumulative Preferred Stock of Subsidiaries:				
$50 par value—authorized 9,000,000 shares; outstanding 6,910,495 shares in 1982 and 6,154,712 shares in 1981				
$100 par value—authorized 550,000 shares; outstanding 500,000 shares in 1982 and 1981				
Dividend Rates	Current Redemption Prices(c)	Shares Outstanding		
Not Subject to Mandatory Redemption: (d)				
$50 par value—				
$1.90 to $2.64	$ 50.50 to $ 54.00	1,824,000	91,200	91,200
$3.24 to $3.80	$ 52.26 to $ 53.05	1,099,925	54,996	55,000
$4.48 to $4.80	$ 53.21 to $ 54.66	2,199,970	109,999	110,000
$100 par value—				
$7.72 to $9.60	$105.44 to $106.39	350,000	35,000	35,000
Total Preferred Stock Not Subject to Mandatory Redemption			291,195	291,200
Subject to Mandatory Redemption: (e)				
$50 par value—				
$5.24	$ 55.24	500,000	25,000	25,000
$5.52	$ 54.14	320,355	16,140	17,695
$5.76	$ 54.32	166,245	8,321	8,906
$7.52	$ 57.52	800,000	40,000	—
$100 par value—				
$16.00	$116.00	150,000	15,000	15,000
			104,461	66,601
Less preferred stock to be redeemed within one year			568	1,200
Total Preferred Stock Subject to Mandatory Redemption			103,893	65,401
Long-Term Debt:				
First Mortgage Bonds—				
Maturity	Interest Rates			
1982	2-5/8% to 13-1/8%		—	154,810
1983	3-3/4%		225	235
1984	2-3/4% to 3-1/8%		23,076	23,186
1985	3-1/4%		20,000	20,000
1986	4-1/2%		9,600	9,600
1987	4-3/8% to 5 %		27,000	27,000
1988-1992	3-7/8% to 17-3/4%		243,040	183,920
1993-1997	4-1/4% to 11-1/2%		141,355	142,895
1998-2002	6-1/2% to 11 %		469,512	472,500
2003-2007	7-1/2% to 9-1/4%		285,000	285,000
2008-2012	9-1/4% to 15 %		270,000	170,000
Total First Mortgage Bonds			1,488,808	1,489,146
Other Long-Term Debt—				
Millstone 3 Construction Trust—variable interest rate (f)			135,334	—
Pollution Control Notes—				
1984-1988	8% to 10%		12,000	12,000
1998-2007	5.90% to 6.50%		27,650	27,650
Notes—				
1982	8.125% to 11.25%		—	40,000
1985	102% of the prime rate		30,000	30,000
1982-1986	10.50%		40,000	50,000
1988-1991	Prime rate		150,000	150,000
Miscellaneous			30,328	23,726
Total Other Long-Term Debt			425,312	333,376
Unamortized premium and discount, net			(4,079)	(4,035)
Total Long-Term Debt (g)			1,910,041	1,818,487
Less amounts due within one year			15,499	210,215
Long-Term Debt, Net			1,894,542	1,608,272
Total Capitalization			$3,449,328	$2,978,078

The accompanying notes are an integral part of these financial statements

NOTES TO THE CONSOLIDATED STATEMENTS OF CAPITALIZATION

(a) At December 31, 1982 a total of 7,378,128 common shares authorized for issuance pursuant to the Dividend Reinvestment and Common Share Purchase Plan were unissued.

(b) Northeast Utilities (NU) is restricted in the amount of dividends it may declare by its long-term debt agreement. At December 31, 1982, approximately $146.3 million of consolidated retained earnings was available for dividends. In addition, many of the consolidated subsidiaries of NU have dividend restrictions imposed by their long-term debt agreements. At December 31, 1982, under the respective agreements, there would be an aggregate total of approximately $161.8 million of consolidated retained earnings available for dividends.

(c) During their respective initial five-year redemption periods, each of these series is subject to certain refunding limitations. Redemption prices reduce in future years.

(d) In 1982, $5,000 of preferred stock not subject to mandatory redemption was retired. There were no changes during 1981 and 1980 in preferred stock not subject to mandatory redemption.

(e) The minimum sinking-fund provisions of the series subject to mandatory redemption aggregate $1,500,000 in each of the years 1983 through 1985, and $3,250,000 in 1986 and 1987. In case of default on sinking-fund payments, no payments may be made on any junior stock by way of dividends or otherwise (other than in shares of junior stock) so long as the default continues. If a subsidiary is in arrears in the payment of dividends on any outstanding shares of preferred stock, the subsidiary would be prohibited from redemption or purchase of less than all of the preferred stock outstanding.

Changes in Preferred Stock Subject to Mandatory Redemption

	(Thousands of Dollars)
Balance January 1, 1980	$ 30,000
Issues	25,000
Reacquisitions and retirements	(1,791)
Balance December 31, 1980	53,209
Issues	15,000
Reacquisitions and retirements	(1,608)
Balance December 31, 1981	66,601
Issues	40,000
Reacquisitions and retirements	(2,140)
Balance December 31, 1982	$104,461

(f) In March 1982 CL&P and WMECO entered into construction trust financing agreements to assist in the financing of the Millstone 3 construction. The trust was given a lien, junior to the liens of the respective indentures, on CL&P's and WMECO's interests in Millstone 3. Once Millstone 3 is in service, but beginning no later than 1988, the trust obligations are to be repaid over a four-year period.

The trust, whose obligations are initially limited to $400 million, will obtain funds by issuing up to $200 million of letter-of-credit (LOC)-backed commercial paper and issuing up to $200 million of term notes. During 1982 all trust obligations were met through the issuance of LOC-backed commercial paper. Interest costs of $8 million were incurred during 1982 in connection with this arrangement and were capitalized by CL&P and WMECO. The weighted average interest rate charged by the trust was 10.7 percent.

(g) Long-term debt maturities and cash sinking-fund requirements on debt outstanding at December 31, 1982 are, for the years 1983 through 1987, as follows: $15,499,000, $39,696,000, $70,257,000, $29,896,000 and $37,306,000, respectively. In addition there are annual 1 percent sinking- and improvement-fund requirements, currently amounting to $12,854,000, $12,750,000, $12,706,000, $12,663,000 and $12,499,000 for the years 1983 through 1987, respectively. Such sinking- and improvement-fund requirements may be satisfied by the deposit of cash or bonds, or by certification of property additions.

Essentially all of CL&P's and WMECO's utility plant is subject to the liens of their respective first mortgage bond indentures.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

	Common Shares	Capital Surplus, Paid In	Retained Earnings	Total
	(Thousands of Dollars)			
Balance at January 1, 1980	$332,970	$214,466	$341,553	$ 888,989
Net income for 1980			88,752	88,752
Cash dividends on common shares — $1.10 per share			(74,311)	(74,311)
Issuance of 1,618,356 common shares, $5 par value	8,092			8,092
Excess proceeds over the par value from the issuance of 1,618,356 common shares		5,955		5,955
Loss on the retirement of subsidiaries' preferred stock			(17)	(17)
Preferred stock issuance and retirement expenses		(216)		(216)
Balance at December 31, 1980	341,062	220,205	355,977	917,244
Net income for 1981			95,118	95,118
Cash dividends on common shares — $1.18 per share			(87,064)	(87,064)
Issuance of 10,789,528 common shares, $5 par value	53,947			53,947
Excess proceeds over the par value from the issuance of 10,789,528 common shares		40,110		40,110
Common share and preferred stock issuance and retirement expenses		(6,150)		(6,150)
Balance at December 31, 1981	395,009	254,165	364,031	1,013,205
Net income for 1982			151,242	151,242
Cash dividends on common shares — $1.28 per share			(110,650)	(110,650)
Issuance of 10,495,896 common shares, $5 par value	52,480			52,480
Excess proceeds over the par value from the issuance of 10,495,896 common shares		58,796		58,796
Common share and preferred stock issuance and retirement expenses		(5,375)		(5,375)
Balance at December 31, 1982	$447,489	$307,586	$404,623	$1,159,698

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Principles of Consolidation: Northeast Utilities (NU, or the company) is the parent company of the Northeast Utilities system (the system). The consolidated financial statements of the company include the accounts of all wholly owned subsidiaries. Significant intercompany transactions have been eliminated in consolidation.

Merger: Effective at the close of business on June 30, 1982, HELCO, a wholly owned subsidiary of NU, and The Connecticut Gas Company, a wholly owned subsidiary of CL&P, were merged into CL&P. The mergers were accounted for as poolings of interests.

Investments: CL&P and WMECO own common stock of four regional nuclear generating companies. These companies, with the system's ownership interest, are:

Connecticut Yankee Atomic Power Company (CY)	44.0%
Yankee Atomic Electric Company	31.5%
Maine Yankee Atomic Power Company	15.0%
Vermont Yankee Nuclear Power Corporation	12.0%

The system's investments in these companies are accounted for on the equity basis. The electricity produced from these facilities is committed to the participants based on their ownership interests and is billed pursuant to contractual agreements.

Public Utility Regulation: NU is registered with the Securities and Exchange Commission (SEC) as a holding company under the Public Utility Holding Company Act of 1935, and it and its subsidiaries are subject to the provisions of the act. Arrangements among the 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. The operating subsidiaries are subject to further regulation for rates and other matters by the FERC and/or their applicable state regulatory commissions, and follow the accounting policies prescribed by the respective commissions.

Revenues: Utility revenues are based on authorized rates applied to each customer's use of electricity or gas. Rates can be increased only through a formal proceeding before the appropriate regulatory commission. At the end of each accounting period, CL&P and WMECO accrue an estimate for the amount of energy delivered but unbilled.

Nuclear Fuel: The cost of nuclear fuel is amortized to operation expense on a unit-of-production method at rates based on estimated kilowatt-hours (kWh) of energy provided. The amortization was $48,305,000 in 1982, $39,390,000 in 1981 and $30,722,000 in 1980. (For details about the cost of nuclear fuel used after December 1, 1982, see Note 6.)

CL&P and WMECO recover through rates, with appropriate regulatory approval, an estimate for spent fuel disposal costs pertaining to nuclear fuel consumed.

On January 7, 1983, the Nuclear Waste Policy Act was signed into law. This act established procedures for the disposal by the United States Department of Energy (DOE) of high-level radioactive waste. Funding of the program will be provided by a 1.0 mil per kWh fee levied on electricity generated by nuclear power reactors after April 7, 1983. In addition, for nuclear fuel used to generate electricity prior to April 7, 1983, a fee is expected to be collected by the DOE no later than the time the spent fuel is delivered to the disposal site. The present on-site nuclear waste storage facilities for the Millstone units, including facilities currently under construction at Millstone 3, are expected to be adequate until the time when the act requires a federal repository facility to be available.

The procedures for calculation, collection and payment of these fees have not been determined at this time. Based on past regulatory practices, management expects that future recoveries of spent fuel disposal costs will be adequate to satisfy any obligations under this act.

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 net salvage value and removal costs as approved by the appropriate regulatory agency. 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 plant, including costs of removal, less salvage, is charged to the accumulated provision for depreciation.

The depreciation rates for the several classes of electric and gas plant in service are equivalent to the following composite rates:

Year	Electric	Gas
1982	3.5%	2.8%
1981	3.5	2.9
1980	3.4	3.0

Nuclear Decommissioning: A 1981 decommissioning study indicates that immediate dismantlement of the nuclear units at their retirement, with an estimated cost of $200 million in 1982 dollars, is the most viable and economic method of decommissioning two nuclear units wholly owned by CL&P and WMECO. This estimate is reviewed and updated periodically to reflect changes in decommissioning requirements, technology and inflation. Although a substantial portion of the estimated total decommissioning costs has been approved by regulatory agencies and is reflected in the depreciation expense of CL&P and WMECO, the companies believe additional revenues will be required to pay the full projected costs of decommissioning.

Income Taxes: The tax effect of timing differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of income subject to tax) is accounted for in accordance with the ratemaking treatment of the applicable regulatory commissions. Beginning in 1981, substantially all of the timing differences were normalized. It is expected that, for years prior to the adoption of normalization, the deferred taxes not provided for currently will be collected in customers' rates when such taxes become payable. (See Note 4 for the detail of income tax expense.)

Investment tax credits, which reduce federal income taxes currently payable, are deferred and amortized over the useful life of the related utility plant. An additional investment tax credit of 1 percent is related to the Tax Reduction Act Employees Stock Ownership Plan (TRAESOP) for the system's employees. Contributions to TRAESOP do not affect net income, but are recorded as a liability until the payment to the plan is made.

Allowance for Funds Used During Construction (AFUDC): AFUDC represents the estimated cost of capital funds used to finance the system's construction program. These costs, which are one component of the total capitalized cost of construction, are not recognized as part of the rate base for ratemaking purposes until facilities are placed in service. AFUDC is recovered over the service life of plant in the form of increased revenue collected as a result of higher depreciation expense.

The effective AFUDC rates for 1982, 1981 and 1980 were 9.1 percent, 8.6 percent, and 7.9 percent, respectively. These rates are calculated under the net-of-income tax method, following FERC guidelines, and include semiannual compounding.

Effective January 1, 1980, the method of accounting for AFUDC was changed from the gross-rate method to the net-of-income tax method. The Connecticut Department of Public Utility Control (DPUC) granted CL&P approval for the use of the net-of-income tax method in October 1980. Early adoption of this method for financial reporting purposes resulted in a reduction of net income of $11.9 million ($0.18 per share) for the period from January 1, 1980 to the approval date.

The net result of an AFUDC rate increase in 1980, semiannual compounding and the early adoption of the net-of-income tax method had no material effect on net income for the year ended December 31, 1980.

Retirement Plan: The company's subsidiaries participate in a uniform noncontributory retirement plan covering all regular system employees. It is the policy of the subsidiaries to fund annually the actuarially determined contribution, which includes that year's normal cost, the amortization of prior years' actuarial gains or losses over 15 years, and the amortization of prior service cost over a period of 40 years. Total pension cost, part of which was charged to utility plant, approximated $25,942,000 in 1982, $24,200,000 in 1981 and $23,400,000 in 1980.

The actuarial present value of accumulated plan benefits and plan net assets available for benefits for the system's plan are:

January 1,	1982	1981
	(Thousands of Dollars)	
Benefits:		
Vested	$264,185	$243,964
Nonvested	33,513	27,776
	$297,696	$271,740
Net assets available for benefits	$308,929	$300,704

The assumed rate of return used to determine the actuarial present value of accumulated plan benefits was 6.5 percent for 1982 and 1981.

Energy Adjustment Clauses: CL&P's retail electric and gas rates include adjustment clauses under which fossil fuel and purchased power costs and purchased gas costs above or below base rate levels are charged or credited to customers. As prescribed by the DPUC, most differences between CL&P's actual fossil fuel and purchased gas costs and the current cost recoveries are deferred until future recovery is permitted.

CL&P's retail base electric rates include a 70 percent composite nuclear generation component. The DPUC has approved the use of a generation utilization adjustment clause which levels the effect on fuel costs caused by variations from a 70 percent composite nuclear generation capacity factor. When actual nuclear performance is above 70 percent, fossil fuel costs are lower than expected, and when nuclear performance is below 70 percent, fossil fuel costs are higher than expected. At the end of a 12-month period ending July 31 of each year, these net variations from the expected cost levels are refunded to or collected from customers over the subsequent 11-month period.

For the 12-month period ended July 31, 1982, the composite nuclear generation capacity factor was 74.1 percent, resulting in lower fossil fuel costs of $20.6 million. That amount is being refunded to customers on a monthly basis, throughout the period ending July 31, 1983, and, accordingly, the balance is included in current liabilities.

WMECO's retail electric rates include a fuel adjustment clause under which forecasted fossil fuel, purchased power and nuclear fuel costs are billed to customers currently. As permitted by the Massachusetts Department of Public Utilities (DPU), WMECO defers fuel costs until they are recovered quarterly under the adjustment clause. In 1981, the Massachusetts legislature passed legislation which established an annual performance program related to fuel procurement and use. The current performance program goals for WMECO cover the period June 1982 to May 1983. All of the revenues currently collected under the WMECO retail fuel clause are subject to potential refund pending the DPU's review of WMECO's actual performance during the performance program year. While WMECO questions the DPU's authority to set performance standards for plants not wholly owned or operated by WMECO, the company is essentially operating within the present performance standards and management believes that the likelihood of a significant refund, as a result of this program, is remote.

2. Rate Matters

In December 1982, the DPUC granted CL&P annual retail electric and gas rate increases of approximately $101.1 million. The total increase granted was 79.5 percent of CL&P's amended request. The new rates went into effect on December 22, 1982.

During 1982, the DPU granted WMECO an annual rate increase of $4.4 million. The level granted was 18 percent of the $24 million WMECO sought in amended rate schedules. The new rates went into effect in June 1982.

WMECO filed new amended rate schedules with the DPU in October 1982, requesting an annual revenue increase of $24.1 million. WMECO also filed a petition for interim rate relief of $5.3 million. If approved, the permanent rates are expected to become effective in May 1983. Hearings on the permanent rate application ended in early March 1983. A decision on the interim request also is pending.

3. Deferred Expenses

In December 1980, the system canceled the Montague nuclear project. CL&P and WMECO had a combined interest of 75 percent in the project. The companies have received approval from applicable state and federal regulatory authorities to recover project costs of approximately $21.7 million through rates over a three- to four-year period. Project costs of $5.2 million not recoverable through rates were expensed during 1981.

In April 1981, Millstone 1 concluded an extended refueling and inspection outage. Certain operation and maintenance expenses totaling approximately $15.0 million were considered abnormal. CL&P and WMECO received permission from the appropriate state and federal regulatory authorities to recover the expenses through rates over a three-year period beginning in 1981.

4. Income Tax Expense

The detail of the federal and state income tax provisions is:

	1982	1981	1980
	(Thousands of Dollars)		
Current income taxes:			
Federal	$ 4,634	$ 6,401	$ (1,575)
State	20,191	6,117	135
Total current	24,825	12,518	(1,440)
Deferred income taxes, net:			
Investment tax credits	67,265	19,098	(8,489)
Federal	(11,715)	(2,661)	28,891
State	(4,561)	892	5,440
Total deferred	50,989	17,329	25,842
Taxes on debt portion of AFUDC	35,139	35,361	22,144
Total income tax expense	110,953	65,208	46,546
Less: Income taxes (credits) included in other income	(2,759)	(2,344)	(289)
Total income taxes charged to operating expenses	$113,712	$67,552	$46,835

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

	1982	1981	1980
	(Thousands of Dollars)		
Investment tax credits	$67,265	$19,098	$(8,489)
Liberalized depreciation	12,521	10,034	4,170
Construction overheads	11,131	10,491	1,777
Decommissioning costs	(2,398)	(2,700)	(309)
Settlement credits — nuclear fuel	(1,668)	(5,175)	(917)
Energy adjustment clauses	(21,733)	(10,528)	25,186
Unbilled revenues	(530)	(1,659)	(1,062)
Spent nuclear fuel storage accruals	(8,449)	(6,047)	(2,627)
Canceled nuclear project	(1,534)	(1,899)	6,838
Deferred unusual operating expense	(2,965)	5,231	1,769
Other	(651)	483	(494)
Deferred income taxes, net	$50,989	$17,329	$25,842

The principal reasons for the difference between total tax expense and the amount calculated by applying the federal income tax rate to pretax income are:

	1982	1981	1980
	(Thousands of Dollars)		
Expected tax at 46% of pretax income	$135,114	$85,991	$73,942
Tax effect of differences:			
Additional depreciation for tax purposes	(6,280)	(6,314)	(10,286)
Allowance for equity funds used during construction—not recognized as income for tax purposes	(23,964)	(15,022)	(11,992)
Overhead costs of construction—expensed for tax purposes	—	—	(4,876)
Investment tax credits	(6,143)	(4,664)	(5,908)
State tax, net of federal benefit	8,440	3,785	3,011
Other, net	3,786	1,432	2,655
Total income tax expense	$110,953	$65,208	$46,546
Effective income tax rate	38%	35%	29%

At December 31, 1982, the system had unused and unrecorded investment tax credits of approximately $24 million, which are available to offset federal income tax provisions through 1997.

5. Short-Term Debt

The system companies use bank loans and commercial paper to finance the system's continuing construction program on a short-term basis and to meet general working capital needs. The system companies have bank credit lines totaling $48 million. Terms call for interest rates equal to the prime rate at the time of borrowing, and compensation for the lines is on the basis of commitment fees, compensating balances, or both. At December 31, 1982 the average annual compensating balance requirements totaled $2.3 million and annual commitment fees totaled $80,000. The credit lines expire at various times in 1983. Although these lines are generally renewable, the continuing availability of the unused lines of credit is subject to review by the banks involved. At December 31, 1982, the amount of unused available borrowing capacity under the credit lines available to the system companies was $32.2 million.

In addition to their customary short-term borrowings from banks and from the sale of commercial paper, CL&P and WMECO also have a joint credit line of $200 million, pursuant to a revolving credit/term loan agreement, with a group of banks. The maximum individual borrowing limits of CL&P and WMECO under the agreement are $200 million and $60 million, respectively. The companies are obligated to pay a commitment fee of three-eighths of 1 percent per annum on their proportionate shares of the daily average of the unborrowed portion of the aggregate commitment. At December 31, 1982, CL&P and WMECO had no borrowings under this agreement.

CL&P also entered into a $50 million floating-rate Eurodollar revolving credit agreement with a group of foreign banks in November 1982. CL&P is obligated to pay a commitment fee of one-quarter of 1 percent per annum on the daily average of the unborrowed portion of the commitment. At December 31, 1982, CL&P had no borrowings outstanding under this agreement.

6. Nuclear Fuel Financing

In February 1982, CL&P and WMECO entered into arrangements with a third party under which the Niantic Bay Fuel Trust (NBFT) will own and finance up to $530 million of nuclear fuel for Millstone 1 and 2 and the system's share of nuclear fuel for Millstone 3. The arrangements provide for CL&P and WMECO to make quarterly lease payments to NBFT for the cost of nuclear fuel consumed in the reactors plus financing costs associated with the fuel in the reactors. Upon discharge from the reactors, the nuclear fuel will be transferred to CL&P and WMECO.

During 1982, NBFT acquired the fuel for Millstone 1 and 2 and the system's share of the fuel for Millstone 3. Before it was acquired by NBFT, the nuclear fuel for Millstone 1 and 2 had been financed by Northeast Nuclear Energy Company (NNECO) with bank loans, secured notes, capital contributions or advances from the company and the Waterford Fuel Supply Trust (WFST) which owned the fuel until it was placed in the reactors. Interest costs of $2,025,000 in 1982, $8,227,000 in 1981, and $4,126,000 in 1980 were incurred in connection with financing the nuclear fuel and were capitalized by NNECO. The weighted average interest rate charged by the trust was 15.1 percent in 1982, 17.8 percent in 1981 and 14.1 percent in 1980.

On December 1, 1982, the WFST was terminated and the nuclear fuel in Millstone 1 and 2 held by NNECO with a book value of $108.9 million was acquired by NBFT.

Pursuant to the transition rules for leases specified in Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71), this nuclear fuel leasing arrangement is currently accounted for as an operating lease. Had it been accounted for as a capital lease, assets and liabilities as of December 31, 1982 would have increased by $267 million. On December 1, 1982,

CL&P and WMECO began accruing rent expense under this obligation to NBFT. This rent expense for the period December 1, 1982, through December 31, 1982 was $5.9 million, consisting of $4.7 million of nuclear fuel amortization and $1.2 million of interest expense.

7. Leases

In addition to the nuclear fuel lease described in Note 6, the system companies have entered into lease agreements for the use of substation equipment, data processing and office equipment, vehicles, and office space. These leases are currently accounted for as operating leases pursuant to the transition rules specified in SFAS 71. Had the system companies capitalized such leases at the beginning of the lease terms, the effect on assets, liabilities, expenses, or net income would not be material.

Rental payments charged to operating expense amounted to $16,299,000 for 1982, $10,612,000 for 1981, and $10,923,000 for 1980.

Future minimum rental payments under long-term noncancelable leases as of December 31, 1982, excluding executory costs such as real estate taxes, state use taxes, insurance, and maintenance, are approximately:

Period	(Thousands of Dollars)
1983	$ 21,900
1984	19,100
1985	15,600
1986	14,100
1987	10,200
After 1987	47,900
	$128,800

8. Commitments and Contingencies

Construction Program: The system companies are engaged in a continuous construction program and currently forecast construction expenditures (including AFUDC but excluding nuclear fuel which will be leased) of $2.2 billion for the years 1983-1987, including $652 million for 1983.

The construction program is subject to periodic review and revision, and actual construction expenditures may vary from such estimates due to factors such as revised load estimates, inflation, revised nuclear safety regulations, the availability and cost of capital, and the granting of timely and adequate rate relief by regulatory commissions, as well as actions by other regulatory bodies.

At December 31, 1982, construction work in progress (CWIP) included an investment of $1.1 billion in jointly owned nuclear generating facilities, consisting of CL&P's and WMECO's combined 65 percent interest in Millstone 3 of $1.0 billion and CL&P's 4.1 percent interest in the Seabrook nuclear project of $95.1 million. All the companies owning undivided interests in these jointly owned facilities are required to provide financing to support their own portion of construction costs.

A 1986 in-service date is planned for Millstone 3. The anticipated cost to CL&P and WMECO for their 65 percent ownership share of the unit is $2.3 billion. This estimate is based on a review that was completed in September 1982.

CL&P and WMECO were parties to contracts expiring on December 31, 1982, for the sale of interests representing an aggregate of 49.6 megawatts (MW) of Millstone 3 to four other utility systems. On the basis of their recent reviews of the estimated cost of constructing Millstone 3 and their power supply needs, three of the utility systems permitted their contracts to lapse. These utilities had been committed to purchase an aggregate of 42.7 MW. The fourth utility system has extended its contract through June 30, 1983, but has reduced its commitment from 6.9 MW to 1.73 MW. CL&P and WMECO intend to continue their efforts to reduce their ownership interests in Millstone 3.

Nuclear Insurance: The Price-Anderson Act currently limits public liability from a single accident at a nuclear power plant to $560 million. If the total damages resulting from the accident exceed the private pool insurance coverage of $160 million, then CL&P and WMECO jointly would be required to pay a maximum of $15.1 million per accident, limited to a maximum of $30.2 million in any calendar year, based on their ownership interest in those nuclear reactors presently in service (i.e. Millstone 1 and 2, and the four regional nuclear generating companies described in Note 1).

CL&P and WMECO have purchased insurance from Nuclear Electric Insurance Limited (NEIL) to cover: (a) the extra costs incurred in obtaining replacement power during a prolonged accidental outage with respect to their ownership interests in Millstone 1 and 2 and CY; and, (b) the cost of repair or replacement of property and the cost of decontamination resulting from specified damages with respect to their insurable interests at Millstone 1, 2 and 3. Under each policy, CL&P and WMECO are subject to retroactive assessments if losses exceed the accumulated funds available to NEIL. The present maximum assessments for CL&P and WMECO would be approximately $18.4 million under the replacement power policy and $10.8 million under the property damage and decontamination liability policy.

CY, Maine Yankee Atomic Power Company and Vermont Yankee Nuclear Power Corporation have also purchased from NEIL property damage and decontamination liability insurance, and are subject to retroactive assessments if losses exceed the accumulated funds available to NEIL. CL&P and WMECO could be assessed an additional $4.8 million based on their ownership interests in these units.

Financial Arrangements for the Regional Nuclear Generating Companies: The owners of CY, including CL&P and WMECO, have agreed to purchase their pro rata share of up to $40 million of CY's subordinated notes. CL&P's and WMECO's share of the notes could aggregate $17.6 million. As of December 31, 1982, there were no notes outstanding. The owners of CY, however, could be called upon to purchase notes in the future.

In December 1981, CY entered into two financing arrangements through which it could obtain $100 million of new debt, of which the owners of CY have guaranteed their pro rata shares. The guarantees of CL&P and WMECO under this arrangement could aggregate $44 million.

The owners of Vermont Yankee Nuclear Power Corporation, including CL&P and WMECO, have guaranteed their pro rata shares of a $40 million nuclear fuel financing. The guarantees of CL&P and WMECO aggregate $4.8 million.

The company expects that CL&P and WMECO may be asked to provide additional capital and/or other types of direct or indirect financial support for one or more of the regional nuclear generating companies.

9. Segments of Business

The following summarizes information relating to NU's electric and gas operations:

For the Years Ended December 31,	1982	1981	1980
		(Thousands of Dollars)	
Operating Information			
Operating Revenues—			
Electric	$1,538,773	$1,473,789	$1,179,161
Gas	224,447	181,268	145,384
Total	$1,763,220	$1,655,057	$1,324,545
Operating expenses excluding provisions for income taxes—			
Electric	$1,194,841	$1,204,896	$ 958,340
Gas	197,999	155,830	127,103
Total	$1,392,840	$1,360,726	$1,085,443
Pretax operating income—			
Electric	$ 343,932	$ 268,893	$ 220,821
Gas	26,448	25,438	18,281
Total	$ 370,380	$ 294,331	$ 239,102
Provision for income taxes—			
Electric	$ 106,290	$ 61,522	$ 43,477
Gas	7,422	6,030	3,358
Total	$ 113,712	$ 67,552	$ 46,835
Operating income—			
Electric	$ 237,642	$ 207,371	$ 177,344
Gas	19,026	19,408	14,923
Total	$ 256,668	$ 226,779	$ 192,267
Depreciation expense—			
Electric	$ 100,623	$ 97,401	$ 91,255
Gas	5,794	5,400	5,011
Total	$ 106,417	$ 102,801	$ 96,266
Capital expenditures:			
Electric	$ 511,814	$ 437,140	$ 329,791
Gas	22,088	21,069	19,903
Total	$ 533,902	$ 458,209	$ 349,694
Investment information at December 31:			
Identifiable assets (a)			
Electric	$3,325,950	$3,192,206	$2,899,412
Gas	186,483	169,792	154,057
Nonallocable assets	516,206	563,583	574,273
Total Assets	$4,028,639	$3,925,581	$3,627,742

(a) Includes construction work in progress, materials and supplies, and allocated common utility plant.

10. Impact of Changing Prices (Unaudited)

Introduction

The following supplementary data presents certain information about the estimated effect of inflation on the company's operations. Such data was prepared in accordance with the requirements of Statement of Financial Accounting Standards No. 33 (SFAS 33), "Financial Reporting and Changing Prices."

The methodology prescribed by SFAS 33 involves numerous assumptions and estimates and, therefore, the resulting information should be viewed as an approximation of the effects of inflation rather than a precise measure.

Constant Dollar and Current Cost

SFAS 33 established two methods for measuring the impacts of inflation: constant dollar and current cost.

Constant dollar amounts represent historical costs stated in dollars of equal purchasing power, as measured by the average level of the Consumer Price Index for all Urban Consumers (CPI-U) during the year. With the exception of CWIP, the data for plant was determined by applying the appropriate CPI-U to the historical cost of plant. Constant dollar restatement, therefore, is a measure of the effect of general inflation.

The current cost method adjusts for changes in specific prices of plant from the date plant was placed in service to the present. Current cost does not necessarily represent the replacement cost of existing plant because such plant is not expected to be replaced precisely in kind. Current cost amounts differ from constant dollar amounts to the extent that specific prices have increased more or less rapidly than the general rate of inflation. The current cost was determined by indexing historical plant using the Handy-Whitman Index of Public Utility Construction Costs. Both the constant dollar and current cost amounts of land have been estimated by using the CPI-U.

The current year's depreciation expense for both constant dollar and current cost methods was determined by applying the company's operating subsidiaries' depreciation rates to adjusted plant amounts. Amortization of nuclear fuel under both methods was adjusted based on the system's present refueling cycle.

Fossil fuel inventories and the cost of fossil fuel used in generation have not been restated from their historical cost, since regulatory authorities permit the recovery of fuel costs through the operation of adjustment clauses. For this reason, fuel inventories are considered monetary assets.

Other items included in the Statement of Income were not adjusted because they were considered to be at average price levels for the year or were specifically excluded from adjustment by SFAS 33.

Discussion

The results of operations under both current cost and constant dollar restatements show a net loss as a result of increased depreciation expense on inflation-adjusted assets. In addition, the company will eventually have to replace its assets at a price many times greater than the original cost without having the opportunity to recover the replacement value of its assets through historical cost depreciation expense.

An adjustment to income taxes would also be necessary to reflect the true economic effect of inflation. Current income tax law does not allow the excess depreciation and amortization expenses under constant dollar and current cost accounting as deductions in determining federal income taxes. As a result, the effective tax rates adjusted for inflation under the constant dollar and current cost methods are 102 percent and 140 percent, respectively. These percentages substantially exceed the statutory rate of 46 percent and the company's 1982 effective tax rate of 38 percent.

During periods of inflation, holders of net monetary assets suffer a loss of purchasing power, while holders of net monetary liabilities experience a gain because debt will be repaid in dollars having less purchasing power. The company's gain from the decline in purchasing power of net amounts owed is attributed to the substantial amount of debt which was used to finance property, plant and equipment. This "gain" is not realizable by the company and, therefore, cannot be considered additional funds for reinvestment or dividend distribution.

Statement of Income Adjusted For Changing Prices
For the Year Ended December 31, 1982

	Conventional Historical Cost	Constant Dollar Average 1982 Dollars	Current Cost Average 1982 Dollars(b)
		(Millions of Dollars)	
Operating revenues	$1,763	$1,763	$1,763
Operating expenses excluding depreciation and nuclear fuel amortization	1,352	1,352	1,352
Depreciation and nuclear fuel amortization	155	308	337
Interest expense	170	170	170
Other income	97	97	97
Preferred dividends of subsidiaries	32	32	32
Net income (loss) (a)	$ 151	$ (2)	$ (31)
Excess of increase in specific prices ($300 million) over increase in the general price level ($234 million) after adjustment to net recoverable cost			$102
Gain from decline in purchasing power of net amounts owed			$ 91

(a) Net income in 1982 would have been $70.5 million on a constant dollar basis and $4.3 million on a current cost basis, if the adjustment to net recoverable cost were included.

(b) At December 31, 1982, the current cost of fixed assets, net of accumulated depreciation, was $6.3 billion, while historical cost, or net cost recoverable through depreciation was $3.5 billion.

Five-Year Comparison of Selected Supplementary Financial Data Adjusted for Effects of Changing Prices
(In Average 1982 Dollars, Except Historical Amounts)

Years Ended December 31,	1982	1981	1980	1979	1978
	(Millions of Dollars, except share and index data)				
Operating revenues:					
Historical	$1,763	$1,655	$1,325	$1,074	$ 934
Constant dollar	1,763	1,756	1,552	1,429	1,382
Net income (loss) (excluding adjustment to net recoverable cost):					
Historical	$ 151	$ 95	$ 89	$ 81	
Constant dollar	(2)	(32)	(31)	(14)	
Current Cost	(31)	(73)	(49)	(79)	
Income (loss) per common share (after dividend requirements on preferred stock and excluding adjustment to net recoverable cost):					
Historical	$ 1.76	$ 1.29	$ 1.31	$ 1.22	
Constant dollar	(.03)	(.43)	(.46)	(.21)	
Current Cost	(.37)	(.98)	(.72)	(1.19)	
Net assets at year-end:					
Historical	$1,160	$1,013	$ 917	$ 889	
Constant dollar and current cost	1,147	1,040	1,026	1,118	
Amount by which the increase in general price level is greater than (or less than) the increase in specific prices after adjustment to net recoverable cost:					
Current cost	$(102)	$ 75	$219	$266	
Gain from decline in purchasing power of net amounts owed	$ 91	$206	$286	$328	
Cash dividends declared per common share:					
Historical	$1.28	$1.18	$1.10	$1.06	$1.02
Constant dollar	1.28	1.26	1.31	1.43	1.51
Market price per common share at year-end:					
Historical	$12.13	$9.13	$8.00	$9.13	$9.00
Constant dollar	11.99	9.37	8.95	11.47	12.83
Average consumer price index	289.1	272.4	246.8	217.4	195.4

SELECTED CONSOLIDATED FINANCIAL DATA

		1982	1981	1980	1979	1978
		(Thousands of Dollars, except percentages and per share data)				
Income Data	Operating Revenues	$1,763,220	$1,655,057	$1,324,545	$1,074,385	$933,757
	Operating Expenses	1,506,552	1,428,278	1,132,278	882,511	742,018
	Operating Income	256,668	226,779	192,267	191,874	191,739
	Net Income	151,242	95,118	88,752	80,765	85,555
Share Data	Earnings per Share	$ 1.76	$ 1.29	$ 1.31	$ 1.22	$ 1.32
	Dividends per Share	$ 1.28	$ 1.18	$ 1.10	$ 1.0582	$ 1.0164
	Payout Ratio (%)	72.7	91.5	83.7	86.6	77.0
	Number of Shares Outstanding—Average	85,777,230	73,783,201	67,555,006	66,054,534	64,793,211
	Rate of Return Earned on Average Common Equity (%)	13.8	9.9	9.9	9.2	10.2
	Book Value per Share	$12.96	$12.83	$13.45	$13.35	$13.27
	Market Price — High	$12½	$ 9¼	$ 9¾	$10⅝	$10¼
	— Low	8⅞	8	7⅛	8⅝	9
Balance Sheet Data	Total Net Utility Plant	$3,473,303	$3,328,037	$3,022,228	$2,825,204	$2,732,917
	Total Assets	4,028,639	3,925,581	3,627,742	3,215,577	3,046,423
Capitalization (includes portions due within one year)	Common Shareholders' Equity	$1,159,698	$1,013,205	$ 917,244	$ 888,989	$ 865,474
	Preferred Stock Not Subject to Mandatory Redemption	291,195	291,200	291,200	291,200	291,200
	Preferred Stock Subject to Mandatory Redemption	104,461	66,601	53,209	30,000	30,000
	Long-Term Debt	1,910,041	1,818,487	1,562,914	1,492,797	1,496,377
	Total Capitalization	$3,465,395	$3,189,493	$2,824,567	$2,702,986	$2,683,051
Capitalization Ratios (includes portions due within one year)	Common Shareholders' Equity	33.5%	31.8%	32.5%	32.9%	32.3%
	Preferred Stock Not Subject to Mandatory Redemption	8.4	9.1	10.3	10.8	10.8
	Preferred Stock Subject to Mandatory Redemption	3.0	2.1	1.9	1.1	1.1
	Long-Term Debt	55.1	57.0	55.3	55.2	55.8
	Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%

Northeast Utilities and Subsidiaries

CONSOLIDATED GENERAL OPERATING STATISTICS

	1982	1981	1980	1979	1978
System Capability — MW (a)	5,946.1	5,594.8	5,984.5	5,921.3	6,206.2
System Peak Demand — MW	4,049.9	4,126.6	4,050.4	3,976.2	3,878.1
Nuclear Capability — MW (a)	2,008.8	2,008.8	2,009.4	2,009.4	1,949.0
Nuclear Capacity Factor (%) (a)	70.8	67.0	61.6	67.7	73.8
Nuclear Contribution To Total Energy Requirements (%)	56.7	53.8	49.6	54.1	57.6
Average Interest Rate On First Mortgage Bonds (%)	9.4	8.6	7.7	7.5	7.5
Average Dividend Rate On Preferred Stock (%)	8.1	7.8	7.6	7.6	7.6

(a) Includes company entitlements in regional nuclear generating companies

Northeast Utilities and Subsidiaries

CONSOLIDATED ELECTRIC OPERATING STATISTICS

	1982	1981	1980	1979	1978
Source of Electric Energy: (kWh-millions)(a)					
Nuclear—Steam	12,343	11,794	10,878	11,793	12,692
Fossil—Steam	7,503	7,813	9,632	7,202	7,617
Hydro—Conventional	791	724	635	900	700
Hydro—Pumped Storage	795	575	856	626	811
Internal Combustion	15	19	57	50	23
Energy Used for Pumping	(1,108)	(807)	(1,186)	(855)	(1,107)
Net Generation	20,339	20,118	20,872	19,716	20,736
Purchased And Net Interchange	883	1,999(b)	1,551	2,374	971
Company Use And Unaccounted For	(1,631)	(1,560)	(1,856)	(1,605)	(1,743)
Net Energy Sold	19,591	20,557(b)	20,567	20,485	19,964
Revenues: (thousands)					
Residential	$ 633,124	$ 584,322	$ 468,543	$ 386,864	$ 343,824
Commercial	479,976	433,276	336,719	279,535	242,872
Industrial	314,418	319,531	244,132	202,457	170,250
Other Utilities	47,863	75,477	71,365	56,550	46,524
Streetlighting	23,726	22,118	18,503	15,679	14,414
Miscellaneous	23,114	21,971	24,848	17,004	15,661
Total Electric	1,522,223	1,456,695	1,164,110	958,089	833,545
Other	16,550	17,094	15,051	10,330	7,827
Total	$1,538,773	$1,473,789	$1,179,161	$ 968,419	$ 841,372
Sales: (kWh — millions)					
Residential	7,342	7,447	7,492	7,436	7,315
Commercial	6,166	6,006	5,855	5,728	5,585
Industrial	4,871	5,287	5,233	5,328	5,097
Other Utilities	1,035	1,638(b)	1,801	1,806	1,778
Streetlighting	177	179	186	187	189
Total	19,591	20,557(b)	20,567	20,48[illegible]	19,964
Customers: (average)					
Residential	991,069	979,963	969,698	957,417	941,763
Commercial	88,315	87,480	87,055	86,584	85,790
Industrial	5,004	5,036	5,016	5,040	5,087
Other	2,398	2,315	2,301	2,340	2,382
Total	1,086,786	1,074,794	1,064,070	1,051,381	1,035,022
Average Annual Use Per Residential Customer (kWh)	7,361	7,548	7,664	7,659	7,648
Average Annual Bill Per Residential Customer	$634.71	$592.29	$479.26	$398.43	$359.51
Average Revenue Per kWh:					
Residential	8.62¢	7.85¢	6.25¢	5.20¢	4.70¢
Commercial	7.78	7.21	5.75	4.88	4.35
Industrial	6.45	6.04	4.67	3.80	3.34

(a) Generated in system and regional nuclear generating plants.

(b) Sales to Connecticut Municipal Electric Energy Cooperative, a power supply agency for three municipal systems in Connecticut, have been shown as sales to other utilities in periods prior to October 1, 1981. Commencing on October 1, 1981, these sales have been recorded as purchased and net interchange power delivered.

Northeast Utilities and Subsidiaries

CONSOLIDATED GAS OPERATING STATISTICS

	1982	1981	1980	1979	1978
Source of Gas (Mcf-thousands)					
Purchased	29,263	29,158	28,342	26,048	24,809
Produced	464	573	410	454	358
Company Use And Unaccounted For	(810)	(702)	(1,206)	(936)	(1,468)
Net Sold	28,917	29,029	27,546	25,566	23,699
Maximum Day Sendout (M-Therms)	2,068	2,036	1,854	1,772	1,467
Revenues: (thousands)					
Residential	$ 94,115	$ 75,500	$ 61,472	$ 48,221	$ 45,990
Commercial	58,189	44,143	31,772	21,472	19,383
Industrial	69,850	59,302	47,053	34,140	25,004
Miscellaneous	2,293	2,323	5,087	2,133	2,008
Total	$224,447	$181,268	$145,384	$105,966	$ 92,385
Sales: (Mcf-thousands)					
Residential	10,294	10,532	10,174	10,003	10,299
Commercial	7,722	7,103	6,075	5,175	4,973
Industrial	10,886	11,378	11,278	10,374	8,075
Other	15	16	19	14	352
Total	28,917	29,029	27,546	25,566	23,699
Customers: (average)					
Residential	137,204	135,992	134,075	131,634	131,036
Commercial	13,829	13,605	13,202	12,617	12,222
Industrial	1,296	1,304	1,297	1,274	1,273
Total	152,329	150,901	148,574	145,525	144,531
Average Annual Use Per Residential Customer (Mcf)	75.0	77.4	75.9	76.0	78.6
Average Annual Bill Per Residential Customer	$685.95	$555.18	$458.49	$366.33	$350.97
Average Revenue Per Mcf:					
Residential	$9.14	$7.17	$6.04	$4.82	$4.47
Commercial	7.54	6.21	5.23	4.15	3.90
Industrial	6.42	5.21	4.17	3.29	3.10

CONSOLIDATED STATEMENTS OF QUARTERLY FINANCIAL DATA (Unaudited)

	Quarter Ended			
1982	March 31	June 30	September 30	December 31
	(Thousands of Dollars, except per share data)			
Operating Revenues	$522,634	$396,266	$404,486	$439,834
Operating Income	$ 82,250	$ 51,456	$ 60,863	$ 62,099
Net Income	$ 50,613	$ 24,739	$ 37,233	$ 38,657
Earnings Per Common Share	$0.64	$0.29	$0.42	$0.41
1981				
Operating Revenues	$455,651	$375,854	$400,282	$423,270
Operating Income	$ 64,381	$ 48,990	$ 53,134	$ 60,274
Net Income	$ 32,415	$ 14,171	$ 18,888	$ 29,644
Earnings Per Common Share	$0.47	$0.21	$0.23	$0.38

COMMON SHARE INFORMATION

The common shares of Northeast Utilities are listed on the New York Stock Exchange. The ticker symbol is "NU", although it is frequently presented as "Noest Ut" in various financial publications. There were approximately 201,269 common shareholders of record of Northeast Utilities at January 31, 1983.

The annual market price range of common shares is included with the Selected Consolidated Financial Data on page 50. The high and low sales prices and dividends paid for the past two years by quarters are shown below:

Year	Quarter	High	Low	Quarterly Dividend Per Share
1981	First	9⅛	8	$0.295
	Second	9¾	8½	0.295
	Third	9¼	8⅛	0.295
	Fourth	9⅜	8⅛	0.295
1982	First	10⅜	8⅞	0.320
	Second	11	9⅝	0.320
	Third	11⅜	9¾	0.320
	Fourth	12½	10⅝	0.320

The Connecticut Bank and Trust Company, Stock Transfer Department, One Constitution Plaza, Hartford, Connecticut 06115 and State Street Bank and Trust Company, Corporate Stock Transfer Department, 225 Franklin Street, Boston, Massachusetts 02107, have been appointed Transfer Agents and Registrars of NU common shares. The Connecticut Bank and Trust Company is the company's dividend paying agent and administers the company's Dividend Reinvestment and Common Share Purchase Plan.

SECURITIES AND EXCHANGE COMMISSION

Washington D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 1982 Commission file number 2-30057

CANAL ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

Massachusetts (State or other jurisdiction of incorporation or organization)	04-1733577 (I.R.S. Employer Identification No.)
675 Massachusetts Avenue, Cambridge, Massachusetts (Address of principal executive offices)	02139 (Zip Code)

Registrant's telephone number, including area code 617 - 864 - 3100

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

Title of each class	Name of each exchange on which registered
None	None

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

None
(Title of Class)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.

Yes X No ____

Shares of common stock outstanding at March 15, 1983 1,523,200

Documents incorporated herein by reference - None

Exhibit index begins on page 33 of this report.

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1982

PART I.

Item 1. Business

Canal Electric Company (the "Company"), a wholly-owned subsidiary of Commonwealth Energy System ("System"), is a wholesale electric generating company organized in 1902 under the laws of the Commonwealth of Massachusetts. The Company assumed its present corporate name in 1966 after the sale to an affiliated company of its electric distribution and transmission properties together with the right to do business in the territories served. The System together with its subsidiaries is sometimes collectively referred to as the "system".

The Company's generating station is located in Sandwich, Massachusetts at the eastern end of the Cape Cod Canal. The station consists of two oil-fired steam electric generating units: Canal Unit No. 1, with a rated capacity of 568 MW, is wholly-owned by Canal; and Canal Unit No. 2, with a rated capacity of 584 MW, is jointly-owned by Canal and Montaup Electric Company (a non-affiliated company). Canal Unit No. 2 is operated under an agreement with Montaup which provides for the equal sharing of output, fixed charges and operating expenses.

Construction of Unit No. 1 was completed in 1968 and Unit No. 2 commenced commercial operation February 1, 1976. The Company also participates as a joint-owner in other generating units being constructed by another New England utility.

By virtue of its charter, which is unlimited in time, the Company generates and sells electricity at wholesale to other utilities without direct competition in kind from any privately or municipally owned utility.

Power Contracts

The Company has entered into substantially identical life-of-the-unit power contracts with Boston Edison Company, Montaup Electric Company and New England Power Company (neighboring utilities), under each of which the customer is severally obligated to purchase one quarter of the capacity and energy of Unit No. 1, and with Commonwealth Electric Company ("Commonwealth Electric") and Cambridge Electric Light Company ("Cambridge Electric"), both distribution subsidiaries of the System, under which the two are jointly obligated to purchase the remaining one quarter of the unit's capacity and energy.

A similar contract is in effect between the Company and Commonwealth Electric and Cambridge Electric, under which those companies are jointly obligated to purchase the Company's entire one-half share of the net capability of Unit No. 2.

The price of power under the power contracts is based on a two-part rate consisting of a demand rate and an energy rate. The demand rate

Item 1. Business (Continued)

Power Contracts (Continued)

covers all expenses except fuel costs and provides for a return on investment as well as recovery of investment over the economic lives of the units. The energy rate is based on the cost of fuel and is billed to each purchaser in proportion to its consumption of power. Purchasers are billed monthly. The power contracts are on file with the Federal Energy Regulatory Commission ("FERC").

New England Power Pool

The Company is a member of the New England Power Pool ("NEPOOL"), whose central dispatching facility ("NEPEX") coordinates the operation of essentially all of the generation and transmission facilities in New England. Under its long-range program, NEPOOL will enable member utilities to install fewer but larger, more efficient generating units and higher voltage transmission lines for the purpose of obtaining lower cost power and increased reliability.

Under NEPEX, the most economically available generating units of member companies are operated to fill the demand for power in the region. In the past, this has required that Unit No. 1 operate whenever possible since it is one of the most efficient oil-fired units in the country. Unit No. 2 is designed for cycling operation which provides for economic changes in unit load permitting reduced generation during nights and weekends when demand is lowest. It has performed as one of New England's most efficient units in this type of service.

The Company and the System's other electric subsidiaries are also members of the Northeast Power Coordinating Council ("NPCC"), an advisory organization which establishes criteria and standards for reliability and serves as a vehicle for coordination in the planning and operations of these systems to enhance reliability.

Regulation

The Company is subject to regulation by the Massachusetts Department of Public Utilities ("DPU") as to the issuance of securities, accounting, and other matters. The Company is a "public utility" within the meaning of Part II of the Federal Power Act and is subject to regulation thereunder by the FERC as to rates, accounting and other matters and has filed its power contracts with the FERC as rate schedules.

Item 1. Business (Continued)

Fuel Supply

Effective January 1, 1981, the Company negotiated a long-term contract with Charter Oil (Massachusetts) Inc., for the purchase of the total estimated requirements of residual fuel oil for Unit No. 1 and Unit No. 2. This contract will expire on June 30, 1985.

During 1982 the Company maintained an average daily inventory of approximately 485,000 barrels of fuel oil which represents 14 days of normal operation of the two units. This supply is maintained by regular tanker deliveries.

Future Generating Plant Commitments

The Company is a joint-owner in Seabrook's nuclear electric generating units which are being constructed by Public Service Company of New Hampshire ("PSNH"). The units will have a total plant capacity of 2300 MW of which the Company will own approximately 81 MW or 3.52%. The Company's total cost of entitlement is presently estimated at approximately $200,000,000 of which $87,207,000 had been expended through December 31, 1982. Estimated completion dates for Unit 1 and Unit 2 are 1984, and 1987, respectively.

The cost estimates and completion dates are based upon the latest information made available to the Company by PSNH and include the estimated cost of nuclear fuel and allowance for funds used during construction ("AFUDC"). The completion dates reflect delays encountered to date by PSNH which have resulted, in part, from government licensing requirements, financing, environmental, legal and other problems. In addition, there has been particular public controversy concerning development of nuclear energy, which may cause further delays in completion of this project and the operation of existing plants.

For additional information concerning the Seabrook units see the "Construction and Financing" section below and Note 6 of Notes to Financial Statements filed under Item 8 of this report.

Construction and Financing

The Company has made substantial commitments in connection with its construction program. Estimated construction expenditures for the five-year period ending in 1987 are $117,000,000. Approximately $113,000,000 or 97% of this amount is applicable to the Company's investment in the jointly-owned Seabrook nuclear generating units. The Company purchased its interest in these units from affiliate Commonwealth Electric Company on December 31, 1981 for approximately $52,330,000 (book value net of related taxes). For additional information concerning the Company's construction program and future expenditures refer to Note 6 of Notes to Financial Statements filed under Item 8 of this report.

Item 1. Business (Continued)

Construction and Financing (Continued)

During the five-year period ending December 31, 1987, it is estimated that internally-generated funds will provide approximately $53,000,000 for construction. The balance will be provided on an interim basis by short-term borrowings which are expected to be replaced by long-term debt and equity securities, and internally generated funds.

Financings presently planned for the period ending December 31, 1987 include $30,000,000 of long-term debt issues, $5,000,000 in the form of a nuclear fuel lease and $30,000,000 from the sale of equity securities to the System. The exact type, timing and amount of future long-term debt and equity financings are subject to change because of market conditions and other factors.

Environmental Matters

The Company's generating facilities are subject to Federal, state and local environmental quality control regulations. With respect to Unit No. 1 and Unit No. 2, these regulations have required capital expenditures by the Company of approximately $16,500,000. Environmental regulations limit the sulphur content of oil burned to 2.2%.

Future compliance with existing regulations will require capital expenditures by the Company through 1987 of an estimated $10,100,000 including approximately $6,300,000 for the Company's proportionate share of such costs to be incurred in connection with the Seabrook project. These amounts have been included in the construction estimates discussed under "Construction and Financing".

Environmental regulations which govern both the site selection for new electric generating facilities and air and water pollution standards which require the installation of costly pollution control facilities have had and may continue to have an effect upon the capital costs and construction schedules of NEPOOL generating facilities. The increases in cost cannot be predicted, since the standards and the technology required to meet them are in a state of rapid change. There has been particular public controversy concerning development of nuclear energy. Despite the safety record of the nation's nuclear power plants, these plants have become the target of certain groups claiming, through litigation or intervention in regulatory proceedings, that the present state of nuclear technology presents unacceptable risks to public health and safety and the environment. These claims may cause delays in, or interfere with, scheduled construction of new nuclear plants.

Although the Company is not aware of any existing or proposed environmental regulations having a significant effect upon its electric business, it is unable to predict the possible effect on capital expenditures or earnings resulting from regulations which may be adopted in the future.

Item 1. Business (Continued)

Employees

The Company has 100 regular employees, 70 of whom are represented by the Utility Workers' Union of America, A.F.L.-C.I.O. The existing collective bargaining agreement expires May 31, 1983. Employee relations have generally been satisfactory.

Item 2. Properties

The Company operates a generating station located at the eastern end of the Cape Cod Canal in Sandwich, Massachusetts. The station consists of two oil-fired steam electric generating units: Canal Unit No. 1 with a rated capacity of 568 MW, which is wholly-owned by Canal, and Canal Unit No. 2, with a rated capacity of 584 MW, which is jointly-owned by Canal and Montaup Electric Company.

Item 3. Legal Proceedings

The Company is not a party to any pending material legal proceedings.

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

None

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1982

PART II.

Item 5. Market for the Registrant's Common Stock and Related Security Holder Matters

(a) Principal Market

Not applicable. The Company is a wholly-owned subsidiary of Commonwealth Energy System.

(b) Number of Shareholders at December 31, 1982

One

(c) Frequency and Amount of Dividends Declared in 1982 and 1981

1982		1981	
Declaration Date	Per Share Amount	Declaration Date	Per Share Amount
April 30, 1982	$ 1.30	April 27, 1981	$ 1.00
July 26, 1982	1.25	July 27, 1981	1.00
October 25, 1982	1.25	October 23, 1981	1.00
December 16, 1982	1.50	December 18, 1981	1.25
	$ 5.30		$ 4.25

Reference is made to Note 4 of Notes to Financial Statements filed under Item 8 of this report for restriction against the payment of cash dividends.

(d) Future dividends may vary depending upon the Company's earnings and capital requirements as well as financial and other conditions existing at that time.

Item 6. Selected Financial Data

	1982	1981	1980	1979	1978
	(In Thousands Except Common Share Data)				
Operating Revenues:					
Electric	$213 109	$229 457	$197 256	$141 976	$110 769
Net Income	$ 7 957	$ 6 731	$ 6 361	$ 5 919	$ 6 027
Common Share Data -					
Earnings per share	$ 5.22	$ 4.42	$ 4.18	$ 3.89	$ 3.96
Dividends declared per share	$ 5.30	$ 4.25	$ 4.20	$ 3.70	$ 3.85
Common shares issued and outstanding	1 523 200	1 523 200	1 523 200	1 523 200	1 523 200
Total Assets	$182 662	$170 310	$143 684	$122 377	$118 498
Long-Term Debt Outstanding	$ 47 604	$ 48 367	$ 49 130	$ 49 893	$ 50 562
Common Share Investment	$ 53 756	$ 53 372	$ 53 615	$ 53 651	$ 53 368

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1982

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Regulation

The Company is a wholly-owned electric generating subsidiary of Commonwealth Energy System (the "System") and is subject to the jurisdiction of the Federal Energy Regulatory Commission with respect to the establishment of rates affecting wholesale electric sales. The Company is also subject to regulation by the Massachusetts Department of Public Utilities as to issue of securities, accounting and other matters.

Capital Resources

At December 31, 1982, the Company had short-term notes payable outstanding totaling $50,650,000 which were used to temporarily finance construction and working capital requirements. Interim and permanent financing is done by the Company, with the System providing, when available, a portion of the Company's short-term financing needs through advances and by purchasing 100% of any new common equity issue.

The Company is also a member of the COM/Energy Money Pool (the "Pool"), an arrangement among the utility and non-utility subsidiaries of the System, in which short-term cash surpluses of all subsidiaries may be used to meet the short-term borrowing needs of the Company. Lenders to the Pool, in general, receive a higher rate of return than they otherwise would on such investments. Borrowers from the Pool pay a lower interest rate than they would otherwise pay to banks and, as a result, the Company has a reduced need of bank lines of credit.

The Company has made substantial commitments in connection with its construction program. Forecasted construction expenditures for the five-year period ending in 1987 are $117,000,000 including $113,000,000 applicable to the Company's 3.52% joint-ownership in the Seabrook nuclear generating units. Financing this program will require a long-term debt issue of $30,000,000 with an additional $5,000,000 to be arranged under the terms of a nuclear fuel leasing agreement and a $30,000,000 equity investment by the System. The exact type, timing and amounts of future long-term debt and equity financings are subject to changes in market conditions and other factors.

Liquidity

The Company's ability to generate adequate cash to meet its needs results primarily from the wholesale sales of electric energy through life-of-the unit power contracts with several affiliate and non-affiliate utilities. Additional sources include periodic short-term borrowings from banks and advances from affiliate companies. Although the Company is projecting significant capital requirements during the next five years for its constuction program, internally generated funds are expected to provide $53,000,000 or approximately 45% of these requirements. In keeping with a sound capital structure, short-term borrowings are, from time to time, permanently financed through debt and equity issues.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (Continued)

	Results of Operations For the Years Ended December 31,		
	1982	1981	1980
	(Dollars in Thousands)		
Electric operating revenues	$213 109	$229 457	$197 256
Costs and Expenses:			
Fuel oil used in production	174 930	192 325	161 722
Other operation	9 000	8 805	6 882
Maintenance	8 675	7 268	7 705
Interest	2 929	4 165	4 299
Income taxes	5 398	6 706	6 459
All other	7 058	7 022	6 630
Total	207 990	226 291	193 697
Other income	2 838	3 565	2 802
Net income	$ 7 957	$ 6 731	$ 6 361
Cash dividends declared on common stock paid to Commonwealth Energy System (Parent Company)	$ 8 073	$ 6 474	$ 6 397
Number of common shares outstanding	1 523 200	1 523 200	1 523 200

Operating Revenues and Expenses

Operating revenues decreased by $16.3 million or approximately 7.1% from 1981. The power contracts for the sale of the capacity of the Canal units provide for the recovery of all operating expenses and fixed charges (including a return on equity) whether or not the units are operating. Variations in revenue result from changes in operating expenses, primarily the cost of fuel oil and to a lesser degree from changes in the length of outages for scheduled maintenance. Such variations have no effect on net income. Fuel expense is the Company's single most significant operating cost, representing over 82% of the total revenue dollar. The per barrel cost of oil averaged $26.28 in 1982, $28.59 in 1981 and $22.57 in 1980.

Inflationary pressures on material costs and wages contributed to the increase in other operating expenses. Maintenance expense increased approximately 19.4% due primarily to the replacement of generation coils for Unit 1 during the first quarter.

Other Income and Interest Charges

The decrease in other income was largely due to a reduction in interest income due to the absence of funds available for short-term investments and to a lesser extent to a lower level of interest income accrued on income tax

Item 7. Mangement's Discussion and Analysis of Financial Condition and Results of Operations (Continued)

issues. These factors were offset by an increase in allowance for equity funds used during construction, reflecting the increased construction activity resulting from the Seabrook project.

Interest charges on short-term borrowings increased due primarily to the higher level of borrowings required to finance the Seabrook project. However, total interest charges for 1982 declined 29.7% due primarily to an increase in allowance for borrowed funds used during construction.

Item 8. Financial Statements

The Company's financial statements required by this item are filed herewith on pages 11 through 27 of this report.

Item 9. Disagreements on Accounting and Financial Disclosures

None

Item 8. Financial Statements

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Canal Electric Company:

We have examined the balance sheets of CANAL ELECTRIC COMPANY (a Massachusetts corporation and wholly-owned subsidiary of Commonwealth Energy System) as of December 31, 1982 and 1981, and the related statements of income, retained earnings and sources of funds used for construction for each of the three years in the period ended December 31, 1982. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the financial statements referred to above present fairly the financial position of Canal Electric Company as of December 31, 1982 and 1981, and the results of its operations and its sources of funds used for construction for each of the three years in the period ended December 31, 1982, in conformity with generally accepted accounting principles applied on a consistent basis.

Our examinations were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The schedules listed in the index to financial statements are presented for purposes of complying with the Securities and Exchange Commission's rules and are not part of the basic financial statements. These schedules have been subjected to the auditing procedures applied in the examinations of the basic financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

ARTHUR ANDERSEN & CO.

Boston, Massachusetts,
February 14, 1983.

CANAL ELECTRIC COMPANY

INDEX TO FINANCIAL STATEMENTS AND SCHEDULES

PART II.

FINANCIAL STATEMENTS

PART IV.

SCHEDULES

SCHEDULES OMITTED

All other schedules are not submitted because they are not applicable or required or because the required information is included in the financial statements or notes thereto.

CANAL ELECTRIC COMPANY

BALANCE SHEETS

DECEMBER 31, 1982 AND 1981

ASSETS

	1982	1981
	(Dollars in Thousands)	
PROPERTY, PLANT AND EQUIPMENT, at original cost:	$131 806	$131 100
Less - Accumulated depreciation	47 025	42 196
Accumulated deferred taxes	13 283	15 463
	71 498	73 441
Add - Construction work in progress, net (Notes 2 and 6)	77 800	53 834
	149 298	127 275
CURRENT ASSETS:		
Cash	52	384
Accounts receivable -		
Affiliated companies	10 999	12 703
Other	15 456	17 826
Unbilled revenues	130	-
Prepaid property taxes	915	915
Income tax refund receivable	1 430	6 436
Electric production fuel oil, at average cost	2 576	2 667
Other	492	896
	32 050	41 827
DEFERRED CHARGES, net	1 314	1 208
	$182 662	$170 310

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

CANAL ELECTRIC COMPANY

BALANCE SHEETS

DECEMBER 31, 1982 AND 1981

CAPITALIZATION AND LIABILITIES

	1982	1981
	(Dollars in Thousands)	
CAPITALIZATION:		
Common Equity -		
Common Stock, $25 par value -		
Authorized and outstanding -		
1,523,200 shares, wholly-owned by		
Commonwealth Energy System (Parent)	$ 38 080	$ 38 080
Amounts paid in excess of par value	8 321	8 321
Retained earnings	7 355	7 471
	53 756	53 872
Long-term debt, including premiums, less current sinking fund requirements	47 604	48 367
	101 360	102 239
CURRENT LIABILITIES:		
Interim Financing -		
Notes payable to banks (Schedule IX)	44 250	22 500
Advances from affiliates	7 205	3 375
	51 455	25 875
Other Current Liabilities -		
Current sinking fund requirements	920	892
Accounts payable -		
Affiliated companies	659	862
Other	11 749	27 237
Accrued taxes -		
Local property and other	915	916
Income	1 945	801
Accrued interest and other	1 767	1 706
	17 955	32 414
	69 410	58 289
DEFERRED CREDITS:		
Unamortized investment tax credits	11 604	9 494
Other	288	288
	11 892	9 782
COMMITMENTS (Note 6)		
	$182 662	$170 310

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

CANAL ELECTRIC COMPANY

STATEMENTS OF INCOME

FOR THE YEARS ENDED DECEMBER 31, 1982, 1981 AND 1980

	1982	1981	1980
	(Dollars in Thousands)		
ELECTRIC OPERATING REVENUES	$213 109	$229 457	$197 256
OPERATING EXPENSES:			
Fuel oil used in production	174 930	192 325	161 722
Other operation	9 000	8 805	6 882
Maintenance	8 675	7 268	7 705
Depreciation	4 909	4 848	4 617
Taxes -			
Income (Note 2)	5 398	6 706	6 459
Local property	1 822	1 888	1 791
Payroll and other	327	286	222
	205 061	222 126	189 398
OPERATING INCOME	8 048	7 331	7 858
OTHER INCOME:			
Allowance for equity funds used during construction	2 349	29	-
Other, net	489	3 536	2 802
	2 838	3 565	2 802
INCOME BEFORE INTEREST CHARGES	10 886	10 896	10 660
INTEREST CHARGES:			
Long-term debt	4 075	4 124	4 174
Other interest charges	4 893	59	161
Allowance for borrowed funds used during construction	(6 039)	(18)	(36)
	2 929	4 165	4 299
NET INCOME	$ 7 957	$ 6 731	$ 6 361

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

CANAL ELECTRIC COMPANY

STATEMENTS OF RETAINED EARNINGS

FOR THE YEARS ENDED DECEMBER 31, 1982, 1981 AND 1980

	1982	1981	1980
	(Dollars in Thousands)		
Balance at beginning of year	$ 7 471	$ 7 214	$ 7 250
Add (Deduct):			
Net income	7 957	6 731	6 361
Cash dividends on common stock	(8 073)	(6 474)	(6 397)
Balance at end of year	$ 7 355	$ 7 471	$ 7 214

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

CANAL ELECTRIC COMPANY

STATEMENTS OF SOURCES OF FUNDS USED FOR CONSTRUCTION

FOR THE YEARS ENDED DECEMBER 31, 1982, 1981 AND 1980

	1982	1981	1980
	(Dollars in Thousands)		
SOURCES OF FUNDS -			
Internal Sources			
From Operations -			
Net income	$ 7 957	$ 6 731	$ 6 361
Items not requiring or (providing) funds:			
Depreciation	4 909	4 848	4 617
Deferred income taxes - long-term	3 418	1 803	451
Investment tax credits, net	2 110	4 427	(110)
Allowance for equity funds used during construction	(2 349)	(29)	-
	16 045	17 780	11 319
Less -			
Payment of dividends	8 073	6 474	6 397
Retirement of long-term debt through sinking funds	763	763	763
Other	(725)	(1 426)	114
	8 111	5 811	7 274
Changes in net current assets:			
Cash	332	26 481	(21 133)
Accounts receivable and unbilled revenue	3 944	1 230	(13 171)
Income taxes, net	6 150	(9 617)	2 896
Electric production fuel oil	91	228	9 496
Accounts payable and other	(15 199)	(1 960)	20 588
	(4 682)	16 362	(1 324)
Net available from internal sources	3 252	28 331	2 721
Increase (Decrease) in Interim Financing	25 580	25 875	(1 300)
	$ 28 832	$ 54 206	$ 1 421
FUNDS USED FOR CONSTRUCTION -			
Canal Unit No. 1	$ 528	$ 1 126	$ 1 241
Canal Unit No. 2	150	779	180
Jointly-Owned Projects (Note 6)	30 503	52 330	-
	31 181	54 235	1 421
Less - Allowance for equity funds used during construction	2 349	29	-
	$ 28 832	$ 54 206	$ 1 421

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

CANAL ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS

(1) Significant Accounting Policies

General and Regulatory

The Company is a wholly-owned subsidiary of Commonwealth Energy System. The parent company is referred to in this report as the System and together with its subsidiaries is sometimes collectively referred to as "the system." The Company is regulated by various authorities, including the Federal Energy Regulatory Commission ("FERC") and the Massachusetts Department of Public Utilities ("DPU"). The System is an exempt holding company under the provisions of the Public Utility Holding Company Act of 1935 and, in addition to its investment in the Company, has interests in other utility companies and several non-regulated companies.

Transactions with Affiliates

Transactions between the Company and other system companies include purchase and sale of electricity and payment for management, accounting, data processing and other services. Transactions with other system companies are subject to review by the FERC and the DPU.

Operating revenues include sales of electricity to affiliated companies of $117,945,000 in 1982, $129,448,000 in 1981 and $105,279,000 in 1980.

Other Major Customers

The Company is a wholesale electric generating company which sells power under life-of-the-unit power contracts to several utility companies in the New England area. Information regarding the customers and their participation in these contracts may be found in the "Business" section of this report.

Depreciation

Depreciation is provided using the straight-line method at rates intended to amortize the original cost of properties over their estimated economic lives. The Company's composite depreciation rate, based on average depreciable property in service, was 3.8% in 1982 and 1981, and 3.6% in 1980.

Maintenance

Expenditures for repairs of property and replacement and renewal of items determined to be less than units of property are charged to maintenance expense. Additions, replacements and renewals of property considered to be units of property, are charged to the appropriate plant accounts. Upon retirement, accumulated depreciation is charged with the original cost of property units and the cost of removal net of salvage.

(1) Significant Accounting Policies (Continued)

Allowance for Funds Used During Construction

The Company includes as an element of the cost of construction of depreciable property an allowance for funds employed during periods when property is under construction. An amount equal to the allowance capitalized in the current period is reflected in the statements of income. Under applicable rate-making practices, property under construction is not included in rate base on which the Company is permitted to earn a return. Amounts so capitalized, while not currently providing funds, are included in rate base when property is placed in service, and these amounts are recoverable in revenues over the service life of the constructed property.

The Company develops rates based upon its current cost of capital and used a compound rate of 12 1/4% in 1982, 11% in 1981 and 19% in 1980.

(2) Income Taxes

For financial reporting purposes, the Company provides taxes on a separate return basis. However, for Federal income tax purposes, the Company's taxable income and deductions are included in the consolidated income tax return of its Parent and it makes tax payments or receives refunds on the basis of its tax attributes in the consolidated income tax return in accordance with applicable Federal income tax regulations.

The following is a summary of the provision for income taxes for the years ended December 31, 1982, 1981 and 1980:

	1982			1981			1980		
	Total	Federal	State	Total	Federal	State	Total	Federal	State
				(Dollars in Thousands)					
Currently payable	$ 117	$ 21	$ 96	$ 272	$ (379)	$651	$6 436	$5 585	$851
Currently deferred	(247)	(440)	193	204	178	26	(318)	(275)	(43)
Long-term deferred	3 418	3 192	226	1 803	1 566	237	451	392	59
Investment tax credits	2 332	2 332	-	4 671	4 671	-	33	33	-
	5 620	5 105	515	6 950	6 036	914	6 602	5 735	867
Less-Amortization of investment tax credits	222	222	-	244	244	-	143	143	-
	$5 398	$4 883	$515	$6 706	$5 792	$914	$6 459	$5 592	$867

(2) Income Taxes (Continued)

Income taxes are provided for the tax effects of timing differences other than certain construction-related costs. Timing differences result from reporting income and expense for tax purposes in periods different from those used for financial reporting purposes. The accumulated deferred income taxes resulting from long-term differences are presented as reductions in the assets to which they relate, consistent with rate-making treatment. Additionally, construction work in progress is presented net of accumulated deferred income taxes which totaled $9,719,000 in 1982 and $3,329,000 in 1981.

The Company's long-term deferred provision for income taxes results from the use of the following:

	1982	1981	1980
	(Dollars in Thousands)		
Adjustment for canal dredging costs	$ -	$1 143	$(1 143)
Accelerated depreciation for tax purposes	693	863	1 470
Cancelled nuclear units	(249)	(249)	(7)
Allowance for borrowed funds used during construction	2 990	8	18
Other	(16)	38	113
Long-term deferred income tax provision	$3 418	$1 803	$ 451

The tax effects of current timing differences are included in the currently deferred provision and accrued income taxes. Investment tax credits are deferred and amortized over the life of the property giving rise to the credits.

The total income tax provision set forth above represents 40% in 1982, and 50% in 1981 and 1980 of income before such income taxes. The table below reconciles the statutory Federal income tax rate to these percentages:

	1982	1981	1980
Statutory Federal income tax rate	46%	46%	46%
Increase (decrease) from statutory rate:			
Allowance for equity funds used during construction	(8)	-	-
State income tax net of Federal tax reduction	2	4	4
Amortization of investment tax credits	(2)	(2)	(1)
Other	2	2	1
	40%	50%	50%

(3) Interim Financing and Long-Term Debt

Advances from Affiliates

The Company had short-term notes payable to the Parent totaling $6,400,000 at December 31, 1982. These notes are written for a term of eleven months and twenty-nine days. Interest is at the prime rate (11.5% at December 31, 1982) and is adjusted for changes in the rate during the term of the notes.

(3) Interim Financing and Long-Term Debt (Continued)

The Company is a member of the COM/Energy Money Pool (the Pool) which is an arrangement among the public utility and non-utility subsidiaries of the system, by which short-term cash surpluses of all subsidiaries may be used to meet the short-term borrowing needs of the utility subsidiaries. The DPU approved the Pool in 1981. Lenders to the Pool, in general, receive a higher rate of return than they otherwise would on such investments. Borrowers from the Pool pay a lower interest rate than they would otherwise pay to banks and, as a result, the system has a reduced need for lines of credit than otherwise would be required. At December 31, 1982, the Company had borrowings from the Pool totaling $805,000.

Notes Payable to Banks

The Company and other system companies have banking relationships in which borrowings are arranged as required for interim financing of construction projects. These arrangements are not formal lines of credit but provide for unsecured borrowings evidenced by notes payable which are written for terms of up to 90 days.

Informal lines of credit with several banks totaling $149,000,000 for the system were utilized by the Company as of December 31, 1982. The terms of one line require a compensating balance of 5% of the line or a fee if such balance is not maintained. The terms of a second line require that when system companies are borrowing, they must maintain normal operating balances for cash demand and bank service charges. The interest on all borrowings is at an adjusted money market rate.

The Company had outstanding borrowings from banks totaling $44,250,000 at December 31, 1982.

Long-Term Debt

Long-term debt outstanding, exclusive of current sinking fund requirements and related premiums, is as follows:

	Original Issue	Balance December 31, 1982	1981
	(Dollars in Thousands)		
First Mortgage Bonds,			
Series A, 7%, due 1996	$19 000	$12 920	$13 680
Series B, 8.85%, due 2006	35 000	34 650	34 650
		$47 570	$48 330

(3) Interim Financing and Long-Term Debt (Continued)

Long-Term Debt (Continued)

The Series A First Mortgage Bonds require an annual sinking fund payment of $760,000 from 1982 to 1996. At December 31, 1982 and 1981 the Company had purchased $190,000 and $218,000 of its bonds, respectively, in anticipation of future sinking fund requirements.

The Series B First Mortgage Bonds require an annual sinking fund payment of $350,000. The requirement may be met by payment, repurchase of bonds or certification of an amount of property additions equal to 60% of bondable property (as that term is defined in the indenture). The Company expects to certify additional bondable property in lieu of making sinking fund payments on these bonds.

(4) Dividend Restriction

At December 31, 1982, approximately $2,089,000 of retained earnings was restricted against payment of cash dividends by the terms of the Indenture of Trust securing long-term debt.

(5) Pension and Employees Savings Plans

The Company has a noncontributory pension plan covering substantially all regular employees who have attained the age of 25. Pension costs are funded as accrued and include amounts applicable to prior service costs which are being amortized over a period of 30 years. Total pension expense was approximately $354,000 in 1982, $317,000 in 1981 and $325,000 in 1980. The assumed rate of return used in determining the actuarial value of accumulated plan benefits was 7 1/2% in 1982 and 1981.

A comparison of accumulated plan benefits and plan net assets for the Company's benefit plan is presented below.

	January 1, 1982	January 1, 1981
	(Dollars in Thousands)	
Actuarial present value of accumulated plan benefits:		
Vested	$1 453	$1 227
Nonvested	161	149
Total actuarial present value of accumulated plan benefits	$1 614	$1 376
Net assets available for benefits	$1 958	$1 738

(5) Pension and Employee Savings Plans (Continued)

The Company has an Employee Savings Plan which provides for Company contributions equal to contributions by eligible employees but not in excess of four percent of each employee's compensation rate. The total Company contribution was approximately $104,000 in 1982, $96,000 in 1981 and $87,000 in 1980.

(6) Commitments

Construction Program

The Company has made substantial commitments in connection with its construction program, most of which relates to its commitment to joint-ownership interest in the Seabrook nuclear electric generating units. Construction expenditures for the five-year period ending in 1987 are estimated at $116,600,000 including approximately $112,800,000 related to commitments by the Company for the Seabrook project. The Company's construction program is subject to periodic review, and actual expenditures may vary from the above estimates because of factors such as changes in business conditions, rates of growth, effects of inflation, equipment delivery schedules, licensing delays, availability and cost of capital and environmental factors.

Purchase of Seabrook Ownership Interest

On December 31, 1981, the Company purchased a 3.52% commitment in the Seabrook nuclear electric generating units, which are presently under construction by the lead participant - Public Service Company of New Hampshire (PSNH). This interest was purchased from Commonwealth Electric Company for approximately $52,330,000, net of income tax reserves. Commonwealth Electric is an affiliated electric distribution company which purchases wholesale power from the Company and from other non-associated companies.

The purchase of the Company's interest in the project was conditioned upon receipt of various regulatory approvals including those of the DPU, the New Hampshire Public Utilities Commission (NHPUC) and the Nuclear Regulatory Commission (NRC). Approvals of the DPU and the NHPUC were received during 1981 and in 1982 the NRC issued its approval.

The project has experienced numerous delays due to regulatory, legal and other problems, resulting in significant increases in cost estimates. In late 1982, PSNH announced its most recent estimate, increasing the cost of the project from $3.56 to $5.24 billion and changes in the commercial operating dates of Unit I and Unit II to December, 1984 and July, 1987. The PSNH estimate includes allowances for funds used during construction but excludes the cost of nuclear fuel. Independent construction consultants have been retained by PSNH to review and evaluate the validity of its estimated cost and completion dates. PSNH has indicated that adequate and timely rate increases and external financing are both essential to enable it to continue its construction program.

CANAL ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS (CONTINUED)

(6) Commitments (Continued)

Purchase of Seabrook Ownership Interest (Continued)

Based upon a $5.24 billion project cost, the Company's ownership interest will amount to approximately $200,000,000, including allowance for funds used during construction and nuclear fuel. Through December 31, 1982 expenditures were $87,000,000.

(7) Supplementary Information to Disclose the Effects of Changing Prices (Unaudited)

The following supplementary information is supplied in accordance with the requirements of Financial Accounting Standards Board Statement No. 33 for the purpose of providing certain information about the effects of changing prices. It should be viewed as an estimate of the approximate effect of inflation, rather than as a precise measure.

Constant dollar amounts represent historical costs stated in terms of dollars of equal purchasing power, as measured by the Consumer Price Index for All Urban Consumers. Current cost amounts reflect the changes in specific prices of plant from the date the plant was acquired to the present, and differ from constant dollar amounts to the extent that specific prices have increased more or less rapidly than prices in general.

The current cost of plant is determined primarily by indexing surviving plant using the Handy-Whitman Index of Public Utility Construction Costs. Since the utility plant is not expected to be replaced in kind, current cost does not necessarily represent the replacement cost of the productive capacity. Depreciation is determined by applying the Company's depreciation rates to the revised asset amounts.

Fuel inventories and the cost of fuel used in generation have not been restated from their historical cost in nominal dollars because regulation provides for the recovery of fuel costs through the operation of adjustment clauses. For this reason fuel inventories are effectively monetary assets. Since only historical costs are deductible for income tax purposes, the historical income tax expense is not adjusted.

Under present ratemaking procedures prescribed by the regulatory commissions, only the historical cost of plant is recoverable in revenues as depreciation. Because the excess cost of plant stated in terms of constant dollars and current cost is not recoverable in rates, a write-down to net recoverable cost is required. While the rate-making process does not recognize the current cost of replacing plant, regulated companies have, historically, been allowed to earn a return on the increased cost of its investment when replacement actually occurs.

(7) Supplementary Information to Disclose the Effects of Changing Prices (Unaudited) (Continued)

During periods of inflation, holders of monetary assets suffer a loss of general purchasing power while holders of monetary liabilities experience a gain. The gain from the decline in purchasing power of net amounts owed is primarily attributable to the substantial amount of debt which has been used to finance property, plant and equipment. These gains are unrealized and, therefore, do not contribute to cash flow or distributable income.

CANAL ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS (CONTINUED)

(7) Supplementary Information to Disclose the Effects of Changing Prices (Unaudited) (Continued)

STATEMENT OF INCOME FROM CONTINUING OPERATIONS
ADJUSTED FOR CHANGING PRICES
For the Year Ended December 31, 1982

	Conventional Historical Cost	Constant Dollar Average 1982 Dollars	Current Cost Average 1982 Dollars
		(Dollars in Thousands)	
Operating revenues	$213 109	$213 109	$213 109
Fuel used in production	174 930	174 930	174 930
Depreciation expense	4 909	10 366	11 467
Other operation and maintenance	17 675	17 675	17 675
Income and other taxes	7 547	7 547	7 547
Interest charges	2 929	2 929	2 929
Other income and deductions - net	(2 838)	(2 838)	(2 838)
	205 152	210 609	211 710
Income from operations (excluding adjustment to net recoverable cost)	$ 7 957	$ 2 500*	$ 1 399
Increase in specific prices (current cost) of property, plant and equipment held during the year**			$ 7 308
Adjustment to net recoverable cost		$ (432)	698
Effect of increase in general price level			(7 337)
Excess of specific prices over the increase in general price level after adjustment to net recoverable cost			669
Gain from decline in purchasing power of net amounts owed		3 492	3 492
Net		$ 3 060	$ 4 161

* Including the reduction to net recoverable cost, the income from operations on a constant dollar basis would have been $2,068,000.

**At December 31, 1982, current cost of property, plant and equipment, net of accumulated depreciation was $189,174,000, while historical cost or net cost recoverable through depreciation was $170,999,000.

CANAL ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS (CONTINUED)

(7) Supplementary Information to Disclose the Effects of Changing Prices (Unaudited) (Continued)

FIVE YEAR COMPARISON OF SELECTED SUPPLEMENTARY FINANCIAL DATA ADJUSTED FOR EFFECTS OF CHANGING PRICES
(in thousands of average 1982 dollars)

	Year Ended December 31,				
	1982	1981	1980	1979	1978
Operating revenues:					
Actual	$213 109	$229 457	$197 256	$141 976	$110 769
Adjusted to average 1982 dollars	$213 109	$243 524	$231 064	$188 801	$163 886
Historical Cost Information adjusted for general inflation:					
Income from continuing operations (excluding adjustment to net recoverable cost)	$ 2 500	$ 2 255	$ 3 362	$ 2 855	
Net assets at year-end at net recoverable cost	$ 53 149	$ 55 326	$ 59 985	$ 67 421	
Current Cost Information:					
Income from continuing operations (excluding adjustment to net recoverable cost)	$ 1 399	$ 1 053	$ 2 196	$ 2 708	
Excess of general prices over the increase (decrease) in specific price level after adjustment to net recoverable costs	$ (669)	$ 4 243	$ 7 862	$ 11 432	
Net assets at year-end at net recoverable cost	$ 53 149	$ 55 326	$ 59 985	$ 67 421	
General Information:					
Gain from decline in purchasing power of net amounts owed	$ 3 492	$ 3 945	$ 4 640	$ 6 041	
Average consumer price index	289.1	272.4	246.8	217.4	195.4

Note: The Company's stock is entirely owned by the Parent System, therefore, per share information is not relevant.

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1982

PART III.

Item 10. Directors and Executive Officers of the Registrant

Name of Director(1)	Position with Company	Business Experience	Age at December 31, 1982
Charles T. Abbott	None	Retired; former President of COM/ Energy Services Company (formerly NEGEA Service Corporation)**	77
*Gerald E. Anderson (2)	Chairman of the Board and President	(3)	51
*Earl G. Cheney (4)	Financial Vice President	(3)	46
Leland R. Crowell	None	Retired; former General Manager and Vice President of the Company	74
Burdette A. Johnson	None	Retired; former Financial Vice President of the Company and its' affiliates	77
*Jeremiah V. Donovan (5)	Executive Vice President - Electric Operations	(3)	47
William R. Smith	Vice President - Energy Supply	(3)	60
Richard G. Velte	Vice President - Facilities Development	(3)	62

Prior to their retirement Messrs. Abbott, Crowell, and Johnson served in executive capacities with the Company and/or an affiliated Company.

All directors have served in executive capacities either with the Company, an affiliated company or with another company for five years or more.

(1) Present term of office of all Directors will expire on January 27, 1984, the date of the next annual meeting of shareholders.

Item 10. Directors and Executive Officers of the Registrant (Continued)

(2) Chairman of the Board - Cambridge Electric Light Company**, COM/Energy Services Company**, Commonwealth Electric Company**, and Commonwealth Gas Company**.

(3) Director is also an executive officer of the Company. (See Executive Officers.)

(4) Director of Cambridge Electric Light Company**, Commonwealth Electric Company**, Commonwealth Gas Company**, and other non-operating affiliate companies.

(5) Director of Cambridge Electric Light Company** and Commonwealth Electric Company**.

* Member of Executive Committee
** Affiliated Companies.

Name of Officer(6)	Position and Business Experience	Age at December 31, 1982
Gerald E. Anderson	Chairman of the Board since 1977; President since 1974; Financial Vice President 1972 - April 1974	51
Earl G. Cheney	Financial Vice President since May 1974; Comptroller 1972-1974	46
Jeremiah V. Donovan	Executive Vice President - Electric Operations since October 1978; Vice President and General Manager, Cambridge Electric Light Company since April 1976; Assistant Vice President, Cambridge Electric Light Company November 1975-1976; Engineer, COM/Energy Services Company (formerly NEGEA Service Corporation) 1963-1975.	47
Michael P. Sullivan	Vice President, Clerk and General Attorney since 1981; Clerk 1976-1981	34
Andrew S. Griffiths	Vice President-Administration since February 1979; Assistant Vice President since April 1975 and Assistant Treasurer since 1972, Commonwealth Electric Company (formerly New Bedford Gas and Edison Light Company).	46

Item 10. Directors and Executive Officers of the Registrant (Continued)

Name of Officer(6)	Position and Business Experience	Age at December 31, 1982
Ronald F. MacDonald	Vice President-Customer Services since February 1979; Executive Vice President and General Manager, Commonwealth Electric Company since April 1973.	52
William R. Smith	Vice President-Energy Supply since February 1979; Vice President and General Manager since 1973.	60
Richard G. Velte	Vice President-Facilities Development since February 1979; Vice President, Engineering since October 1974 and Chief Engineer since January 1972, COM/Energy Services Company (formerly NEGEA Service Corporation).	62
Robert E. Healey	Vice President-Human Resources since February 1979; Assistant Vice President and General Manager, since April 1975 and Manager of Employee and Public Relations since 1972, Commonwealth Electric Company (formerly New Bedford Gas and Edison Light Company).	45
John J. Tasillo	Vice President-Rates since February 1979; Rate Manager, COM/Energy Services Company (formerly NEGEA Service (Corporation) since 1973.	40
Robert S. Parker	Treasurer since 1971	57
John A. Whalen	Comptroller since September 1978; Audit Manager, COM/Energy Services (formerly NEGEA Service Corporation) since 1975; Product Line Controller, Rockwell International since 1973.	35

(6) The Vice President, Clerk and General Attorney and the Treasurer of the Company are elected to serve until the next annual shareholders' meeting. All other officers are appointed to serve until the next annual organization meeting of directors which follows the shareholders' meeting.

Item 10. Directors and Executive Officers of the Registrant (Continued)

There is no family relationship between any director or executive officer and any other director or executive officer of the Company. There were no arrangements or understandings between any officer or director and any other person pursuant to which he was or is to be selected as an officer, director or nominee.

There have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any director or executive officer during the past five years.

Item 11. Management Remuneration and Transactions

The following table shows remuneration of each person deemed to be an Executive Officer or Director of the Company whose total remuneration exceeded $50,000, and all Officers and Directors as a group.

Name of Individual or Number of Persons in Group	Capacities in which Remuneration was Received	Cash or Cash Equivalent Forms of Remuneration* Salaries and Fees	Insurance Benefits	Employees' Savings and TRASOP Plan Contributions**
W. R. Smith	Officer	$ 55 762	$259	$3 496
Officers and Directors of the Company as a Group (15)	Officers and Directors	$139 721	$444	$6 534

* No remuneration is paid directly by the Company to its officers. Their compensation is paid by affiliated companies, of which they are officers and employees. For the year 1982, approximately 15% of these officers' compensation was charged by affiliated companies to the Company. In his capacity as Vice President of Energy Supply, Mr. Smith was closely associated with the daily operation of the Company's generating facility and, as such, $55,762 or approximately 77% of Mr. Smith's compensation was charged to the Company by, an affiliated company, Commonwealth Electric Company.

**This represents the aggregate contributions by the Company during 1982 on behalf of the above group to the Employees Savings Plan of Commonwealth Energy System and Subsidiary Companies and/or the Tax Reduction Act of 1975 Employees Stock Ownership Plan of Commonwealth Energy System and Subsidiary Companies. No Director, as such, receives any benefits under the above Plans.

Item 11. Management Remuneration and Transactions (Continued)

Pension costs are not included in the table because the Pension Plan for Employees of Commonwealth Energy System and Subsidiary Companies costs are computed on an aggregate acturarial basis without individual allocation. During 1982, the System and/or its subsidiaries made aggregate contributions to the Plan in the amount of 12.0% of the total base salary of qualified Plan participants in effect on January 1, 1982. Remuneration covered under the Plan includes base salary with the limited exception of certain commission sales persons. No Director, as such, receives any benefits under the above Plan.

The following table shows annual pension benefits payable to employees, including Officers, upon retirement at age 65, in various remuneration and years-of-service classifications, assuming the election of a retirement allowance payable as a life annuity:

Highest Annual Consecutive 3-Year Average Basic Salary of Last 10 Years	Annual Benefits For Years of Service			
	10 Years	20 Years	30 Years	40 Years
$ 60 000	$ 8 542	$17 084	$25 626	$ 31 626
90 000	13 542	27 084	40 626	49 626
120 000	18 542	37 084	55 626	67 626
150 000	23 542	47 084	70 626	85 626
180 000	28 542	57 084	85 626	103 626

Item 12. Security Ownership of Certain Beneficial Owners and Management

Title of Class	Name of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common	Commonwealth Energy System 675 Massachusetts Avenue Cambridge, MA 02139	1 523 200	100.00
Common	All Directors and Officers as a group (16 persons)	41 455 (1)	.50

(1) In accordance with the Securities Exchange Act of 1934, officers and directors beneficial ownership set forth in the above schedule includes, where applicable, shares owned by the wife of any directors or officers. The directors and officers of the Company as a group at December 31, 1982 owned 41,455 shares of the parent company (based on information furnished to the System by these persons) which represents less than one percent of the total number of shares at that date.

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1982

PART IV.

Item 13. Exhibits, Financial Statement Schedules and Reports on Form 8-K

	Incorporated Documents Exhibit	Incorporated Documents SEC File No.	Filed Herewith at Page
(a) The following documents are filed as part of this report:			
1. Financial statements of the Company together with the Report of Independent Public Accountants, are filed under Item 8 of this report and listed on the Index to Financial Statements and Schedules in Item 8.			11
2. The following financial statement schedules are attached hereto:			
Schedule V - Property, Plant and Equipment for the Years Ended December 31, 1982, 1981 and 1980.			40 - 42
Schedule VI - Accumulated Depreciation of Property, Plant and Equipment for the Years Ended December 31, 1982, 1981 and 1980.			43
Schedule IX - Short-term Borrowings for the Years Ended December 31, 1982, 1981 and 1980.			44
(b) No reports on Form 8-K were filed during the three months ended December 31, 1982. However, a report on Form 8-K dated December 21, 1982 was filed with the Commission on February 2, 1983 in response to Public Service Company of New Hampshire revised cost estimate for the Seabrook nuclear electric generating units of which the Company is a 3.52% owner.			
(c) List of Exhibits:			
Exhibit 3. Articles of incorporation and by-laws.			
Incorporated herein by reference thereto:			
3(a) Articles of incorporation of the Company have been filed with the Commission as an exhibit in the Company's 1980 Form 10-K.	1	2-30057	

Item 13. Exhibits, Financial Statement Schedules and Reports on Form 8-K (Continued)

	Incorporated Documents Exhibit	SEC File No.	Filed Herewith at Page
3(b) By-laws of the Company, as amended, have been filed with the Commission as an exhibit in the Company's 1980 Form 10-K.	2	2-30057	
Exhibit 4. Instruments defining the rights of security holders, including indentures.			
Incorporated herein by reference thereto:			
4(b)1 Copy of Indenture of Trust and First Mortgage dated as of October 1, 1968 between the registrant and State Street Bank and Trust Company, Trustee, has been filed with the Commission as an exhibit to Form S-1.	4(b)	2-30057	
4(b)2 Copy of First and General Mortgage Indenture dated as of September 1, 1976, between the registrant and Citibank, N.A., Trustee, has been filed with the Commission as an exhibit to Form S-1.	4(b)2	2-56915	
4(b)3 Copy of First Supplemental Indenture dated as of September 1, 1976, to Indenture of Trust and First Mortgage dated as of October 1, 1968 between the registrant and State Street Bank and Trust Company, Trustee, closing such indenture, has been filed with the Commission as an exhibit to Form S-1.	4(b)3	2-56915	

Item 13. Exhibits, Financial Statement Schedules and Reports on Form 8-K (Continued)

		Incorporated Documents Exhibit	SEC File No.	Filed Herewith at Page
Exhibit 10. Material contracts.				
Incorporated herein by reference thereto:				
10(a)	Power contracts.			
10(a)(1)	Copies of power contracts dated December 1, 1965 between Canal Electric Company and other utility companies have been filed by the Company with the Commission as an exhibit to Form S-1.	13(a)(1-4)	2-30057	
10(a)(2)	The following have been filed with the Commission as exhibits to the 1975 Form 10-K of Canal Electric Company:			
	Copy of agreement between the registrant and Montaup Electric Company for use of common facilities by Canal Units I and II and for allocation of related costs.	1	2-30057	
	Copy of agreement between the registrant and Montaup Electric Company for joint ownership of Canal Unit II.	2	2-30057	
	Copy of agreement between the registrant and Montaup Electric Company for lease relating to Canal Unit II.	3	2-30057	

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1982

Item 13. Exhibits, Financial Statement Schedules and Reports on Form 8-K (Continued)

		Incorporated Documents		Filed Herewith at Page
		Exhibit	SEC File No.	
10(a)(3)	Copy of Contract dated January 12, 1976 between Canal Electric Company and Commonwealth Electric Company (formerly New Bedford Gas and Edison Light Company) and Cambridge Electric Light Company, affiliated companies, for the sale of specified amounts of electricity from Canal Unit No. 2 has been filed with the Commission as an exhibit to the System's 1975 Form 10-K.	4	1-7316	
10(a)(4)	Copy of amendment dated August 6, 1976 to joint-ownership agreement between Canal Electric Company, New England Power Company, and other utilities dated January 11, 1976 has been filed with the Commission as an exhibit to the Company's 1976 Form 10-K.	1	2-30057	
10(a)(5)	Copy of Purchase and Sale Agreement dated January 2, 1981 together with an implementing Addendum dated December 31, 1981, between the Company and Commonwealth Electric for the purchase and sale of that company's 3.52% joint-ownership interest in the Seabrook nuclear electric generating units has been filed as an exhibit to the Company's Form 8-K (December 1981).	1	2-30057	

Item 13. Exhibits, Financial Statement Schedules and Reports on Form 8-K (Continued)

		Incorporated Documents		Filed Herewith at Page
		Exhibit	SEC File No.	
10(a)(6)	Copy of Fourteenth Amendment to Agreement for Joint Ownership of New Hampshire Nuclear Units between Commonwealth Electric Company (for itself and for Canal Electric Company) and Public Service Company of New Hampshire and others amending certain rights and provisions has been filed with the Commission as an exhibit to Commonwealth Electric Company's Form 10-Q (June, 1982).	3	2-7749	
10(a)(7)	Copy of the Capacity Acquisition Agreement dated September 25, 1980 between Canal Electric Company, Cambridge Electric Light Company and Commonwealth Electric Company has been filed with the Commission on the Company's Form 10-Q (March 1981).	1	2-30057	
10(b)	Other agreements.			
10(b)(1)	Copy of Tax Reduction Act of 1975 Employee Stock Ownership Plan and Trust of Commonwealth Energy System and Subsidiary Companies as amended May 11, 1981 has been filed with the Commission as an exhibit to the System's Form 10-Q, September 1981.	1	1-7316	
10(b)(2)	Copy of Employees Savings Plan of Commonwealth Energy System and Subsidiary Companies as amended May 11, 1981 has been filed as an exhibit to Form S-8 (October 1981) by the System.	3	2-74536	

Item 13. Exhibits, Financial Statement Schedules and Reports on Form 8-K (Continued)

		Incorporated Documents Exhibit	Incorporated Documents SEC File No.	Filed Herewith at Page
10(b)(3)	Copy of Pension Plan for Employees of Commonwealth Energy System and Subsidiary Companies as amended May 11, 1981 has been filed with the Commission by the System on Form 10-Q (September 1981).	2	1-7316	
10(b)(4)(a)	Copies of New England Power Pool Agreement (NEPOOL) dated September 1, 1971 as amended through August 1, 1977, between COM/Energy Services Company (formerly NEGEA Service Corporation), as agent for Cambridge Electric Light Company, Canal Electric Company, Commonwealth Electric Company (formerly New Bedford Gas and Edison Light Company), and various other electric utilities operating in New England, together with amendments dated August 15, 1978 and January 31, 1979 filed with the Commission as an exhibit to Commonwealth Energy System's Form S-16 (May 1980).	5(c)13	2-64731	
10(b)(4)(b)	Copy of an amendment to the New England Power Pool Agreement dated September 1, 1981 filed as an exhibit with Commonwealth Energy System's 1981 Form 10-K.	5	1-7316	
10(b)(5)	Copy of Oil Supply Contract effective January 1, 1981, between Canal Electric Company and Charter Oil (Massachusetts) Inc. filed with the Commission as an exhibit in the Company's Form 10-Q (September 1981).	1	2-30057	

Item 13. Exhibits, Financial Statement Schedules and Reports on Form 8-K (Continued)

		Incorporated Documents		
		Exhibit	SEC File No.	Filed Herewith at Page
10(b)(6)	Copy of the Assignment Agreement between Charter Oil (Massachusetts) Inc., COFI Credit (Massachusetts) Inc., and Canal Electric Company.	1		47
10(b)(7)	Copy of Facilities Lease and Operating Agreement between Canal Electric Company and Nepco Terminal, Inc. effective January 1, 1981 filed with the Commission as an exhibit to the Company's Form 10-Q (September 1981).	2	2-30057	

CANAL ELECTRIC COMPANY

Property, Plant and Equipment (A)

For the Year Ended December 31, 1982

Classification	Balance Beginning of Year	Additions at Cost	Retirements Charged to Reserve	Transfers	Balance End of Year
		(Dollars in Thousands)			
ELECTRIC					
Land and rights of way	$ 236	$ -	$ -	$ -	$ 236
Structures and leasehold improvements	15 687	16		-	15 703
Production equipment	108 881	593	62	-	109 412
Transmission equipment	5 011	-	-	-	5 011
General equipment and other	299	9	2	-	306
Total electric plant in service	130 114	618	64	-	130 668
Construction work in progress	57 163	30 356	-	-	87 519
Total electric	187 277	30 974	64	-	218 187
OTHER					
Realty property	588	49	55	-	582
Miscellaneous physical property (principally real estate)	397	159	-	-	556
Total other	985	208	55	-	1 138
Total Property, Plant and Equipment	188 262	31 182	119	-	219 325
Less-Accumulated deferred income taxes on:					
Property, plant and equipment	15 463	(2 180)(B)	-	-	13 283
Construction work in progress	3 328	6 391 (B)	-	-	9 719
Property, Plant and Equipment	$169 471	$26 971	$119	$ -	$196 323

(A) Refer to Note 1 of Notes to Financial Statements for depreciation method and rates.
(B) Net change.

SCHEDULE V

CANAL ELECTRIC COMPANY

Property, Plant and Equipment (A)

For the Year Ended December 31, 1981

Classification	Balance Beginning of Year	Additions at Cost	Retirements Charged to Reserve	Transfers	Balance End of Year
	(Dollars in Thousands)				
ELECTRIC					
Land and rights of way	$ 236	$ -	$ -	$ -	$ 236
Structures and leasehold improvements	15 558	129	-	-	15 687
Production equipment	107 611	1 763	493	-	108 881
Transmission equipment	5 011	-	-	-	5 011
General equipment and other	250	62	13	-	299
Total plant in service	128 666	1 954	506	-	130 114
Construction work in progress	817	(358)	-	56 704	57 163
Total electric	129 483	1 596	506	56 704	187 277
OTHER					
Realty property	618	80	110	-	588
Miscellaneous physical property (principally real estate)	136	261	-	-	397
Total other	754	341	110	-	985
Total Property, Plant and Equipment	130 237	1 937	616	56 704(B)	188 262
Less-Accumulated deferred income taxes on:					
Property, plant and equipment	13 420	2 043 (C)	-	-	15 463
Construction work in progress	129	3 199 (C)	-	-	3 328
Property, Plant and Equipment, net	$116 688	$(3 305)	$616	$56 704	$169 471

(A) Refer to Note 1 of Notes to Financial Statements for depreciation method and rates.
(B) Purchase of Seabrook nuclear generating units from Commonwealth Electric Company, an affiliate. (See Note 6 of Notes to Financial Statements.)
(C) Net change.

CANAL ELECTRIC COMPANY

Property, Plant and Equipment (A)

For the Year Ended December 31, 1980

Classification	Balance Beginning of Year	Additions at Cost	Retirements Charged to Reserve	Transfers	Balance End of Year
	(Dollars in Thousands)				
ELECTRIC					
Land and rights of way	$ 236	$ -	$ -	$ -	$ 236
Structures and leasehold improvements	15 314	243	-	1	15 558
Production equipment	107 543	148	79	(1)	107 611
Transmission equipment	5 009	2	-	-	5 011
General equipment and other	244	6	-	-	250
Total plant in service	128 346	399	79	-	128 666
Construction work in progress	13	804	-	-	817
Total electric	128 359	1 203	79	-	129 483
OTHER					
Realty property	452	218	52	-	618
Miscellaneous physical property (principally real estate)	136	-	-	-	136
Total other	588	218	52	-	754
Total Property, Plant and Equipment	128 947	1 421	131	-	130 237
Less-Accumulated deferred income taxes on:					
Property, plant and equipment	9 924	3 496 (B)	-	-	13 420
Construction work in progress	4 327	(4 198)(B)	-	-	129
Property, Plant and Equipment, net	$114 696	$2 123	$131	$ -	$116 688

(A) Refer to Note 1 of Notes to Financial Statements for depreciation method and rates.
(B) Net change

SCHEDULE VI

CANAL ELECTRIC COMPANY

ACCUMULATED DEPRECIATION OF PROPERTY, PLANT AND EQUIPMENT

FOR THE YEARS ENDED DECEMBER 31, 1982, 1981 AND 1980

(Dollars in Thousands)

Classification	Balance at Beginning of Year	Provision: Charged to Operations	Provision: Clearing Accounts and Other Income	Retirements	Removal Cost	Salvage	Balance at End of Year
	YEAR ENDED DECEMBER 31, 1982						
Electric	$42 171	$4 909	$ 11	$ 64	$17	$ 1	$47 011
Other	25	-	41	55	-	3	14
Total Accumulated Depreciation	$42 196	$4 909	$ 52	$119	$17	$ 4	$47 025
	YEAR ENDED DECEMBER 31, 1981						
Electric	$37 637	$4 848	$ 27	$506	$ -	$165	$42 171
Other	36	-	84	110	1	16	25
Total Accumulated Depreciation	$37 673	$4 848	$111	$616	$ 1	$181	$42 196
	YEAR ENDED DECEMBER 31, 1980						
Electric	$33 094	$4 617	$ 7	$ 79	$ 2	$ -	$37 637
Other	42	-	42	52	-	4	36
Total Accumulated Depreciation	$33 136	$4,617	$ 49	$131	$ 2	$ 4	$37,673

SCHEDULE IX

CANAL ELECTRIC COMPANY

Short-Term Borrowings

For the Years Ended December 31, 1982, 1981 and 1980

(Dollars in Thousands)

Category (A)	Notes Outstanding at Year-End	Weighted Average Interest Rate	Maximum Amount Outstanding During the Year	Average Amount Outstanding During the Year(B)	Weighted Average Interest Rate at Year-End(C)
		Year Ended December 31, 1982			
Banks	$44 250	13.6%	$44 250	$30 962	10.1%
		Year Ended December 31, 1981			
Banks	$22 500	13.0%	$22 500	$1 731	13.0%
		Year Ended December 31, 1980			
Banks	$ -	- %	$ -	$ -	- %

(A) Refer to Note 3 of Notes to Financial Statements for the general terms of notes payable.

(B) The average amount of short-term debt outstanding is determined by averaging the level of short-term debt outstanding at month-end for the thirteen-month period ending December 31, 1982.

(C) The weighted average interest rate at year-end is determined by annualizing the interest cost based on rates in effect during December and dividing this by the notes outstanding at year-end.

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1932

SIGNATURES

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

CANAL ELECTRIC COMPANY
(Registrant)

By: GERALD E. ANDERSON
Gerald E. Anderson,
Chairman of the Board and President

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

Principal Executive Officer:

GERALD E. ANDERSON Gerald E. Anderson, Chairman of the Board and President	March 28, 1983

Principal Financial Officer:

EARL G. CHENEY Earl G. Cheney, Financial Vice President	March 28, 1983

Principal Accounting Officer:

JOHN A. WHALEN John A. Whalen, Comptroller	March 28, 1983

A majority of the Board of Directors:

CHARLES T. ABBOTT Charles T. Abbott, Director	March 26, 1983
GERALD E. ANDERSON Gerald E. Anderson, Director	March 28, 1983

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1982

SIGNATURES
(Continued)

EARL G. CHENEY Earl G. Cheney, Director	March 28, 1983
 Leland R. Crowell, Director	March , 1983
JEREMIAH V. DONOVAN Jeremiah V. Donovan, Director	March 21, 1983
BURDETTE A. JOHNSON Burdette A Johnson, Director	March 17, 1983
WILLIAM R. SMITH William R. Smith, Director	March 18, 1983
RICHARD G. VELTE Richard G. Velte, Director	March 18, 1983

NEW HAMPSHIRE ELECTRIC COOPERATIVE, INC., PLYMOUTH, N.H.

1982 Annual Report

TO THE MEMBERS

DIRECTORS (for terms expiring)

1983	1984	1985
Fletcher Adams, Plymouth Treasurer	Edwin Moulton, Meredith Secretary	Everett Sackett, Dover
Gail F. Paine, Intervale	Arthur Wadleigh, Ashland	James Page, Benton President
Ezra Mann, Woodsville Vice-President	Dennis Fenton, Andover	Ted Putnam, Charlestown
Grace H. Bean, Waterville Valley	Whitman Ide, Belmont	

MANAGER	AUDITOR	ATTORNEY
John Pillsbury	Mulrennan, Tyrrel & Gleason	Mayland H. Morse


President James Page

DEAR MEMBERS:

This has been a challenging year for your Cooperative and Board of Directors. The same good weather that helped us avoid storm damage expense cut into power consumption in November and December and reduced expected operating margins. The 40 percent increase in the projected final cost of the Seabrook nuclear plant caused questions to be raised about our investment in future generation. A small group of members have continued their opposition to certain action of the board and, through the news media, court and legislative actions, have kept their opposition before the membership.

The year 1982 was one of slow growth. Average household electric use responded to rising costs and continuing conservation efforts. Industrial use, affected by the economy dropped this year. Your Cooperative increased its load management effort, controlling water heaters by radio command in the Conway and Thornton areas. By this effort, and with member cooperation during peak load periods, the high demands of winter were shaved down to avoid year-round capacity charges on the wholesale bills. Rate relief was sought during the year and was granted at year's end.

The rising cost of power is a constant problem, and the decision to invest in Seabrook, while less of a bargain then it appeared in its original conception, definitely remains the best alternative for us to stabilize our power supply and our rates some years down the road. The completion of both Units 1 and 2 as rapidly as possible is in the best interest of the Cooperative.

The members of the Cooperative elect the Board of Directors and charge the board with the responsibility of operating the second largest utility in New Hampshire for the benefit of all the members. With over 40,000 members, there are always some who will disagree with certain actions of the board. Such a minority group sprang up following the board's decision to purchase a small percentage of the nuclear generation at Seabrook. At the last three Annual Meetings of the Cooperative, this group has actively sought to elect directors favorable to their cause and to pass bylaw amendments limiting the power of the Board of Directors in the operation of the Cooperative. Each time the members have rejected their nominees and proposals.

During the year the board was challenged under the new state corporate law on action taken to channel bylaw amendments through the board but to guarantee the right of any member to take his or her case directly to the membership. A Superior Court decision upholding the board action was overturned at the Supreme Court level. Your board, with the assistance of the Membership Advisory Committee on Bylaws, is proceeding with study of a major revision of our 44 year old bylaws.

Unfortunately, the Bylaws of the Cooperative limit voting to those who attend the annual meeting. Each member attending may vote one (and only one) proxy for an absent member. Most of the proxies sent in cannot be voted. All members must have the right and ability to vote for the directors to whom they entrust the affairs of the Cooperative.

Our Annual Meeting will be held on June 7, 1983.

I hope you will attend and vote in the best interests of your Cooperative. I assure you that the board is grateful for your understanding and support. I welcome any inquiry, or suggestions you may have at anytime.

For the Board of Directors,

James J. Page

James Page, President

STATEMENT OF INCOME AND EXPENSE

NEW HAMPSHIRE ELECTRIC COOPERATIVE, INC.

Years 1982 and 1981

	1982	1981
INCOME:		
Operating Revenues:		
Residential Sales	$19,843,283	$19,068,596
General (Commercial Sales)	9,391,151	9,366,120
Outdoor Lighting (Street & Yard Lights)	575,831	575,027
Rents from Electric Property	363,585	467,780
Miscellaneous Electric Revenues	210,427	220,758
Total Operating Revenues	$30,384,277	$29,698,281
EXPENSE:		
Operating Revenue Deductions:		
Purchased Power	$21,742,691	$21,834,854
Transmission Expense	5,584	5,796
Distribution, Operations & Maintenance Expense	1,504,857	1,247,248
Consumer Accounts Expense	840,468	822,023
Administrative & General Expense	1,664,523	1,357,192
Total Operating Revenue Deductions	$25,758,123	$25,267,113
NET OPERATING REVENUES:	$ 4,626,154	$ 4,431,168
OTHER INCOME:		
Interest Income	$ 354,890	$ 165,350
Other Income	5,794	8,207
Total Other Income	$ 360,684	$ 173,557
OTHER INCOME DEDUCTIONS:		
Depreciation Expense	$ 1,833,399	$ 1,697,702
Tax Expense	573,912	684,943
Interest Expense	7,453,622	1,641,986
Interest Charged to Construction	(5,670,714)	(63,837)
Donations	2,719	2,251
Total Other Income Deductions	$ 4,192,938	$ 3,963,045
NET INCOME TO SURPLUS:	$ 793,900	$ 641,680

(Capital Credits allocated to each patron at the rate of 2.6% of revenue for 1982)

1982 WHOLESALE POWER COSTS	Kwh Purchased	Percent	Total Cost	Average Cost Per Kwh
Public Service Company of N.H.	346,460,755	88.0	$20,579,337	5.940¢
Green Mountain Power Company	1,512,300	.4	56,928	3.764¢
New England Power Company	4,663,300	1.2	256,034	5.490¢
Central Vermont Public Service Corp.	8,004,780	2.0	377,822	4.720¢
Maine-Yankee Atomic Power Company	33,179,600	8.4	872,797	2.631¢
TOTALS	393,820,735	100.0%	$22,142,918	5.623¢

BALANCE SHEET

NEW HAMPSHIRE ELECTRIC COOPERATIVE, INC.

Years 1982 and 1981

ASSETS

	1982	1981
UTILITY PLANT		
Electric Plant in Service	$ 56,125,336	$52,021,644
Construction Work in Progress – Seabrook	49,480,606	8,900,362
Construction Work in Progress – Other	1,230,265	770,139
Total Utility Plant	$106,836,207	$61,692,145
Accumulated Provision for Depreciation	13,508,487	12,426,259
Net Utility Plant	$ 93,327,720	$49,265,886
OTHER INVESTMENTS		
Other Utility Property	$ 202,284	$ 211,041
Investments in Cooperative Finance Corp.	1,246,722	1,092,460
Other Investments	2,000	2,000
Total Other Property and Investments	$ 1,451,006	$ 1,305,501
CURRENT ASSETS:		
Cash – General	$ 425,144	$ 1,635,123
Cash – Loan Funds	12,818	35,580
Accounts Receivable – Net	2,827,377	2,345,271
Materials and Supplies	888,524	780,965
Prepayments	320,225	163,901
Other Current and Accrued Assets	14,270	27,495
Temporary Cash Investments	1,217,549	------------
Total Current Assets	$ 5,705,907	$ 4,988,335
DEFERRED DEBITS:		
Other Deferred Charges	$ 1,927,191	$ 1,971,958
Total Deferred Debits	$ 1,927,191	$ 1,971,958
TOTAL ASSETS	$102,411,824	$57,531,680

LIABILITIES

	1982	1981
EQUITIES & MARGINS		
Patronage Capital	$ 2,997,091	$ 2,203,192
LONG TERM DEBT:		
Rural Electrification Administration	$ 45,343,317	$41,864,910
Plymouth Guaranty Savings Bank	199,428	211,078
Cooperative Finance Corporation (CFC)	324,485	328,597
Federal Financing Bank (Seabrook)	49,330,864	8,851,238
Total Long Term Debt	$ 95,198,094	$51,255,823
CURRENT LIABILITIES:		
Accounts Payable	$ 3,360,836	$ 3,422,830
Customer Deposits	121,974	91,689
Other Current & Accrued Liabilities	670,833	413,401
Total Current Liabilities	$ 4,153,643	$ 3,927,920
DEFERRED CREDITS:		
Other Deferred Credits	$ 62,996	$ 144,745
Total Deferred Credits	$ 62,996	$ 144,745
TOTAL LIABILITIES	$102,411,824	$57,531,680

NEW HAMPSHIRE ELECTRIC COOPERATIVE, INC.

YEAR IN REVIEW

GENERAL STATISTICS	1982	1981
Average Number of Accounts	45,492	44,448
Total Miles of Electric Lines	4,007	3,958
Number of New Services Connected During Year	1,209	1,345
Kilowatt-hour Sales – Total	356,796,481	352,399,018
Residential Sales	237,962,364	231,392,730
General (Commercial Sales)	115,582,414	117,754,199
Street & Yard Lights	3,251,703	3,252,089

REA LONG TERM DEBT (LESS SEABROOK BORROWINGS)		
Total Amount of Borrowing Authorized by REA	$61,070,000	$52,687,000
Total Amount of Advances	56,940,000	52,376,000
Interest on Debt Coming Due & Paid During Year	1,734,410	1,535,391
Principal on Debt Coming Due & Paid During Year	1,101,451	958,014
Total Repayment of Interest & Principal to Date	$25,478,955	$22,643,094

FIVE YEAR COMPARISONS	1982	1981	1980	1979	1978
Annual Kilowatt-hours Per Member (Domestic)	6,079	6,045	6,129	6,199	6,275
Annual Revenue Per Kilowatt-hour (Domestic)	8.38¢	8.28¢	6.80¢	5.80¢	5.21¢
Average Distribution Plant Per Member	$1,125	$1,061	998	947	892
Operations & Maintenance Per Mile of Line	$ 376	$ 315	$ 344	$ 307	$ 279
Consumer Accounts Expense Per Member	$ 18	$ 18	$ 15	$ 14	$ 13
Number of Employees	177	176	175	178	178
Average Number of Consumers Per Employee	257	252	247	236	229
Operating Payroll Per 1,000 Kilowatt-hours Sold	$ 5.98	$ 5.26	$ 5.21	$ 5.01	$ 4.41
Gross Payroll to Investment in Distribution Plant	7.32%	7.16%	7.50%	7.41%	7.41%
Wholesale Cost of Power as a Percent of Revenue	71.56%	73.52%	71.26%	67.13%	64.31%

NOTE ON SEABROOK

The Cooperative is joint owner with other New England utilities of the Seabrook nuclear units now under construction. In 1981, it purchased 2.17391 percent of each unit being built, acquiring 25,000 kilowatts of capacity in each unit. The plant was purchased from Public Service Company of New Hampshire, which is the lead participant in the project (35.56942 percent) and which also is the principal wholesale supplier of power purchased by the Cooperative.

As of December 31, 1982, the Cooperative has paid into Seabrook a total of $43,746,055 construction and related costs, borrowing the funds from the U.S. Federal Financing Bank in a loan guaranteed by the Rural Electrification Administration. It has also borrowed the funds necessary to pay interest on the borrowings to date. The interest will be capitalized with other plant costs and be paid back over operating life of the plant. Total cost of construction and interest to December 31, 1982 came to $49,480,606.

The lead owner's estimates of the cost of the two Seabrook units were increased substantially during 1982 as a result of revised construction estimates and changes (delay) in scheduled completion dates.

The Cooperative, in March 1983, applied for $50 million of supplemental borrowing to complete its share of cost. Unit 1 is currently scheduled to operate in December 1984 with Unit 2 coming on line in mid-1987.

Copies of the audit report are on file with the New Hampshire Public Utilities Commission, Concord, New Hampshire; the Rural Electrification Administration, Washington, D.C. and the Cooperative Office, Plymouth, N.H.

MUNICIPAL LIGHTING PLANTS

The Commonwealth of Massachusetts

RETURN

OF THE

TOWN OF

HUDSON LIGHT + POWER DEPARTMENT

TO THE

DEPARTMENT OF PUBLIC UTILITIES

OF MASSACHUSETTS

For the Year Ended December 31,

1982

The Commonwealth of Massachusetts

OFFICE OF THE
DEPARTMENT OF PUBLIC UTILITIES
100 Cambridge Street
Boston, Massachusetts 02202

To the Mayors, Selectmen, Municipal Light Boards and Managers of Municipal Lighting in the Several Cities and Towns in this Commonwealth operating Gas or Electric Light Plants:

This form of Annual Return should be filled out in duplicate and the original copy returned to the Office of the Department of Public Utilities, Accounting Division, by MARCH 31st in accordance with the requirements of the statutes of the Commonwealth of Massachusetts and the regulations of the Department made in pursuance thereof.

Where the word "None" truly and completely states the fact, it should be given as the answer to any particular inquiry or portion of an inquiry.

If respondent so desires, cents may be omitted in the balance sheet, income statement and supporting schedules. All supporting schedules on an even-dollar basis, however, shall agree with even-dollar amounts in the main schedules. Averages and extracted figures, where cents are important, must show cents for reasons which are apparent.

Special attention is called to the legislation in regard to the Returns printed on the last page.

Inquiries and other communications in relation to Returns should be addressed to the DIRECTOR OF UTILITY ACCOUNTING

The Commonwealth of Massachusetts

RETURN

OF THE

TOWN ....OF

HUDSON LIGHT AND POWER DEPARTMENT

TO THE

DEPARTMENT OF PUBLIC UTILITIES

OF MASSACHUSETTS

For the Year Ended December 31,

Name of officer to whom correspondence should be addressed regarding this report. Horst Huehmer

Official title Manager; Office address 49 Forest Avenue

Hudson, MA 01749

Form AC-19. 500-12-71-050708

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TABLE OF CONTENTS

FOR GAS PLANTS ONLY:

PAGES INTENTIONALLY OMITTED: 23 to 36 and 53 to 56

GENERAL INFORMATION.

1. Name of town (or city) making this report. Hudson, Massachusetts 01749

2. If the town (or city) has acquired a plant,
   Kind of plant, whether gas or electric. Electric
   Owner from whom purchased, if so acquired. Hudson Electric Light Company 7/1/1891
   Date of votes to acquire a plant in accordance with the provisions of chapter 164 of the General Laws. 9/1/1981
   Record of votes: First vote: Yes, 30 ; No, 7 Second vote: Yes, 69 ; No, 11
   Date when town (or city) began to sell gas and electricity,

   January 15, 1897

3. Name and address of manager of municipal lighting:

   Horst Huehmer
   49 Forest Avenue
   Hudson, MA 01749

4. Name and address of mayor or selectmen:
   Chairman: George McGee, 271 Cox St. Hudson, MA 01749
   Clerk: Paul R. Boire, 10 Ridge Rd. Hudson, MA 01749
   Joseph J. Durant, 22 Hariman Road, Hudson, MA 01749
   William G. Collette, 29 Maple St. Hudson, MA 01749
   Albert A. Morel, Jr., 364 Main St. Hudson, MA 01749

5. Name and address of town (or city) treasurer:
   David J. O'Neil
   49 Temi Road
   Hudson, MA 01749

6. Name and address of town (or city) clerk:
   Ralph Warner
   18 Riverview Street
   Hudson, MA 01749

7. Names and addresses of members of municipal light board:
   Chairman: Roland L. Plante, 136 Murphy St. Hudson, MA 01749
   Clerk: Richard J. Dion, 110 Murphy St. Hudson, MA 01749
   Robert F. Wood, 14 Parkhurst Drive, Hudson, MA 01749

8. Total valuation of estates in town (or city) according to last State valuation $ 309,000,000.00

9. Tax rate for all purposes during the year: $ 54.80

10. Amount of manager's salary: $ 48,433.38

11. Amount of manager's bond: $ 1,000.00

12. Amount of salary paid to members of municipal light board (each): $ 400.00

FURNISH SCHEDULE OF ESTIMATES REQUIRED BY GENERAL LAWS, CHAPTER 164, SECTION 57 FOR GAS AND ELECTRIC LIGHT PLANTS FOR THE FISCAL YEAR, ENDING DECEMBER 31, NEXT.

		Amount.
	INCOME FROM PRIVATE CONSUMERS:	
1	From sales of gas	
2	From sales of electricity	10,083,762.00
3	TOTAL	10,083,762.00
4		
5	EXPENSES:	
6	For operation, maintenance and repairs	9,280,507.00
7	For interest on bonds, notes or scrip	None
8	For depreciation fund (5 per cent. on $ 10,366,437.76 as per page 9)	543,321.39
9	For sinking fund requirements	11,950.00
10	For note payments	None
11	For bond payments	None
12	For loss in preceding year	None
13	TOTAL	9,835,778.39
14		
15	COST: For fiscal year ending 6/30/84	
16	Of gas to be used for municipal buildings	None
17	Of gas to be used for street lights	None
18	Of electricity to be used for municipal buildings	307,650.00
19	Of electricity to be used for street lights	66,350.00
20	Total of the above items to be included in the tax levy	374,000.00
21		
22	New construction to be included in the tax levy	None
23	Total amounts to be included in the tax levy	374,000.00

CUSTOMERS

Names of the cities or towns in which the plant supplies GAS, with the number of customers' meters in each		Names of the cities or towns in which the plant supplies ELECTRICITY, with the number of customers' meters in each	
City or Town	Number of Customers' Meters, Dec. 31	City or Town	Number of Customers' Meters, Dec. 31
		Hudson	6211
		Stow	1910
		Berlin, Bolton, Boxboro Harvard, Maynard, Marlboro	100
NOT APPLICABLE			
TOTAL		TOTAL	8221

APPROPRIATIONS SINCE BEGINNING OF YEAR

(Include also all items charged direct to tax levy, even where no appropriation is made or required.)

FOR CONSTRUCTION OR PURCHASE OF PLANT:

*At	meeting	19	, to be paid from †	$
*At	meeting	19	, to be paid from †	
			TOTAL	$ None

FOR THE ESTIMATED COST OF THE GAS OR ELECTRICITY TO BE USED BY THE CITY OR TOWN FOR:

1. Street lights		$ 63,000.00
2. Municipal buildings	Amounts are included in overall appropriations	-
3.	for each department	
	TOTAL	$ 63,000.00

*Date of meeting and whether regular or special. †Here insert bonds, notes or tax levy.

CHANGES IN THE PROPERTY

1. Describe briefly all the important physical changes in the property during the last fiscal period including additions, alterations or improvements to the works or physical property retired.

In electric property:

NONE

In gas property:

NOT APPLICABLE

BONDS
(Issued on Account of Gas or Electric Lighting.)

When Authorized*	Date of Issue	Amount of Original Issue†	Period of Payments		Interest		Amount Outstanding at End of Year
			Amounts	When Payable	Rate	When Payable	
April 7, 1913	Spec.June 1,1913	$ 9,000.00					
March 4, 1918	Reg.April 1,1918	50,000.00					
June 14, 1920	Spec.Feb. 1,1921	25,000.00					
March 5, 1928	Reg.Nov. 1,1928	40,000.00					
Nov. 29, 1954	Spec.Mar. 1,1955	250,000.00					
March 7, 1955	Reg.May 1, 1955	100,000.00					
March 7, 1955	Reg.Nov. 1, 1955	150,000.00					
June 8, 1959	Spec.Aug. 1, 1959	300,000.00					
Nov. 7, 1961	Spec.July 15, 1962	450,000.00					
	TOTAL	$1,374,000.00				TOTAL	

The bonds and notes outstanding at end of year should agree with the Balance Sheet. When bonds and notes are repaid report the first three columns only.

*Date of meeting and whether regular or special.

†List original issues of bonds and notes including those that have been retired.

TOWN NOTES

(Issued on Account of Gas or Electric Lighting.)

When Authorized*	Date of Issue	Amount of Original Issue†	Period of Payments		Interest		Amount Outstanding at End of Year
			Amounts	When Payable	Rate	When Payable	
Dec.18,1896.Spec.	Jan. 1, 1897	$ 18,000.00					
June20,1897.Spec.	Jan. 1, 1898	17,000.00					
June20,1898.Spec.	July 1, 1898	5,000.00					
Nov.5,1903.Spec.	Nov. 2, 1903	13,000.00					
Mar.7,1904.Reg.	Jan. 1, 1905	5,000.00					
Apr.2,1912.Spec.	May 1, 1912	2,000.00					
Aug.4,1941 Spec.	Oct. 15, 1941	100,000.00					
Sept.14,1942 Spec	Oct. 15, 1942	100,000.00					
Feb. 8,1943 Spec.	Feb. 15, 1943	50,000.00					
Mar.6,1950 Reg.	Sept. 15, 1950	241,000.00					
	TOTAL	$ 551,000.00				TOTAL	

The bonds and notes outstanding at end of year should agree with the Balance Sheet. When bonds and notes are repaid report the first three columns only.

*Date of meeting and whether regular or special. †List original issues of bonds and notes including those that have been retired.

TOTAL COST OF PLANT — ELECTRIC

1. Report below the cost of utility plant in service according to prescribed accounts.
2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.
3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such accounts.
4. Reclassifications or transfers within utility plant accounts should be shown in column (f).

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)
1	1. INTANGIBLE PLANT	$	$	$	$	$	$
2							
3							
4							
5	2. PRODUCTION PLANT						
6	A. Steam Production						
7	310 Land and Land Rights						
8	311 Structures and Improvements						
9	312 Boiler Plant Equipment						
10	313 Engines and Engine Driven Generators						
11	314 Turbogenerator Units						
12	315 Accessory Electric Equipment						
13	316 Miscellaneous Power Plant						
14	Equipment						
15	Total Steam Production Plant						
16	B. Nuclear Production Plant						
17	320 Land and Land Rights	944.00					944.00
18	321 Structures and Improvements						
19	322 Reactor Plant Equipment						
20	323 Turbogenerator Units						
21	324 Accessory Electric Equipment						
22	325 Miscellaneous Power Plant Equipment						
23	Total Nuclear Production Plant	944.00	None	None	None	None	944.00

TOTAL COST OF PLANT — ELECTRIC (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)
1	C. Hydraulic Production Plant	$	$	$	$	$	$
2	330 Land and Land Rights						
3	331 Structures and Improvements						
4	332 Reservoirs, Dams and Waterways						
5	333 Water Wheels, Turbines and Generators						
6	334 Accessory Electric Equipment						
7	335 Miscellaneous Power Plant Equipment						
8	336 Roads, Railroads and Bridges						
9	Total Hydraulic Production Plant	None	None	None	None	None	None
10	D. Other Production Plant						
11	340 Land and Land Rights	5,500.00	None				5,500.00
12	341 Structures and Improvements	332,639.70	128.00				332,767.70
13	342 Fuel Holders, Producers and Accessories	124,588.30	None				124,588.30
14	343 Prime Movers	2,452,173.12	4,272.80				2,456,445.92
15	344 Generators	287,549.94	None				287,549.94
16	345 Accessory Electric Equipment	832,477.01	None				832,477.01
17	346 Miscellaneous Power Plant Equipment	20,666.07	6,210.00				26,876.07
18	Total Other Production Plant	4,055,594.14	10,610.80				4,066,204.94
19	Total Production Plant	4,056,538.14	10,610.80				4,067,148.94
20	3. TRANSMISSION PLANT						
21	350 Land and Land Rights	53,804.14					53,804.14
22	351 Clearing Land and Rights of Way	None					None
23	352 Structures and Improvements	168,166.08					168,166.08
24	353 Station Equipment	298,288.34					298,288.34
25	354 Towers and Fixtures	None					None
26	355 Poles and Fixtures	796,839.02					796,839.02
27	356 Overhead Conductors and Devices	227,329.01					227,329.01
28	357 Underground Conduit	258.07					258.07
29	358 Underground Conductors and Devices	None					None
30	359 Roads and Trails	None					None
31	Total Transmission Plant	1,544,684.66	None	None	None	None	1,544,684.66

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COMPARATIVE BALANCE SHEET Assets and Other Debits

Line No.	Title of Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Increase or (Decrease) (d)
1	UTILITY PLANT			
2	101 Utility Plant — Electric (P. 17)	4,774,935.27	4,942,990.19	168,054.92
3	101 Utility Plant — Gas (P. 20)	None	None	None
4				
5	Total Utility Plant	4,774,935.27	4,942,990.19	168,054.92
6				
7				
8				
9				
10				
11	FUND ACCOUNTS			
12	125 Sinking Funds	None	None	None
13	126 Depreciation Fund (P. 14)	1,661,315.44	1,903,394.95	242,079.51
14	128 Other Special Funds	88,140.07	29,226.28	(58,913.79)
15	Total Funds	1,749,455.51	1,932,621.23	183,165.72
16	CURRENT AND ACCRUED ASSETS			
17	131 Cash (P. 14)	2.80	9,166.90	9,164.10
18	132 Special Deposits	128,221.07	117,743.71	(10,477.36)
19	135 Working Funds	200.00	200.00	None
20	171 Interest & Div. Receivable	26,755.32	12,631.59	(14,123.73)
21	142 Customer Accounts Receivable	945,533.82	971,951.72	26,417.90
22	143 Other Accounts Receivable	16,854.35	15,066.33	(1,788.02)
23	146 Receivables from Municipality	5,657.88	None	(5,657.88)
24	151 Materials and Supplies (P. 14)	843,839.79	908,765.30	64,925.51
25	173 Accrued Utility revenue	277,915.70	None	(277,915.70)
26	165 Prepayments	210,180.13	219,070.49	8,890.36
27	174 Miscellaneous Current Assets	.00	452.51	452.51
28	Total Current and Accrued Assets	2,455,160.86	2,255,048.55	(200,112.31)
29	DEFERRED DEBITS			
30	181 Unamortized Debt Discount	None	None	None
31	182 Extraordinary Property Losses	None	None	None
32	185 Other Deferred Debits	42,111.37	34,387.96	(7,723.41)
33	Total Deferred Debits	42,111.37	34,387.96	(7,723.41)
34		9,021,663.01	9,165,047.93	143,384.92
35	Total Assets and Other Debits			

COMPARATIVE BALANCE SHEET Liabilities and Other Credits

Line No.	Title of Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Increase or (Decrease) (d)
1	APPROPRIATIONS			
2	201 Appropriations for Construction	None	None	None
3	SURPLUS			
4	205 Sinking Fund Reserves	None	None	None
5	206 Loans Repayment	1,925,000.00	1,925,000.00	None
6	207 Invest. by Municipality	20,093.39	20,093.39	None
7	208 Unappropriated Earned Surplus (P. 12)	6,125,985.12	6,743,689.71	617,764.59
8	Total Surplus	8,071,078.51	8,688,783.10	617,704.59
9	LONG TERM DEBT			
10	221 Bonds (P. 6)	None	None	None
11	231 Notes Payable (P. 7)	None	None	None
12	Total Bonds and Notes	None	None	None
13	CURRENT AND ACCRUED LIABILITIES			
14	232 Accounts Payable	772,554.09	284,906.11	(487,647.98)
15	234 Payables to Municipality	None	None	None
16	235 Customers' Deposits	128,221.07	117,743.71	(10,477.36)
17	236 Taxes Accrued	None	None	None
18	237 Interest Accrued	None	None	None
19	242 Miscellaneous Current and Accrued Liabilities	12,787.34	4,668.39	(8,118.95)
20	Total Current and Accrued Liabilities	913,562.50	407,318.21	(506,244.29)
21	DEFERRED CREDITS			
22	251 Unamortized Premium on Debt	None	None	None
23	252 Customer Advances for Construction	33,800.00	32,400.00	(1,400.00)
24	253 Other Deferred Credits	3,222.00	4,276.50	1,054.50
25	Total Deferred Credits	37,022.00	36,676.50	(345.50)
26	RESERVES			
27	260 Reserves for Uncollectible Accounts			
28	261 Property Insurance Reserve			
29	262 Injuries and Damages Reserves			
30	263 Pensions and Benefits Reserves			
31	265 Miscellaneous Operating Reserves			
32	Total Reserves	None	None	None
33	CONTRIBUTIONS IN AID OF CONSTRUCTION			
34	271 Contributions in Aid of Construction	None	32,270.12	32,270.12
35	Total Liabilities and Other Credits	9,021,663.01	9,165,047.93	143,384.92

State below if any earnings of the municipal lighting plant have been used for any purpose other than discharging indebtedness of the plant, the purpose for which used and the amount thereof.

STATEMENT OF INCOME FOR THE YEAR

Line No.	Account (a)	Total: Current Year (b)	Total: Increase or (Decrease) from Preceding Year (c)
1	OPERATING INCOME		
2	400 Operating Revenues (P. 37 and 43)	$ 9,697,661.22	$ 113,182.28
3	Operating Expenses:		
4	401 Operation Expense (P. 42 and 47)	8,240,269.40	192,805.80
5	402 Maintenance Expense (P. 42 and 47)	342,342.72	41,232.87
6	403 Depreciation Expense	532,027.29	21,600.77
7	407 Amortization of Property Losses	None	None
8			
9	408 Taxes (P. 49)	4,808.11	1,209.23
10	Total Operating Expenses	9,119,447.52	256,848.67
11	Operating Income	578,213.70	(143,666.39)
12	414 Other Utility Operating Income (P. 50)	None	None
13			
14	Total Operating Income	578,213.70	(143,666.39)
15	OTHER INCOME		
16	415 Income from Merchandising, Jobbing and Contract Work (P. 51)	958.79	(1,151.21)
17	419 Interest Income	215,781.55	17,076.55
18	421 Miscellaneous Nonoperating Income	None	None
19	Total Other Income	216,740.34	15,925.34
20	Total Income	794,954.04	(127,741.05)
21	MISCELLANEOUS INCOME DEDUCTIONS		
22	425 Miscellaneous Amortization	None	None
23	426 Other Income Deductions	None	None
24	Total Income Deductions	None	None
25	Income Before Interest Charges	794,954.04	(127,741.05)
26	INTEREST CHARGES		
27	427 Interest on Bonds and Notes	None	None
28	428 Amortization of Debt Discount and Expense	None	None
29	429 Amortization of Premium on Debt — Credit	None	None
30	431 Other Interest Expense	2,249.45	2,531.51
31	432 Interest Charged to Construction — Credit	None	None
32	Total Interest Charges	2,249.45	2,531.51
33	NET INCOME	792,704.59	(130,272.56)

EARNED SURPLUS

Line No.	(a)	Debits (b)	Credits (c)
34	208 Unappropriated Earned Surplus (at beginning of period)		6,125,985.12
35			
36			
37	433 Balance Transferred from Income		792,704.59
38	434 Miscellaneous Credits to Surplus (P. 21)		
39	435 Miscellaneous Debits to Surplus (P. 21)		
40	436 Appropriations of Surplus (P. 21)	175,000.00	
41	437 Surplus Applied to Depreciation		
42	208 Unappropriated Earned Surplus (at end of period)	6,743,689.71	
43			
44	TOTALS	6,918,689.71	6,918,689.71

CASH BALANCES AT END OF YEAR (Account 131)

Line No.	Items (a)	Amount (b)
1	Operation Fund	9,166.90
2	Interest Fund	None
3	Bond Fund	None
4	Construction Fund (128)	25,531.88
5	Miscellaneous Cash (128)	2,704.02
6	Advances from Contractors (128)	990.38
7		
8		
9		
10		
11		
12	TOTAL	38,393.18

MATERIALS AND SUPPLIES (Accounts 151-159, 163)
Summary Per Balance Sheet

Line No.	Account (a)	Amount End of Year: Electric (b)	Amount End of Year: Gas (c)
13	Fuel (Account 151) (See Schedule, Page 25)	710,958.95	
14	Fuel Stock Expenses (Account 152)		NOT
15	Residuals (Account 153)		
16	Plant Materials and Operating Supplies (Account 154)	197,806.35	APPLICABLE
17	Merchandise (Account 155)		
18	Other Materials and Supplies (Account 156)		
19	Nuclear Fuel Assemblies and Components — In Reactor (Account 157)		
20	Nuclear Fuel Assemblies and Components — Stock Account (Account 158)		
21	Nuclear Byproduct Materials (Account 159)		
22	Stores Expense (Account 163)		
23	Total Per Balance Sheet $	908,765.30	

DEPRECIATION FUND ACCOUNT (Account 136)

Line No.	(a)	Amount (b)
24	DEBITS	
25	Balance of account at beginning of year	1,661,315.44
26	Income during year from balance on deposit	220,823.64
27	Amount transferred from income	532,027.29
28	Reimbursement for plant sold or damaged	145,365.00
29	TOTAL	2,559,531.37
30	CREDITS	
31	Amount expended for construction purposes (Sec. 57, C. 164 of G.L.)	656,136.42
32	Amounts expended for renewals, viz.:—	
33		
34		
35		
36		
37		
38		
39	Balance on hand at end of year	1,903,394.95
40	TOTAL	2,559,531.37

UTILITY PLANT — ELECTRIC

1. Report below the items of utility plant in service according to prescribed accounts.
2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c).
3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.
4. Reclassifications or transfers within utility plant accounts should be shown in column (f).

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Depreciation (d)	Other Credits (e)	Adjustments Transfers (f)	Balance End of Year (g)
1	1. INTANGIBLE PLANT	$	$	$	$	$	$
2							
3							
4							
5	2. PRODUCTION PLANT						
6	A. Steam Production						
7	310 Land and Land Rights						
8	311 Structures and Improvements						
9	312 Boiler Plant Equipment						
10	313 Engines and Engine Driven Generators						
11	314 Turbogenerator Units						
12	315 Accessory Electric Equipment						
13	316 Miscellaneous Power Plant						
14	Equipment						
15	Total Steam Production Plant						
16	B. Nuclear Production Plant						
17	320 Land and Land Rights	944.00					944.00
18	321 Structures and Improvements						
19	322 Reactor Plant Equipment						
20	323 Turbogenerator Units						
21	324 Accessory Electric Equipment						
22	325 Miscellaneous Power Plant Equipment						
23	Total Nuclear Production Plant	944.00					944.00

UTILITY PLANT — ELECTRIC (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Depreciation (d)	Other Credits (e)	Adjustments Transfers (f)	Balance End of Year (g)
1	C. Hydraulic Production Plant	$	$	$	$	$	$
2	330 Land and Land Rights						
3	331 Structures and Improvements						
4	332 Reservoirs, Dams and Waterways						
5	333 Water Wheels, Turbines and Generators						
6	334 Accessory Electric Equipment						
7	335 Miscellaneous Power Plant Equipment						
8	336 Roads, Railroads and Bridges						
9	Total Hydraulic Production Plant	None	None	None	None	None	None
10	D. Other Production Plant						
11	340 Land and Land Rights	5,500.00					5,500.00
12	341 Structures and Improvements	29,517.10	128.00	4,157.99			25,487.11
13	342 Fuel Holders, Producers and Accessories	24,312.54		3,114.70			21,197.84
14	343 Prime Movers	488,115.19	4,272.80	76,893.02			415,494.97
15	344 Generators	37,873.45		3,594.37			34,279.08
16	345 Accessory Electric Equipment	111,252.84		10,405.96			100,846.88
17	346 Miscellaneous Power Plant Equipment	2,348.46	6,210.00	258.33			8,300.13
18	Total Other Production Plant	698,919.58	10,610.80	98,424.37			611,106.01
19	Total Production Plant	699,863.58	10,610.80	98,424.37			612,050.01
20	3. TRANSMISSION PLANT						
21	350 Land and Land Rights	53,804.14					53,804.14
22	351 Clearing Land and Rights of Way	25,964.43		4,204.15			21,760.28
23	352 Structures and Improvements	80,337.55		11,185.81			69,151.74
24	353 Station Equipment	84,952.12		9,920.98			75,031.14
25	354 Towers and Fixtures	None		None			None
26	355 Poles and Fixtures	496,910.92		142,226.32			354,684.60
27	356 Overhead Conductors and Devices	140,273.24		11,366.45			128,906.79
28	357 Underground Conduit	196.90		12.90			184.00
29	358 Underground Conductors and Devices	None		None			None
30	359 Roads and Trails	None		None			None
31	Total Transmission Plant	882,439.30		178,916.61			703,522.69

UTILITY PLANT — ELECTRIC (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Depreciation (d)	Other Credits (e)	Adjustments Transfers (f)	Balance End of Year (g)
1	4. DISTRIBUTION PLANT	$	$	$	$	$	$
2	360 Land and Land Rights	None		None			None
3	361 Structures and Improvements	1,475.22		172.09			1,303.13
4	362 Station Equipment	247,424.20		19,867.89			227,556.31
5	363 Storage Battery Equipment	None		None			None
6	364 Poles, Towers and Fixtures	78,617.29	24,881.65	21,061.39	8,405.95		74,031.60
7	365 Overhead Conductors and Devices	294,102.84	99,501.00	55,708.72	7,387.35		330,507.77
8	366 Underground Conduit	76,841.84	4,365.67	5,696.93	8.50		75,502.08
9	367 Underground Conductors & Devices	207,442.42	19,920.06	13,658.45	16,397.75		197,306.28
10	368 Line Transformers	367,514.53	19,984.31	47,265.17	1,395.36		338,838.31
11	369 Services	112,553.36	11,709.17	14,960.03	673.59		108,628.91
12	370 Meters	104,583.14	24,684.24	15,025.91	1,484.21		112,757.26
13	371 Installations on Cust's Premises	None	None	None	None		None
14	372 Leased Prop. on Cust's Premises	None	None	None	None		None
15	373 Street Lighting and Signal Systems	65,621.77	6,856.83	12,640.56	976.69		58,861.35
16	Total Distribution Plant	1,556,176.61	211,902.93	206,057.14	36,729.40		1,525,293.00
17	5. GENERAL PLANT						
18	389 Land and Land Rights	None	None	None	None		None
19	390 Structures and Improvements	206,691.90	3,580.15	21,288.55			188,983.50
20	391 Office Furniture and Equipment	168,631.37	33,021.75	11,510.82	12,133.10		178,009.20
21	392 Transportation Equipment	102,186.13	13,011.65	12,532.42			102,665.36
22	393 Stores Equipment	7,208.36	550.80	535.24			7,223.92
23	394 Tools, Shop and Garage Equipment	4,367.81	3,131.80	374.74			7,124.87
24	395 Laboratory Equipment	16,802.76	771.55	942.79			16,631.52
25	396 Power Operated Equipment	936.92		56.91			880.01
26	397 Communication Equipment	11,085.04		1,216.09			9,868.95
27	398 Miscellaneous Equipment	2,308.72	205.95	171.61			2,343.06
28	399 Other Tangible Property	5,754.69		None	782.76		4,971.93
29	Total General Plant	525,973.70	54,273.65	48,629.17	12,915.86		518,702.32
30	Total Electric Plant in Service	3,664,453.19	276,787.38	532,027.29	49,645.26		3,359,568.02
31	104 Utility Plant Leased to Others	None	None	None	None	None	None
32	105 Property Held for Future Use	None	None	None	None	None	None
33	107 Construction Work in Progress	1,110,482.08	472,940.09	None	None	None	1,583,422.17
34	Total Utility Plant Electric	4,774,935.27	749,727.47	532,027.29	49,645.26	None	4,942,990.19

PRODUCTION FUEL AND OIL STOCKS (Included in Account 151)
(Except Nuclear Materials)

1. Report below the information called for concerning production fuel and oil stocks.
2. Show quantities in tons of 2,000 lbs., gal., or Mcf., whichever unit of quantity is applicable.
3. Each kind of coal or oil should be shown separately.
4. Show gas and electric fuels separately by specific use.

Line No.	Item (a)	Total Cost (b)	Kinds of Fuel and Oil: #2 DIESEL Quantity (c)	#2 DIESEL Cost (d)	GAS MCF Quantity (e)	GAS MCF Cost (f)
1	On Hand Beginning of Year	$ 665,224.52	1,202,376	$ 665,224.52	None	$ None
2	Received During Year	1,113,589.60	258,503	245,577.85	195,865	868,011.75
3	TOTAL	1,778,814.12	1,460,879	910,802.37	195,865	868,011.75
4	Used During Year (Note A)	1,067,855.17	278,918	199,843.42	195,865	868,011.75
5						
6						
7						
8						
9						
10						
11	Sold or Transferred					
12	TOTAL DISPOSED OF	1,067,855.17	278,918	199,843.42	195,865	868,011.75
13	BALANCE END OF YEAR	710,958.95	1,181,961	710,958.95	None	None

Line No.	Item (g)	Kinds of Fuel and Oil — Continued: Quantity (h)	Cost (i)	Quantity (j)	Cost (k)
14	On Hand Beginning of Year		$		$
15	Received During Year				
16	TOTAL				
17	Used During Year (Note A)				
18					
19					
20					
21					
22					
23					
24	Sold or Transferred				
25	TOTAL DISPOSED OF				
26	BALANCE END OF YEAR				

Note A — Indicate specific purpose for which used, e.g., Boiler Oil, Make Oil, Generator Fuel, etc.

MISCELLANEOUS NONOPERATING INCOME (Account 421)

Line No.	Item (a)	Amount (b)
1		
2		
3		
4		
5		
6	TOTAL	None

OTHER INCOME DEDUCTIONS (Account 426)

Line No.	Item (a)	Amount (b)
7		
8		
9		
10		
11		
12		
13		
14	TOTAL	None

MISCELLANEOUS CREDITS TO SURPLUS (Account 434)

Line No.	Item (a)	Amount (b)
15		
16		
17		
18		
19		
20		
21		
22		
23	TOTAL	None

MISCELLANEOUS DEBITS TO SURPLUS (Account 435)

Line No.	Item (a)	Amount (b)
24		
25		
26		
27		
28		
29		
30		
31		
32	TOTAL	None

APPROPRIATIONS OF SURPLUS (Account 436)

Line No.	Item (a)	Amount (b)
33	Transferred to Town Treasury	175,000.00
34		
35		
36		
37		
38		
39		
40	TOTAL	175,000.00

MUNICIPAL REVENUES (Accounts 482, 444)

(K.W.H. sold under the provisions of Chapter 269, Acts of 1927)

Line No.	Acc't No.	Gas Schedule (a)	Cubic Feet (b)	Revenue Received (c)	Average Revenue per M.C.F. ($0.0000) (d)
1	482				
2					
3		NOT APPLICABLE			
4		TOTALS			

Line No.	Acc't No.	Electric Schedule (a)	K.W.H. (b)	Revenue Received (c)	Average Revenue per K.W.H. (cents) (0.0000) (d)
5	444	Municipal: (Other than Street Lighting)			
6		All Electric	5,892,000	350,239.61	.059443
7		Power	3,193,919	229,437.96	.071836
8		Commercial	310,276	28,232.66	.090992
9		Yard Lighting	22,805	2,200.22	.096480
10					
11		TOTALS	9,419,000	610,110.45	.064774
12					
13		Street Lighting: Town of Hudson	1,150,283	75,244.58	.065414
14		Town of Stow	64,360	6,888.90	.107037
15		Towns of Bolton & Berlin	1,176	133.43	.113461
16					
17					
18		TOTALS	1,215,819	82,266.91	.067664
19		TOTALS	10,634,819	692,377.36	.065105

PURCHASED POWER (Account 555)

Line No.	Names of Utilities from Which Electric Energy Is Purchased (a)	Where and at What Voltage Received (b)	K.W.H. (c)	Amount (d)	Cost per K.W.H. (cents) (0.0000) (e)
20					
21					
22	SEE PAGES 54 & 55	FOR DETAILS			
23					
24					
25					
26					
27					
28					
29		TOTALS	121,547,438	4,686,169	3.8554

SALES FOR RESALE (Account 447)

Line No.	Names of Utilities to Which Electric Energy Is Sold (a)	Where and at What Voltage Delivered (b)	K.W.H. (c)	Amount (d)	Revenues per K.W.H. (cents) (0.0000) (e)
30					
31	SEE PAGES 52 & 53	FOR DETAILS			
32					
33					
34					
35					
36					
37					
38		TOTALS	23,200	2,757	11.8836

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below the amount of operating revenue for the year for each prescribed account and the amount of increase or decrease over the preceding year.

2. If increases and decreases are not derived from previously reported figures explain any inconsistencies.

3. Number of customers should be reported on the basis of number of meters, plus number of flat rate accounts, except that where separate meter readings are added for billing purposes, one customer shall be counted for each group of meters so added. The average number of customers means the average of the 12 figures at the close of each month. If the customer count in the residential service classification includes customers counted more than once because of special services, such as water heating, etc., indicate in a footnote the number of such duplicate customers included in the classification.

4. Unmetered sales should be included below. The details of such sales should be given in a footnote.

5. Classification of Commercial and Industrial Sales, Account 442, according to Small (or Commercial) and Large (or Industrial) may be according to the basis of classification regularly used by the respondent if such basis of classification is not greater than 1000 Kw of demand. See Account 442 of the Uniform System of Accounts. Explain basis of classification.

Line No.	Account (a)	Operating Revenues: Amount for Year (b)	Operating Revenues: Increase or (Decrease) from Preceding Year (c)	Kilowatt-hours Sold: Amount for Year (d)	Kilowatt-hours Sold: Increase or (Decrease) from Preceding Year (e)	Average Number of Customers per Month: Number for Year (f)	Average Number of Customers per Month: Increase or (Decrease) from Preceding Year (g)
1	SALES OF ELECTRICITY	$	$				
2	440 Residential Sales	3,800,775.13	(158,463.14)	52,649,657	422,511	7121	126
3	442 Commercial and Industrial Sales:						
4	Small (or Commercial) see instr. 5	502,614.54	15,367.13	5,584,192	361,453	703	58
5	Large (or Industrial) see instr. 5	4,903,493.56	348,535.32	77,976,321	10,780,941	165	(5)
6	444 Municipal Sales (P. 22)	692,377.36	(14,452.57)	10,634,819	257,411	87	5
7	445 Other Sales to Public Authorities	None	None	None	None	None	None
8	446 Sales to Railroads and Railways	None	None	None	None	None	None
9	449 Fuel Charge Adjustment	(277,915.70)	23,942.80	None	None	None	None
10	449 Miscellaneous Electric Sales	46,384.87	(953.04)	464,491	7,109	133	3
11	Total Sales to Ultimate Consumers	9,667,729.76	213,976.50	147,309,480	11,829,425	8209	187
12	447 Sales for Resale	2,756.68	(107,437.46)	23,200	(1,001,699)	1	(1)
13	Total Sales of Electricity*	9,670,486.44	106,539.04	147,332,680	10,827,726	8210	186
14	OTHER OPERATING REVENUES						
15	450 Forfeited Discounts	None	None				
16	451 Miscellaneous Service Revenues	None	None				
17	453 Sales of Water and Water Power	None	None				
18	454 Rent from Electric Property	None	None				
19	455 Interdepartmental Rents	None	None				
20	456 Other Electric Revenues	56.22	(91.42)				
21	456-1 Other Elec. Revenues	27,118.56	6,734.66				
22	RCS						
23							
24							
25	Total Other Operating Revenues	27,174.78	6,643.24				
26	Total Electric Operating Revenues	9,697,661.22	113,182.28				

*Includes revenues from application of fuel clauses $ 4,949,967.54

Total KWH to which applied 146,159,197

SALES OF ELECTRICITY TO ULTIMATE CONSUMERS

Report by account, the K.W.H. sold, the amount derived and the number of customers under each filed schedule or contract. Contract sales and unbilled sales may be reported separately in total.

Line No.	Account No.	Schedule (a)	K.W.H. (b)	Revenue (c)	Average Revenue per K.W.H. (cents) (0.0000) (d)	Number of Customers (Per Bills Rendered) July 31, (e)	December 31, (f)
1	440	"A" Rate Domestic	39,668,895	$ 2,992,051.16	.075426	6511	6597
2	442	"C" Rate Commercial	5,458,796	494,583.66	.090603	734	717
3	442	"D" Rate Power	77,976,321	4,903,493.56	.062884	168	161
4	440	"F" Rate All Elec.	12,980,762	808,723.97	.062302	604	622
5	442	"G" Rate Com. Heat	125,396	8,030.88	.064044	3	3
6	444	Street Lighting	1,215,819	82,266.91	.067664	4	4
7	444	Municipal Sales	9,419,000	610,110.45	.064774	92	92
8	449	Yard Lighting	464,491	46,384.87	.099862	125	129
9	449	Fuel Charge Adj.		(277,915.70)			
10							
11							
12							
13							
14							
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48							
49		TOTAL SALES TO ULTIMATE CONSUMERS (Page 37 line 11)	147,309,480	9,667,729.76	.065629	8241	8325

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

1. Enter in the space provided the operation and maintenance expenses for the year.
2. If the increases and decreases are not derived from previously reported figures explain in footnote.

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	POWER PRODUCTION EXPENSES	$	$
2	STEAM POWER GENERATION		
3	Operation:		
4	500 Operation supervision and engineering		
5	501 Fuel		
6	502 Steam expenses		
7	503 Steam from other sources		
8	504 Steam transferred — Cr.		
9	505 Electric expenses		
10	506 Miscellaneous steam power expenses		
11	507 Rents		
12	Total operation	None	None
13	Maintenance:		
14	510 Maintenance supervision and engineering		
15	511 Maintenance of structures		
16	512 Maintenance of boiler plant		
17	513 Maintenance of electric plant		
18	514 Maintenance of miscellaneous steam plant		
19	Total maintenance	None	None
20	Total power production expenses — steam power	None	None
21	NUCLEAR POWER GENERATION		
22	Operation:		
23	517 Operation supervision and engineering		
24	518 Fuel		
25	519 Coolants and water		
26	520 Steam expenses		
27	521 Steam from other sources		
28	522 Steam transferred — Cr.		
29	523 Electric expenses		
30	524 Miscellaneous nuclear power expenses		
31	525 Rents		
32	Total operation	None	None
33	Maintenance:		
34	528 Maintenance supervision and engineering		
35	529 Maintenance of structures		
36	530 Maintenance of reactor plant equipment		
37	531 Maintenance of electric plant		
38	532 Maintenance of miscellaneous nuclear plant		
39	Total maintenance	None	None
40	Total power production expenses-nuclear power	None	None
41	HYDRAULIC POWER GENERATION		
42	Operation:		
43	535 Operation supervision and engineering		
44	536 Water for power		
45	537 Hydraulic expenses		
46	538 Electric expenses		
47	539 Miscellaneous hydraulic power generation expenses		
48	540 Rents		
49	Total operation	None	None

ELECTRIC OPERATION AND MAINTENANCE EXPENSES — Continued

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	HYDRAULIC POWER GENERATION — Continued	$	$
2	Maintenance:		
3	541 Maintenance supervision and engineering		
4	542 Maintenance of structures		
5	543 Maintenance of reservoirs, dams and waterways		
6	544 Maintenance of electric plant		
7	545 Maintenance of miscellaneous hydraulic plant		
8	Total maintenance	None	None
9	Total power production expenses — hydraulic power	None	None
10	OTHER POWER GENERATION		
11	Operation:		
12	546 Operation supervision and engineering	11,564.49	438.18
13	547 Fuel	1,067,855.17	59,460.41
14	548 Generation expenses	155,311.27	16,595.78
15	549 Miscellaneous other power generation expenses	35,893.80	1,090.52
16	550 Rents	None	None
17	Total operation	1,270,624.73	77,584.89
18	Maintenance:		
19	551 Maintenance supervision and engineering	11,575.98	671.47
20	552 Maintenance of structures	14,824.19	8,363.54
21	553 Maintenance of generating and electric plant	133,151.20	8,061.99
22	554 Maintenance of miscellaneous other power generation plant	3,349.93	614.99
23	Total maintenance	162,901.30	17,711.99
24	Total power production expenses — other power	1,433,526.03	95,296.88
25	OTHER POWER SUPPLY EXPENSES		
26	555 Purchased power	5,795,654.31	12,410.60
27	556 System control and load dispatching	16,936.45	(539.43)
28	557 Other expenses	118,008.90	77,512.26
29	Total other power supply expenses	5,930,599.66	89,383.43
30	Total power production expenses	7,364,125.69	184,680.31
31	TRANSMISSION EXPENSES		
32	Operation:		
33	560 Operation supervision and engineering	None	None
34	561 Load dispatching	None	None
35	562 Station expenses	273.65	(7.15)
36	563 Overhead line expenses	None	None
37	564 Underground line expenses	None	None
38	565 Transmission of electricity by others	194,074.96	1,820.42
39	566 Miscellaneous transmission expenses	None	None
40	567 Rents	None	None
41	Total operation	194,348.61	1,813.27
42	Maintenance:		
43	568 Maintenance supervision and engineering	None	None
44	569 Maintenance of structures	None	None
45	570 Maintenance of station equipment	166.06	141.08
46	571 Maintenance of overhead lines	224.00	(2,617.72)
47	572 Maintenance of underground lines	None	None
48	573 Maintenance of miscellaneous transmission plant	None	None
49	Total maintenance	390.06	(2,476.64)
50	Total transmission expenses	194,738.67	(663.37)

ELECTRIC OPERATION AND MAINTENANCE EXPENSES — Continued

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	DISTRIBUTION EXPENSES	$	$
2	Operation:		
3	580 Operation supervision and engineering	12,836.94	999.16
4	581 Load dispatching	None	None
5	582 Station expenses	None	None
6	583 Overhead line expenses	2,608.67	(66.53)
7	584 Underground line expenses	36.60	36.60
8	585 Street lighting and signal system expenses	5,071.63	(258.07)
9	586 Meter expenses	13,015.04	3,133.16
10	587 Customer installations expenses	9,384.33	(2,234.76)
11	588 Miscellaneous distribution expenses	3,894.37	413.96
12	589 Rents	None	None
13	Total operation	46,847.58	2,023.52
14	Maintenance:		
15	590 Maintenance supervision and engineering	12,758.60	920.82
16	591 Maintenance of structures	None	None
17	592 Maintenance of station equipment	None	None
18	593 Maintenance of overhead lines	118,703.90	16,645.07
19	594 Maintenance of underground lines	3,803.25	2,767.15
20	595 Maintenance of line transformers	3,358.86	3,192.54
21	596 Maintenance of street lighting and signal systems	6,267.06	(731.99)
22	597 Maintenance of meters	614.80	(2,424.80)
23	598 Maintenance of miscellaneous distribution plant	None	None
24	Total maintenance	145,506.47	20,368.79
25	Total distribution expenses	192,354.05	22,392.31
26	CUSTOMER ACCOUNTS EXPENSES		
27	Operation:		
28	901 Supervision	5,642.57	59.02
29	902 Meter reading expenses	27,713.21	4,869.52
30	903 Customer records and collection expenses	86,405.13	16,870.69
31	904 Uncollectible accounts	11,532.04	(24,875.02)
32	905 Miscellaneous customer accounts expenses	None	None
33	Total customer accounts expenses	131,292.95	(3,075.79)
34	SALES EXPENSES		
35	Operation:		
36	911 Supervision	None	None
37	912 Demonstrating and selling expenses	None	None
38	913 Advertising expenses	45.00	(20.00)
39	916 Miscellaneous sales expenses	22,466.19	(10,397.21)
40	Total sales expenses	22,511.19	(10,417.21)
41	ADMINISTRATIVE AND GENERAL EXPENSES		
42	Operation:		
43	920 Administrative and general salaries	115,572.78	16,628.88
44	921 Office supplies and expenses	9,515.17	1,149.73
45	922 Administrative expenses transferred — Cr.	None	None
46	923 Outside services employed	12,167.72	2,159.89
47	924 Property insurance	18,836.20	6,665.43
48	925 Injuries and damages	42,511.01	2,848.00
49	926 Employee pensions and benefits	386,813.78	(6,277.40)
50	928 Regulatory commission expenses	9,329.89	395.14
51	933 Transportation Expense	31,438.44	4,285.31
52	930 Miscellaneous general expenses	17,859.69	7,638.71
53	931 Rents	None	None
54	Total operation	644,044.68	35,493.69

ELECTRIC OPERATION AND MAINTENANCE EXPENSES — Continued

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	ADMINISTRATIVE AND GENERAL EXPENSES — Cont.	$	$
2	Maintenance:		
3	932 Maintenance of general plant	33,544.89	5,620.73
4	Total administrative and general expenses	677,589.57	41,122.42
5	Total Electric Operation and Maintenance Expenses	8,582,612.12	234,030.67

SUMMARY OF ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Functional Classification (a)	Operation (b)	Maintenance (c)	Total (d)
6	Power Production Expenses	$	$	$
7	Electric Generation:			
8	Steam power			
9	Nuclear power			
10	Hydraulic power			
11	Other power	1,270,624.73	162,901.30	1,433,526.03
12	Other power supply expenses	5,930,599.66	.00	5,930,599.66
13	Total power production expenses	7,201,224.39	162,901.30	7,364,125.69
14	Transmission Expenses	104,348.61	390.06	104,738.67
15	Distribution Expenses	46,847.58	145,506.47	192,354.05
16	Customer Accounts Expenses	131,292.95	.00	131,292.95
17	Sales Expenses	22,511.19	.00	22,511.19
18	Administrative and General Expenses	644,044.68	33,544.89	677,589.57
19-20	Total Electric Operation and Maintenance Expenses	8,240,269.40	342,342.72	8,582,612.12

21 Ratio of operating expenses to operating revenues (carry out decimal two places, e.g.: 0.00%) Compute by dividing Revenues (Acct. 400) into the sum of Operation and Maintenance Expenses (Page 42, line 20), Depreciation (Acct. 403) and Amortization (Acct. 407) 93.92%

22 Total salaries and wages of electric department for year, including amounts charged to operating expenses, construction and other accounts .... $ 737,991.70

23 Total number of employees of electric department at end of year including administrative, operating, maintenance, construction and other employees (including part time employees) 33

TAXES CHARGED DURING YEAR

1. This schedule is intended to give the account distribution of total taxes charged to operations and other final accounts during the year.
2. Do not include gasoline and other sales taxes which have been charged to accounts to which the material on which the tax was levied was charged. If the actual or estimated amounts of such taxes are known, they should be shown as a footnote and designated whether estimated or actual amounts.
3. The aggregate of each kind of tax should be listed under the appropriate heading of "Federal," "State," and "Local" in such manner that the total tax for each State and for all subdivisions can readily be ascertained.
4. The accounts to which the taxes charged were distributed should be shown in columns (c) to (h). Show both the utility department and number of account charged. For taxes charged to utility plant show the number of the appropriate balance sheet plant account or subaccount.
5. For any tax which it was necessary to apportion to more than one utility department or account, state in a footnote the basis of apportioning such tax.
6. Do not include in this schedule entries with respect to deferred income taxes, or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.

Line No.	Kind of Tax (a)	Total Taxes Charged During Year (omit cents) (b)	Distribution of Taxes Charged (omit cents) (Show utility department where applicable and account charged)							
			Electric (Acct. 408, 409) (c)	Gas (Acct. 408, 409) (d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Real Estate Tax	4808.11	4808.11							
2										
3										
4										
5										
6										
7										
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9										
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11										
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13										
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19										
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21										
22										
23										
24										
25										
26										
27										
28	TOTALS	4808.11	4808.11							

OTHER UTILITY OPERATING INCOME (Account 414)

Report below the particulars called for in each column.

Line No.	Property (a)	Amount of Investment (b)	Amount of Revenue (c)	Amount of Operating Expenses (d)	Gain or (Loss) from Operation (e)
		NONE			
51	TOTALS				

Annual report of TOWN OF HUDSON LIGHT AND POWER DEPARTMENT Year ended December 31, 1982

INCOME FROM MERCHANDISING, JOBBING, AND CONTRACT WORK (Account 415)

Report by utility departments the revenues, costs, expenses, and net income from merchandising, jobbing, and contract work during year.

Line No.	Item (a)	Electric Department (b)	Gas Department (c)	Other Utility Department (d)	Total (e)
1	Revenues:	$	$	$	$
2	Merchandise sales, less discounts,				
3	allowances and returns				
4	Contract work	958.79			958.79
5	Commissions				
6	Other (list according to major classes)				
7					
8					
9					
10	Total Revenues	958.79	None	None	958.79
11					
12					
13	Costs and Expenses:				
14	Cost of sales (list according to major				
15	classes of cost)				
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26	Sales expenses				
27	Customer accounts expenses				
28	Administrative and general expenses				
29					
30					
31					
32					
33					
34					
35					
36					
37					
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39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
50	TOTAL COSTS AND EXPENSES	None	None	None	None
51	Net Profit (or Loss)	958.79	None	None	958.79

SALES FOR RESALE (Account 447)

1. Report sales during year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) R.E.A. Cooperatives, and (5) Other Public Authorities. For each sale designate statistical classification in column (b), thus: firm power, FP; dump or surplus power, DP; other, G, and place an "x" in column (c) if sale involves export across a state line.

3. Report separately firm, dump, and other power sold to the same utility. Describe the nature of any sales classified as Other Power, column (b).

4. If delivery is made at a substation indicate ownership in column (e), thus: respondent owned or leased, RS; customer owned or leased, CS.

Line No.	Sales to (a)	Statistical Classification (b)	Export Across State Lines (c)	Point of Delivery (d)	Substation (e)	Kw or Kva of Demand (Specify Which) Contract Demand (f)	Average Monthly Maximum Demand (g)	Annual Maximum Demand (h)
1	MMWEC	G		Marlboro-Hudson		2000	NA	NA
2				Town Line				
3								
4								
5								
6								
7								
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SALES FOR RESALE (Account 447) — Continued

5. If a fixed number of kilowatts of maximum demand is specified in the power contract as a basis of billings to the customer this number should be shown in column (f). The number of kilowatts of maximum demand to be shown in column (g) and (h) should be actual based on monthly readings and should be furnished whether or not used in the determination of demand charges. Show in column (i) type of demand reading (instantaneous, 15, 30, or 60 minutes integrated).

6. The number of kilowatt-hours sold should be the quantities shown by the bills rendered to the purchasers.

7. Explain any amounts entered in column (n) such as fuel or other adjustments.

8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (i)	Voltage at Which Delivered (j)	Kilowatt-hours (k)	Revenue (Omit Cents) Demand Charges (l)	Energy (m)	Other Charges (n)	Total (o)	Revenue per kwh (Cents) (0.0000) (p)	Line No.
60 min.	115 KVA	23,200	1,507	1,250	None	2,757	11.8336	1
								2
								3
								4
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								39
								40
								41
	TOTALS		1,507	1,250	None	2,757	11.8336	42

PURCHASED POWER (Account 555)

(except interchange power)

1. Report power purchased for resale during the year. Exclude from this schedule and report on page 56 particulars concerning interchange power transactions during the year.
2. Provide subheadings and classify purchases as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Associated Nonutilities, (4) Other Nonutilities, (5) Municipalities, (6) R.E.A. Cooperatives, and (7) Other Public Authorities. For each purchase designate statistical classification in column (b), thus: firm power, FP; dump or surplus power, DP; other, O, and place an "x" in column (c) if purchase involves import across a state line.
3. Report separately firm, dump, and other power purchased from the same company. Describe the nature of any purchases classified as Other Power, column (b).

Line No.	Purchased From (a)	Statistical Classification (b)	Import Across State Lines (c)	Point of Receipt (d)	Substation (e)	Kw or Kva of Demand (Specify Which) Contract Demand (f)	Average Monthly Maximum Demand (g)	Annual Maximum Demand (h)
1	NEPCO	O	X	Marlboro-Hudson		16,000	NA	NA
2	Pilgrim	O		Line		2,500	NA	NA
3	Vermont Yankee	O	X	"		587	NA	NA
4	Maine Yankee	O	X	"		1,234	NA	NA
5	Wyman-Yarmouth	O	X	"		2,090	NA	NA
6	NEPCO-Brayton Point	O		"		2,000	NA	NA
7	MMWEC- B.P./S.H.	O		"		4,000	NA	NA
8								
9								
10								
11								
12								
13								
14								
15				POWER USED AT POWER PLANT AND				
16								
17								
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PURCHASED POWER (Account 555) — Continued

(except interchange power)

4. If receipt of power is at a substation indicate ownership in column (e), thus: respondent owned or leased, RS; seller owned or leased, SS.

5. If a fixed number of kilowatts of maximum demand is specified in the power contract as a basis of billing, this number should be shown in column (f). The number of kilowatts of maximum demand to be shown in columns (g) and (h) should be actual based on monthly readings and should be furnished whether or not used in the determination of demand charges. Show in column (i) type of demand reading (instantaneous, 15, 30, or 60 minutes integrated).

6. The number of kilowatt hours purchased should be the quantities shown by the power bills.

7. Explain any amount entered in column (n) such as fuel or other adjustments.

Type of Demand Reading (i)	Voltage at Which Delivered (j)	Kilowatt-hours (k)	Cost of Energy (Omit Cents) Charges (l)	Energy Charges (m)	Other Charges (n)	Total (o)	Cost per KWH (Cents) (0.0000) (p)	Line No.
NA	115 KV	91,680,780	965,008	2,367,537	90,502	3,423,047	3.7336	1
NA	115 KV	12,265,256	491,977	59,459		551,436	4.4959	2
NA	115 KV	4,641,771	82,755	35,278		118,033	2.5428	3
NA	115 KV	6,707,148	111,189	49,665	2,716	163,570	2.4387	4
NA	115 KV	3,843,599	99,436	207,385		306,821	7.9826	5
NA	115 KV	1,911,081	14,668	80,899		95,557	5.0000	6
NA	115 KV	978,795	5,123	40,146		45,269	4.6250	7
								8
								9
								10
								11
								12
								13
								14
CHARGED TO	549	(480,992)	—			(17,564)		15
								16
								17
								18
								19
								20
								21
								22
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								40
								41
	TOTALS	121,547,438	1,770,156	2,840,359	93,218	4,686,169	3.8554	42

INTERCHANGE POWER (Included in Account 555)

1. Report below the kilowatt-hours received and delivered during the year and the net charge or credit under interchange power agreements.

2. Provide subheadings and classify interchanges as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Associated Nonutilities, (4) Other Nonutilities, (5) Municipalities, (6) R.E.A. Cooperatives, and (7) Other Public Authorities. For each interchange across a state line place an "x" in column (b).

3. Particulars of settlements for interchange power shall be furnished in Part B, Details of Settlement for Interchange Power. If settlement for any transaction also includes credit or debit amounts other than for increment generation expenses, show such other component amounts separately, in addition to debit or credit for increment generation expenses, and give a brief explanation of the factors and principles under which such other component amounts were determined. If such settlement represents the net of debits and credits under an interconnection, power pooling, coordination, or other such arrangement, submit a copy of the annual summary of transactions and billings among the parties to the agreement. If the amount of settlement reported in this schedule for any transaction does not represent all of the charges and credits covered by the agreement, furnish in a footnote a description of the other debits and credits and state the amounts and accounts in which such other amounts are included for the year.

A. Summary of Interchange According to Companies and Points of Interchange

Line No.	Name of Company (a)	Interchange Across State Lines (b)	Point of Interchange (c)	Voltage at Which Interchanged (d)	Kilowatt-hours: Received (e)	Kilowatt-hours: Delivered (f)	Kilowatt-hours: Net Difference (g)	Amount of Settlement (h)
1	NEPEX	X	Marlboro-Hudson Line	115KV	26,278,700	6,490,250	19,788,450	1,115,734.57
2	Used as Station Power and Charged to (549)				(109,080)		(109,080)	(6,248.93)
3								
4								
5								
6								
7								
8								
9								
10								
11								
12				TOTALS	26,169,620	6,490,250	19,679,370	1,109,485.64

B. Details of Settlement for Interchange Power

Line No.	Name of Company (i)	Explanation (j)	Amount (k)
13	NEPEX	Energy Received by H.L. & P. - Economy	1,343,121.71
14		- Scheduled Outage	106,417.85
15		- Unscheduled Outage	5,299.76
16		- Deficiency	34.18
17		Energy Delivered by H.L. & P.	(183,995.24)
18		NEPEX Savings	(172,256.39)
19		NEPEX Expenses	10,112.70
20			
21		TOTAL	1,115,734.57

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, and interchanged during the year.

Line No.	Item (a)		Kilowatt-hours (b)
1	SOURCES OF ENERGY		
2	Generation (excluding station use):		
3	Steam		
4	Nuclear		
5	Hydro		
6	Other		21,882,632
7	Total generation		21,882,632
8	Purchases		121,547,438
9	Interchanges — In (gross)	26,169,620	....
10	Interchanges — Out (gross)	6,490,250	....
11	Interchanges — Net (kwh)		19,679,370
12	Transmission for/by others (wheeling) — Received		....
13	Transmission for/by others (wheeling) — Delivered		....
14	Transmission for/by others (wheeling) — Net (kwh)		
15	TOTAL		163,109,440
16	DISPOSITION OF ENERGY		
17	Sales to ultimate consumers (including interdepartmental sales)		147,309,430
18	Sales for resale		23,200
19	Energy furnished without charge		None
20	Energy used by the company (excluding station use):		260,256
21	Electric department only		
22	Energy losses:		
23	Transmission and conversion losses	4,828,080	
24	Distribution losses	6,193,824	
25	Unaccounted for losses	4,494,600	
26	Total energy losses		15,516,504
27	Energy losses as percent of total on line 15 ....9.5129.... %		
28		TOTAL	163,109,440

MONTHLY PEAKS AND OUTPUT

1. Report hereunder the information called for pertaining to simultaneous peaks established monthly (in kilowatts) and monthly output (in kilowatt-hours) for the combined sources of electric energy of respondent.
2. Monthly peak col. (b) should be respondent's maximum kw load as measured by the sum of its coincidental net generation and purchases plus or minus net interchange, minus temporary deliveries (not interchange) of emergency power to another system. Monthly peak including such emergency deliveries should be shown in a footnote with a brief explanation as to the nature of the emergency.
3. State type of monthly peak reading (instantaneous 15, 30, or 60 minutes integrated.)
4. Monthly output should be the sum of respondent's net generation and purchases plus or minus net interchange and plus or minus net transmission or wheeling. Total for the year should agree with line 15 above.
5. If the respondent has two or more power systems not physically connected, the information called for below should be furnished for each system.

________________ System

Line No.	Month (a)	Monthly Peak: Kilowatts (b)	Day of Week (c)	Day of Month (d)	Hour (e)	Type of Reading (f)	Monthly Output (kwh) (See Instr. 4) (g)
29	January	29,300	Tues/Mon.	12/18	9:00/11:00am	60 min	15,886,318
30	February	26,800	Thursday	11	9:00 am	60 min	13,486,157
31	March	27,200	Thursday	4	8:00 am	60 min	14,497,072
32	April	26,300	Monday	5	11:00am	60 min	12,854,325
33	May	23,400	Thursday	27	3:00 pm	60 min	12,186,487
34	June	24,400	Tuesday	29	1:00 pm	60 min	12,465,524
35	July	30,000	Monday	19	2:00 pm	60 min	13,601,669
36	August	25,500	Tuesday	10	2:00 pm	60 min	13,347,358
37	September	24,400	Wednesday	15	2:00 pm	60 min	12,706,566
38	October	26,100	Monday	25	10:00am	60 min	13,127,711
39	November	26,500	Monday	29	9:00 am	60 min	13,598,227
40	December	29,600	Tuesday	14	9:00 am	60 min	15,352,026
41						TOTAL	163,109,440

Annual report of TOWN OF HUDSON LIGHT AND POWER DEPARTMENT Year ended December 31, 1982

GENERATING STATION STATISTICS (Large Stations)

(Except Nuclear, See Instruction 10)

1. Large stations for the purpose of this schedule are steam and hydro stations of 2,500 Kw* or more of installed capacity and other stations of 500 Kw* or more of installed capacity (name plate ratings). (*10,000 Kw and 2,500 Kw, respectively, if annual electric operating revenues of respondent are $25,000,000 or more.)

2. If any plant is leased, operated under a license from the Federal Power Commission, or operated as a joint facility, indicate such facts by the use of asterisks and footnotes.

3. Specify if total plant capacity is reported in kva instead of kilowatts as called for on line 5.

4. If peak demand for 60 minutes is not available, give that which is available, specifying period.

5. If a group of employees attends more than one generating station, report on line 11 the approximate average number of employees assignable to each station.

6. If gas is used and purchased on a therm basis, the B.t.u. content of the gas should be given and the quantity of fuel consumed converted to M cu. ft.

7. Quantities of fuel consumed and the average cost per unit of fuel consumed should be consistent with charges to expense accounts 501 and

Line No.	Item (a)	Plant (b) Cherry St. Sta.	Plant (c) H.L&P. Peaking	Plant (d)
1	Kind of plant (steam, hydro, int. comb., gas turbine)	Int. Comb.	Int. Comb.	
2	Type of plant construction (conventional, outdoor boiler, full outdoor, etc.)	Conventional	Conventional	
3	Year originally constructed	1897	1962	
4	Year last unit was installed	1972	1962	
5	Total installed capacity (maximum generator name plate ratings in kw)	17150*	4,400	
6	Net peak demand on plant-kilowatts (60 min.)	14,000	4,200	
7	Plant hours connected to load	2,569	1,594	
8	Net continuous plant capability, kilowatts:			
9	(a) When not limited by condenser water	15,200	4,400	
10	(b) When limited by condenser water	15,200	4,400	
11	Average number of employees	12		
12	Net generation, exclusive of station use	17,636,150	4,246,482	
13	Cost of plant (omit cents):			
14	Land and land rights	5,500	None	
15	Structures and improvements	332,640	None	
16	Reservoirs, dams, and waterways	None	None	
17	Equipment costs	3,016,955	712,054	
18	Roads, railroads, and bridges	None	None	
19	Total cost	3,355,095*	712,054	
20	Cost per kw of installed capacity	$207	$162	
21	Production expenses: Total Combined Plants			
22	Operation supervision and engineering	11,564.49		
23	Station labor	124,605.47		
24	Fuel	1,067,855.17		
25	Supplies and expenses, including water	66,599.60		
26	Maintenance	162,901.30		
27	Rents	None		
28	Steam from other sources	None		
29	Steam transferred—Credit	None		
30	Total production expenses	1,433,526.03		
31	Expenses per net Kwh (5 places)	.0655097		
32	Fuel: Kind	#2 Diesel	Natural Gas	
33	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-M cu. ft.) (Nuclear, indicate)	42 Gal.	M Cu. Ft.	
34	Quantity (units) of fuel consumed	6641	195,865	
35	Average heat content of fuel (B.t.u. per lb. of coal, per gal. of oil, or per cu. ft. of gas)	140,000 BTU	910 BTU	
36	Average cost of fuel per unit, del. f.o.b. plant	$39.8989 BBL	$4.43168 MCF	
37	Average cost of fuel per unit consumed	$30.0924 BBL	$4.43168 MCF	
38	Average cost of fuel consumed per million B.t.u.	$5.11782	$4.86998	
39	Average cost of fuel consumed per kwh net gen.	.048799		
40	Average B.t.u. per kwh net generation	9930		
41				
42				

*Limited to 16,200 by Diesel

GENERATING STATION STATISTICS (Large Stations) — Continued
(Except Nuclear, See Instruction 10)

547 as shown on line 24.

8. The items under cost of plant and production expenses represents accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production expenses, however, do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

9. If any plant is equipped with combinations of steam, hydro, internal combustion engine or gas turbine equipment, each should be reported as a separate plant. However, if a gas turbine unit functions in a combined operation with a conventional steam unit, the gas turbine should be included with the steam station.

10. If the respondent operates a nuclear power generating station submit: (a) a brief explanatory statement concerning accounting for the cost of power generated including any attribution of excess costs to research and development expenses; (b) a brief explanation of the fuel accounting specifying the accounting methods and types of cost units used with respect to the various components of the fuel cost, and (c) such additional information as may be informative concerning the type of plant, kind of fuel used, and other physical and operating characteristics of the plant.

Plant (e)	Plant (f)	Plant (g)	Plant (h)	Plant (i)	Plant (j)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

STEAM GENERATING STATIONS

1. Report the information called for concerning generating stations and equipment at end of year.
2. Exclude from this schedule, plant, the book cost of which is included in Account 121, Nonutility Property.
3. Designate any generating station or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any generating station, other than a leased station or portion thereof for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars as to such matters as percent ownership by respondent, name of co-owner, basis of sharing output,

			Boilers					
Line No.	Name of Station (a)	Location of Station (b)	Number and Year Installed (c)	Kind of Fuel and Method of Firing (d)	Rated Pressure in lbs. (e)	Rated Steam Temperature* (f)	Rated Max. Continuous M lbs. Steam per Hour (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16			NOT APPLICABLE				
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							

Note reference:

*Indicate reheat boilers thusly, 1050/1000.

STEAM GENERATING STATIONS — Continued

expenses or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

4. Designate any generating station or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent and how determined. Specify whether lessee is an associated company.

5. Designate any plant or equipment owned, not operated, and not leased to another company. If such plant or equipment was not operated within the past year explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Turbine-Generators*

Year Installed (h)	Type† (i)	Steam Pressure at Throttle p.s.i.g. (j)	R.P.M. (k)	Name Plate Rating in Kilowatts: At Minimum Hydrogen Pressure (l)	Name Plate Rating in Kilowatts: At Maximum Hydrogen Pressure (m)	Hydrogen Pressure‡ Min. (n)	Hydrogen Pressure‡ Max. (o)	Power Factor (p)	Voltage K.v.†† (q)	Station Capacity Maximum Name Plate Rating‡‡ (r)	Line No.
											1
											2
											3
											4
											5
											6
											7
											8
											9
											10
											11
				NOT APPLICABLE							12
											13
											14
											15
											16
											17
											18
											19
											20
											21
											22
											23
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											25
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											30
											31
											32
											33
											34
											35
											36
				TOTALS							37

Note references:

*Report cross-compound turbine-generator units ~~on~~ two lines — H.P. section and L.P. section.

†Indicate tandem-compound (T.C.); cross-compound (C.C.); all single casing (S.C.); topping unit (T), and noncondensing (N.C.). Show back pressures.

‡Designate air cooled generators.

††If other than 3 phase, 60 cycle, indicate other characteristic.

‡‡Should agree with column (m).

Annual report of TOWN OF HUDSON LIGHT AND POWER DEPARTMENT Year ended December 31, 1982

HYDROELECTRIC GENERATING STATIONS

1. Report the information called for concerning generating stations and equipment at end of year. Show associated prime movers and generators on the same line.
2. Exclude from this schedule, plant, the book cost of which is included in Account 121, Nonutility Property.
3. Designate any generating station or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any generating station, other than a leased station, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars as to such matters as

Line No.	Name of Station (a)	Location (b)	Name of Stream (c)	Water Wheels: Attended or Unattended (d)	Type of Unit* (e)	Year Installed (f)	Gross Static Head with Pond Full (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16			NOT APPLICABLE				
17							
18							
19							
20							
21							
22							
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39							

*Horizontal or vertical. Also indicate type of runner — Francis (F), fixed propeller (FP), automatically adjustable propeller (AP), Impulse (I).

HYDROELECTRIC GENERATING STATIONS — Continued

percent of ownership by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

4. Designate any generating station or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent and how determined. Specify whether lessee is an associated company.

5. Designate any plant or equipment owned, not operated and not leased to another company. If such plant or equipment was not operated within the past year explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Water Wheels — Continued			Generators						Total Installed Generating Capacity in Kilowatts (name plate ratings) (q)	Line No.
Design Head (h)	R.P.M. (i)	Maximum hp. Capacity of Unit at Design Head (j)	Year Installed (k)	Voltage (l)	Phase (m)	Frequency or d.c. (n)	Name Plate Rating of Unit in Kilowatts (o)	Number of Units in Station (p)		
										1
										2
										3
										4
										5
										6
										7
										8
										9
										10
										11
										12
										13
			NOT APPLICABLE							14
										15
										16
										17
										18
										19
										20
										21
										22
										23
										24
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										29
										30
										31
										32
										33
										34
										35
										36
										37
										38
						TOTALS				39

COMBUSTION ENGINE AND OTHER GENERATING STATIONS

(except nuclear stations)

1. Report the information called for concerning generating stations and equipment at end of year. Show associated prime movers and generators on the same line.
2. Exclude from this schedule, plant, the book cost of which is included in Account 121, Nonutility Property.
3. Designate any generating station or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any generating station, other than a leased station, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars as to such matters as percent owner-

Line No.	Name of Station (a)	Location of Station (b)	Prime Movers: Diesel or Other Type Engine (c)	Prime Movers: Name of Maker (d)	Prime Movers: Year Installed (e)	Prime Movers: 2 or 4 Cycle (f)	Prime Movers: Belted or Direct Connected (g)
1	Cherry St.	Cherry St. Hudson	Diesel	American Loco.	1937	2	Direct
2	Cherry St.	Cherry St. Hudson	Diesel	Nordberg-Mfg.Co.	1951	2	Direct
3	Cherry St.	Cherry St. Hudson	Diesel	Nordberg-Mfg.Co.	1955	2	Direct
4	Cherry St.	Cherry St. Hudson	Diesel	Nordberg-Mfg.Co.	1960	2	Direct
5	Cherry St.	Cherry St. Hudson	Diesel	Cooper-Bessemer	1972	4	Direct
6							
7							
8							
9	Hudson Light						
10	Peaking Plt.	Cherry St. Hudson	Diesel	Fairbanks-Morse	1962	2	Direct
11	Hudson Light						
12	Peaking Plt.	Cherry St. Hudson	Diesel	Fairbanks-Morse	1962	2	Direct
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
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34							
35							
36							
37							
38							
39							

COMBUSTION ENGINE AND OTHER GENERATING STATIONS — Continued

(except nuclear stations)

ship by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

4. Designate any generating station or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent and how determined. Specify whether lessee is an associated company.

5. Designate any plant or equipment owned, not operated and not leased to another company. If such plant or equipment was not operated within the past year, explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Prime Movers — Continued		Generators						Total Installed Generating Capacity in Kilowatts (name plate ratings) (p)	Line No.
Rated hp. of Unit (h)	Total Rated hp. of Station Prime Movers (i)	Year Installed (j)	Voltage (k)	Phase (l)	Frequency or d.c. (m)	Name Plate Rating of Unit in Kilowatts (n)	Number of Units in Station (o)		
1480	1480	1937	2300	3∅	60 cyl	1000	1	1000	1
4250	5730	1951	4160	3∅	60 cyl	3300	1	3000	2
5100	10830	1955	4160	3∅	60 cyl	4000	1	3600	3
4250	15080	1943	4160	3∅	60 cyl	3250	1	3000	4
7760	22840	1972	4160	3∅	60 cyl	5600	1	5600	5
									6
									7
									8
									9
3168	3168	1962	4160	3∅	60 cyl	2200	1	2200	10
									11
3168	6336	1962	4160	3∅	60 cyl	2200	1	2200	12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
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									34
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									36
									37
									38
						TOTALS 21,550	7	20,600	39

GENERATING STATION STATISTICS (Small Stations)

1. Small generating stations, for the purpose of this schedule, are steam and hydro stations of less than 2,500 KW* and other stations of less than 500 KW* installed capacity (name plate ratings). (*10,000 KW and 2,500 KW, respectively, if annual electric operating revenues of respondent are $25,000,000 or more.)

2. Designate any plant leased from others, operated under a license from the Federal Power Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote.

3. List plants appropriately under subheadings for steam, hydro, nuclear internal combustion engine and gas turbine stations. For nuclear, see instruction 10 page 59.

4. Specify, if total plant capacity is reported in kva instead of kilowatts.

5. If peak demand for 60 minutes is not available, give that which is available, specifying period.

6. If any plant is equipped with combinations of steam, hydro, internal combustion engine or gas turbine equipment, each should be reported as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, report as one plant.

Line No.	Name of Plant (a)	Year Const. (b)	Installed Capacity Name Plate Rating-KW (c)	Peak Demand KW (60 Min.) (d)	Net Generation Excluding Station Use (e)	Cost of Plant (Omit Cents) (f)	Plant Cost Per KW Inst. Capacity (g)	Production Expenses Exclusive of Depreciation and Taxes (Omit Cents)			Kind of Fuel (k)	Fuel Cost Per KWH Net Generation (Cents) (0.0000) (l)
								Labor (h)	Fuel (i)	Other (j)		
1												
2												
3												
4												
5												
6												
7												
8					NOT APPLICABLE							
9												
10												
11												
12												
13												
14												
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16												
17												
18												
19												
20												
21												
22												
23												
24												
25												
26												
27												
28	TOTALS											

TRANSMISSION LINE STATISTICS

Report information concerning transmission lines as indicated below.

Line No.	Designation From (a)	Designation To (b)	Operating Voltage (c)	Type of Supporting Structure (d)	Length (Pole Miles) On Structures of Line Designated (e)	Length (Pole Miles) On Structures of Another Line (f)	Number of Circuits (g)	Size of Conductor and Material (h)
1	Marl-Hudson	Forest Ave.						
2	Town Line	Substation	115KV	Steel	3.2		2	336.4 MCM
3	at River St.	Hudson		Poles				ACSR
4								"Linnet"
47				TOTALS	3.2	None	2	

*Where other than 60 cycle, 3 phase, so indicate.

OVERHEAD DISTRIBUTION LINES OPERATED

Line No.		Length (Pole Miles)		
		Wood Poles	Steel Towers	Total
1	Miles — Beginning of Year	175.2		175.2
2	Added During Year	.4		.4
3	Retired During Year	None		None
4	Miles — End of Year	175.6		175.6

5
6
7
8 Distribution System Characteristics — A.C. or D.C., phase, cycles and operating voltages for Light and Power.
9 Primary distribution at 2400/4160Y, 4800/8300Y, 8000/13800Y volts, 60 cycle,
10 3 phase secondary power at 600 volts, 60 cycle, 3 phase 3 wire; 480 volts
11 3 phase, 3 wire; 277/480 volts, 3 phase 4 wire; 220 volts, 3 phase 3 or 4 wire;
12 120/208 volts, 3 phase, 4 wire, lighting, heating and air conditioning
13 120/240 volts, 120/208 volts, 60 cycle single or three phase.
14
15

ELECTRIC DISTRIBUTION SERVICES, METERS AND LINE TRANSFORMERS

Line No.	Item	Electric Services	Number of Watt-hour Meters	Line Transformers	
				Number	Total Capacity (kva)
16	Number at beginning of year	6822	8579	2810	67,120.5
17	Additions during year:				
18	Purchased	....	394	39	1,500.0
19	Installed	167	....	....	....
20	Associated with utility plant acquired	None	None	None	None
21	Total additions	167	394	39	1,500.0
22	Reductions during year:				
23	Retirements	29	64	None	None
24	Associated with utility plant sold	None	None	None	None
25	Total reductions	29	64	None	None
26	Number at End of Year	6960	8909	2849	68,620.5
27	In stock		663	437	10,222.5
28	Locked meters on customers' premises		None	None	None
29	Inactive transformers on system		None	None	None
30	In customers' use		8221	2404	58,264.0
31	In company's use		25	8	134.0
32	Number at End of Year		8909	2849	68,620.5

CONDUIT, UNDERGROUND CABLE AND SUBMARINE CABLE — (Distribution System)

Report below the information called for concerning conduit, underground cable, and submarine cable at end of year.

Line No.	Designation of Underground Distribution System (a)	Miles of Conduit Bank (All Sizes and Types) (b)	Underground Cable		Submarine Cable	
			Miles* (c)	Operating Voltage (d)	Feet* (e)	Operating Voltage (f)
1	Route 495 Underpass	.1	.1	13,800		
2	Harvard Acres Estates, tow	6.5	6.5	13,800		
3	Meadowbrook Mobile Home Park, Hudson	1.8	1.9	13,800		
4	Colburn & Margaret Circle, Hudson	.0	.2	4,800		
5	Main, Felton, Central St. Hudson	.7	.7	13,800		
6	Seven Star Lane, Stow, MA	.0	.09	4,800		
7	Forest Avenue, Hudson, MA	1.5	1.5	13,800		
8	Juniper Estates, Stow, MA	.5	.5	13,800		
9	Carriage Lane, Stow, MA	.0	.14	4,800		
10	Brigham Circle, Hudson, MA	.9	.9	13,800		
11	Rustic Lane, Hudson, MA	.0	.2	4,800		
12	Wildwood Subdivision, Stow, MA	.0	.6	13,800		
13	Birch Hill Estates, Stow, MA	1.8	1.8	13,800		
14	Appleton Drive, Hudson, MA	.1	.1	13,800		
15	Cedar Street, Hudson, MA	.03	.03	4,800		
16	Country Estates, Hudson, MA	.0	.34	4,800		
17	Deacon Benham Drive, Stow, MA	.0	.07	8,320		
18	Forest Road, Stow, MA	.0	.22	8,320		
19	Francis Circle, Stow, MA	.0	.1	4,800		
20	Karen Circle, Hudson, MA	.0	.07	8,320		
21	Main Street, Hudson, MA (Whispering Pines)	.11	.11	13,800		
22	Glen Road, Hudson, MA	.24	.24	13,800		
23	Brigham Street (Valley Park) Hudson, MA	.12	.12	13,800		
24	Brigham Street (Assabet Village) Hudson, MA	.04	.04	13,800		
25	Chapin Road, Hudson, MA	.07	.07	13,800		
26	Great Road, Stow, MA	.07	.07			
27						
28						
29						
30						
31						
32						
33						
34	TOTALS	14.53	16.71		None	

*Indicate number of conductors per cable.

STREET LAMPS CONNECTED TO SYSTEM

Line No.	City or Town (a)	Total (b)	Type: Incandescent Municipal (c)	Incandescent Other (d)	Mercury Vapor Municipal (e)	Mercury Vapor Other (f)	Fluorescent Municipal (g)	Fluorescent Other (h)	Municipal (i)	Other (j)
1	Hudson	1622	397	19	890	297	None	None	13	6
2	Stow	176	104	3	17	52	None	None	None	None
3	Berlin	1	1	None	None	None	None	None	None	None
4	Bolton	3	2	None	None	1	None	None	None	None
5	Marlboro	1	None	None	None	1	None	None	None	None
	TOTALS	1803	504	22	907	351	None	None	13	6

RATE SCHEDULE INFORMATION

1. Attach copies of all Filed Rates for General Consumers.
2. Show below the changes in rate schedules during year and the estimated increase or decrease in annual revenue predicated on the previous year's operations.

Date Effective	M.D.P.U. Number	Rate Schedule	Estimated Effect on Annual Revenues	
			Increases	Decreases
		NONE		

THIS RETURN IS SIGNED UNDER THE PENALTIES OF PERJURY

Mayor

Horst Huehmer Manager of Electric Light

[illegible]

Robert F. Wood

Roland L. Plante

Selectmen or Members of the Municipal Light Board

SIGNATURES OF ABOVE PARTIES AFFIXED OUTSIDE THE COMMONWEALTH OF MASSACHUSETTS MUST BE PROPERLY SWORN TO

ss. 19

Then personally appeared

and severally made oath to the truth of the foregoing statement by them subscribed according to their best knowledge and belief.

Notary Public or Justice of the Peace

INDEX

EXTRACTS FROM CHAPTER 164 OF THE GENERAL LAWS AS AMENDED

SECTION 56. The Mayor of a city, or the selectmen or municipal light board, if any, of a town acquiring a gas or electric plant hall appoint a manager of municipal lighting who shall, under the direction and control of the mayor, selectmen or municipal light oard, if any, and subject to this chapter, have full charge of the operation and management of the plant, the manufacture and istribution of gas or electricity, the purchase of supplies, the employment of agents and servants, the method, time, price, quantity nd quality of the supply, the collection of bills, and the keeping of accounts. His compensation and term of office shall be fixed n cities by the city council and in towns by the selectmen or municipal light board, if any; and, before entering upon the performance f his official duties, he shall give bond to the city or town for the faithful performance thereof in a sum and form and with sureties o the satisfaction of the mayor, selectmen or municipal light board, if any, and shall, at the end of each municipal year, render o them such detailed statement of his doings and of the business and financial matters in his charge as the department may pre- cribe. All moneys payable to or received by the city, town, manager or municipal light board in connection with the operation f the plant, for the sale of gas or electricity or otherwise, shall be paid to the city or town treasurer. All accounts rendered to or ept in the gas or electric plant of any city shall be subject to the inspection of the city auditor or officer having similar duties, nd in towns they shall be subject to the inspection of the selectmen. The auditor or officer having similar duties, or the selectmen, nay require any person presenting for settlement an account or claim against such plant to make oath before him or them, in such orm as he or they may prescribe, as to the accuracy of such account or claim. The wilful making of a false oath shall be punish- ble as perjury. The auditor or officer having similar duties in cities, and the selectmen in towns, shall approve the payment of ll bills or pay rolls of such plants before they are paid by the treasurer, and may disallow and refuse to approve for payment, in whole or in part, any claim as fradulent, unlawful or excessive; and in that case the auditor or officer having duties, or the select- nen, shall file with the city or town treasurer a written statement of the reasons for the refusal; and the treasurer shall not pay ny claim or bill so disallowed. This section shall not abridge the powers conferred on town accountants by sections fifty-five o sixty-one, inclusive, of chapter forty-one. The manager shall at any time, when required by the mayor, selectmen, municipal ight board, if any, or department, make a statement to such officers of his doings, business, receipts, disbursements, balances, and f the indebtedness of the town in his department.

SECTION 57. At the beginning of each fiscal year, the manager of municipal lighting shall furnish to the mayor, selectmen r municipal light board, if any, an estimate of the income from sales of gas and electricity to private consumers during the ensuing iscal year, and of the expense of the plant during said year, meaning the gross expenses of operation, maintenance and repair, the nterest on the bonds, notes or certificates of indebtedness issued to pay for the plant, an amount for depreciation equal to three per cent of the cost of the plant exclusive of land and any water power appurtenant thereto, or such smaller or larger amount as he department may approve, the requirements of the sinking fund or debt incurred for the plant, and the loss, if any, in the opera- ion of the plant during the preceding year, and of the costs, as defined in section 58, of the gas and electricity to be used by the own. The town shall include in its annual appropriations and in the tax levy not less than the estimated cost of the gas and lectricity to be used by the town as above defined and estimated. By cost of the plant is intended the total amount expended n the plant to the beginning of the fiscal year for the purpose of establishing, purchasing, extending or enlarging the same. By oss in operation is intended the difference between the actual income from private consumers plus the appropriations for mainte- nance for the preceding fiscal year and the actual expense of the plant, reckoned as above, for that year in case such expense xceeded the amount of such income and appropriation. The income from sales and the money appropriated as aforesaid shall e used to pay the annual expense of the plant, defined as above, for the fiscal year, except that no part of the sum therein included or depreciation shall be used for any other purpose than renewals in excess of ordinary repairs, extensions, reconstruction, enlarge- nents and additions. The surplus, if any, of said annual allowances for depreciation after making the above payments shall be kept as a separate fund and used for renewals other than ordinary repairs, extensions, reconstructions, enlargements and additions n succeeding years; and no debt shall be incurred under section forty for any extension, reconstruction or enlargements of the plant n excess of the amount needed therefor in addition to the amount then on hand in said depreciation fund. Said depreciation fund shall be kept and managed by the town treasurer as a separate fund, subject to appropriation by the city council or selectmen or municipal light board, if any, for the foregoing purpose. So much of said fund as the department may from time to time approve may also be used to pay notes, bonds or certificates of indebtedness issued to pay for the cost of reconstruction or renewals in excess of ordinary repairs, when such notes, bonds or certificates of indebtedness become due. All appropriations for the plant shall be either for the annual expense defined as above, or for extensions, reconstruction, enlargements or additions; and no appropriation shall be used for any purpose other than that stated in the vote making the same. No bonds, notes or certificates of indebtedness shall be issued by a town for the annual expenses as defined in this section.

SECTION 63. A town manufacturing or selling gas or electricity for lighting shall keep records of its work and doings at its manufacturing station, and in respect to its distributing plant, as may be required by the department. It shall install and main- tain apparatus, satisfactory to the department, for the measurement and recording of the output of gas and electricity, and shall sell the same by meter to private consumers when required by the department, and, if required by it, shall measure all gas or elec- tricity consumed by the town. The books, accounts and returns shall be made and kept in a form prescribed by the department, and the accounts shall be closed annually on the last day of the fiscal year of such town, and a balance sheet of that date shall be taken therefrom and included in the return to the department. The mayor, selectmen or municipal light board and manager shall, at any time, on request, submit said books and accounts to the inspection of the department and furnish any statement or information required by it relative to the condition, management and operation of said business. The department shall, in its annual report, describe the operation of the several municipal plants with such detail as may be necessary to disclose the financial condition and results of each plant; and shall state what towns, if any, operating a plant have failed to comply with this chapter, and what towns, if any, are selling gas or electricity with the approval of the department at less than cost. The mayor, or selectmen, or municipal light board, if any, shall annually, on or before such date as the department fixes, make a return to the department, for the preceding fiscal year, signed and sworn to by the mayor, or by a majority of the selectmen or municipal light board, if any, and by the manager, stating the financial condition of said business, the amount of authorized and existing indebtedness, a statement of income and expenses in such detail as the department may require, and a list of its salaried officers and the salary paid to each. The mayor, the selectmen or the municipal light board may direct any additional returns to be made at such time and in such detail as he or they may order. Any officer of a town manufacturing or selling gas or electricity for lighting who, being required by this section to make an annual return to the department, neglects to make such annual return shall, for the first fifteen days or portion thereof during which such neglect continues, forfeit five dollars a day; for the second fifteen days or any portion thereof, ten dollars a day; and for each day thereafter not more than fifteen dollars a day. Any such officer who unreasonably refuses or neglects to make such return shall, in addition thereto, forfeit not more than five hundred dollars. If a return is defective or appears to be erroneous, the department shall notify the officer to amend it within fifteen days. Any such officer who neglects to amend said return within the time specified, when notified to do so, shall forfeit fifteen dollars for each day during which such neglect continues. All forfeitures incurred under this section may be recovered by an information in equity brought in the supreme judicial court b the attorney general, at the relation of the department, and when so recovered shall be paid to the commonwealth.

SECTION 69. The supreme judicial court for the county where the town is situated shall have jurisdiction on petition of the department or of twenty taxable inhabitants of the town to compel the fixing of prices by the town in compliance with sections fifty-seven and fifty-eight, to prevent any town from purchasing, operating or selling a gas or electric plant in violation of any provision of this chapter, and generally to enforce compliance with the terms and provisions thereof relative to the manufacture or distribution of gas or electricity by a town.

FINANCIAL STATEMENTS AND AUDITORS' REPORT

TAUNTON MUNICIPAL LIGHTING PLANT

December 31, 1982

Alexander Grant
& COMPANY

FINANCIAL STATEMENTS AND AUDITORS' REPORT

TAUNTON MUNICIPAL LIGHTING PLANT

December 31, 1982

C O N T E N T S

Alexander Grant
& COMPANY
CERTIFIED PUBLIC ACCOUNTANTS

MEMBER FIRM
GRANT THORNTON INTERNATIONAL

Municipal Light Commission
of the City of Taunton
Taunton, Massachusetts

We have examined the balance sheet of Taunton Municipal Lighting Plant, (a department of the City of Taunton) as of December 31, 1982, and the related statements of earnings, surplus and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

As discussed in note G, Taunton Municipal Lighting Plant records pension expense based on a formula determined by the Town; whereas, generally accepted accounting principles require the use of actuarial methods in determining annual pension expense.

In our opinion, except for the effect on the financial statements of the accounting policy discussed in the second paragraph, the financial statements referred to above present fairly the financial position of the Taunton Municipal Lighting Plant at December 31, 1982, and the results of its operations and changes in its financial position for the year then ended, in conformity with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Alexander Grant & Company

Boston, Massachusetts
April 1, 1983

99 HIGH STREET BOSTON, MA 02110 (617) 357-5787

Taunton Municipal Lighting Plant

BALANCE SHEET

December 31, 1982

ASSETS

UTILITY PLANT - AT COST		
Plant in service	$55,062,184	
Less accumulated depreciation (note A2)	24,064,273	
Net utility plant in service		$30,997,911
Construction work in progress (note D)		2,284,773
Total utility plant		33,282,684
DEPRECIATION FUND		
Cash		2,542,984
CURRENT ASSETS		
Cash (note F)		1,407,732
Customer deposits (note F)		
Principal fund		149,213
Interest fund		20,876
Accounts receivable	4,714,414	
Less allowance for doubtful receivables	449,239	4,265,175
Materials and supplies inventory (note A4)		2,878,194
Prepaid insurance		114,837
Total current assets		8,836,027
		$44,661,695

The accompanying notes are an integral part of this statement.

LIABILITIES AND SURPLUS

SURPLUS		
Appropriated surplus		
Loans repayment	$10,167,000	
Construction repayment	32,434	
	10,199,434	
Unappropriated surplus	7,045,065	
Total surplus		$17,244,499
LONG-TERM DEBT (note C)		
Bonds payable	23,027,417	
Less current maturities	470,000	
Total long-term debt		22,557,417
CURRENT LIABILITIES		
Accounts payable	2,628,358	
Customer deposits	149,213	
Current maturities of long-term debt	470,000	
Accrued liabilities		
Interest	743,842	
Compensated absences	820,247	
Payroll	48,119	
Total current liabilities		4,859,779
COMMITMENTS AND CONTINGENCIES (notes D and E)		
		$44,661,695

Taunton Municipal Lighting Plant

STATEMENT OF EARNINGS

Year ended December 31, 1982

Operating revenues		
Sales of electricity		
Commercial and industrial	$13,720,331	
Residential	10,437,331	
Sales for resale (note D)	9,881,981	
Municipal	1,553,408	$35,593,051
Other operating revenues		38,900
Total operating revenues		35,631,951
Operating expenses		
Power production	24,815,777	
Transmission and distribution	948,061	
Customer accounts	597,853	
Administrative and general	2,758,809	
Depreciation (note A2)	1,539,074	
Total operating expenses		30,659,574
Earnings from operations		4,972,377
Other income (expense)		
Interest income	272,374	
Interest expense on bonds	(1,783,483)	
Other	(44,249)	
Total other income (expense)		(1,555,358)
NET EARNINGS BEFORE PROVISION FOR PAYMENT IN LIEU OF TAXES		3,417,019
Provision for payment to the City of Taunton in lieu of taxes (note B)		938,000
EXCESS NET EARNINGS AFTER PAYMENTS TO CITY OF TAUNTON		$ 2,479,019

The accompanying notes are an integral part of this statement.

Taunton Municipal Lighting Plant

STATEMENT OF SURPLUS

Year ended December 31, 1982

	Appropriated Surplus		
	Loans Repayment	Construction Repayment	Unappropriated Surplus
Balance at January 1, 1982	$ 9,722,000	$32,434	$5,011,046
ADD OR (DEDUCT)			
Transfer from unappropriated surplus of bond payments during year	445,000		(445,000)
Excess net earnings after payments to City of Taunton			2,479,019
Balance at December 31, 1982	$10,167,000	$32,434	$7,045,065

The accompanying notes are an integral part of this statement.

Taunton Municipal Lighting Plant

STATEMENT OF CHANGES IN FINANCIAL POSITION

Year ended December 31, 1982

Sources of working capital	
From operations	
Net earnings before payment in lieu of taxes	$3,417,019
Charges (credits) to earnings not using (providing) working capital	
Depreciation of utility plant (note A2)	1,539,074
Amortization of bond premium	(3,354)
Funds from operations before payment in lieu of taxes	4,952,739
Provision for payment to City in lieu of taxes (note B)	(938,000)
Net working capital provided from operations	4,014,739
Applications of working capital	
Current maturities of long-term debt (note C)	470,000
Utility plant additions - net	3,583,390
Increase in depreciation fund	101,378
Total applications of working capital	4,154,768
DECREASE IN WORKING CAPITAL	(140,029)
Working capital at January 1, 1982	4,116,277
Working capital at December 31, 1982	$3,976,248
Changes in components of working capital	
Increase (decrease) in current assets	
Cash	$ 814,469
Customer deposits	2,600
Accounts receivable - net	(1,333,856)
Inventories	(63,953)
Prepaid insurance	36,149
	(544,591)
(Increase) decrease in current liabilities	
Accounts payable	490,612
Customer deposits	4,710
Current maturities of long-term debt	(25,000)
Accrued liabilities	(65,760)
	404,562
DECREASE IN WORKING CAPITAL	$ (140,029)

The accompanying notes are an integral part of this statement.

Taunton Municipal Lighting Plant

NOTES TO FINANCIAL STATEMENTS

December 31, 1982

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A summary of Taunton Municipal Lighting Plant's ("the Plant's") significant accounting policies consistently applied in the preparation of the accompanying financial statements follows.

1. Rates

Rates charged by the Plant are not subject to the approval of regulatory agencies. Pursuant to state laws, rates must be such that the resulting net earnings less bond payments do not exceed 8% of the cost of utility plant. During 1982, the Plant's earnings amounted to 5.4% of utility plant.

2. Depreciation

Pursuant to state laws, depreciation is calculated as a percentage of depreciable property at January 1. Depreciation was computed at 3% of the cost of depreciable property for 1982 and 1981.

The amount transferred from the operating fund to the depreciation fund during the year was $3,919,074.

Depreciation Fund cash is used in accordance with state laws for replacements and additions to the electric plant in service.

3. Pension Plan

Substantially all employees of the Plant are covered by a contributory pension plan administered by the City of Taunton in conformity with State Retirement Board requirements. In addition, the Lighting Plant has a separate Employees Retirement Trust for the financing of future pension premiums. At December 31, 1982, the Retirement Trust had net assets of approximately $1,177,000. The plant contributed approximately $984,000 for pensions in 1982, which included $350,000 to the separate Retirement Trust.

4. Inventory

Materials and supplies inventory is carried at cost, principally on the average cost and first-in, first-out methods.

Taunton Municipal Lighting Plant

NOTES TO FINANCIAL STATEMENTS - CONTINUED

December 31, 1982

NOTE B - CONTRIBUTION TO THE CITY OF TAUNTON IN LIEU OF TAXES

By vote of the Municipal Light Commission, the Plant contributed $938,000 in 1982 to the City of Taunton in lieu of taxes. All contributions to the City are voted by the Municipal Light Commission and are voluntary.

NOTE C - LONG-TERM DEBT

Long-term debt at December 31, 1982, is comprised of the following:

Electric loan, Act of 1969 Interest rate - various rates from 7% to 8.5% dated February 1, 1976. Interest payable February 1 and August 1. Due serially from February 1, 1977 to February 1, 2006	$22,515,000
Unamortized premium	77,417
Electric loan, Act of 1963 Interest rate 3.1% dated August 15, 1965. Interest payable August 15 and February 15. Due serially from August 15, 1966 to August 15, 1985	135,000
Electric loan, Act of 1963 Interest rate 3% dated January 1, 1965. Interest payable January 1, and July 1. Due serially from January 1, 1966 to January 1, 1985	300,000
	23,027,417
Less current maturities	470,000
Total long-term debt	$22,557,417

NOTE C - LONG-TERM DEBT - Continued

Annual maturities of long-term debt are:

	3% Bonds	3.1% Bonds	7% - 8.5% Bonds	Total
1983	$100,000	$ 45,000	$ 325,000	$ 470,000
1984	100,000	45,000	350,000	495,000
1985	100,000	45,000	380,000	525,000
1986			410,000	410,000
1987			445,000	445,000
1988-2006			20,605,000	20,605,000
Bond premium			77,417	77,417
	$300,000	$135,000	$22,592,417	$23,027,417

NOTE D - COMMITMENTS

Interconnection Agreement

The City of Taunton, acting by vote of its Municipal Lighting Plant Commission, has entered into an agreement with Montaup Electric Company ("Montaup"), dated July 31, 1970, as amended, concerning interconnection of electrical operations, purchase and sale of kilowatt capacity, and construction by Taunton of a generating unit of approximately 110 megawatt capability. The agreement is for a period of twelve years following the commencement of operations of Unit No. 9 on December 1, 1975. Under the interconnection agreement, the City agrees to sell and Montaup agrees to purchase all capacity of Unit No. 9 not utilized by the City with a maximum not to exceed 95 megawatts in the first year of operation and on a declining scale in subsequent years. It is estimated that by 1986 or 1987 Montaup will have purchased the maximum capacity allowed by law for sale to that utility. The Plant credited to sales for resale $9,290,194 of capacity and energy charges billed to Montaup Electric Company in 1982 for its share of power under the interconnection agreement. This agreement includes a provision that Taunton will purchase 8.2163% of the capacity and associated energy from Montaup's Somerset No. 6. generating unit for the period November 1, 1978 through October 31, 1984.

NOTE D - COMMITMENTS - Continued

Entitlements

The Plant is a joint owner of the Seabrook Units 1 and 2 nuclear generating station located in Seabrook, New Hampshire. The lead participant in the project is Public Service Company of New Hampshire. The Plant's ownership share is .10034%. Expenditures of $2,018,946 through December 31, 1982, are included in the Construction work-in-progress account.

It is estimated that Unit 1 will be completed in December, 1984, and Unit 2 will be completed in July, 1987. Public Service Company's latest estimates put the cost of building the two units at $5.24 billion.

NOTE E - CONTINGENCIES

Several contractors have initiated litigation to recover additional costs alleged to have been incurred during the construction of Unit No. 9. The Lighting Plant has disputed these claims which total approximately $282,000. Although it is not possible to determine the outcome of this litigation, management of the Lighting Plant does not anticipate that the ultimate disposition of these suits, even if adversely decided, will have a material adverse effect on earnings or financial position of the Plant since such amounts would be capitalized to the cost of Utility Plant.

NOTE F - CASH

Municipal Lighting Plant cash is in the custody of the City of Taunton Treasurer and is commingled with other city funds.

NOTE G - DEPARTURE FROM GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

Pension expense is not recorded in accordance with generally acceptred accounting principles which require, as a minimum, an annual provision equal to the total of normal cost of present employees under the plan, an amount equivalent to interest on any unfunded prior service cost, and a provision for vested benefits.

NOTE G - DEPARTURE FROM GENERALLY ACCEPTED ACCOUNTING PRINCIPLES - Continued

Instead, the Plant's pension expense is based on the current year contributions to the City's retirement fund and the Plant's retirement trust. The contribution to the City's retirement fund is based on the projected benefits to be paid during the year, while the contribution to the retirement trust is a straight-line funding of $350,000 per year for ten years. The Plant's retirement trust is presently being actuarially viewed.

The effect on the accompanying financial statements of this departure from generally accepted accounting principles has not been determined.

SUPPLEMENTAL INFORMATION

AUDITORS' REPORT ON SUPPLEMENTAL INFORMATION

Taunton Municipal Lighting Plant

Our examination was made for the purpose of forming an opinion on the basic financial statements taken as a whole of Taunton Municipal Lighting Plant for the year ended December 31, 1982, which are presented in the preceding section of this report. The supplemental information presented hereinafter is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the audit procedures applied in the examination of the basic financial statements, and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

Alexander Grant & Company

Boston, Massachusetts
April 1, 1983

Taunton Municipal Lighting Plant

UTILITY PLANT

Year ended December 31, 1982

	Balance January 1, 1982
Utility plant in service	
Steam production plant	
Land and land rights	$ 245,509
Structures and improvements	5,791,295
Boiler plant equipment	14,054,535
Turbo-generator units	11,888,375
Accessory electric equipment	2,507,298
Miscellaneous power plant equipment	228,448
Total steam production plant	34,715,460
Other production plant	
Fuel holders, producers, and accessories	507,164
Generators	82,607
Accessory electric equipment	402,423
Total other production plant	992,194
Transmission plant	
Land and land rights	217,807
Clearing land and rights of way	22,601
Structures and improvements	129,376
Station equipment	1,871,529
Towers and fixtures	849,092
Poles and fixtures	284,208
Overhead conductors and devices	234,501
Underground conduit	3,104
Underground conductors	6,113
Total transmission plant	3,618,331
Distribution plant	
Land and land rights	189,056
Structures and improvements	101,704
Station equipment	1,669,928
Poles, towers and fixtures	1,876,759
Overhead conductors and devices	1,893,640
Underground conduit	1,383,927
Underground conductors and devices	1,443,531
Line transformers	1,160,060
Services	270,395
Meters	993,524
Street lighting and signal system	603,772
Total distribution plant	11,586,296
Forward	50,912,281

Also Available On Aperture Card

Additions	Retirements	Balance December 31, 1982	Accumulated Depreciation December 31, 1982	Net Book Value December 31, 1982
		$ 245,509		$ 245,509
$ 13,775		5,805,070	$ 3,141,413	2,663,657
294,873		14,349,408	6,031,994	8,317,414
1,866,641		13,755,016	4,113,510	9,641,506
21,255		2,528,553	1,607,682	920,871
175,368		403,816	75,336	328,480
2,371,912		37,087,372	14,969,935	22,117,437
800		507,964	116,017	391,947
800		83,407	18,996	64,411
		402,423	92,357	310,066
1,600		993,794	227,370	766,424
		217,807		217,807
6,300		28,901		28,901
113		129,489	18,833	110,656
440,591		2,312,120	364,636	1,947,484
10,354		859,446	192,314	667,132
20,397		304,605	53,369	251,236
73,531		308,032	43,933	264,099
		3,104	501	2,603
		6,113	630	5,483
551,286		4,169,617	674,216	3,495,401
		189,056		189,056
		101,704	94,919	6,785
9,944		1,679,872	1,344,602	335,270
27,949		1,904,708	1,608,747	295,961
21,926	$ 33,660	1,881,906	852,098	1,029,808
11,612		1,395,539	978,434	417,105
24,104	35,500	1,432,135	833,254	598,881
40,393	8,697	1,191,756	739,418	452,338
9,349	1,980	277,764	76,495	201,269
28,097	29,600	992,021	639,964	352,057
8,178	3,960	607,990	316,550	291,440
181,552	113,397	11,654,451	7,484,481	4,169,970
3,106,350	113,397	53,905,234	23,356,002	30,549,232

Taunton Municipal Lighting Plant

UTILITY PLANT - CONTINUED

Year ended December 31, 1982

	Balance January 1, 1982
Forwarded	$50,912,281
General plant	
Land and land rights	35,691
Structures and improvements	281,965
Office furniture and equipment	101,284
Transportation equipment	534,336
Stores equipment	1,740
Tools, shop and garage equipment	13,093
Laboratory equipment	14,888
Power operated equipment	17,388
Communication equipment	85,101
Miscellaneous equipment	15,363
Total general plant	1,100,849
Total utility plant in service	52,013,130
Construction work in progress	1,893,795
	$53,906,925

Additions	Retirements	Balance December 31, 1982	Accumulated Depreciation December 31, 1982	Net Book Value December 31, 1982
$3,106,350	$113,397	$53,905,234	$23,356,002	$30,549,232
		35,691		35,691
		281,965	231,868	50,097
7,446		108,730	54,385	54,345
81,151	34,539	580,948	351,998	228,950
		1,740	1,684	56
		13,093	13,093	
		14,888	10,003	4,885
		17,388	14,294	3,094
1,757		86,858	19,762	67,096
286		15,649	11,184	4,465
90,640	34,539	1,156,950	708,271	448,679
3,196,990	147,936	55,062,184	24,064,273	30,997,911
390,978		2,284,773		2,284,773
$3,587,968	$147,936	$57,346,957	$24,064,273	$33,282,684

Taunton Municipal Lighting Plant

OPERATING EXPENSES

Year ended December 31, 1982

POWER PRODUCTION EXPENSES		
Operation		
Supervision and engineering	$ 233,055	
Fuel	9,353,105	
Labor and expenses	752,796	$10,338,956
Maintenance		
Supervision and engineering	61,547	
Structures	51,723	
Boiler plant	491,082	
Electric plant	869,251	
Miscellaneous	28,964	1,502,567
Purchased power		12,974,254
Total power production expenses		24,815,777
TRANSMISSION AND DISTRIBUTION EXPENSES		
Operation		
Supervision and engineering	161,981	
Labor	187,560	
Supplies and expenses	44,603	
Meter expenses	53,290	
Customer installation	54	
Street lighting and signal systems	154	
Miscellaneous	76,421	524,063
Maintenance		
Lines - electric	273,240	
Lines - steam	757	
Street lighting and signal systems	51,812	
Meters	42,308	
Structures and equipment	43,337	
Line transformers	717	
Station equipment	9,255	
Miscellaneous	2,572	423,998
Total transmission and distribution expenses		948,061
Forward		25,763,838

Taunton Municipal Lighting Plant

OPERATING EXPENSES - CONTINUED

Year ended December 31, 1982

Forwarded		$25,763,838
CUSTOMER ACCOUNTS EXPENSES		
Operation		
Meter reading labor and expenses	$ 98,647	
Accounting and collecting expenses	439,724	
Uncollectible accounts	42,000	
Advertising expense	17,482	
Total customer accounts expenses		597,853
ADMINISTRATIVE AND GENERAL EXPENSES		
Operation		
Administrative and general salaries	202,673	
Office supplies and expenses	82,683	
Outside services employed	221,114	
Property insurance	136,728	
Injuries and damages	257,189	
Employee pensions and benefits	1,624,621	
Miscellaneous general expenses	36,615	
Transportation expenses	89,136	
Regulatory commission expense	15,593	2,666,352
Maintenance		
General plant		92,457
Total administrative and general expenses		2,758,809
DEPRECIATION EXPENSE		1,539,074
		$30,659,574