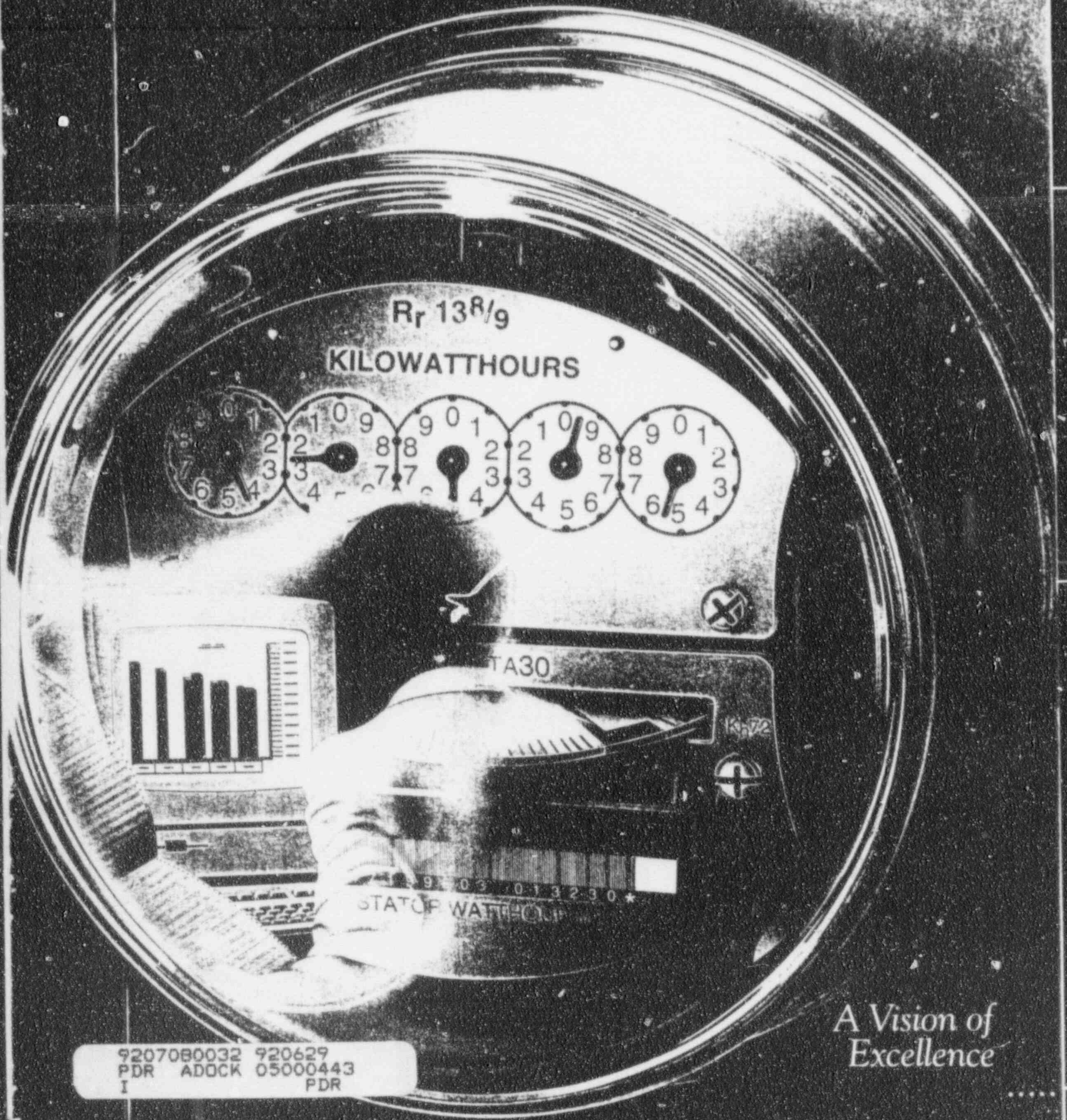
NORTHEAST UTILITIES

1991 Annual Report



A Vision of Excellence

1991 ANNUAL REPORT

Service meters measure the use of electricity, but they also symbolize the needs that individuals and enterprises have for adequate supplies of energy, reliably delivered. The work setting reflected in the meter represents NU's dedicated employees. It is also symbolic of the myriad skills needed to meet today's energy requirements, to plan effectively for tomorrow's, and to merge these objectives with financial performance considerations that will assure the continued profitable growth of the company.

The environment in which NU now operates—an amalgam of regulation and aggressive competition—also imposes a level of complex business dynamics that is fundamentally changing the way NU views and conducts its business. Both operationally and financially, our objectives are clearly delineated in our strategic plan. Our approach is changing, but our commitment to superior performance remains constant.

THE REPORT

The past year had elements of great satisfaction, tempered somewhat by the economy and a temporary falloff in our nuclear operations. On the whole, however, it was a year of positive achievements. Our aggressive cost-management activities—supplemented by the impact of rate decisions—helped offset the effects of the recession and resulted in improved financial performance.

Most of the activities that contributed positively to 1991 results will have a sustained, positive influence. This strong basis for the continued improvement and strengthening of NU's operations is enhanced by adequate generating capacity until midway through the next decade. As a result, our new construction needs for the next several years will be relatively modest and should have a positive influence on the level and quality of future earnings.

The essence of our strategic plan is to improve financial performance by increasing the competitiveness of NU's core business. Much of this annual report is devoted to elements of our business strategy. The report also discusses the progress achieved in the complementary strategies that address business diversification and geographical expansion: One section describes the activities of the two subsidiaries involved with diversification, and another provides an update of the Public Service Company of New Hampshire acquisition. Finally, the report includes a guest essay that addresses the ways in which the functions and operations of successful utilities will evolve in response to the competitive business environment.

THE COMPANY

Northeast Utilities is the parent company of the NU system (collectively referred to as NU). NU is one of the largest electric utilities in the country and the largest in New England, with 7,948 employees serving about 1.26 million customers in Connecticut and western Massachusetts.

During 1989 and 1990, NU added two nonutility subsidiary companies as part of its strategic diversification activities. These two entities, Charter Oak Energy, Inc., and HEC Inc., are discussed in more detail on page 15 of this report. Current NU subsidiaries are listed below:

Electric Operating Subsidiaries
The Connecticut Light and Power Company
Western Massachusetts Electric Company
Holyoke Water Power Company
Support Subsidiaries
Northeast Nuclear Energy Company (Millstone nuclear operations)
Northeast Utilities Service Company (systemwide service)
Nonutility Subsidiaries
Charter Oak Energy, Inc. (cogeneration)
HEC Inc. (energy management)
Realty Subsidiaries
The Quinnehtuk Company
The Rocky River Realty Company

NU is in the process of acquiring Public Service Company of New Hampshire (PSNH), including its share of the Seabrook nuclear power plant. The three subsidiaries that relate to the acquisition appear below:

Public Service Company of New Hampshire
North Atlantic Energy Corporation (ownership of PSNH's share of Seabrook)
North Atlantic Energy Service Corporation (Seabrook nuclear operations)

Contents	Page

HIGHLIGHTS	1991	1990	% Increase or (Decrease)
Operating Revenues	$2,753,803,000	$2,616,319,000	5.3
Net Income	$236,709,000	$211,007,000	12.2
Earnings Per Common Share	$2.12	$1.94	9.3
Common Shares Outstanding (Average)	111,453,550	109,003,818	2.2
Dividends Paid Per Share	$1.76	$1.76	—
Sales of Electricity (kWh—Thousands)	29,300,000	29,611,000	(1.1)
Electric Customers (Year-end)	1,264,928	1,260,181	.4
Construction Expenditures (a)	$250,482,000	$292,902,000	(14.5)

(a) Excludes nuclear fuel.

LETTER TO OUR SHAREHOLDERS

In its first 20 years of existence, Northeast Utilities (NU) put in place one of the nation's premier systems for providing reliable, efficient electric service. As a key example, by the end of 1986 NU was operating four nuclear plants and had capaci[illegible]ntitlements in three of the oth[illegible]ur nuclear facilities operating in New England. In fact, nuclear power is now the primary source of energy in the NU system, typically accounting for some 60 percent of total energy requirements.

In the late 1980s, we were faced with the emergence of tough competition, primarily

William B. Ellis

from nonutility power producers. The business strategy we developed in response to this radically altered business environment is based on the conviction that improvement in financial performance is fundamentally related to the increased competitiveness and strength of NU's core business. It also recognizes the incremental contributions of geographical expansion and diversification into related enterprises.

To the pressures of competition, we can now add—as we enter the 1990s—the impact of a sagging regional economy. We're pleased to report that our strategy has been sufficiently flexible to accommodate all these pressures. We have the resources, capabilities, and the skilled employees necessary for ultimate success. Our dedication to outstanding operational performance and customer service remains and is paired with an equal and compatible focus upon competitiveness and financial results. Likewise, our planning capabilities are allied with the insights necessary to meet the competitive and economic challenges that lie ahead. We've a way to go, but the results achieved in a very difficult year are indicative of our will and ability to succeed.

1991 In Review

The year just ended was both different and difficult. We take pride in the level of NU's overall per[illegible]ormance for the ye[illegible] in both financial and operational areas, but that pride is tempered by concerns about our nuclear performance. Three significant aspects of 1991 ar[illegible]ticularly noteworthy: [illegible]ecisions, our cost-[illegible]agement initiatives, and a falloff in our nuclear performance.

The major disappointment of the year was a series of problems at the nuclear plants we operate. The causes of these problems and the actions taken to correct them are described elsewhere in this report. Here, however, we would like to make three specific observations. First, NU has operated nuclear plants exceedingly well for 23 years: We've set a number of records for outstanding performance, and—prior to 1991—our composite capacity factors exceeded national averages for well over ten years. Second, because our performance levels were not meeting our own high expectations, we had initiated comprehensive studies aimed at improving nuclear operations even before the advent of the major outages experienced during 1991. Finally, we are committed to resolving our current problems and to regaining our position as a leader in nuclear operations and have every reason to be confident we will succeed.

Overall, we are somewhat disappointed that 1991 rate case decisions granted only about 40 percent of the total amounts requested. However, it is important to note that The Connecticut Light and Power Company (CL&P) was allowed about 70 percent of those requested revenues that directly affect earnings. The phase-in of an additional 5 percent of allowed Millstone 3 costs and a

Bernard M. Fox

three-year phase-in of CL&P's share in Seabrook are particularly significant, since they increase the cash portion of total earnings. From 1988 through 1991, the noncash portion of earnings dropped from over 50 percent to approximately 28 percent.

The Massachusetts rate case decision reflects economic realities in that state and corresponding pressures on regulators to deny any increases. Western Massachusetts Electric Company (WMECO) remains well below industry financial performance levels, and a new rate application was filed in December.

Our expansion of cost-containment measures had a positive influence on 1991 earnings and helped offset the impact of lower retail sales and less-than-adequate rate relief. Some of the spending cuts represented postponements, but many will become permanent. The latter measures have become part of cost-management efforts that fundamentally address the way we will conduct our business in the future. Two other important cost-control initiatives were the implementation of a five-year business planning process and the establishment of a Corporate Business Practices Group. These and related accomplishments are described more fully on page 14 of this report. The goal of our cost-management efforts is to help improve earnings while limiting the level of future rate requests.

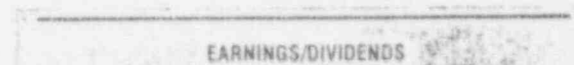
We've been quite pleased that key operational indicators in the areas of system reliability and fossil/hydro plant availability were met or exceeded, even as costs were very tightly controlled.

Earlier in our history, our commitment to nuclear power was achieved without having to reduce or eliminate dividends, unlike many others in our industry. This year, we've demonstrated our ability not only to maintain earnings, but also to improve them somewhat, during a major economic downturn. The lower sales we experienced in 1991 reflect the impact of a deepening of the recession, a continuation of moderate weather, and the effectiveness of conservation programs. Still, NU's earnings for 1991 were $2.12 per share, up 18 cents from 1990. This improvement is attributable to cost-control measures, rate decisions, and lower interest charges.

Performance Outlook

In addition to the transient effects of the current recession, the region is also undergoing an economic restructuring that may have longer term implications. Thus, we project that annual growth of retail sales in NU's existing service area will be about 1 percent for the next five years, while a combined NU-Public Service Company of New Hampshire (PSNH) system would achieve slightly higher levels.

While the overall economic outlook for the region is modest, there are a number of bright spots in NU's financial prospects. Aside from the acquisition of PSNH, NU has rather limited financing needs for the next several years. The most significant requirement will be approximately $190 million for the replacement of two steam generators at Millstone 2. No new generating capacity investment is currently expected until at least 2005. Also, WMECO's allowed investment in Millstone 3 is now completely reflected in rates and CL&P's investment should be totally in rate base by the beginning of 1995. A three-year phase-in of CL&P's Seabrook investment is in place with regulatory approval. The end of these deferments, along with modest new construction needs, means that the noncash portion of total earnings should



be 1.4 percent at the end of 1996, compared to 28 percent for 1991.

Progress also continues in the two strategic areas designed to supplement the performance of our core business—diversification and geographical expansion. Charter Oak Energy, Inc., (COE) and HEC Inc., (HEC) represent our relatively modest diversification into energy-related businesses. COE was formed to invest in nonutility power generation, while HEC provides energy conservation services. Both subsidiaries are discussed on page 15 of this report.

The acquisition of PSNH will expand NU's revenue and should

enhance the cost-effectiveness of the expanded system. Despite delays in obtaining necessary regulatory approvals, we remain convinced that the merger offers significant benefits for all customers and would contribute to improved long-term earnings. A major obstacle in the way of completion was overcome, on January 29, 1992, when the Federal Energy Regulatory Commission approved an amended decision that resolved concerns about equitable transmission access. While we still need several more regulatory approvals, we have reasonable expectations that the merger can be completed during the second quarter of 1992.

It should be clear, then, that we have done much to improve operational and financial performance of our core business. Our diversification and expansion initiatives will also contribute to NU's improved financial outlook. Based on everything we know today, we believe NU's dividend is well-founded at the current level, and we're guardedly optimistic about the longer term prospects for dividend growth. Based upon this overall assessment, the Board of Trustees voted, on January 28, 1992, to maintain the indicated annual dividend rate at $1.76.

A New Business Environment

The pace of change in our industry has accelerated dramatically. Utilities have had to become proficient in competitive techniques and the complexities of mergers and acquisitions. Where quality was once a matter of inspections and controls, more insightful utilities now integrate quality concepts into every aspect of performance. Cost-management initiatives, the five-year business planning concept, and creation of the Corporate Business Practices Group are but three of NU's varied responses to this new reality. In different ways and to varying degrees, each response directly affects our employees.

It's important that employees understand that NU must continue to change the way it operates and that such changes will entail different expectations and job requirements. As a first step in this transitional process, we have introduced new performance appraisal and compensation programs for exempt employees. The new programs are more flexible and participatory. They provide a clearer relationship between individual performance and corporate objectives and more effectively link performance to pay by emphasizing compensation incentives. Change of any type can be disconcerting, and we recognize that employees are concerned about changes that have such a direct bearing on their careers and their compensation. We are convinced, however, that—more than ever—individual performance is vitally important to the success of the company.

In our opinion, the steps already taken are necessary for that success and equitable for employees, but they are only the first steps. We still have ahead of us the task of exploring compensation programs that build collaboration and teamwork into the process. Our goal is to build upon an organizational philosophy that fully recognizes the contributions of NU's skilled and dedicated work force and that treats all employees as business partners working for the overall success of the company. Customers and shareholders expect much of the company, and it is our commitment that neither will find us wanting.

William B. Ellis

William B. Ellis
Chairman and
Chief Executive Officer

Bernard M. Fox

Bernard M. Fox
President and
Chief Operating Officer

March 2, 1992

PS: In response to my expressed intention to retire from NU on my fifty-fifth birthday in 1995, seventeen years since I became president of NU, the Board of Trustees announced an orderly management succession plan. Under the terms of the plan—announced on January 29, 1992—I will step down as chief executive officer on July 1, 1993. On that date, the NU Board plans to name Bernard Fox, current NU president and chief operating officer, to succeed me as chief executive officer. The plan calls for me to remain active as chairman of NU's Board of Trustees until August 1, 1995. Bernie Fox is an extraordinarily effective general executive, and I personally look forward to working with him and the Board to make the change occur smoothly and effectively.

WBE

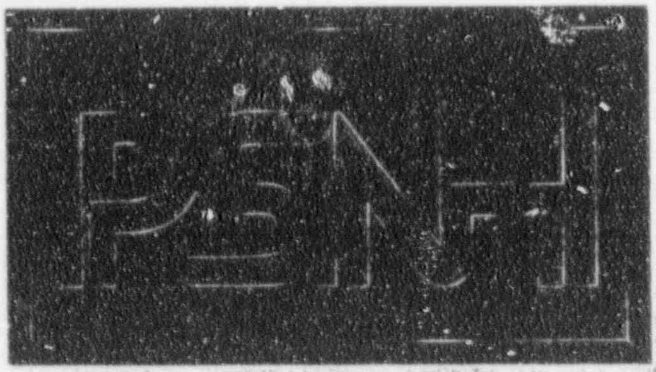
W.B.E.

PSNH ACQUISITION UPDATE

In early 1988, Public Service Company of New Hampshire (PSNH) filed for bankruptcy as a result of the financial burden of its ownership interest in the Seabrook nuclear power plant. Northeast Utilities (NU) capitalized on this opportunity to expand its system, since the PSNH system and service territory offer substantial strategic and economic benefits.

An NU-PSNH merger should reduce overall costs as a result of merger-related efficiencies in nuclear operations, fossil-fuel unit availability, peak-load diversity, and administrative expenses. These savings should amount to some $958 million (present-value basis) over time.

The cornerstone of NU's acquisition is a comprehensive rate plan for PSNH based on seven annual 5.5 percent rate increases. The plan has been approved by the New Hampshire Public Utilities Commission and the New Hampshire Legislature and has been affirmed by the New Hampshire Supreme Court.



The acquisition process was structured to take place in two steps. In Step 1, which occurred on May 16, 1991, PSNH emerged from bankruptcy as a reorganized, independent company managed by NU under a management services agreement. The actual merger will be consummated at Step 2 but will not occur until NU has secured the necessary regulatory approvals.

Step 2 Status

In August 1991, the acquisition process took a major step forward when the Federal Energy Regulatory Commission (FERC) unanimously approved the merger, subject to conditions which would have limited NU's ability to use its transmission system freely. However, in January 1992, the FERC amended its previous decision and developed favorable provisions concerning transmission access.

State regulators in Connecticut are now reviewing the merger in light of the recent FERC decision. In addition, the Nuclear Regulatory Commission and the Securities and Exchange Commission still must deliver favorable rulings on the merger. We anticipate that these approvals will be secured during the second quarter of 1992 and that the merger will occur shortly thereafter.

Step 2 Financing

In order to consummate the merger, NU will need to purchase existing PSNH common stock and meet several additional financial obligations. In total, NU's financing requirements will amount to approximately $925 million. The largest piece of this financing will be approximately $575 million of NU common equity. NU began the process of raising these funds on December 3, 1991, when it sold $175 million of 15-year notes to fund an Employee Stock Ownership Plan (ESOP). NU is planning an additional ESOP financing of up to $75 million during the first quarter of 1992.

NU also is planning a public offering of about $200 million this spring. In addition, NU's dividend reinvestment program has been extremely well-received by its shareholders and should provide up to $125 million in equity over the next three years. Lastly, some $355 million of bonds will be sold by North Atlantic Energy Corporation (NAEC), a new company that will be formed at the merger. NAEC will own PSNH's existing share of Seabrook.

Summary

Since NU first expressed interest in acquiring PSNH, several developments have impacted the economics of the merger. The economic recession in the Northeast has lowered our forecast of sales growth for PSNH. However, substantially lower interest rates, combined with continuing success in identifying operational cost savings, have generally balanced the lost sales revenue. Further, Seabrook's excellent performance to date and lower-than-predicted oil prices have kept PSNH rates within the rate plan projections. Thus, we continue to believe that this merger will produce real cost savings and represents significant growth opportunities for NU's shareholders.

SYSTEM PERFORMANCE—DEMAND

Primarily as a result of the downturn of the regional economy, the needs of Northeast Utilities (NU) retail customers declined slightly during 1991, while wholesale sales increased 3.3 percent. NU projects positive annual growth for the 1991-1996 period of about 1.5 percent for a combined NU-PSNH system. That projection would have been at 2.3 percent without the influence of NU's effective conservation and load-management (C&LM) programs.

During 1991, NU served an average of 1,261,568 retail customers, meeting their need for 23.9 billion kilowatt-hours (kWh) of electricity. Within the retail segment, residential customers accounted for 40 percent of 1991 sales, followed by commercial establishments (37 percent) and the industrial sector (22 percent). Excluding bulk power sales, NU's wholesale customers required another 704 million kWh, a 3.3 percent increase when compared to 1990.

The NU system experienced a summer peak load of 5,000 megawatts (MW) on July 23, 1991, breaking the previous high established during the summer of 1988. The winter peak load of 4,704 MW occurred on January 16, 1992.

Hadley, Massachusetts
Peter Peluquin, Larry LaCroix, David York

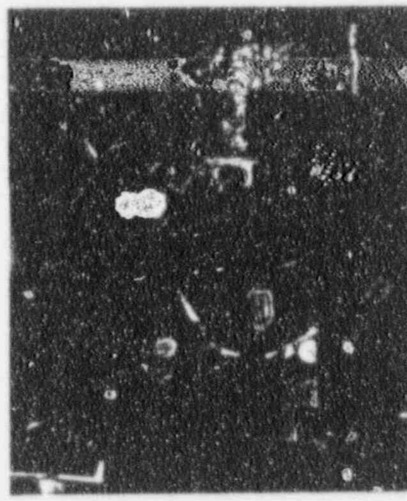
Demand Forecast

The 1980s represented a period of sustained economic expansion in the region. NU was a direct beneficiary, with sales growing at an average annual rate of 3.7 percent during 1983-1988. The subsequent economic downturn had an analogous effect—systemwide sales were flat during 1990 and declined slightly for 1991.

Current NU and PSNH economic forecasts indicate a slow recovery beginning in 1992. However, we don't see the region experiencing during the 1990s the phenomenal growth achieved during the previous decade. Total sales for the NU system are projected to grow at an average annual compound rate of about 1.2 percent through 1996, excluding the impact of the PSNH merger. Combined NU-PSNH annual growth should approximate 1.5 percent through 1996.

While a moderate economic outlook represents the foundation of our sales projections, other factors—particularly C&LM programs and competition from self-generators—do have an impact. For example, annual growth in the commercial sector could exceed 3 percent in the 1991-1996 period, absent the effects of conservation; including those effects, the rate could be about 1.8 percent. Similarly, sales to industrial customers are

Middletown, Connecticut
Dean Jones, James Heil



projected to be 0.2 percent, rather than the 1.1 percent level that would be likely without the effect of conservation. Reflecting the effects of conservation and projections of a sustained weakness in the housing market, NU's residential sales could increase 0.9 percent annually, well below the levels in the 1980s.

Resource Planning

Excluding the effects of the NU-PSNH merger, NU's most recent *Forecast of Loads and Resources* identifies a need for new resources beginning in the year 2005. At that time, the winter peak load demand is projected to be some 5,777 MW, or 23 percent higher than the 1991 winter peak. A reserve margin must be added to that projection, bringing the total to 7,080 MW. This level would have been higher without the

positive influence of NU's C&LM programs, which are projected to yield winter peak capacity savings of roughly 840 MW and summer peak savings of about 870 MW.

Again excluding the NU-PSNH merger, existing capacity and purchases should satisfy 80 percent of the projected year 2005 requirements, and C&LM will provide 11 percent. Cogenerators and small-power producers will provide some 600 MW, or 8 percent, of the requirement. New supply or demand resources will supply the remaining 1 percent.

Under a combined NU-PSNH system, capacity requirements in 2005 would be 8,985 MW, including necessary reserves. Still, no major added capacity resources will be needed until 2005.

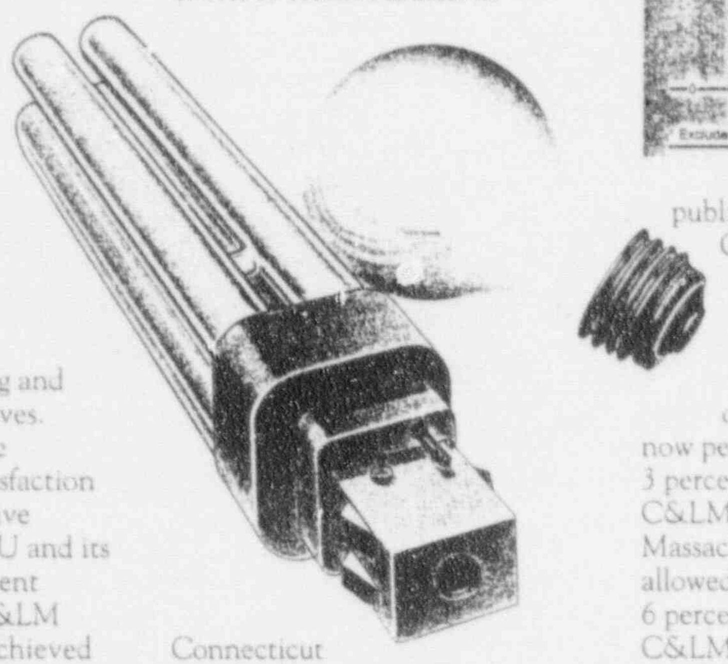
Conservation and Load-Management Programs

In 1991, we continued to develop C&LM programs in a manner that complements and reinforces NU marketing and customer service objectives. These objectives include improving customer satisfaction and enhanced competitive effectiveness for both NU and its customers through efficient utilization of energy. C&LM programs to date have achieved reductions in peak load resource requirements in excess of 300 MW.

NU expended nearly $100 million dollars in energy conservation programs in 1991. The majority of these resources was utilized to improve the efficiency of NU's commercial and industrial customer base, thereby improving their competitiveness. This activity also created full-time employment for over 1,000 people during a time of economic sluggishness.

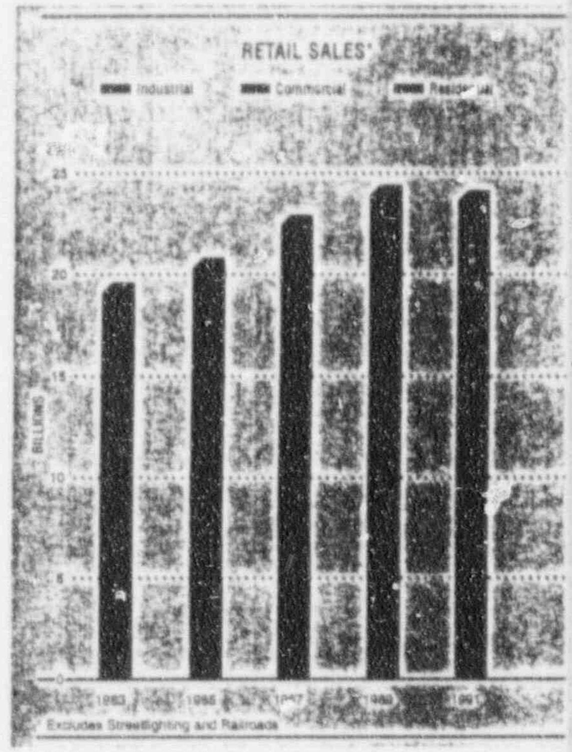
In 1991, NU's programs provided comprehensive services to over 150,000 residential customers and more than 8,000 industrial and commercial customers. Over their lives, these measures will achieve annualized energy savings of 1.2 million megawatt-hours.

NU has made participating in its conservation programs an eligibility requirement for economic-development-oriented flexible pricing for both new and economically threatened customers. The combination of C&LM programs and flexible rate plans is enabling NU to become more effective in its efforts to retain business in



Connecticut and western Massachusetts. Working closely with three manufacturers that had been considering out-of-state options, economic packages were developed that allowed each to remain or expand in Connecticut. Many such opportunities exist, and NU is actively seeking similar partnerships with members of the private and public sectors to strengthen our economy and to retain jobs in both states.

NU's C&LM programs have found favor with regulators and



public energy policy advocates. Consequently, NU is allowed to earn incentive returns for its C&LM programs. The Connecticut Department of Public Utility Control now permits CL&P to collect a 3 percent after-tax bonus on C&LM expenditures. In Massachusetts, WMECO is allowed to collect an approximate 6 percent after-tax return on C&LM expenditures.

NU's C&LM programs are improving the efficiency and competitive effectiveness of NU. They are also contributing to a substantial reduction in the need for future capacity additions, thus improving the environmental health of the entire region.

SYSTEM PERFORMANCE—SUPPLY

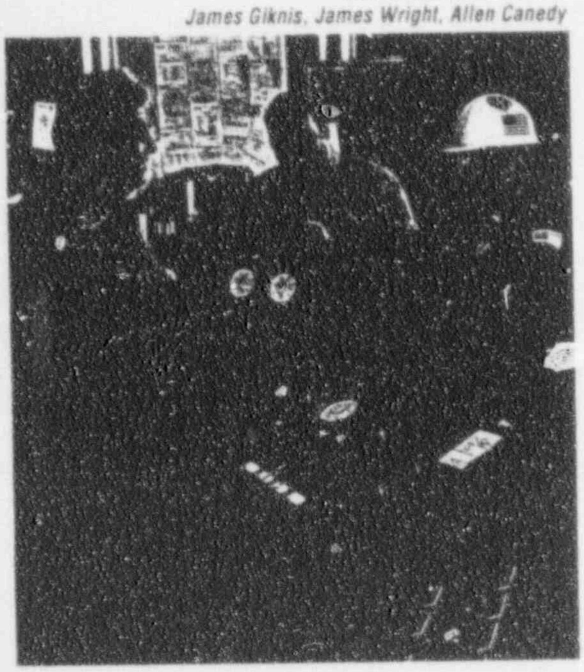
Northeast Utilities (NU) can proudly and justifiably claim to be a "70 percent nuclear capacity factor" utility—a level that typically exceeds the national average by several percentage points, and one that has placed NU among the leaders in the industry. During 1991 we stumbled badly, but we're recovering quickly. More importantly, we have instituted new programs and have the people, the resources, and the needed commitment to avoid a recurrence and to achieve our goal of becoming a "75 percent nuclear capacity factor" utility by the mid-1990s.

The net year-end generating capacity of the NU system was 5,916 megawatts (MW). In addition to supplying the needs of its retail and wholesale customers for 24.6 billion kilowatt-hours (kWh) of electricity, NU also supplied other New England utilities with an average of 1.4 million kilowatts (kW) of capacity. In 1991, NU collected some $200 million in revenues associated with those capacity sales. Many of those capacity contracts will expire in 1993 and 1994.

NU is pursuing renewal of those contracts, but New England now has a capacity surplus. This reduces our ability to sustain bulk power sales. The termination of existing contracts is a major reason for a projected increase in our reserve margins, currently 4 percentage points above our 22 percent requirement. We estimate that the combined NU-PSNH surplus will reach approximately 1,060 MW by 1995. This surplus should decrease as a result of projected future load growth.

During 1991, the eight nuclear units in which NU has entitlements provided 44 percent of our total energy requirements. Fossil-fueled units provided 39 percent, followed by hydropower at 5 percent. The remaining 12 percent was provided by 44 qualifying cogenerators and small-power producers. By 1996, nonutility sources will account for about 15 percent of systemwide needs.

Northfield, Massachusetts
James Giknis, James Wright, Allen Canedy



Nuclear

Historically, our nuclear performance has been exemplary in terms of safe, efficient operations. The composite capacity factor for the four plants operated by NU was 70.2 percent during 1986-1990, compared to the national average of 62.2 percent. Moreover, all four units have received consistently high safety and operational performance ratings from the Nuclear Regulatory Commission (NRC).

The 1991 composite capacity factor for the plants we operate fell to 42.4 percent. Scheduled refuelings at three of the units obviously had an impact. Our focus, however, is upon an unusually high number of incidents that led to unplanned outages, particularly the three discussed below.

Millstone 3 was shut down late in July 1991 as a result of corrosion and an unprecedented growth of mussels. After maintenance, clean-up, and inspection, the unit was returned to service in early February 1992. Plant modifications and improved monitoring procedures should preclude a recurrence at the Millstone site.

In September 1991, eight of 20 license holders evaluated at Millstone 1 failed NRC operator requalification tests that have become increasingly complex. We elected to shut down so all operators could concentrate upon an upgraded training program. Testing of 20 additional license holders was completed satisfactorily in November 1991.

NU initiated a computer-assisted pipe analysis and inspection program at all four facilities after a pipe failure at Millstone 3 late in 1990. A

subsequent failure at Millstone 2 in early November 1991 caused us to accelerate and expand the program and to keep each facility shut down until it had been inspected. Millstone 1, 2, and 3 have returned to service, and Connecticut Yankee should be back on line by mid-March.

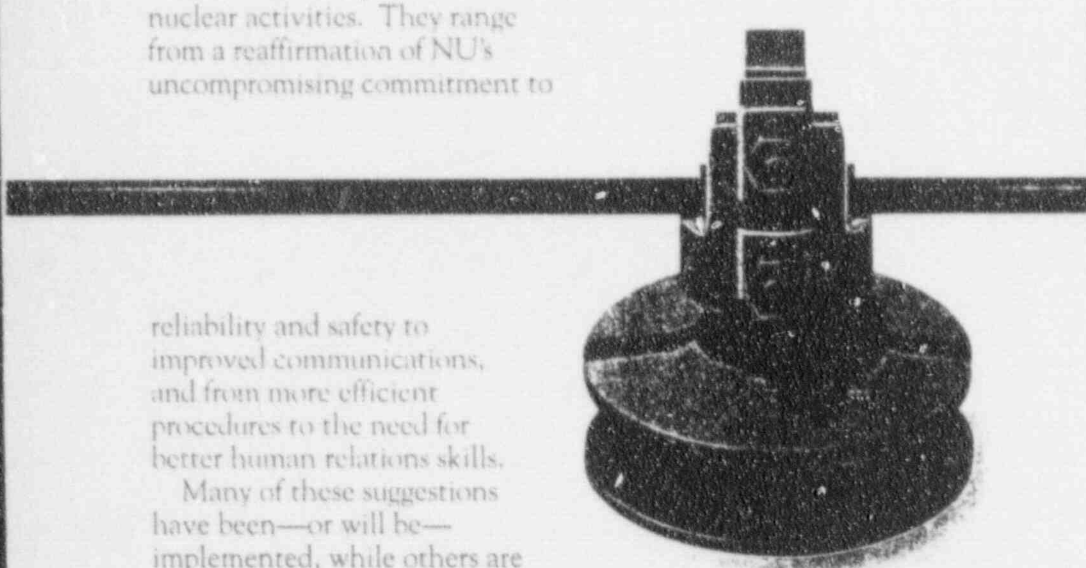
Even before these incidents, we had appointed four task forces to review and critique our nuclear operations. All four completed their assignments by September, making 56 recommendations that address various aspects of our nuclear activities. They range from a reaffirmation of NU's uncompromising commitment to reliability and safety to improved communications, and from more efficient procedures to the need for better human relations skills.

Many of these suggestions have been—or will be—implemented, while others are undergoing further review. Two separate actions have also been taken. First, all nuclear operations have been consolidated under the new position of executive vice president—Nuclear, thereby eliminating one or more layers of management and concentrating nuclear operations under one individual. Second, NU has committed some $10 million for improved operational and training resources, including the addition of about 200 employees. These actions illustrate our very real commitment to enhancing the contributions from a skilled and dedicated work force and to regaining our reputation as a leader in safe, efficient nuclear operations.

Fossil/Hydro

NU's fossil-fired units had a composite availability of 89 percent in 1991, compared to a New England Power Pool target of 84 percent. During 1986-1990—the latest five-year period for which comparative data exist—the availability of our units exceeded the national average by 5.5 percentage points.

At the end of the third quarter in 1991, seven of the oldest and least efficient of NU's fossil-steam units were retired.

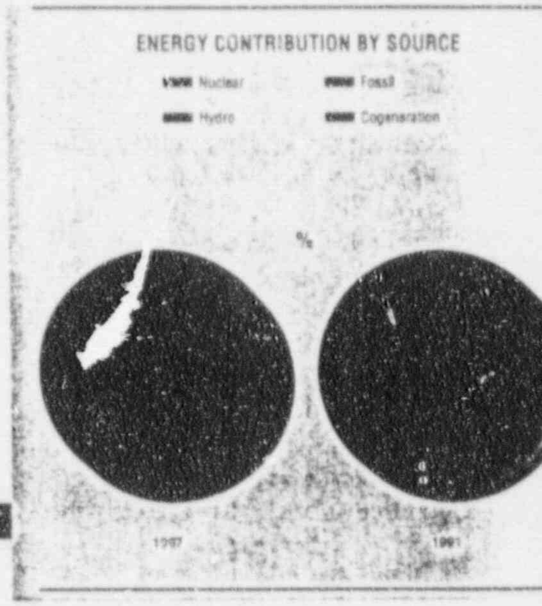


These units represented about 6 percent of NU's overall generating capability.

Aided by above-average rainfall, production at NU's conventional hydroelectric plants exceeded one billion kWh for the first time in 1990. Under more normal conditions, 1991 production fell slightly but was still some 5.4 percent above the average for the past five years. NU is also entitled to 22.8 percent of the capability of Phase II of the Hydro-Quebec interconnection, through which New England utilities will purchase 70 million megawatt-hours of Canadian hydropower during this decade.

System Reliability

NU's key electric distribution system reliability statistic improved by 14 percent during 1991, reflecting the cumulative



impact of an intensified distribution reliability program begun in 1987. In that five-year period, capital expenditures of nearly $667 million were made for distribution system expansion and improvements and for plant modernization work, much of which contributes to improved reliability. Noncapital expenditures totaled some $627 million in the five-year period, including $106 million for tree-trimming operations.

Customer needs for reliable service have increased and will continue to do so. Obviously, rate case decisions play a role in our ability to sustain the level of our efforts, but we remain committed to improved reliability. Our 1992 plans call for $141 million in capital expenditures and $122 million in noncapital expenditures, including $15 million for tree-trimming operations.

UTILITY BUSINESS DYNAMICS

The remainder of this decade will present extraordinary challenges and significant opportunities for the nation's electric utility companies. Dynamic markets, competitive restructuring, and a constantly shifting boundary between regulated and market-based activities will continue to be facts of life within the industry.

In almost every industry with a regulatory heritage that I have studied—airlines, banking, trucking, railroads, gas pipelines, and retail brokerage—the regulatory umbrella has sown the seeds of its own destruction. In all of these industries, regulation stimulated a high-cost system by rewarding capital intensiveness, requiring cross subsidies, and barring competition. At the same time, service differentiation was discouraged by such practices as bundled services and the failure to reward innovation. Invariably, new entrants, innovative traditional players, changing economics, and new technology resulted in price competition, service unbundling, and cost reductions. As these market and competitive forces gained strength, industry and market restructuring were the inevitable results.

New Industry Dynamics

We already see evidence of many of these same forces at work in the electric utility industry. Examples include the emergence of independent power producers (IPPs) and cogenerators, mergers and acquisitions by traditional regulated utilities, selected unbundling of services, and growing cost and price competition. Based on the experience in other industries, I anticipate that these and other forces will accelerate rapidly over the next few years. Equally important, the regulatory barriers that buffered the vertically integrated electric utility industry are changing, if not collapsing. In the 1980s, we witnessed the removal of barriers to unregulated power generation. However, there are no economic nor political reasons to assume that this is where it will end. In fact, the evolution of regulation in other industries suggests that common carrier/open access is an almost inevitable consequence. Similarly, large industrial customers will have more options to bypass traditional, regulated electric power systems.

Business strategies developed by electric utility companies can not only respond effectively to this newly competitive environment, but can also gain significant advantages. However, this will only be possible by dealing with realities, not wishes. Specifically, strategies that ignore the changes that are occurring—and that will continue to evolve—will not work. Likewise, strategies that focus upon diversification into totally unrelated areas are destined to fail.

There are many indications that some utilities will soon begin building regulated, rate-of-return capacity—either new plants or major repowering projects. Notwithstanding the capacity needs that might be projected, such undertakings should not be instituted under a "good old days" mentality that ignores the new risk-reward profile that utilities face under current regulatory treatment. With competition, such new capacity is capped at regulated rates of return but has unlimited downside consequences if available market-based options prove to be cheaper.

A second flawed strategy is a "business as usual" approach of operating solely like a regulated utility with a protected market monopoly. Pursuit of this strategy will allow the rate making process to ignore the real costs of serving different market segments, will provide a cost umbrella for competitors, and will result in unmet customer needs. As a result, new, unregulated competitors could become more firmly entrenched.

Finally, the perception among some within the industry that "the grass is always greener" in completely unrelated businesses is—at best—extremely risky. The outcome of such ventures is always clear; only the timing is in question.

Workable Strategies

These five elements will provide the cornerstone for the long-range business strategies of successful electric utilities during the remainder of the 1990s and into the next century:

- Restructured costs;
- Market resegmentation;
- Development of related opportunities;
- Resource portfolio management;
- Responsive organizational restructuring.

Many electric utilities have embarked on cost-reduction programs, often more than once. Cost cutting can be a valuable and viable means for improving financial performance over a relatively short period, but narrowly defined cost-reduction

programs simply don't work from a strategic perspective. Rather, the focus must be on restructuring what is done, not on what it costs to do it. Moreover, many companies fall into that fatal trap of believing that costs and quality of service are tradeoffs: Better service can only be had at high cost and vice-versa. Nothing could be further from the truth. The most successful companies invariably provide superior or innovative services at low cost.

Market resegmentation also is crucial in businesses where customer categories have been set by regulators rather than by distinct customer needs, differing costs of service, and competitive economics. Bundling, unbundling, augmentation, and differentiation of services provided can work in any business, even those—such as electric utilities—historically viewed as providers of commodity services. Just compare "telephone service" ten years ago with such current service innovations as residential voice mail services, call waiting, and inside wire insurance, to name but a few.

Developing related opportunities is crucial to the enhancement of shareholder value. Shareholders place a premium on a company's assets—the market-to-book ratio—based on returns and growth prospects. To the extent that a utility can find opportunities to grow more rapidly than its existing service territory and can capture the operating synergies from doing so, its success will be reflected in a higher market value. Many utilities are pursuing various IPP and cogeneration opportunities, but few have made the strategic commitment or developed the strategic alliances that will be needed to succeed in the highly competitive, consolidating industry which will surely result. Moreover, conservation and other demand-side management activities should be pursued as a new, expanding business opportunity as well as an important service and a means of deferring the need for new generating capacity.

Most large companies use sophisticated portfolio management techniques to allocate available resources among business segments. Typically, large utilities do not do so, because of the historic view that all investments "yield the same returns." Nothing could be further from the truth in this new environment. Resource portfolio management will become an important management tool for the successful utilities of the future.

Finally, the organizational structure of regulated utilities must be designed to become more responsive to customer needs and expectations and to competitive forces. In the past, utilities evolved along functional lines. In the future, I doubt very much that continuation of that approach will succeed. Today, transmission and distribution and electric power generation are fundamentally different businesses, with different customers, competitors, and regulatory bodies. To build the responsive, market-oriented culture needed to serve such distinct and diverse requirements will be a most difficult, but necessary, step. A utility's organization will have to reflect this new, more complex reality.

My message is a simple one—it is not a regulated industry any more. It is a dynamic, market-driven enterprise where the best and the worst performers will no longer both earn 12 or 13 percent. Others have navigated these reefs before and the fundamentals of their success can work for electric utilities. It's a demanding task, and some will not be up to it. For those with the foresight and the will, the challenges will not be insurmountable, and the opportunities will be exciting.

Based on an article, by Mr. Zausner, appearing in The Energy Daily

Eric Zausner is the founder and president of Strategic Performance Management, a management consulting and investment company. Earlier, Mr. Zausner was associated with Booz, Allen & Hamilton, Inc., serving as a member of the board and the six-person executive committee, and as managing director of commercial consulting.

As deputy administrator of the Federal Energy Administration, he coordinated preparation of the President's national energy program. Earlier in his government career, Mr. Zausner was a senior staff member of the Council on Environmental Quality in the Executive Office of the President.

REGULATORY ACTIVITIES

The rate decision in Connecticut granted a significant portion of the earnings-related revenues that were requested by The Connecticut Light and Power Company (CL&P). As a result, CL&P now has a reasonable chance to earn its allowed 12.9 percent rate of return. Success in Massachusetts was more limited and necessitated filing another rate case in late 1991.

From 1984 through 1990, CL&P was able to counter significant increases in nonfuel costs by a combination of robust sales growth, cost reduction measures, capacity sales to other utilities, a reduction in federal tax rates, and the deferral of

Waterford, Connecticut
John Swenarton, JoAnne Konefal, Linda Bireley, Raymond Heller

substantial costs for future recovery. As a result, CL&P customers were paying only slightly more for their electricity in 1990 than they were seven years earlier, while the Consumer Price Index (CPI) increased more than 30 percent. In Massachusetts, rates increased to a greater extent—still well below the CPI, but not nearly enough to overcome cost increases nor to provide an adequate return on equity (ROE).

Faced with a dramatic slowdown in sales growth and the exhaustion of federal tax credits that had been used to offset rate increases, Western Massachusetts Electric Company (WMECO) filed for a rate increase on December 14, 1990 to reflect cost increases and the need to recover system investments. CL&P filed shortly thereafter, on January 7, 1991.

Connecticut Rate Decision

CL&P's original request for $228 million was subsequently lowered to $200 million to reflect the effectiveness of cost-management programs and lowered costs of capital. On August 1, 1991, the Connecticut Department of Public Utility Control (DPUC) approved a $77.2 million increase, equivalent to about 4 percent. We are somewhat disappointed that CL&P received less than 40 percent of its request. However, it is significant to note that the DPUC did grant nearly 70 percent of the overall $188 million sought in earnings-related increases, while deferring certain items for future recovery.

Among the key provisions of the decision was a continuation of the existing 12.9 percent ROE. The decision also incorporated an equal sharing between shareholders and ratepayers of returns over 12.9 but less than 14.9 percent, with all earnings over the latter figure going to ratepayers. Also approved were the phase-in of an additional 5 percent of allowed Millstone 3 costs, bringing the total of those costs in rate base to 85 percent, and the start of a three-year phase-in of CL&P's 4.06 percent share of Seabrook.

Concerning reductions, the single largest item was nearly $26 million in nonearnings-related conservation expenses, achieved through a reduction in annual spending and amortization of costs over ten years. Another $14.2 million represented previously approved deferrals related to Millstone 3, Hydro-Quebec, and elimination of certain tax benefits. Despite these denials, the commission recognized that deferred accounting plays an important role in ratemaking, so this decision is properly an exception and is not precedent-setting. The remaining reductions included costs and/or recovery time for Hydro-Quebec Phase II amortization, PSNH acquisition costs, medical insurance and benefits, nuclear insurance, and nuclear outage amortization.

Massachusetts Rate Decision

In April 1991, WMECO and the Massachusetts Attorney General reached a settlement that was accepted by the Department of Public Utilities (DPU) on May 3, 1991.

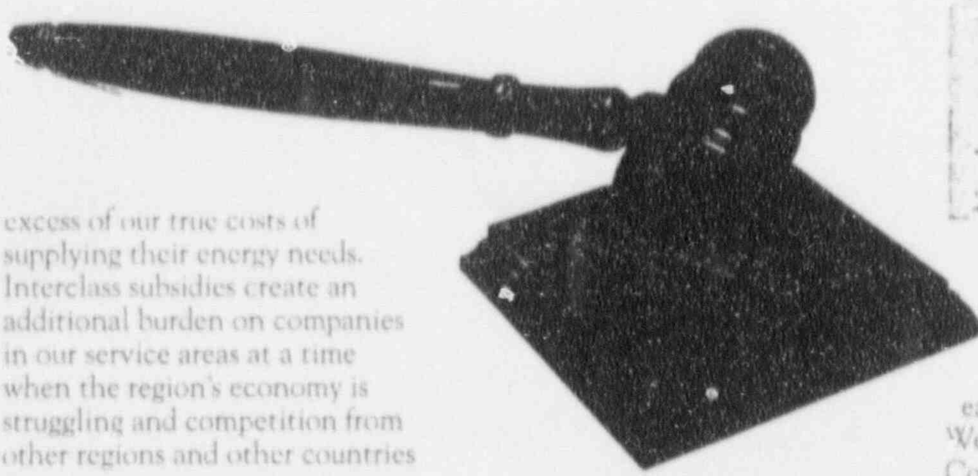
WMECO had requested an increase just over $43 million, or about 11.9 percent. Nearly one-fourth of the request reflected increased state and local taxes and the end of flow-through to

customers of federal tax benefits. The settlement provided 42 percent of that request, or some $18 million. WMECO's earnings will also benefit from an additional six million dollars via a decrease in depreciation expense. Nevertheless, the settlement didn't represent the level of progress needed to restore WMECO to financial health, and another rate case had to be filed in 1991.

Rate Structure

NU has consistently urged the adoption of c...-based rates that would eliminate prevailing cross subsidies that penalize our larger customers with rates well in excess of our true costs of supplying their energy needs. Interclass subsidies create an additional burden on companies in our service areas at a time when the region's economy is struggling and competition from other regions and other countries is fierce. Moreover, a more equitable rate structure for our largest manufacturing customers would better enable NU to retain load, and this directly benefits all ratepayers, regardless of type or size.

Our Connecticut rate filing included a proposed rate structure that would alleviate, but not eliminate, such cross subsidies. To a degree, the DPUC did show progress in this area. Rates for most residential customers increased about 4.9 percent and those for most commercial and industrial customers went up between 2 and 3.5 percent, while the increase for larger manufacturers was held to approximately 1.5 percent.

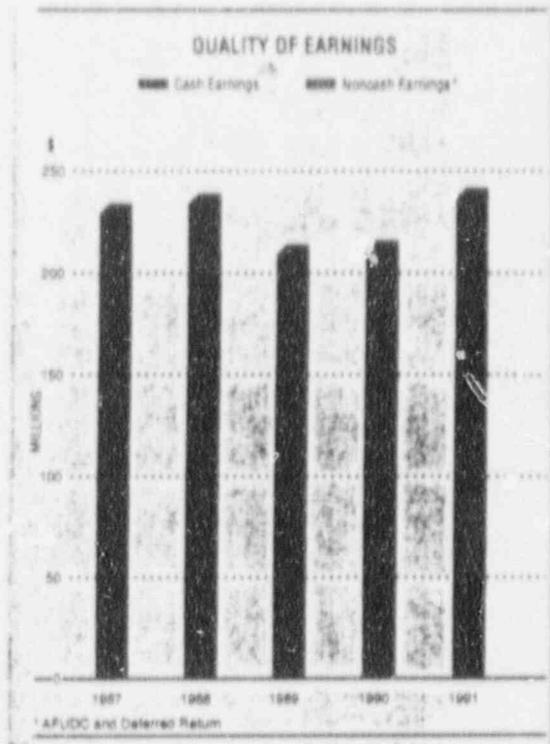


Berlin, Connecticut
Michael Mahoney, Rodney Powell, Janet Palmer

In addition, CL&P received DPUC approval for a series of flexible rates designed to help businesses survive and grow. Each qualifying company will benefit from a five-year schedule of declining discounts and NU will benefit from incremental revenues from in-state business retention and expansion.

Outlook

The wording of the DPUC decision indicated strong support, stating, "It is important...that this DPUC assures that Connecticut's utility companies, including NU, remain strong." The progress made and the



additional revenues granted in the DPUC decision provided CL&P a realistic opportunity to earn its allowed ROE in 1991. We anticipate avoiding another Connecticut rate filing until mid-1992.

The decision in Massachusetts helped set the stage for some progress. Still, immediate further improvement was needed and warranted. Thus, WMECO filed a rate increase application on December 13, 1991, requesting an increase in retail revenues of $35.8 million, or 9.1 percent.

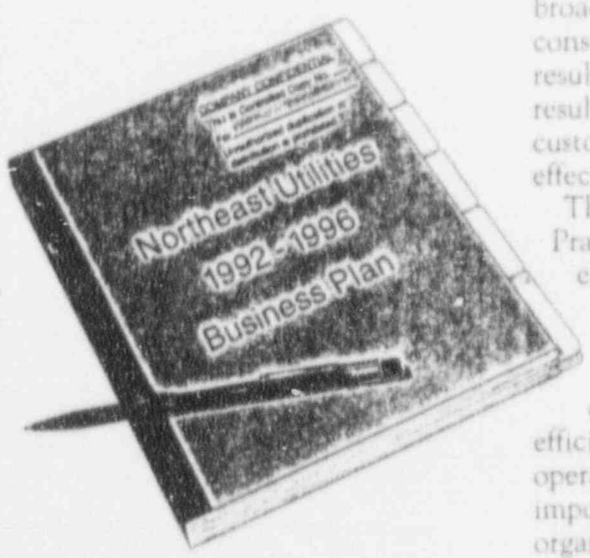
COST MANAGEMENT

The goal of cost-management activities at Northeast Utilities (NU) is to provide service at the lowest possible cost, consistent with our heritage of outstanding service and performance levels. We are working with our employees to contain costs, relying on their experience and dedication and recognizing their value in the achievement of our cost-management initiatives. As a result of this collaborative effort, NU is more cost-effective than it's ever been. Our efforts will continue—and both shareholders and customers will benefit from this dedication.

In response to emerging competition, NU initiated major cost-management efforts in 1987. As a result, NU customers are currently paying only slightly more, on average, for their electricity than they did in 1984.

1991 Accomplishments

In 1991, we intensified our cost-management efforts in response to the continued erosion of the regional economy. All possible expenses that didn't impinge upon safety and service levels were either eliminated or delayed. By year-end, such measures allowed us to reduce budgeted expenses by $101 million, contributing directly to better-than-expected earnings and reducing pressure on rate filings.



Meriden, Connecticut
Glenn Cox, Martin Bartel, Linda Jackson

Between 1987 and 1991, we reduced our staffing level by about 700 employees, primarily through hiring freezes and attrition. In the fall of 1991, just over 400 employees agreed to accept a voluntary early retirement package during 1991/1992. These retirement plans will result in payroll savings estimated at $27 million annually and will bring the total work force reduction since 1987 to more than 1100.

During the third quarter of 1991, NU retired seven of its oldest and least-efficient oil-fired generating units. This action will lower operating and maintenance costs more than $100 million during the 1992-2001 period.

A Systematic Approach

Two innovative cost-management approaches are increasing the scope and comprehensiveness of our cost-management activities. Starting in 1992, we are using a proprietary five-year business plan that features integration across functions. This new approach to planning provides broad business goals in a consistent, well-defined, and results-oriented fashion. The result is a more efficient, customer-responsive, and cost-effective company.

The Corporate Business Practices Group (CBP) was established in June 1991 to work with management throughout the company to identify new opportunities for more efficient, cost-effective operations. Rather than to impose change on a particular organization, the CBP approach is to help the organization identify opportunities for efficiency improvements and to support its members in successful implementation.

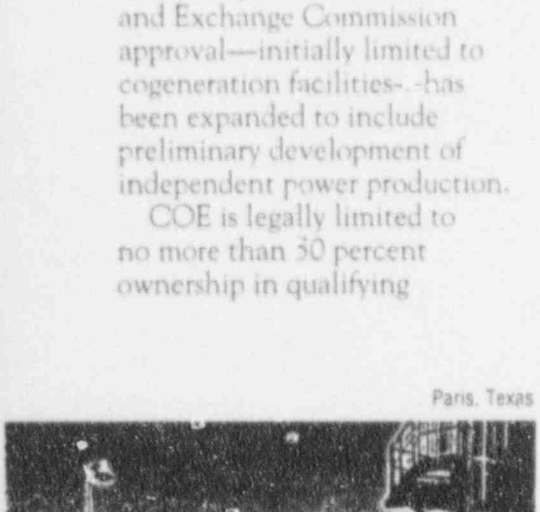
The underlying objective of CBP is to balance cost-effectiveness with outstanding service levels and to do so by working with employees rather than by edict. To date, CBP has actively worked with members of Customer Service Operations and Administrative Services, helping those organizations to identify potential capital and expense reductions in excess of $30 million per year.

Northeast Utilities (NU) is modestly diversifying into unregulated areas, concentrating on the business it knows best—energy-related services. Charter Oak Energy, Inc., (COE) was established to invest in the development and joint ownership of private power generation facilities. HEC Inc., (HEC) was added to provide energy management services. HEC also provides NU state-of-the-art energy conservation services that will benefit customers.

We view cogeneration and independent power production—the focus of COE's activities—as beneficial sources of capacity in the many areas of the country where energy shortages already exist or will soon occur. The diversification initiative represented by HEC puts NU into an important growth area that is focusing upon conservation as a means of addressing the nation's long-term capacity shortages and constraints.

COE is in the early stages of its development. Its Securities and Exchange Commission approval—initially limited to cogeneration facilities—has been expanded to include preliminary development of independent power production.

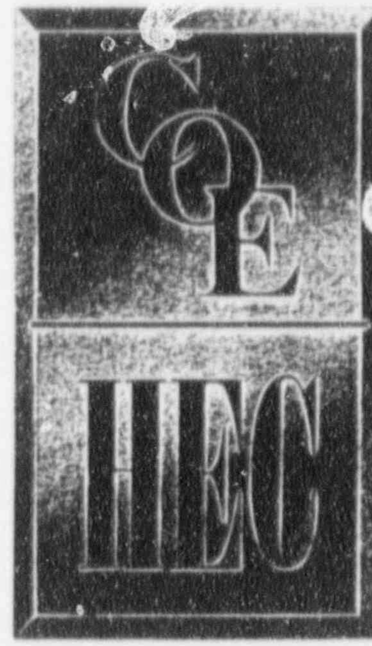
COE is legally limited to no more than 50 percent ownership in qualifying facilities. Thus, it actively seeks strategic alliances with established developers to pursue joint development opportunities. One partner is Tenaska, Inc., the lead developer of a 220-megawatt plant in Paris, Texas, in which COE has a 10 percent interest. Another partner is the Power Development Group, a consortium of six electric utility subsidiaries and an independent development firm, J. Makowski Associates, Inc. COE is pursuing other opportunities in Washington, Texas, Florida, and the Mid-Atlantic states.



Paris, Texas

HEC provides energy services to utilities and to major commercial, industrial, and institutional clients. For utilities, HEC offers consulting services related to demand-side management programs. For hospitals, universities, manufacturers, and office complexes, the HEC mission is to improve the energy efficiency of existing facilities and to recommend energy-conserving measures for new construction and additions.

HEC has more than 100 clients in 15 states, primarily in the Northeast and Midwest. A market expansion program will increase its penetration in West Coast and Canadian markets. HEC typically provides turnkey operations, including post-installation service, but it also offers discrete services such as concept development and engineering. Projects range in value from one hundred thousand to several million dollars. Among projects in progress or completed in NU's service area are those for Hartford Hospital, Connecticut College, and the United States Coast Guard Academy.



COE and HEC represent two very different opportunities, but they also share important common attributes. Both are well-positioned in high-growth, energy-related markets. Both have the potential for returns in excess of those currently allowed or projected for our regulated core business. Finally, both should create future value for shareholders, and—over time—contribute to earnings.

CUSTOMER AND COMMUNITY SERVICE

The needs and expectations of our customers are growing. It is also important that NU's customer service functions become more cost effective. Thorough analysis and judicious planning will result in achievement of both requirements.

Our concept of service also encompasses assistance for customers experiencing economic hardships. Likewise, it focuses upon individuals whose special needs benefit from the charitable activities supported by the company and by the spirit of giving and volunteerism of its employees.

Customer Service

Formation of the new Customer Service Operations (CSO) organization in 1990 was the initial step in a plan to increase the efficiency of services provided to customers. CSO is now in process of implementing three fundamental changes that will improve the quality of services provided and—at the same time—lessen the costs associated with these services.

In the first case, reorganization of the Transmission and Distribution staff will result in a smaller, more streamlined operation. An entire layer of management will be eliminated in some units. Consolidation of the five regional customer inquiry functions in Connecticut into a new Customer Inquiry Center represents the second change being

implemented. By taking advantage of more intensive automation, this change will improve our response time to customer inquiries and requests and will promote more uniform service for our customers. Once fully implemented, these changes will save almost $5 million annually. In a similar fashion, centralization of the Credit and Collection function will retain and enhance existing skills, while gaining substantial benefits from new collection software and a more sophisticated telephone system.

Madison, Connecticut
Sharon Fantarella, Grace Barbour, John Fuller

Community Service

NU actively supports charitable endeavors by direct financial aid, donation of in-kind services, and encouraging customer contributions to energy fuel funds. The NU commitment to community service has always been matched by the concern of our employees, who give most generously of their money, time, and talents. Our long-standing involvement with the Connecticut Special Olympics is an excellent example of the synergism represented by NU and its employees. For the 1991 Connecticut Special Olympics Nordic events—of which NU was the primary sponsor—the support provided for the normal preparation for the competition was augmented by a massive snow-making operation in order to avoid postponements that occurred in two of the three previous years. With equipment and supplies donated by NU and other concerned companies, NU volunteers worked around the clock on two weekends and after-hours on the days preceding the event to give Mother Nature an assist and to assure the events went off as scheduled.

Our concept of community service goes beyond support of charitable activities and organizations. Our energy conservation programs focus upon the special needs of disadvantaged customers. For example, NU conducted saturation campaigns in selected cities as part of our SPECTRUM™ Neighborhood Program. During 1991, 15,000 needy customers in Connecticut and Massachusetts benefited from the free energy conservation products and services provided as a result of these campaigns.

Contents

This section contains management's assessment of Northeast Utilities' (the company or NU) financial condition and the principal factors having 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

Overview

The company's earnings per share increased to $2.12 in 1991 from $1.94 in 1990. This increase was primarily attributable to lower interest charges resulting from lower interest rates and lower capital requirements. The increase was also attributable to the effects of the August 1991 Connecticut Department of Public Utility Control (DPUC) retail rate decision for The Connecticut Light and Power Company (CL&P) and the 1990 and 1991 Massachusetts Department of Public Utilities (DPU) retail rate decisions for Western Massachusetts Electric Company (WMECO). These rate decisions provided for the recovery of higher operating expenses, which were limited by intensive cost-containment measures instituted by management. These items were partially offset by lower 1991 electric sales, which were primarily the result of a downturn in the region's economy and moderate weather throughout most of 1991.

As of December 31, 1991, CL&P and WMECO have phased into rate base 80 percent and 100 percent of their respective allowed Millstone 3 investments. In the August 1991 decision, the DPUC authorized CL&P to recognize in rates, effective September 1, 1991, the first step of a three-year phase-in plan for its allowed Seabrook 1 investment. In addition, CL&P was authorized to recognize in rates, effective January 1, 1992, an additional 5 percent of its allowed Millstone 3 investment. As a result of additional phase-in recoveries, cash earnings, which exclude deferred return and allowance for funds used during construction (AFUDC), have continued to increase. The percentage of cash earnings has increased from 67.2 percent for the year ending December 31, 1990 to 71.6 percent for the year ending December 31, 1991. Despite this improvement, other factors continue to affect the financial health of the company. The continued decline in New England's economy has adversely affected the company's sales. Sales in 1992 are projected to be relatively flat, compared to 1991 sales, with slight increases forecasted throughout the remainder of the 1990s.

The market price of the company's common shares continued to remain well above book value in 1991. The closing price of the company's common shares at December 31, 1991 was $23⅝ per share, compared to $20 per share in 1990. Common dividends paid in 1991 and 1990 were $1.76 per share. After considering the current high dividend payout ratio (1991 dividends were equal to 83 percent of earnings), a 1992 projection of continued modest earnings, and the potential dividend requirements on new common share issues that will be needed to finance the acquisition of Public Service Company of New Hampshire (PSNH), the company's Board of Trustees concluded that a dividend increase at this time is not appropriate. Therefore, on January 28, 1992, the Board voted to maintain the current quarterly dividend level at $0.44 per share. Projected 1992 earnings are also subject to continued uncertainty about when the PSNH acquisition will occur, the performance of the regional economy, and the outcome of the pending WMECO retail rate increase request.

Because of the prevailing poor economic climate, the company's 1992 financial objectives continue to be very conservative. The principal focus in the short-term is to maintain financial ratios and earnings at their current levels. If current financial performance is maintained in this difficult economic environment and adequate rate relief is provided, these circumstances, coupled with the addition of earnings from PSNH and the new subsidiary that will hold PSNH's Seabrook interest, North Atlantic Energy Corporation (NAEC), should bolster NU's earnings in the long run and enable the company to consider dividend increases and improve key financial indicators.

Management had hoped for more favorable rate decisions in 1991 in both the CL&P and WMECO retail rate cases in order to accelerate the pace at which the company could improve its financial condition. Although management is somewhat disappointed with the level of relief provided, they believe that the rate increases, together with the company's cost-management efforts, have provided NU an opportunity to maintain its financial stability. Management also believes that a favorable decision in the upcoming WMECO retail rate case will afford the company a realistic opportunity to improve earnings. The company would then be in a better position to meet its ongoing responsibility of providing quality energy services to its customers while building a base upon which progress can be made toward achieving the company's long-term financial objective of providing a fair return to investors and allowing access to capital markets on more reasonable terms.

Cost Containment

In 1991, the company offered voluntary early retirement programs to 631 eligible employees in Connecticut and Massachusetts. The programs were available generally to general offices, regional and district services support staff, and employees at certain fossil generating facilities.

Of the 631 eligible employees, 438 accepted the offer. The programs resulted in a one-time, pretax cost of approximately $32 million. Management believes that the plans will save the company approximately $27 million in annual payroll costs. The retirement offers were made as a result of management's continuing efforts to maintain competitiveness in the energy services business and to limit the need for future rate increases.

NU has reduced its work force by more than 1,100 employees, or approximately 12 percent, from its 1987 levels, mainly through attrition and the early retirement programs.

On August 31, 1991, NU retired seven oil-fired generating units at two locations in Connecticut and one in Massachusetts. The company's continued commitment to cost management and the surplus of electric generating capacity in New England were factors in the decision to retire the generating units, which represented approximately 6 percent of the company's overall generating capability. All of the units were among the oldest, least-used, and costliest-to-operate facilities in the NU system. NU estimates that retirement of the seven generating units will save the company more than $1.0 million over the next decade, mostly through reduced operating and maintenance costs.

PSNH

After hearing oral arguments on January 8, 1992, the Federal Energy Regulatory Commission (FERC) voted unanimously, on January 29, 1992, to approve an amended decision on the PSNH acquisition. NU's management believes that the FERC's amended decision addresses the most critical concerns raised in an August 1991 FERC decision, with respect to conditions on which others would be permitted to use the NU-PSNH transmission system. Management also believes that the decision should allow NU and PSNH to move promptly toward the completion of the acquisition.

The FERC decision was the subject of DPUC hearings that were completed in February 1992. The DPUC also held hearings last fall on the financial impact of the acquisition but had been awaiting the FERC decision before issuing an overall decision on the transaction. NU hopes to complete the acquisition soon after a final DPUC decision, now expected on March 31, 1992.

For information regarding acquisition financings, see the "Financing" section in the next column.

For additional information regarding the PSNH acquisition, see the "Notes to Consolidated Financial Statements."

Construction Program

The construction program's main focus is now on the upgrading of existing transmission, distribution, and generating facilities. To complement an already strong base of generation capability, the company budgeted more than $100 million over the next five years to improve transmission and distribution reliability. The company does not foresee the need for new major generating facilities until the year 2005, primarily because of the implementation of comprehensive conservation and load-management (C&LM) programs that have already resulted in significant energy savings, low forecasted sales growth, and firm long-term purchase commitments for Canadian hydropower. In addition, energy provided by new cogeneration and small power producers continues to postpone the need for the construction of new generating facilities.

The charts on the next page show the projected level of electric construction expenditures for the period 1992 to 1996, compared with the actual level for the period 1987 to 1991, and the change in the nature of the expenditures.

The company plans to replace the Millstone 2 steam generators in mid-1992. The total cost of the replacement is currently estimated to be $190 million. That amount includes AFUDC but does not include the cost of replacement power.

Financing

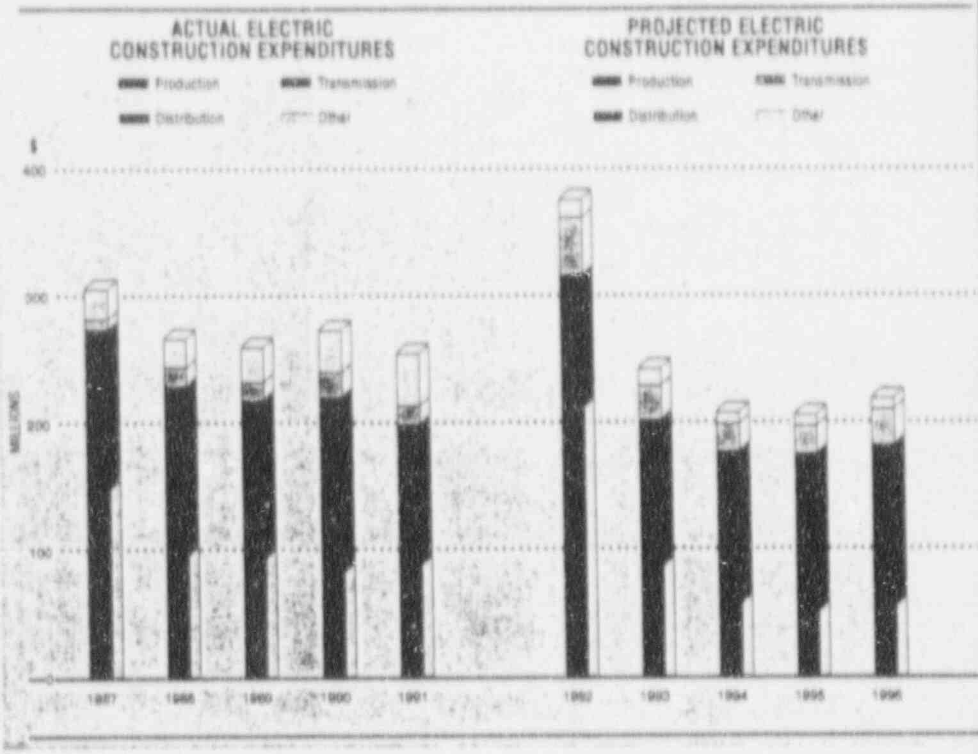
Cash requirements in excess of internally generated funds generally are financed through short-, intermediate-, and long-term borrowings, nuclear fuel trust financing, leasing agreements, and the sale of preferred and common stock. In addition to construction and nuclear fuel requirements, the system companies are obligated to meet maturities and cash sinking-fund requirements for long-term debt and preferred stock totaling $714.6 million for the years 1992 through 1996, without giving effect to any financings associated with the acquisition of PSNH. External financing will continue to be necessary to meet total cash requirements.

In December 1991, NU sold $175 million of amortizing unsecured 15-year notes at a rate of 8.58 percent. Proceeds of the sale were used to make a loan to the NU Employee Stock Ownership Plan Trust (ESOP trust). The ESOP trust then used the proceeds to purchase approximately 7.6 million common shares from NU at a price of $23 a share. Over the coming years, these shares will be allocated to eligible employees of the NU system companies in connection with the employer match feature of the existing 401(k) supplemental retirement and savings plan. The proceeds to NU from the sale of the common shares are expected to be used to fund part of NU's equity investment in PSNH and NAEC.

Prior to the expected acquisition of PSNH, the net proceeds of $173.7 million were loaned by NU to the system's money pool and, in turn, were used by system companies to repay outstanding short-term debt.

CL&P and WMECO continue to utilize a nuclear fuel trust to finance their nuclear fuel requirements for Millstone 1, 2, and 3. As of December 31, 1991, the trust's investment in nuclear fuel was $222.2 million. Nuclear fuel requirements for Millstone 1, 2, and 3 of $322.7 million for the years 1992 to 1996 are expected to be financed by the trust.

The chart on the next page illustrates the relative percentages of all major sources of funds for the five-year period 1987 to 1991.



In 1992, the NU system companies expect to finance $193 million, or approximately 38 percent, of their non-PSNH requirements externally. This amount includes $50 million for nuclear fuel requirements that are expected to be financed by the Niantic Bay Fuel Trust. The system companies continue to pursue opportunities to refinance high-cost securities. Elimination of higher cost debt, or replacement with lower cost capital, provides opportunities for short-term improvement in earnings and a long-term reduction in revenue requirements.

The total cash required to effect the acquisition of PSNH is approximately $922 million, assuming an April 1, 1992 merger date. Each month of delay adds about $7 million to the cost of the acquisition due to the additional accrual of stock dividends. The merger is expected to take place in the second quarter of 1992. The expected sources of the $922 million requirement are a $410 million equity investment by NU in PSNH, a $157 million equity investment by NU in NAEC, (both of which are expected to be funded by NU sales of common shares and borrowings), and NAEC's issue and sale of $355 million principal amount of first mortgage bonds. The proceeds will be used to pay $639 million to PSNH common stockholders, pay $132 million for stock dividends accrued to April 1, 1992, reimburse $45 million of NU acquisition expenses under the plan of reorganization, pay a $7 million tax on the transfer of Seabrook from PSNH to NAEC, and provide $52 million to reduce PSNH's term note. The balance would be used to reduce PSNH's revolving credit arrangements.

In total, NU plans to offer approximately 25 million new common shares in connection with this acquisition. As a part of this total, NU issued 7.6 million common shares to the ESOP trust in December 1991. The ESOP trust purchased these shares from NU for $175 million with the proceeds of a public offering by NU of its debt securities. A second $75 million issue of NU common shares to the ESOP trust is planned for the end of the first quarter of 1992. A public offering of about $200 million of NU common shares is expected at or shortly before the acquisition. Any remaining balance would be raised by NU in the commercial paper markets or through bank borrowings and would be repaid over a period of three years or less by additional sales of NU common shares through NU's Dividend Reinvestment Plan.

In addition, the reorganization plan calls for PSNH equity security holders to receive warrants to purchase approximately 8.4 million NU common shares. The warrants would be exercisable for five years after the acquisition at an exercise price of $24 per share.

Management expects that, if the market conditions for NU common shares remain at the levels attained at the end of 1991 and early 1992, then any dilution of its earnings resulting from the issuance of additional common shares should be minimal and should

be more than offset by the benefits of the acquisition. The company expects that over the long-term, the acquisition will enhance shareholders' prospects for improved dividends.

The PSNH financing plan has been structured so that NU will ultimately obtain its cash requirements from the sale of common shares. In addition, PSNH and NAEC will meet their own debt and preferred stock obligations. Accordingly, NU will not be dependent on cash distributions from any current NU operating company either to pay interest or principal on the debt NU incurs for the acquisition or to pay dividends on common shares issued in connection with the acquisition.

Rate Matters

In August 1991, the DPUC approved CL&P's first retail base rate increase since late 1988. The August decision provided for an annual increase in electric revenues of $77.2 million, or approximately 4 percent. CL&P had requested an annual increase in revenues of approximately $200 million, or 10.4 percent. Other significant aspects of the decision include the continuation of CL&P's allowed return on equity (ROE) at 12.9 percent, with levels between 12.9 percent and 14.9 percent shared equally between CL&P and its customers, provisions for a three-year phase-in of $167 million of CL&P's initial investment in Seabrook 1, and approval of requested nuclear decommissioning expenses.

Although the amount and timing have not been determined, management presently expects that it will be necessary for CL&P to apply to the DPUC in the second half of 1992 for increased rates, to become effective in the first half of 1993.

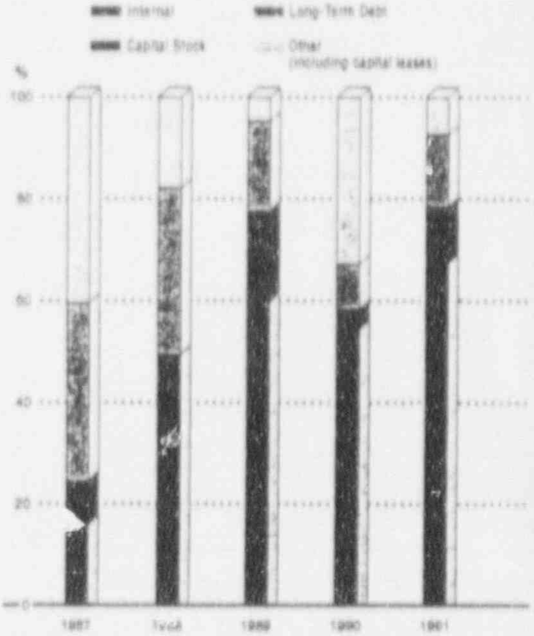
The DPU issued a final decision, effective July 1, 1991, which increased WMECO's base rates by more than $32 million and provided for the continuation of its 12.5 percent allowed ROE. WMECO had requested an increase of $43.3 million, or 11.9 percent. The order incorporated a partial settlement agreement that was approved by the DPU in May 1991, which allowed an $18 million retail rate increase and authorized WMECO to depreciate its electric generation, transmission, and distribution equipment over a longer period. While the July 1991 order provided an additional $9.9 million increase for C&LM expenditures and a $4.3 million increase for WMECO's investment in Hydro-Quebec, these amounts represented only a shift in the recovery mechanism for these costs to base rates from the fuel adjustment clause and did not increase WMECO's total revenues.

Even with the July 1991 rate increase, WMECO's 1991 ROE was 10.1 percent, far below the 12.5 percent that the DPU had authorized. Notwithstanding the rate decision, management believes WMECO cannot earn its allowed ROE in 1992 without increased rates. Therefore, in December 1991, WMECO filed an application with the DPU requesting an increase in annual retail electric revenues of $35.8 million, or 9.1 percent. The need for an increase is driven by necessary capital projects, higher costs of service, and a depressed market for wholesale power.

Environmental Matters

The company devotes substantial resources to identifying and then attempting to meet the multitude of environmental requirements that it faces. The company has active auditing programs that address a variety of different regulatory requirements, including an environmental auditing program. To the extent that management determines that a system operation or facility is not in full compliance with applicable environmental laws or

SOURCE OF CASH REQUIREMENTS



regulations, the company attempts to resolve noncompliance through the auditing response process or other management processes.

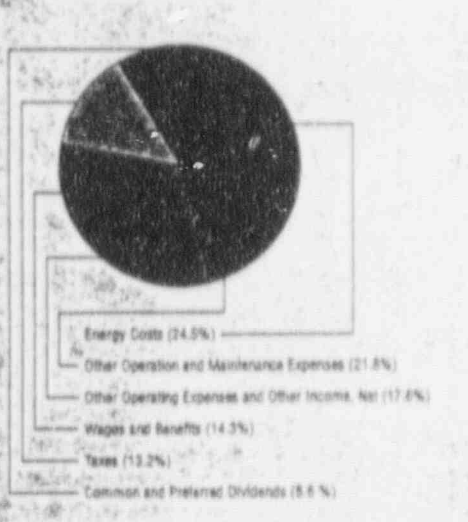
For information regarding nuclear decommissioning, environmental matters, and other contingencies, see the "Notes to Consolidated Financial Statements."

Nuclear Performance

The performance of the three nuclear electric generating units located at Millstone Station was less than satisfactory in 1991. The three units' composite capacity factor was only 38.4 percent in 1991 compared with 79.3 percent in 1990. In 1990 the national average was 66.1 percent. These lower capacity factors were the result of planned outages and a number of unexpected technical and operating difficulties that led to unplanned outages.

When the nuclear units are out of service, CL&P and WMECO must generate and/or purchase replacement

1991 DISTRIBUTION OF REVENUE



power to meet their customers' needs. In January 1992, the DPUC announced plans to conduct public hearings to determine whether replacement power costs incurred by CL&P during extended outages at the three nuclear power units at Millstone should be passed on to customers or borne by shareholders. The DPUC could disallow some or all of the replacement power costs if the company is found imprudent in the outages at the nuclear units. Replacement power costs are estimated at about $108 million and $21 million for CL&P and WMECO, respectively, and are related to four separate Millstone outages. One outage occurred during October 1990, and the other three outages occurred at different times between July 1991 and February 1992.

In Massachusetts, the DPU allows full recovery of energy costs through a fuel adjustment clause that is calculated on a quarterly basis. An annual performance program related to fuel procurement and use was established by Massachusetts law and requires the DPU to review generating unit performance and fuel costs if the utility fails to meet the performance goals set for that utility. Fuel clause revenues collected in Massachusetts are subject to potential refund, pending the DPU's examination of the actual performance of generating units in which WMECO has interests.

Management believes that the companies have acted prudently in the operation of their nuclear units during the periods discussed above and that their fuel adjustment clauses permit recovery for prudently incurred costs. However, it will be necessary for CL&P and WMECO to demonstrate to the DPUC and the DPU, respectively, that their actions have been prudent.

In an effort to improve nuclear performance, NU management has decided, among other actions, to add approximately 200 new positions in the nuclear engineering and operations function and to expedite completion of certain programs, at an annual payroll cost of $10 million.

Accounting Standards

The Financial Accounting Standards Board (FASB) has superseded previously issued income tax accounting standards with the issuance of Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109). SFAS 109 requires, among other things, that regulated utilities reflect, on their balance sheets, the taxes related to the cumulative amount of income tax timing differences for which deferred taxes have not been provided. The company expects that, when the new standard becomes effective in 1993, it will increase assets and liabilities by approximately $600 to $700 million but will not have a material effect on net income.

In December 1990, the FASB issued Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions (SFAS 106). This new standard, which will be adopted in 1993, requires that the expected cost of these benefits be charged to expense during the years that employees render service. This is a significant change from the company's current policy of recognizing these costs as they are paid. CL&P and WMECO will petition their regulators to recover these costs, including those related to prior service, in future rate proceedings. While CL&P and WMECO expect to recover these costs, should the timing of recovery differ from the accrual of such costs, the companies would expect to record a regulatory asset for the difference.

For additional information regarding SFAS 106, see the "Notes to Consolidated Financial Statements."

RESULTS OF OPERATIONS

The relative magnitude of the various expenditures incurred by the system's continuing operations is illustrated in the chart on this page.

Operating Revenues

Operating revenues increased $137.5 million from 1990 to 1991 and increased $142.7 million from 1989 to 1990. The components of the change in operating revenues for the past two years are provided in the table on the next page.

Revenues related to regulatory decisions increased in 1991, as compared to 1990, primarily because of the effects of the June 1990 and the July 1991 DPU retail rate decisions for WMECO and the December 1990 and the August 1991 DPUC retail rate decisions for CL&P. Fuel cost recoveries increased primarily because of a significantly higher level of higher priced outside energy purchases. Sales and other revenues increased primarily because of a

Change in Operating Revenues

	Increase/(Decrease)	
	1991 vs. 1990	1990 vs. 1989
	(Millions of Dollars)	
Regulatory decisions	$ 57.8	$ 39.0
Fuel cost recoveries	38.1	79.9
Sales and other revenues	41.6	23.8
Total revenue change	$137.5	$142.7

settlement agreement associated with the reactivation of various units at three fossil generating facilities and higher 1991 WMECO cost recoveries associated with conservation, capacity, and transmission activities.

Revenues related to regulatory decisions increased in 1990, as compared to 1989, primarily because of the effects of the June 1989 and June 1990 DPU retail rate decisions. Fuel cost recoveries increased primarily because of higher energy costs. Sales and other revenues increased primarily as a result of an increase in bulk power sales.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power increased $55.4 million in 1990, as compared to 1989, primarily because of a greater level of higher priced cogeneration purchases, partially offset by a greater utilization of lower cost nuclear generation.

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased $58.8 million in 1991, as compared to 1990, primarily because of higher costs associated with the voluntary early retirement programs, the commercial operation of the Phase II Hydro-Quebec project, and the identification and expensing of excess/obsolete inventory at the Millstone units.

Other operation and maintenance expenses increased $64.6 million in 1990, as compared to 1989, primarily because of higher costs associated with C&LM programs, refueling and maintenance activities at nuclear electric production facilities, including the amortization of prior-period outage costs, legal and regulatory activities associated with NU's efforts to acquire PSNH, and the general impact of inflation on most expenses, partially offset by management's cost-containment efforts in 1990.

Depreciation Expenses

Depreciation expenses increased $26.4 million in 1991, as compared to 1990, primarily as a result of a regulatory decision that required the company to return, in 1990, excess deferred taxes associated with net-of-tax AFUDC and higher depreciable plant balances in 1991.

Depreciation expenses increased $14.6 million in 1990, as compared to 1989, primarily because of greater plant investment and higher depreciation rates.

Taxes

Federal and state income taxes increased $57.0 million in 1991, as compared to 1990, primarily because of higher taxable income, partially offset by an adjustment for revenue agent reviews which were concluded in the fourth quarter. Taxes other than income taxes increased $5.0 million in 1991, as compared to 1990, primarily because of higher property taxes and higher Connecticut gross earnings taxes due to higher revenues.

Federal and state income taxes decreased $6.4 million in 1990, as compared to 1989, primarily because of tax benefits associated with the 1990 write-off of a portion of CL&P's initial investment in Seabrook 1 resulting from a settlement agreement approved by the DPUC in November 1990. Taxes other than income taxes increased $7.2 million in 1990, as compared to 1989, primarily because of higher property taxes.

Interest Charges

Interest charges decreased $22.9 million in 1991, as compared to 1990, primarily because of more favorable interest rates and lower capital requirements.

Interest charges decreased $13.3 million in 1990, as compared to 1989, primarily because of lower long-term debt levels, partially offset by higher short-term debt levels.

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 audited by Arthur Andersen & Co., were prepared in accordance with generally accepted accounting principles using estimates and judgment, where required, and giving consideration to materiality.

The company has endeavored to establish a control environment that encourages the maintenance of high standards of conduct in all of its business activities. 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. Through established programs, the company regularly communicates to its management employees their internal control responsibilities and policies prohibiting 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 audit matters, financial reporting, and the adequacy of internal controls.

Because of inherent limitations in any system of internal controls, errors or irregularities may occur and not be detected. The company believes, however, that its system of internal accounting controls and control environment provide 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.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Trustees and Shareholders of Northeast Utilities:

We have audited the consolidated balance sheets and consolidated statements of capitalization of Northeast Utilities (a Massachusetts trust) and subsidiaries as of December 31, 1991 and 1990, and the related consolidated statements of income, common shareholders' equity, cash flows, and income taxes for each of the three years in the period ended December 31, 1991. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Northeast Utilities and subsidiaries as of December 31, 1991 and 1990, and the results of their operations and cash flows for each of the three years in the period ended December 31, 1991, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN & CO.

Hartford, Connecticut
February 26, 1992

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	1991	1990	1989
	(Thousands of Dollars, except share information)		
Operations Excluding Discontinued Gas Operations:			
Operating Revenues	$ 2,753,803	2,616,319	$ 2,473,571
Operating Expenses:			
Operation—			
Fuel, purchased and net interchange power	674,096	678,257	622,814
Other	763,610	696,699	629,791
Maintenance	230,166	238,323	240,587
Depreciation	238,575	212,212	197,630
Amortization/deferrals of regulatory assets, net	80,643	74,166	71,763
Federal and state income taxes (See Consolidated Statements of Income Taxes)	190,556	154,412	151,401
Taxes other than income taxes	186,645	181,688	174,480
Total operating expenses	2,364,291	2,235,757	2,088,466
Operating Income	389,512	380,562	385,105
Other Income:			
Allowance for other funds used during construction	1,959	3,444	2,713
Deferred nuclear plants return—other funds	39,477	38,992	42,407
Equity in earnings of regional nuclear generating companies and transmission companies	14,431	14,152	12,030
Write-off of plant costs	—	(19,388)	(9,010)
Other, net	9,753	12,967	8,090
Income taxes—credit	14,873	37,790	27,797
Other income, net	80,493	87,957	84,027
Income before interest charges	470,005	468,519	469,132
Interest Charges:			
Interest on long-term debt	205,585	218,858	230,212
Other interest	10,915	20,558	22,538
Allowance for borrowed funds used during construction	(6,770)	(7,191)	(5,876)
Deferred nuclear plants return—borrowed funds, net of income taxes	(19,023)	(19,678)	(19,770)
Interest charges, net	190,707	212,547	227,104
Income after interest charges	279,298	255,972	242,028
Preferred Dividends of Subsidiaries	42,589	44,965	38,803
Income from Continuing Operations	236,709	211,007	203,225
Income from Discontinued Gas Operations	—	—	5,858
Net Income	$ 236,709	$ 211,007	$ 209,083
Earnings Per Common Share:			
Continuing operations	$ 2.12	$ 1.94	$ 1.87
Discontinued gas operations	—	—	.05
Net Income	$ 2.12	$ 1.94	$ 1.92
Common Shares Outstanding (average)	111,453,550	109,003,818	108,669,106

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	1991	1990	1989
		(Thousands of Dollars)	
Cash Flows From Operations:			
Income before preferred dividends	$ 279,298	$ 255,972	$ 242,028
Adjusted for the following:			
Depreciation and amortization of leased property	292,471	325,354	304,724
Deferred income taxes and investment tax credits, net	109,820	33,066	37,506
Deferred nuclear plants return, net of amortization	4,687	(1,476)	(10,397)
Deferred fuel, net of amortization	(128,047)	15,060	(3,430)
Deferred conservation and load-management costs, net of amortization	(47,402)	(5,196)	—
Net change in deferred charges and other noncash items	42,088	17,307	71,673
Changes in working capital:			
Receivables and accrued utility revenues	(57,289)	24,602	(41,898)
Fuel, materials, and supplies	33,191	(18,967)	(24,767)
Accounts payable	83,891	(24,750)	38,967
Accrued taxes	(46,208)	19,227	10,360
Other working capital (excludes cash)	29,369	(21,608)	(22,727)
Net cash flows from operations	595,869	618,591	602,039
Cash Flows From Financing Activities:			
Common shares	42,420	17,888	—
Long-term debt and preferred stock	197,207	61,144	295,121
Increase in obligations under capital leases	29,263	88,982	32,515
Net increase (decrease) in short-term debt	(125,615)	67,115	(25,000)
Reacquisitions and retirements of long-term debt and preferred stock	(119,488)	(99,523)	(390,168)
Repayment of capital lease obligations	(65,014)	(108,314)	(103,283)
Cash dividends on preferred stock	(42,589)	(44,965)	(39,779)
Cash dividends on common shares	(195,056)	(191,851)	(191,258)
Special dividend—discontinuance of gas operations	—	—	(101,012)
Net cash flows from financing activities	(278,872)	(209,524)	(522,864)
Investment Activities:			
Investments in plant (including capital leases):			
Electric and other utility plant	(250,482)	(292,902)	(259,430)
Gas utility plant	—	—	(11,159)
Nuclear fuel	(23,253)	(86,375)	(22,636)
Less: Allowance for other funds used during construction	(1,959)	(3,444)	(2,713)
Net cash flows used for investments in plant	(271,776)	(375,833)	(290,512)
Discontinuance of gas operations	—	—	244,980
Other investment activities, net	(24,252)	(25,466)	(38,987)
Net cash flows used for investments	(296,028)	(401,299)	(84,519)
Net Increase (Decrease) In Cash For The Period	20,969	7,768	(5,344)
Cash beginning of period	16,302	8,534	13,878
Cash end of period	$ 37,271	$ 16,302	$ 8,534
Supplemental Cash Flow Information:			
Cash paid during the year for:			
Interest, net of amounts capitalized during construction	$ 201,021	$ 214,233	$ 244,239
Income taxes	$ 116,334	$ 61,642	$ 90,479

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

For the Years Ended December 31,	1991	1990	1989
	(Thousands of Dollars, except percentages)		
The components of the federal and state income tax provisions charged to continuing operations are:			
Current income taxes:			
Federal	$ 44,417	$ 55,581	$ 60,796
State	21,446	27,975	25,302
Total current	65,863	83,556	86,098
Deferred income taxes, net:			
Federal	88,659	43,776	44,275
State	28,007	7,792	8,002
Total deferred	116,666	51,568	52,277
Investment tax credits, net	(7,869)	(17,414)	(14,305)
Total income tax expense	$ 174,660	$ 117,710	$ 124,070
The components of total income tax expense are classified as follows:			
Income taxes charged to operating expenses	$ 190,556	$ 154,412	$ 151,401
Income taxes associated with the amortization of deferred nuclear plants return—borrowed funds	(15,208)	(13,454)	(13,942)
Income taxes associated with the allowance for funds used during construction (AFUDC) and deferred nuclear plants return—borrowed funds	14,185	14,542	14,408
Other income taxes—credit	(14,873)	(37,790)	(27,797)
Total income tax expense	$ 174,660	$ 117,710	$ 124,070
Deferred income taxes are comprised of the tax effects of timing differences as follows:			
Depreciation, excluding leased nuclear fuel	$ 59,807	$ 53,439	$ 51,857
Construction overheads	(979)	(11,156)	(10,473)
Depreciation on leased nuclear fuel, settlement credits, and disposal costs	(2,367)	2,369	7,068
Decommissioning costs	(1,186)	(1,245)	942
Energy adjustment clauses	48,892	2,398	(4,825)
AFUDC and deferred nuclear plants return, net	(1,023)	1,088	465
Early retirement program accrual	(11,612)	—	—
Pension accrual	(656)	5,408	7,587
Conservation and load management	22,175	4,355	(1,595)
Other	3,615	(5,088)	1,251
Deferred income taxes, net	$ 116,666	$ 51,568	$ 52,277
The effective income tax rate is computed by dividing total income tax expense by the sum of such taxes and income after interest charges. The differences between the effective rate and the federal statutory income tax rate are:			
Federal statutory income tax rate	34.00%	34.00%	34.00%
Tax effect of differences:			
Depreciation differences	2.24	1.26	1.25
Deferred nuclear plants return—other funds	(2.96)	(3.55)	(3.94)
Amortization of deferred nuclear plants return—other funds	3.48	3.77	3.50
Construction overheads	(0.22)	(3.09)	(3.14)
Investment tax credit amortization	(1.73)	(4.66)	(2.62)
State income taxes, net of federal benefit	7.23	6.37	6.08
Adjustment for prior years taxes	(1.76)	—	—
Other, net	(1.81)	(2.60)	(1.24)
Effective income tax rate	38.47%	31.50%	33.89%

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

CONSOLIDATED BALANCE SHEETS

At December 31,	1991	1990
	(Thousands of Dollars)	
Assets		
Utility Plant, at original cost:		
Electric	$6,898,919	$6,753,512
Other	103,779	100,852
	7,002,698	6,854,364
Less: Accumulated provision for depreciation	2,182,144	2,033,568
	4,820,554	4,820,796
Construction work in progress	200,843	184,551
Nuclear fuel, net	236,170	259,821
Total net utility plant	5,257,567	5,265,168
Other Property and Investments:		
Nuclear decommissioning trusts, at cost (Note 3)	124,592	100,196
Investments in regional nuclear generating companies, at equity	68,125	67,489
Investments in transmission companies, at equity	30,800	28,551
Other, at cost	31,286	32,023
	254,803	228,259
Current Assets:		
Cash and special deposits	37,271	16,302
Receivables, less accumulated provision for uncollectible accounts of $11,607,000 in 1991 and $10,588,000 in 1990	309,801	264,939
Accrued utility revenues	112,581	100,154
Fuel, materials, and supplies, at average cost	146,753	179,944
Prepayments and other	41,521	41,559
	647,927	602,898
Deferred Charges:		
Unamortized debt expense	15,953	14,461
Energy adjustment clauses, net	127,164	21,265
Unrecovered spent nuclear fuel disposal costs	26,702	29,866
Deferred costs—nuclear plants	263,772	275,267
Amortizable property investments	61,587	75,582
Other	126,271	88,605
	621,449	505,046
Total Assets	$6,781,746	$6,601,371

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

At December 31,	1991	1990
	(Thousands of Dollars)	
Capitalization and Liabilities		
Capitalization: (See Consolidated Statements of Capitalization)		
Common shareholders' equity:		
Common shares, $5 par value—authorized 225,000,000 shares; outstanding 119,254,125 shares in 1991 and 109,615,926 shares in 1990	$ 596,271	$ 548,080
Capital surplus, paid in	640,119	469,647
Deferred benefit plan—ESOP (Note 6)	(175,000)	—
Retained earnings	814,684	773,031
Total common shareholders' equity	1,876,074	1,790,758
Preferred stock not subject to mandatory redemption	394,695	394,695
Preferred stock subject to mandatory redemption	167,892	174,392
Long-term debt	2,616,932	2,501,891
Total capitalization	5,055,593	4,861,736
Obligations Under Capital Leases	213,374	221,833
Current Liabilities:		
Notes payable to banks	62,500	105,500
Commercial paper	—	82,615
Long-term debt and preferred stock—current portion	82,833	104,123
Obligations under capital leases—current portion	66,355	97,715
Accounts payable	228,285	144,394
Accrued taxes	120,775	166,983
Accrued interest	43,418	49,005
Other	77,566	55,552
	681,732	805,887
Deferred Credits:		
Accumulated deferred income taxes	569,079	462,122
Accumulated deferred investment tax credits	216,647	210,356
Other	45,321	39,437
	831,047	711,915
Commitments and Contingencies (Note 7)		
Total Capitalization and Liabilities	$6,781,746	$6,601,371

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31,			1991	1990
			(Thousands of Dollars)	
Common Shareholders' Equity (See Consolidated Balance Sheets)			$1,876,074	$1,790,758
Cumulative Preferred Stock of Subsidiaries:				
$25 par value—authorized 11,600,000 shares at December 31, 1991 and 1990; outstanding 10,280,000 shares in 1991 and 10,340,000 shares in 1990				
$50 par value—authorized 9,000,000 shares at December 31, 1991 and 1990; outstanding 5,461,737 shares in 1991 and 5,561,745 shares in 1990				
$100 par value—authorized 1,000,000 shares at December 31, 1991 and 1990; outstanding 350,000 shares in 1991 and 1990				
Dividend Rates	Current Redemption Prices(a)	Current Shares Outstanding		
Not Subject to Mandatory Redemption:				
$25 par value—Adjustable Rate	$ 25.00	4,140,000	103,500	103,500
$50 par value—$1.90 to $4.80	$ 50.50 to $ 54.00	5,123,895	256,195	256,195
$100 par value—$7.72 to $9.60	$103.51 to $103.99	350,000	35,000	35,000
Total Preferred Stock Not Subject to Mandatory Redemption			394,695	394,695
Subject to Mandatory Redemption:(b)				
$25 par value—$1.90 to $2.275	$ 26.67 to $ 26.95	6,140,000	153,502	155,000
$50 par value—$5.24 to $5.76	$ 51.38 to $ 52.62	337,842	16,892	21,892
Total Preferred Stock Subject to Mandatory Redemption			170,394	176,892
Less: Preferred Stock to be redeemed within one year			2,502	2,500
Preferred Stock Subject to Mandatory Redemption, Net			167,892	174,392
Long-Term Debt:(c)				
First Mortgage Bonds—				
Maturity — Interest Rates				
1992 — 4-3/8%			8,000	8,000
1993 — 4-[illegible]/4% to 8-1/2%			140,000	140,000
1994 — 4-1/2% to 9-3/4%			107,000	107,000
1995 — 9-1/4% to 10%			169,324	175,000
1996 — 8-7/8%			100,000	100,000
1997-2001 — 5-5/8% to 9-3/8%			450,000	450,000
2002-2006 — 7-1/2% to 9-1/4%			355,000	355,000
2007-2008 — 8-7/8% to 9-3/8%			125,000	125,000
2016 — 9-3/4%			25,000	25,000
2018-2019 — 7-3/8% to 10-1/8%			279,650	279,650
Total First Mortgage Bonds			1,758,974	1,764,650
Other Long-Term Debt—				
Pollution Control Notes—				
1998-2007 — 5.90% to 6.50%			24,450	25,250
2003-2020 — Adjustable Rate			430,800	430,800
Notes—				
1991-2006 — 8.25% to 8.925%			240,000	85,000
Fees and interest due for spent fuel disposal costs			157,137	148,281
Other			91,353	155,660
Total Other Long-Term Debt			943,740	844,991
Unamortized premium and discount, net			(5,451)	(6,127)
Total Long-Term Debt			2,697,263	2,603,[illegible]14
Less amounts due within one year			80,331	101,623
Long-Term Debt, Net			2,616,932	2,501,891
Total Capitalization			$5,055,593	$4,861,736

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

(a) Each of these series is subject to certain refunding limitations for the first five years after they were issued. Redemption prices reduce in future years.

(b) Changes in Preferred Stock Subject to Mandatory Redemption:

	(Thousands of Dollars)
Balance at January 1, 1989	$ 111,832
Issues	75,000
Reacquisitions and Retirements	(4,940)
Balance at December 31, 1989	181,892
Reacquisitions and Retirements	(5,000)
Balance at December 31, 1990	176,892
Reacquisitions and Retirements	(6,498)
Balance at December 31, 1991	$170,394

The minimum sinking-fund provisions of the series subject to mandatory redemption aggregate approximately $2,500,000 in 1992, $6,400,000 in 1993, $5,000,000 in 1994, and $8,750,000 in 1995 and 1996. 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.

(c) Long-term debt maturities and cash sinking-fund requirements on debt outstanding at December 31, 1991 for the years 1992 through 1996 are approximately $80,300,000, $176,700,000, $119,700,000, $186,200,000, and $120,300,000, respectively. In addition, there are annual 1 percent sinking- and improvement-fund requirements of approximately $17,300,000 for 1992, $17,200,000 for 1993, $16,000,000 for 1994, $15,000,000 for 1995, and $13,400,000 for 1996. Such sinking- and improvement-fund requirements may be satisfied by the deposit of cash or bonds or by certification of property additions.

Essentially all utility plant of The Connecticut Light and Power Company (CL&P) and Western Massachusetts Electric Company (WMECO), wholly owned subsidiaries of Northeast Utilities, is subject to the liens of their respective first mortgage bond indentures. In addition, CL&P and WMECO have secured $346,100,000 of pollution control notes with second mortgage liens on Millstone 1, junior to the liens of their respective first mortgage bond indentures.

In connection with the July 1, 1989 divestiture of its gas business, CL&P extinguished its obligations with respect to the $25,000,000 principal amount of its Series R First and Refunding Mortgage Bonds. CL&P extinguished its obligations with respect to this bond issue by depositing funds into an irrevocable trust on June 29, 1989. The interest income and principal from the trust's investments in United States Treasury issues will be used to meet the interest and principal payments of the Series R obligation as they come due. At December 31, 1991, the $25,000,000 principal amount of the Series R Bonds remains outstanding but is considered extinguished for financial reporting purposes.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

	Common Shares	Capital Surplus, Paid In	Deferred Benefit Plan—ESOP	Retained Earnings(a)	Total
			(Thousands of Dollars)		
Balance at January 1, 1989	$ 543,346	$ 456,626	$	$ 837,062	$1,837,034
Net income for 1989				209,083	209,083
Cash dividends on common shares—$1.76 per share				(191,258)	(191,258)
Capital stock expenses, net		(1,452)			(1,452)
Special dividend—discontinuance of gas operations				(101,012)	(101,012)
Balance at December 31, 1989	543,346	455,174		753,875	1,752,395
Net income for 1990				211,007	211,007
Cash dividends on common shares—$1.76 per share				(191,851)	(191,851)
Issuance of 946,820 common shares, $5 par value	4,734	13,154			17,888
Capital stock expenses, net		1,319			1,319
Balance at December 31, 1990	548,080	469,647		773,031	1,790,758
Net income for 1991				236,709	236,709
Cash dividends on common shares—$1.76 per share				(195,056)	(195,056)
Issuance of 7,608,695 common shares, $5 par value to ESOP Trust (Note 6)	38,043	136,957	(175,000)		—
Issuance of 2,029,504 common shares, $5 par value	10,148	32,272			42,420
Capital stock expenses, net		1,243			1,243
Balance at December 31, 1991	$596,271	$640,119	$(175,000)	$ 814,684	$1,876,074

(a) Certain consolidated subsidiaries have dividend restrictions imposed by their long-term debt agreements. At December 31, 1991, these restrictions, which also limit the amount of retained earnings available for NU common dividends, totaled approximately $588.4 million.

The accompanying notes are an integral part of these 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.

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 (1935 Act), and it and its subsidiaries are subject to the provisions of the 1935 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 applicable state regulatory commissions, and they 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. Rates can be increased only through a formal proceeding before the appropriate regulatory commission. At the end of each accounting period, The Connecticut Light and Power Company (CL&P) and Western Massachusetts Electric Company (WMECO), wholly owned subsidiaries of NU, accrue an estimate for the amount of energy delivered but unbilled.

Spent Nuclear Fuel Disposal Costs

Under the Nuclear Waste Policy Act of 1982, CL&P and WMECO must pay the United States Department of Energy (DOE) for the disposal of spent nuclear fuel and high-level radioactive waste. For nuclear fuel used to generate electricity prior to April 7, 1983 (prior period fuel), payment may be made anytime prior to the first delivery of spent fuel to the DOE. At December 31, 1991, fees due to the DOE for the disposal of prior period fuel were approximately \$157.1 million, including interest costs of \$75.0 million. As of December 31, 1991, approximately \$130.4 million had been collected through rates.

Fees for nuclear fuel burned after April 7, 1983 are paid to the DOE on a quarterly basis.

Investments and Jointly Owned Electric Utility Plant

Regional Nuclear Generating Companies: CL&P and WMECO own common stock of four regional nuclear generating companies. These companies, with the system's ownership interests, are:

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

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

YAEC went out of service permanently on February 26, 1992. For more information on YAEC, see Note 7, "Commitments and Contingencies."

Millstone 3: CL&P and WMECO have a 65.17 percent joint-ownership interest in Millstone 3, a 1,146-megawatt (MW) nuclear generating unit. As of December 31, 1991, plant-in-service and the accumulated provision for depreciation included approximately \$2.3 billion and \$334.1 million, respectively, for the system's share of Millstone 3. The system's share of Millstone 3 expenses is included in the corresponding operating expenses on the accompanying Consolidated Statements of Income.

Seabrook: CL&P has a 4.06 percent joint-ownership interest in Seabrook 1. Seabrook 1 is a 1,150-MW nuclear generating unit that was declared to be in commercial operation on June 30, 1990. As of December 31, 1991, plant-in-service and the accumulated provision for depreciation included approximately \$172.8 million and \$7.3 million, respectively, for CL&P's share of Seabrook 1. CL&P's share of Seabrook 1 expenses is included in the corresponding operating expenses on the accompanying Consolidated Statements of Income.

CL&P also owns 4.06 percent of Seabrook 2, which has been canceled by the joint owners. A 1990 settlement agreement with the Connecticut Department of Public

Utility Control (DPUC) provides for the continued amortization of CL&P's investment in Seabrook 2 until the full retail investment is recovered, without a return on the unamortized balance.

Hydro-Quebec: NU has a 22.66 percent equity ownership interest, approximating $30.8 million, in two companies that import electricity from the Hydro-Quebec system in Canada. Phase II began operation at full-facilities ratings beginning in July 1991, increasing the capability of the Phase II Hydro-Quebec interconnection from 690 MW to 2,000 MW. Under the terms of the Phase II equity agreement, the equity sponsors guarantee the obligations of other participants that have below-investment-grade credit ratings, and they receive compensation for such guarantees. See Note 7, "Commitments and Contingencies," for additional information about Hydro-Quebec.

Depreciation

The provision for depreciation is calculated using the straight-line method based on estimated remaining lives of depreciable utility plant-in-service, adjusted for salvage value and removal costs as approved by the appropriate regulatory agency. Except for major facilities, depreciation factors 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. For nuclear production plants, the costs of removal, less salvage, that have been funded through external decommissioning trusts will be charged to those trusts. See Note 3, "Nuclear Decommissioning," for additional information.

The depreciation rates for the several classes of electric plant-in-service are equivalent to a composite rate of 3.6 percent in 1991 and 1990 and 3.4 percent in 1989.

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. See Consolidated Statements of Income Taxes, on page 27, for the components of income tax expense.

The company has not provided deferred income taxes for certain timing differences during periods when applicable regulatory authorities did not permit the recovery of such income taxes through rates charged to customers. The cumulative net amount of income tax timing differences for which deferred taxes have not been provided was approximately $700 to $800 million at December 31, 1991. As allowed under current regulatory practices, deferred taxes not previously provided are being collected in customers' rates as such taxes become payable.

In February 1992, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* (SFAS 109). SFAS 109 supersedes previously issued income tax accounting standards and will be effective beginning in 1993. The company expects that when SFAS 109 is adopted it will increase assets and liabilities by approximately $600 to $700 million but will not have a material effect on net income.

Allowance for Funds Used During Construction

Allowance for funds used during construction (AFUDC), a noncash cost calculated in accordance with FERC guidelines, represents the estimated costs 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. The effective AFUDC rates under the gross-of-income tax method for 1991, 1990, and 1989 were 7.8 percent, 9.7 percent, and 10.1 percent, respectively.

Energy Adjustment Clauses

CL&P: Retail electric rates include a fuel adjustment clause (FAC) under which fossil-fuel prices above or below base-rate levels are charged or credited to customers. Administrative proceedings are required each month to approve the FAC charges or credits proposed for the following month. Monthly FAC rates are also subject to retroactive review and appropriate adjustment by the DPUC each quarter after public hearings.

The DPUC does not permit deferred fossil-fuel accounting. The DPUC permits CL&P to recover prior deferred fossil-fuel balances, which at December 31, 1991 amounted to $37.7 million, over a remaining period of four and one-half years, without earning a return on the outstanding balance.

Beginning in 1979, the DPUC approved the use of a generation utilization adjustment clause (GUAC) which levels the effect on fuel costs caused by variations from a specified composite nuclear generation capacity factor embedded in base rates (70 percent, effective January 1, 1990 through August 19, 1991; 72 percent, effective August 20, 1991). At the end of a 12-month period ending July 31 of each year, these net variations from the amounts included in base-rate cost levels are refunded to, or collected from, customers over the subsequent 11-month period beginning in September. Should the annual nuclear capacity factor fall below 55 percent, CL&P would have to apply to the DPUC for permission to recover the additional fuel expense. During the period from August 1, 1990 to July 31, 1991, the composite nuclear generation factor for the eight operating nuclear units in which CL&P has an ownership interest was 64.3 percent, resulting in an additional net fuel cost of approximately $21.2 million, which is being collected from ratepayers.

WMECO: In Massachusetts, all retail fuel costs are collected on a current basis by means of a separate fuel charge billing rate. As permitted by the Massachusetts Department of Public Utilities (DPU), WMECO defers the difference between forecasted and actual fuel costs until it is recovered or refunded quarterly under a retail fuel adjustment clause. Massachusetts law requires the establishment of an annual performance program related to fuel procurement and use. The program establishes performance standards for plants owned and operated by WMECO or plants in which WMECO has a life-of-unit contract. Therefore, revenues collected under the WMECO retail fuel adjustment clause are subject to refund pending review [illegible] the DPU. To date, there have been no significant adjustments as a result of this program.

See Note 7, "Commitments and Contingencies," for additi[illegible]formation on energy adjustment clauses.

Phase-in Plans

As discussed below, CL&P is phasing into rates the recoverable parts of its investments in Millstone 3 and Seabrook 1. WMECO has completed the phase-in portion of its phase-in plan for Millstone 3. Both plans are in compliance with Statement of Financial Accounting Standards No. 92, *Regulated Enterprises—Accounting for Phase-in Plans.*

CL&P: As allowed by the DPUC, CL&P is phasing into rate base its allowed investment in Millstone 3. The DPUC has provided for full deferred earnings and carrying charges on the portion of CL&P's allowed investment in Millstone 3 not included in rate base. Through December 31, 1991, CL&P had placed into rate base $1.4 billion, or 80 percent, of its allowed investment in Millstone 3. The remaining $351.3 million, or 20 percent, is to be phased into rate base annually in four 5-percent steps beginning January 1, 1992. The amortization and recovery of deferrals through rates began January 1, 1988 and will end no later than December 31, 1995. As of December 31, 1991, $215.8 million of the deferred return, including carrying charges, has been recovered, and $206.5 million of the deferred return recorded to date, plus carrying charges, remains to be recovered by December 31, 1995.

As allowed by the DPUC's August 1, 1991 decision, CL&P is phasing into rate base its allowed investment in Seabrook 1. The DPUC has provided for full deferred earnings and carrying charges on the portion of CL&P's allowed investment in Seabrook 1 not included in rate base. Through December 31, 1991, CL&P had placed into rate base $55.6 million, or one-third, of its allowed investment in Seabrook 1. The remaining $111.1 million, or two-thirds, is to be phased into rate base over a two-year period beginning in 1992. The amortization and recovery of deferrals through rates began September 1, 1991 and will end no later than August 31, 1996.

WMECO: As of December 31, 1991, all of WMECO's recoverable investment in Millstone 3 was in rate base. Beginning in 1986, the DPU has permitted WMECO to recover the portion of its Millstone 3 investment representing the amount currently determined to be "unuseful" by the DPU ($42.4 million at December 31, 1991), excluding the applicable equity AFUDC, over a ten-year period, without earning a return. On June 30, 1987, WMECO also began recovering the deferred return, including carrying charges, on the recoverable but not yet phased-in portion of its investment in Millstone 3. This recovery is taking place over a nine-year period. As of December 31, 1991, $41.1 million of the deferred return, including carrying charges, has been recovered, and $41.1 million of the deferred return, including carrying charges, remains to be recovered over the period ending June 30, 1995.

2. Leases

CL&P and WMECO have entered into the Niantic Bay Fuel Trust (NBFT) capital lease agreement to finance up to $530 million of nuclear fuel for Millstone 1 and 2 and their share of the nuclear fuel for Millstone 3. CL&P and WMECO make quarterly lease payments for the cost of nuclear fuel consumed in the reactors (based on a units-of-production method at rates which reflect estimated kilowatt-hours of energy provided) plus financing costs associated with the fuel in the reactors. Upon permanent discharge from the reactors, ownership of the nuclear fuel transfers to CL&P and WMECO.

The system companies have also entered into lease agreements, some of which are capital leases, for the use of substation equipment, data processing and office equipment, vehicles, nuclear control room simulators, and office space. The provisions of these lease agreements generally provide for renewal options. The following rental payments have been charged to operating expense:

Year	Capital Leases	Operating Leases
1991	$ 73,761,000	$23,571,000
1990	133,318,000	24,526,000
1989	127,602,000	29,274,000

Interest included in capital lease rental payments was $22,677,000 in 1991, $25,889,000 in 1990, and $31,177,000 in 1989.

Substantially all of the capital lease rental payments were made pursuant to the nuclear fuel lease agreement. Future minimum lease payments under the nuclear fuel capital lease cannot be reasonably estimated on an annual basis due to variations in the usage of nuclear fuel.

Future minimum rental payments, excluding annual nuclear fuel lease payments and executory costs, such as property taxes, state use taxes, insurance, and maintenance, under long-term noncancelable leases, as of December 31, 1991, are approximately:

Year	Capital Leases	Operating Leases
	(Thousands of Dollars)	
1992	$ 7,600	$ 23,200
1993	7,600	17,100
1994	7,600	14,200
1995	7,600	12,600
1996	7,300	11,100
After 1996	68,900	43,600
Future minimum lease payments	106,600	$121,800
Less amount representing interest	58,300	
Present value of future minimum lease payments for other than nuclear fuel	48,300	
Present value of future nuclear fuel lease payments	231,400	
Total	$279,700	

3. Nuclear Decommissioning

The company's 1989 decommissioning study concluded that complete and immediate dismantlement at retirement continues to be the most viable and economic method of decommissioning the three Millstone units. The estimated cost of decommissioning the system's ownership share of these units is $769.7 million in year-end 1991 dollars. A 1991 Seabrook decommissioning study also confirmed that complete and immediate dismantlement at retirement is the most viable and economic method of decommissioning Seabrook 1. The estimated cost of decommissioning CL&P's ownership share of Seabrook 1 is $13.7 million in year-end 1991 dollars. Decommissioning studies are reviewed and updated periodically to reflect changes in decommissioning requirements, technology, and inflation.

CL&P and WMECO have established independent decommissioning trusts for their portions of the costs of decommissioning Millstone 1, 2, and 3. CL&P's portion of the cost of decommissioning Seabrook 1 is paid to an independent decommissioning financing fund managed by the state of New Hampshire.

As of December 31, 1991, CL&P and WMECO have collected, through rates, $133.0 million toward the future decommissioning costs of the Millstone units, of which $101.9 million has been transferred to external decommissioning trusts. As of December 31, 1991, CL&P has paid $288 thousand into Seabrook 1's decommissioning financing fund. The decommissioning trusts are disclosed on the Consolidated Balance Sheets, at cost, which approximates market.

4. Short-Term Debt

The system companies have various credit lines totaling $400 million. Of this amount, $350 million is available to NU, CL&P, and WMECO through a revolving-credit agreement with a group of 11 banks. The maximum borrowing limit of CL&P under the agreement is $350 million, less amounts borrowed by WMECO (not to exceed $105 million) and by NU (not to exceed $100 million). NU, CL&P, and WMECO may borrow funds on a short-term revolving basis using either fixed-rate loans or standby loans. Fixed rates are set using competitive bidding. Standby loan rates are based upon several alternative variable rates. NU, CL&P, and WMECO are obligated to pay a facility fee of .1875 percent per annum on their proportionate shares of the commitment. At December 31, 1991, there were no borrowings under this agreement.

The remaining $50 million is available to the NU system companies through a revolving-credit agreement with a group of six banks. Under this agreement, the NU system companies can borrow in the aggregate an amount not to exceed $50 million. Loans under this agreement are on a short-term revolving basis in the form of either Eurodollar Loans based on the London Interbank Offered Rate, plus 3/8 of 1 percent, or as Alternative Base Rate Loans at the greater of the prime rate or 1/2 of 1 percent over the Federal Funds Effective Rate. This agreement will expire on August 25, 1994 unless extended, on an annual basis, for a maximum of four years beyond the expiration of the initial three-year term. At December 31, 1991, there were no borrowings under this agreement.

The amount of short-term borrowings that may be incurred by the NU system companies is subject to periodic approval by the SEC under the 1935 Act. In addition, the charters of CL&P and WMECO contain provisions restricting the amount of short-term borrowings. Under the SEC and charter restrictions, NU, CL&P, and WMECO were authorized, as of January 1, 1991, to incur short-term borrowings up to a maximum of $135 million, $300 million, and $95 million, respectively.

5. Postretirement Benefits

The company's subsidiaries participate in a uniform noncontributory defined benefit retirement plan covering all regular system employees. Benefits are based on years of service and employees' compensation during the last five years of employment. Total pension cost, part of which was charged to utility plant, approximated $29,517,000 in 1991, $11,275,000 in 1990, and $14,537,000 in 1989. Pension costs for 1991 include approximately $19,831,000 related to the voluntary early retirement program described below.

Currently, the subsidiaries fund annually an amount at least equal to that which will satisfy the requirements of the Employee Retirement Income Security Act and the Internal Revenue Code. Pension costs are determined using market-related values of pension assets. Pension assets are invested primarily in equity securities, bonds, and insurance contracts.

The components of net pension cost are:

For the Years Ended December 31,	1991	1990	1989
	(Thousands of Dollars)		
Service cost	$ 48,738	$30,459	$ 31,020
Interest cost	71,041	64,352	61,415
Return on plan assets	(198,437)	10,498	(160,750)
Net amortization	108,175	(94,034)	82,852
Net pension cost	$ 29,517	$11,275	$ 14,537

For calculating pension cost, the following assumptions were used:

For the Years Ended December 31,	1991	1990	1989
Discount rate	9.0%	9.0%	9.5%
Expected long-term rate of return	9.7	9.7	9.7
Compensation/progression rate	7.5	7.5	8.5

The following table represents the plan's funded status reconciled to the Consolidated Balance Sheets:

At December 31,	1991	1990
	(Thousands of Dollars)	
Accumulated benefit obligation, including $585,419,000 of vested benefits at December 31, 1991 and $489,398,000 of vested benefits at December 31, 1990	$ 623,795	$525,056
Projected benefit obligation	$ 848,374	$792,818
Less: Market value of plan assets	1,031,699	865,497
Market value in excess of projected benefit obligation	183,325	72,679
Unrecognized transition amount	(26,958)	(28,897)
Unrecognized prior service costs	7,323	7,768
Unrecognized net gain	(176,380)	(42,573)
Accrued pension asset (liability)	$ (12,690)	$ 8,977

The following actuarial assumptions were used in calculating the plan's year-end funded status:

At December 31,	1991	1990
Discount rate	8.5%	9.0%
Compensation/progression rate	6.8	7.5

During 1991, the NU system offered voluntary early retirement programs to 631 eligible employees. The programs were generally available to general offices and regional support staff and employees at certain fossil-fuel generating facilities. Of the eligible employees, 438 accepted the offer, resulting in a one-time pretax cost of approximately $32 million, including $19.8 million in pension costs, to the NU system.

In addition to pension benefits, the company's subsidiaries currently have a practice of providing certain health care and life insurance benefits to retired employees. The cost of providing those benefits was approximately $10,815,000 in 1991, $11,133,000 in 1990, and $9,618,000 in 1989. The company currently recognizes health care benefits primarily as paid and provides for life insurance benefits through premiums paid to an insurance company.

In December 1990, the FASB issued Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (SFAS 106). This new standard requires that the expected cost of postretirement benefits, primarily health and life insurance benefits, must be charged to expense during the years that employees render service. This is a significant change from the company's current policy of recognizing these costs as paid. Based upon the information available to date, and assuming that postretirement benefits similar to those currently provided are maintained in the future, when SFAS 106 is adopted in 1993, the NU system estimates its SFAS 106 liability, related to prior years service, will be approximately $400 to $500 million. The accrual of the SFAS 106 liability is not expected to have a material effect on net income. CL&P and WMECO will petition their regulators for recovery of these costs, including those related to prior years service, in future rate proceedings. The companies would expect to record a regulatory asset for the difference between the accrual and current recovery of these costs.

6. Employee Stock Ownership Plan (ESOP)

On December 3, 1991, the company issued $175 million principal amount of unsecured and amortizing notes bearing an annual interest rate of 8.58 percent. The company used the proceeds to loan $175 million to the trustee of the ESOP in exchange for the ESOP's note, which will accrue interest at a rate of 8.58 percent per annum on the outstanding principal amount. The ESOP used the proceeds from the loan to purchase approximately 7.6 million common shares from NU at $23 per share. The common shares will be allocated to eligible employees of the NU system companies in connection with the employer match feature of NU's 401(k) employee benefits plan beginning January 1, 1992.

The common shares in the ESOP trust will be allocated to employees at the same rate as principal and interest are paid over the life of the ESOP note. Pursuant to the ESOP trust agreement, Northeast Utilities Service Company, a wholly owned subsidiary of NU, will be able to direct the ESOP trustee as to the timing, amount, and source of principal and interest payments. Although the ESOP note is scheduled to mature on December 1, 2011, management anticipates that the ESOP trustee will make quarterly payments of interest and prepayments of principal on the ESOP note, and that the ESOP note will be fully paid by December 1, 2006. The interest expense recognized by the company on the ESOP note will be offset by the interest income earned on the ESOP note.

7. Commitments and Contingencies

Construction Program

The construction program is subject to periodic review and revision. Actual construction expenditures may vary from estimates due to factors such as revised load estimates, inflation, revised nuclear safety regulations, delays, difficulties in the licensing process, 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.

The system companies currently forecast construction expenditures (including AFUDC) of $1.25 billion for the years 1992-1996, including $379.4 million for 1992. In addition, the system companies estimate that nuclear fuel requirements, including nuclear fuel financed through the NBFT, will be $330.1 million for the years 1992-1996, including $51.4 million for 1992. See Note 2, "Leases" for additional information about the financing of nuclear fuel.

Corrosion, pitting, and denting of tubes within the steam generator assemblies have been recurring problems at Millstone 2 for a number of years. In light of continuing repairs and concerns about future performance, the NU system plans to replace the Millstone 2 steam generators beginning late in the second quarter of 1992. The cost of replacement is estimated to be approximately $190 million, including AFUDC, but excluding the cost of replacement power.

Nuclear Performance

When their nuclear units are out of service, CL&P and WMECO need to generate and/or purchase replacement power. CL&P and WMECO have incurred approximately $108 million and $21 million, respectively, in replacement power costs associated with four separate Millstone outages. Recovery of prudently incurred replacement power costs is permitted, with limitations, through [illegible] and GUAC for CL&P and through a retail fuel adjustment clause for WMECO.

CL&P will have to apply to the DPUC to recover the additional fuel costs when the GUAC capacity factor falls below the 55 percent level for the 12-month GUAC period. For the 12-month GUAC period ending July 31, 1992, management projects that the GUAC capacity factor will be approximately 49 percent. Based upon past regulatory practices, CL&P expects to recover approximately $96 million through the GUAC. CL&P expects to seek recovery of the additional costs for operations between the projected 49 percent level and the 55 percent level (estimated to be $29 million) in a future rate proceeding.

Management does not believe that the lower capacity factors, in themselves, are cause for the DPUC and the DPU to deny CL&P and WMECO full recovery. Management believes that the companies have acted prudently in the operation of their nuclear generating units during the period in question and recognizes that CL&P and WMECO will be called upon to demonstrate that their actions have been prudent.

See Note 1, "Summary of Significant Accounting Policies—Energy Adjustment Clauses," for additional information regarding nuclear performance and energy adjustment clauses.

Environmental Matters

The NU system is subject to regulation by federal, state, and local authorities with respect to air and water quality and the disposal of toxic substances and hazardous and solid wastes. The cumulative long-term economic cost impact of increasingly stringent environmental requirements cannot be estimated. However, the NU system has an active environmental auditing program to detect and remedy noncompliance with environmental laws or regulations. The system may incur significant additional costs, greater than amounts included in cost of removal and other reserves, in connection with the generation and transmission of electricity and the storage, transportation, and disposal of by-products and wastes. The system may also encounter significantly increased costs to remedy the environmental effects of prior waste handling and disposal practices.

The system has recorded a liability for what it believes is, based upon information currently available, the estimated environmental remediation costs for sites for which the system's subsidiaries expect to bear legal liability. To date, these costs have not been material with respect to the earnings or financial position of the company. In most cases, the extent of additional future environmental cleanup costs is not estimable due to factors such as the unknown magnitude of possible contamination, the possible effects of future legislation and regulation, the possible effects of technological changes related to future cleanup, and the difficulty of determining future liability, if any, for the cleanup of sites at which a system company has been

informed that it may be determined to be legally liable by the United States Environmental Protection Agency, the Connecticut Department of Environmental Protection, or the Massachusetts Department of Environmental Protection. In addition, the system cannot estimate the potential liability for future claims that may be brought against it by private parties. However, considering known facts and existing laws and regulatory practices, management does not believe such matters will have a materially adverse effect on the system's financial position or future results of operations.

Changing environmental requirements could hinder the construction of new fossil-fuel generating units, could require extensive and costly modifications to the system's existing hydro, nuclear, and fossil-fuel generating units, and could raise operating costs significantly. The system may also face significantly increased capital and operating costs for work centers, substations, and other facilities as a result of environmental regulations. However, the NU system believes that it is in substantial compliance with current environmental laws and regulations.

Nuclear Insurance Contingencies

The Price-Anderson Act currently limits public liability from a single incident at a nuclear power plant to \$7.8 billion. The first \$200 million of liability would be provided by purchasing the maximum amount of commercially available insurance. Additional coverage of up to a total of \$7.2 billion would be provided by an assessment of \$63 million per incident, levied on each of the 115 nuclear units with operating licenses in the United States, subject to a maximum assessment of \$10 million per incident per nuclear unit in any year. In addition, if the sum of all public liability claims and legal costs arising from any nuclear incident exceeds the maximum amount of financial protection, each reactor operator can be assessed an additional 5 percent, up to \$3.2 million, or \$362.3 million in total, for all 115 nuclear units. The maximum assessment is to be adjusted at least every five years to reflect inflationary changes. Based on CL&P's and WMECO's ownership interests in the three Millstone units, and CL&P's ownership interest in Seabrook 1, the NU system's maximum liability would be \$178.1 million per incident. In addition, through CL&P's and WMECO's power purchase contracts with the four Yankee regional nuclear generating companies, the NU system would be responsible for up to an additional \$67.8 million per incident. Payments for the NU system's ownership interest in nuclear generating facilities would be limited to a maximum of \$37.2 million per incident per year.

Insurance has been purchased from Nuclear Electric Insurance Limited (NEIL) to cover: (i) certain extra costs incurred in obtaining replacement power during prolonged accidental outages with respect to CL&P's and WMECO's ownership interests in Millstone 1, 2, and 3, and CY; and (ii) the cost of repair, replacement, or decontamination or premature decommissioning of utility property resulting from insured occurrences at Millstone 1, 2, and 3, Seabrook 1, CY, MY, and VY. All companies insured with NEIL are subject to retroactive assessments if losses exceed the accumulated funds available to NEIL. The maximum potential assessments against CL&P and WMECO with respect to losses arising during current policy years are approximately \$10.2 million under the replacement power policies and \$11.5 million under the property damage, decontamination, and decommissioning policies. Although CL&P and WMECO have purchased the limits of coverage currently available from the conventional nuclear insurance pools, the cost of a nuclear incident could exceed available insurance proceeds.

Insurance has been purchased from American Nuclear Insurers/Mutual Atomic Energy Liability Underwriters, aggregating \$200 million on an industry basis, for coverage of worker claims. All companies insured under this coverage are subject to retrospective assessments of \$3.2 million per reactor. The maximum potential assessments against CL&P and WMECO with respect to losses arising during the current policy period are approximately \$12.0 million.

Financing Arrangements for the Regional Nuclear Generating Companies

CL&P and WMECO believe that the regional nuclear generating companies will require additional external financing in the next several years for construction expenditures, nuclear fuel, and other purposes. Although the ways in which each regional nuclear generating company will attempt to finance these expenditures have not been determined, CL&P and WMECO expect that they may be asked to provide direct or indirect financial support for one or more of these companies.

Yankee Atomic Electric Company

CL&P and WMECO together have a 31.5 percent equity investment, approximating $6.7 million, in YAEC, a regional nuclear generating company which owns and operates a 173-MW nuclear power plant. On February 26, 1992, the Board of Directors of YAEC voted to permanently cease power operation at YAEC and begin preparations for an orderly decommissioning of the facility. The unit was shut down because of economic and nuclear regulatory uncertainty associated with the restart of the plant prior to the end of its current license, which expires in the year 2000. Management believes that CL&P and WMECO will recover their investments in YAEC, along with any other costs associated with the shutdown and decommissic.ning of the unit.

Hydro-Quebec

Along with other New England utilities, CL&P, WMECO, and Holyoke Water Power Company (HWP), all wholly owned operating companies of the NU systei.., entered into agreements to support transmission and terminal facilities to import electricity from the Hydro-Quebec system in Canada. CL&P, WMECO, and HWP, in the aggregate, are obligated to pay, over a 30-year period, their proportionate share of the annual operation, maintenance, and capital costs of these facilities, which are currently forecast to be $132.7 million for the years 1992-1996, including $28.0 million for 1992.

8. Public Service Company of New Hampshire (PSNH)

NU intends to acquire PSNH, the largest utility in New Hampshire, which supplies electricity to approximately three-quarters of the state's population.

The Plan of Reorganization (the Plan)

PSNH was in Chapter 11 reorganization proceedings from January 1988 to May 16, 1991 (the Reorganization Date). PSNH emerged from bankruptcy on the Reorganization Date as a free-standing, independent company subject to a contractual obligation to be acquired by NU. When regulatory approvals and all other conditions are satisfied, PSNH will then become a wholly owned subsidiary of NU. PSNH's 35.6 percent ownership in Seabrook 1 will be transferred to North Atlantic Energy Corporation (NAEC), a newly formed company that will be a wholly owned subsidiary of NU.

The Rate Agreement

The Rate Agreement which provides the financial basis for the acquisition allows, among other things, for seven successive annual rate increases of 5.5 percent per year (the Fixed Rate Period). The first rate increase, which went into effect on January 1, 1990, was held in escrow, with part being released on the Reorganization Date, and the remainder to be released when the acquisition occurs. The second 5.5 percent rate increase went into effect on the Reorganization Date. In addition, the Rate Agreement contemplates that after the acquisition and the transfer of Seabrook 1 to NAEC, PSNH and NAEC will enter into the Seabrook Power Contract (Contract). Under that Contract, PSNH will be required to purchase the capacity and output of Seabrook 1 for the full term of Seabrook 1's operating license and to pay NAEC's cost of service.

Regulatory Approval

On December 20, 1990, the SEC approved NU's acquisition of PSNH. The SEC has reserved jurisdiction over several financings for which the record was incomplete. The SEC decision has been appealed by intervenors to the United States Court of Appeals. Two Seabrook license amendments, necessary for the acquisition, are pending before the Nuclear Regulatory Commission (NRC). One would permit NAEC to purchase PSNH's interest in Seabrook 1 and authorize North Atlantic Energy Service Corporation (NAESCO), a newly formed company that will be a wholly owned subsidiary of NU, to manage Seabrook as agent for the Seabrook joint owners. The proposal for NAESCO to be manager/operator of the Seabrook project is also subject to SEC approval.

On August 9, 1991, the FERC issued a decision approving NU's acquisition of PSNH, subject to certain conditions. After considering various appeals of the August 9 decision, the FERC voted unanimously, on January 29, 1992, to approve an amended decision on the acquisition. The amended FERC decision has been appealed by numerous intervenors and, on limited and technical grounds, by NU. The FERC decision will not become final until any and all appeals are resolved. However, based on a review of the amended decision, management believes that the decision should allow NU and PSNH to move promptly toward completion of the acquisition.

The FERC decision was the subject of further hearings before the DPUC, which were completed in February 1992. The DPUC also held hearings last fall on the financial impact of

the acquisition but had been awaiting the final FERC decision before issuing an overall decision on the transaction. The DPUC's decision is scheduled for March 31, 1992.

For planning purposes, management is projecting that the PSNH acquisition will be completed during the second quarter of 1992. While management remains optimistic about the ultimate success of the acquisition, financing arrangements have not been completed and regulatory approvals are not assured.

Acquisition Costs
In accordance with the merger agreement, PSNH, with certain exceptions, will reimburse NU at the time of the acquisition for its reasonable out-of-pocket costs, up to a maximum of $45 million, incurred in connection with the PSNH bankruptcy and acquisition. However, NU would not be entitled to such reimbursement if the acquisition terminates under certain conditions. Through December 31, 1991, NU has expensed approximately $41.5 million of costs associated with the acquisition of PSNH.

In addition, if the acquisition were terminated by PSNH, PSNH would have to pay NU a termination fee of $25 million in certain circumstances. If termination were a result of NU's breach of the merger agreement, then NU would have to pay PSNH a termination fee of $25 million.

9. Condensed Financial Statements—Pro Forma NU/PSNH (Unaudited)

The following pro forma financial statements of NU give effect to the proposed acquisiti of PSNH by NU. For purposes of presenting pro forma consolidated income statement data, it was assumed that PSNH's emergence from bankruptcy on the Reorganization Date and the proposed acquisition of PSNH by NU had occurred sequentially, but otherwise simultaneously, as of the beginning of the period presented. For purposes of presenting pro forma consolidated balance sheet data, it was assumed that the proposed acquisition of PSNH by NU occurred at the end of the period presented.

The pro forma statements included in this report combine the company's historical December 31, 1991 consolidated financial statements with PSNH's historical December 31, 1991 financial statements. PSNH's historical 12-month income statement for the period ended December 31, 1991 is derived from the sum of four and one-half months of pre-reorganization data and seven and one-half months of post-reorganization data.

The adjustments necessary to derive the pro forma data are based on available information and certain assumptions, including the following:

(1) PSNH will apply traditional utility principles of accounting that will recognize the economic impact of the Rate Agreement, which provides the financial basis for the acquisition, in its financial statements. For purposes of deriving pro forma data, it is assumed that the rate increases were reflected in income beginning on January 1 of each year, commencing with January 1, 1990.

(2) The amount of the regulatory asset, which represents the aggregate value placed by the Plan on PSNH's assets in excess of the net book value of PSNH's non-Seabrook assets and the $700 million value assigned to Seabrook by the Plan, will be calculated at the acquisition date in accordance with the Rate Agreement.

(3) The Plan provides for the issuance at the acquisition date of warrants to purchase approximately 8,431,000 NU shares to holders of certificates issued in accordance with the Plan to former preferred and common stockholders of PSNH. Each warrant holder will have the right to purchase one NU common share at a price of $24 per share until the warrants expire five years from the acquisition date. Since the $23⅞ market price of NU's common shares at December 31, 1991 was below the exercise price, the warrants have no effect on the pro forma financial information presented.

(4) In accordance with the Plan, PSNH will, with certain exceptions, reimburse NU for its reasonable out-of-pocket costs, fees, and expenses, up to a maximum of $45 million. The reimbursement for these costs is not reflected in the pro forma statement of income other than as reflected in the calculation of the regulatory asset.

The pro forma financial statements do not give effect to the synergies arising from the acquisition, which are expected to occur after the acquisition date. The New Hampshire Public Utilities Commission found, in its July 20, 1990 decision approving the acquisition of PSNH by NU, that NU, acting prudently, should be able to bring a minimum of $300 million in net present value of savings to PSNH as a result of the acquisition.

The equity collar under the Rate Agreemer ovides upper and lower limits on the level of the cumulative present value return on equity that may be achieved during the Fixed Rate Period. These pro forma financial statements do not include any effects on revenues or expenses that may result in the future if the equity collar goes into effect.

NU/PSNH Condensed Pro Forma Consolidated Statement of Income (Unaudited)

For the Twelve Months Ended December 31, 1991	Historical* NU Consolidated	PSNH	Pro Forma Adjustments (Unaudited)	Pro Forma Giving Effect To Proposed Transactions (Unaudited)
	(Thousands of Dollars, except share information)			
Operating Revenues	$ 2,753,803	$ 786,108	$ 18,268 (a) (127,572)(b)	$ 3,430,607
Operating Expenses:				
Other operation	1,935,160	537,777	(22,425)(a) (127,572)(b) (9,725)(c)	2,313,215
Depreciation	238,575	64,859	(6,685)(d)	296,749
Amortization of regulatory asset	—	53,554	31,745 (e)	85,299
Federal and state income taxes	190,556	25,547	20,805 (f)	236,908
Total operating expenses	2,364,291	681,737	(113,857)	2,932,171
Operating Income	389,512	104,371	4,553	498,436
Other Income	80,493	38,478	(8,999)(c) 29,744 (f) (1,191)(g)	138,525
Interest Charges	190,707	151,624	(20,348)(g) (151,624)(h) 156,406 (h) 13,200 (h)	339,965
Income After Interest Charges	279,298	(8,775)	26,473	296,996
Preferred Dividends of Subsidiaries	42,589	8,282	(8,282)(h) 13,250 (h)	55,839
Extraordinary Loss From Reorganization	—	39,322	(39,322)(c)	—
Net Income (Loss)	236,709	(56,379)	60,827	241,157
Tax Benefit of ESOP Dividend	—	—	6,423 (i)	6,423
Earnings For Common Shares	$ 236,709	$ (56,379)	$ 67,250	$ 247,580
Earnings Per Common Share	$ 2.12	$ N/A	$ N/A	$ 1.91
Common Shares Outstanding (average)	111,453,550	N/A	18,432,970 (j)	129,886,520

**Derived from audited data.*

The pro forma financial data are presented to comply with the SEC's regulations, which permit only limited adjustments to historical data.

The pro forma financial data are not a forecast or projection for any future date or period, nor are they a representation of what the company's financial position or results of operations would actually have been if such transactions in fact had occurred during the period presented.

See accompanying Notes to Condensed Pro Forma Consolidated Statement of Income.

Notes to Condensed Pro Forma Consolidated Statement of Income

(a) Reflects PSNH's Operating Revenues and Fuel and Purchased and Net Interchange Power effects of the Rate Agreement.

(b) Eliminates intercompany transactions between NU and PSNH.

(c) Eliminates the company's nonrecurring expenses associated with the acquisition of PSNH.

(d) Adjusts depreciation of PSNH's Seabrook plant to reflect depreciation on the $700 million value permitted by the Rate Agreement plus capital additions subsequent to the Reorganization Date. The Seabrook plant is being depreciated on the straight-line method at rates designed to depreciate the plant fully over the remaining life of the NRC operating license.

(e) Amortizes $425 million of PSNH's regulatory asset on a straight-line basis over the first seven years after the Reorganization Date, and the remainder of $491.7 million on a straight-line basis over the first 20 years after the Reorganization Date.

(f) Reflects the income tax effects of the pro forma adjustments.

(g) Reflects the deferred return on PSNH's Seabrook investment not yet in rate base. The Rate Agreement provides for the phase-in to rate base of PSNH's $700 million initial investment in Seabrook over a six-year period.

(h) Eliminates PSNH's historical interest/preferred dividends and reflects the annualized interest/preferred dividends subsequent to the acquisition as follows:

	Pro Forma	
	Principal Outstanding or Aggregate Par Value	Annualized Interest/ Preferred Dividends
	(Thousands of Dollars)	
Long-Term Debt:		
PSNH:		
First Mortgage Bonds:		
Series A Bonds, 8 7/8%, due 1996 (1)	$ 172,500	$ 15,309
Series B Bonds, 9.17%, due 1998 (1)	170,000	15,589
Securing Taxable Pollution Control Revenue Bonds, Variable Rate (assume 5.0%) due 2021 (1)(2)	229,000	11,450
Securing Tax Exempt Pollution Control Revenue Bonds, 7.59% due 2021 (1)	287,485	21,820
Term Loan, Variable Rate (assume 5.0%) (3)	400,000	20,000
Amortization of Debt Issuance Costs	N/A	3,381
	1,258,985	87,549
NAEC:		
First Mortgage Bonds: (assume 9.0%)	355,000	31,950
Notes 15.23%, due 2000 (4)	205,000	31,222
Amortization of Debt Issuance Costs	N/A	1,050
	560,000	64,222
NU:		
Term Loan, Variable Rate (assume 5.0%)	51,000	2,550
NU Debt Securities:		
ESOP I, 8.58% (11/12 of one year)(5)	175,000	13,764
ESOP II (assume 8.5%)	75,000	6,375
ESOP Dividends Used to Pay Debt Service	N/A	(18,891)
Amortization of Debt Issuance Costs	N/A	837
	301,000	4,635
	$2,119,985	$156,406

Other Debt:		
PSNH Revolving Credit Facility (assume 5.0%)	$ 76,000	$ 3,800
NAEC Money Pool (assume 5.0%)	4,000	200
NU Consolidated (assume 5.0%) —Refinance Money Pool Borrowings	175,000	8,750
Amortization of PSNH Preferred Stock Issuance Costs	N/A	450
	$ 255,000	$ 13,200
Preferred Stock:		
PSNH Preferred Stock Subject to Mandatory Redemption, 10.6% (1)	$ 125,000	$ 13,250

(1) Issued on May 16, 1991, in connection with the emergence of PSNH from bankruptcy.

(2) Interest rate includes letter of credit fees.

(3) On May 16, 1991, in connection with the emergence of PSNH from bankruptcy, PSNH borrowed $452 million under a Term Loan Agreement. At the time of the acquisition of PSNH by the company, PSNH will be required to reduce the Term Loan Agreement to $400 million (or a lesser amount if the acquisition occurs after amortization of the Term Loan Agreement has begun). Borrowings under the Term Loan Agreement may be prepaid in whole or in part.

(4) On May 16, 1991, in connection with the emergence of PSNH from bankruptcy, PSNH issued $205 million of Notes. At the acquisition date, PSNH will transfer its obligations under the Notes to NAEC along with its interest in Seabrook.

(5) On December 3, 1991, NU issued $175 million in notes, the proceeds of which were loaned to the trustee of the ESOP.

(i) Reflects the tax benefit of deducting common dividends on shares held by the trustee of the ESOP.

(j) Reflects the issuance of additional common shares to finance part of the company's requirements for the acquisition of PSNH.

NU/PSNH Condensed Pro Forma Consolidated Balance Sheet (Unaudited)

As of December 31, 1991	Historical* NU Consolidated	PSNH	Pro Forma Adjustments (Unaudited)	Pro Forma Giving Effect To Proposed Transactions (Unaudited)
		(Thousands of Dollars)		
Assets				
Utility Plant, net	$ 5,257,567	$ 1,384,560	$ —	$ 6,642,127
Other Property and Investments	254,803	23,598	—	278,401
Current Assets:				
Cash and special deposits	37,271	1,357	(340)(a)	38,288
Other	610,656	203,638	(24,528)(b)	789,766
	647,927	204,995	(24,868)	828,054
Deferred Charges:				
Regulatory asset	—	864,972	51,729 (c)	916,701
Other	621,449	158,400	14,200 (d) 64,987 (e) (8,772)(b)	850,264
	621,449	1,023,372	122,144	1,766,965
Total Assets	$ 6,781,746	$ 2,636,525	$ 97,276	$ 9,515,547
Capitalization and Liabilities:				
Capitalization:				
Common shareholders' equity	$ 1,876,074	$ 684,424	$ (460,724)(f)	$ 2,099,774
Preferred stock not subject to mandatory redemption	394,695	—	—	394,695
Preferred stock subject to mandatory redemption	167,892	125,000	—	292,892
Long-term debt	2,616,932	1,436,221	429,000 (f)	4,482,153
	5,055,593	2,245,645	(31,724)	7,269,514
Obligations Under Capital Leases	213,374	—	—	213,374
Short-Term Debt	62,500	108,000	147,000 (f)	317,500
Other Current Liabilities	619,232	251,387	(33,300)(b) 15,300 (f)	852,619
Accumulated Deferred Income Taxes	569,079	—	—	569,079
Other Deferred Credits	261,968	31,493	—	293,461
Total Capitalization and Liabilities	$ 6,781,746	$ 2,636,525	$ 97,276	$ 9,515,547

**Derived from audited data.*

The pro forma financial data are presented to comply with the SEC's regulations, which permit only limited adjustments to historical data.

The pro forma financial data are not a forecast or projection for any future date or period, nor are they a representation of what the company's financial position or results of operations would actually have been if such transactions in fact had occurred during the period presented.

See accompanying Notes to Condensed Pro Forma Consolidated Balance Sheet.

Notes to Condensed Pro Forma Consolidated Balance Sheet

(a) Reduces cash to reflect amounts to be paid at the acquisition date.

(b) Eliminates intercompany payables and receivables between NU and PSNH.

(c) Adjusts PSNH's assumed regulatory asset as allowed under the terms of the Rate Agreement.

(d) Reflects the new debt issuance expenses on the acquisition date, which are to be amortized over the terms of the respective debt issues.

(e) Adjusts deferred charges by $65 million to reflect previously unrecorded net operating loss carryforwards. The Rate Agreement stipulates that such carryforwards be calculated in accordance with the Plan, and that to the extent realization is assured beyond a reasonable doubt, such assured amounts be recorded as an asset.

(f) Adjusts capitalization at the acquisition date as follows (1):

	(Thousands of Dollars)
Common Equity:	
Eliminate PSNH's Common Equity	$(684,424)
Issue Common Shares—Public Offering	200,000
Reflect Common Share Issuance Costs	(6,000)
Reflect PSNH's Reimbursement of NU's Expenses on the Aquisition Date (2)	29,700
	$(460,724)
Long-Term Debt:	
PSNH Term Note	$ (52,000)
NAEC First Mortgage Bonds	355,000
NU Term Note	51,000
NU Debt Securities—ESOP II	75,000
	$ 429,000
Short-Term Debt:	
Northeast Utilities Consolidated—Refinance Money Pool Borrowings	$ 175,000
PSNH Revolving Credit Facility	(32,000)
NAEC Money Pool Borrowings	4,000
	$ 147,000

(1) For additional information regarding the financings contemplated by the Plan, see Note (h) of the Notes to the Condensed Pro Forma Consolidated Statement of Income.

(2) Recorded net of $15.3 million of income taxes.

CONSOLIDATED STATEMENTS OF QUARTERLY FINANCIAL DATA (UNAUDITED)

1991	Quarter Ended March 31	June 30	September 30	December 31
	(Thousands of Dollars, except per share data)			
Operating Revenues	$ 701,289	$ 636,962	$ 692,722	$ 722,830
Operating Income	$ 110,503	$ 88,482	$ 105,453	$ 85,074
Net Income	$ 68,825	$ 50,931	$ 67,113	$ 49,840
Earnings Per Common Share	$ 0.63	$ 0.46	$ 0.60	$ 0.43
1990				
Operating Revenues	$ 680,522	$ 603,801	$ 675,307	$ 656,689
Operating Income	$ 109,021	$ 86,962	$ 105,681	$ 78,898
Net Income	$ 66,109	$ 40,678	$ 65,896	$ 38,324
Earnings Per Common Share	$ 0.61	$ 0.37	$ 0.61	$ 0.35

CONSOLIDATED GENERAL OPE ING STATISTICS

	1991	1990	1989	1988	1987
System Capability—MW (a)	5,916.2	5,909.6	5,963.7	5,737.7	5,564.5
System Peak Demand—MW	4,999.8	4,753.9	4,858.0	4,883.3	4,590.5
Nuclear Capacity—MW (a)	2,380.0	2,459.5	2,397.1	2,590.4	2,420.2
Nuclear Capacity Factor (%) (a)	46.4	72.2	71.2	79.2	74.9
Nuclear Contribution to Total Energy Requirements (%) (a)	43.5	57.5	56.8	68.5	68.5

(a) Includes the system's entitlements in regional nuclear generating companies, net of capacity sales and purchases

SELECTED CONSOLIDATED FINANCIAL DATA

	1991	1990	1989	1988
	(Thousands of Dollars, except percentages and share data)			
Balance Sheet Data:				
Net Utility Plant—				
Continuing Operations	$5,257,567	$5,265,168	$5,237,805	$5,267,629
Discontinued Gas Plant	—	—	—	254,587
Total Assets	6,781,746	6,601,371	6,523,202	6,764,608
Total Capitalization (a)	5,138,426	4,965,859	4,954,083	5,123,504
Obligations Under Capital Leases (a)	279,729	319,548	341,246	410,352
Income Data:				
Continuing Operations:				
Operating Revenues	$2,753,803	$2,616,319	$2,473,571	$2,268,607
Net Income	236,709	211,007	203,225	224,844
Earnings per Common Share	$ 2.12	$ 1.94	$ 1.87	$ 2.07
Discontinued Gas Operations:				
Operating Revenues	$ —	$ —	$ 124,229	$ 200,243
Net Income	—	—	5,858	9,078
Earnings per Common Share	$ —	$ —	$ 0.05	$ 0.08
Common Share Data:				
Earnings per Share	$ 2.12	$ 1.94	$ 1.92	$ 2.15
Dividends per Share	$ 1.76	$ 1.76	$ 1.76	$ 1.76
Payout Ratio (%)	83.0	90.7	91.7	81.9
Number of Shares				
Outstanding—Average	111,453,550	109,003,818	108,669,106	108,669,106
Market Price—High	$24 3/8	$22 5/8	$23	$23 1/8
Market Price—Low	$19	$17 7/8	$18 1/2	$18 1/4
Market Price—Closing Price				
(end of year)	$23 5/8	$20	$22 1/2	$19 7/8
Book Value per Share (end of year)	$15.73	$16.34	$16.13	$16.90
Rate of Return Earned on Average				
Common Equity (%)	13.0	12.0	11.8	13.0
Dividend Yield (end of year) (%)	7.4	8.8	7.8	8.9
Market-to-Book Ratio (end of year)	1.5	1.2	1.4	1.2
Price-Earnings Ratio (end of year)	11.1	10.3	11.7	9.2
Capitalization: (a)				
Common Shareholders' Equity	$1,876,074	$1,790,758	$1,752,395	$1,837,034
Preferred Stock Not Subject				
to Mandatory Redemption	394,695	394,695	394,695	344,695
Preferred Stock Subject to				
Mandatory Redemption	170,394	176,892	181,892	111,832
Long-Term Debt	2,697,263	2,603,514	2,625,101	2,829,943
Total Capitalization	$5,138,426	$4,965,859	$4,954,083	$5,123,504

(a) Includes portions due within one year.

1987	1986	1985	1984	1983	1982
(Thousands of Dollars, except percentages and share data)					
$5,229,242	$5,120,812	$5,204,687	$4,650,428	$4,122,692	$3,570,710
237,903	224,581	214,115	204,187	192,861	183,322
6,663,794	6,299,755	6,147,720	5,507,040	4,957,927	4,309,368
4,956,080	4,743,914	4,681,995	4,319,404	3,954,569	3,465,395
432,714	441,183	440,587	392,593	337,636	286,603
$2,038,554	$2,006,842	$1,969,225	$2,030,557	$1,746,425	$1,641,308
214,529	171,234	277,768	276,615	209,905	143,040
$ 1.97	$ 1.58	$ 2.62	$ 2.73	$ 2.24	$ 1.67
$202,816	$203,814	$220,010	$224,430	$238,999	$224,447
14,616	10,705	10,773	12,323	11,643	8,202
$ 0.14	$ 0.10	$ 0.10	$ 0.12	$ 0.13	$ 0.09
$ 2.11	$ 1.68	$ 2.72	$ 2.85	$ 2.37	$ 1.76
$ 1.76	$ 1.68	$ 1.58	$ 1.48	$ 1.38	$ 1.28
83.4	100.0	58.1	51.9	58.2	72.7
108,669,106	108,352,517	106,221,131	101,398,235	93,497,945	85,777,230
$28	$28¼	$18¾	$14¾	$13⅞	$12½
$18	$17⅜	$13¾	$10⅝	$11¼	$ 8⅞
$20¼	$24¼	$17¾	$14¼	$12¼	$12⅛
$16.53	$16.24	$16.21	$15.07	$13.84	$12.96
12.8	10.4	17.4	19.8	17.8	13.8
8.7	6.9	8.9	10.4	11.3	10.6
1.2	1.5	1.1	0.9	0.9	0.9
9.6	14.4	6.5	5.0	5.2	6.9
$1,796,293	$1,765,090	$1,738,871	$1,575,705	$1,361,724	$1,159,698
291,195	291,195	291,195	291,195	291,195	291,195
205,832	166,832	185,833	186,978	188,547	104,461
2,662,760	2,520,797	2,466,096	2,265,526	2,113,103	1,910,041
$4,956,080	$4,743,914	$4,681,995	$4,319,404	$3,954,569	$3,465,395

CONSOLIDATED ELECTRIC OPERATING STATISTICS

	1991	1990	1989	1988
Source of Electric Energy:				
(kWh—millions) (a)				
Nuclear—Steam	11,062	17,724	17,119	19,146
Fossil—Steam	6,179	6,829	8,956	8,805
Hydro—Conventional	994	1,174	956	825
Hydro—Pumped Storage	1,173	1,250	1,194	1,111
Internal Combustion	25	11	77	84
Energy Used for Pumping	(1,605)	(1,688)	(1,629)	(1,509)
Net Generation	17,828	25,300	26,673	28,462
Purchased and Net Interchange	13,430	6,249	5,178	2,456
Company Use and Unaccounted for	(1,958)	(1,938)	(2,304)	(2,333)
Net Energy Sold	29,300	29,611	29,547	28,585
Revenues: (thousands)				
Residential	$ 995,098	$ 938,032	$ 898,471	$ 838,011
Commercial	828,117	788,478	734,709	673,819
Industrial	419,003	410,125	391,661	366,517
Other Utilities	366,231	346,087	301,045	227,653
Streetlighting and Railroads	38,656	37,195	35,499	33,151
Miscellaneous	49,539	42,882	64,282	82,169
Total Electric	2,696,644	2,562,799	2,425,667	2,221,320
Other	57,159	53,520	47,904	47,287
Total	$2,753,803	$2,616,319	$2,473,571	$2,268,607
Sales: (kWh—millions)				
Residential	9,518	9,500	9,594	9,412
Commercial	8,900	8,981	8,757	8,585
Industrial	5,208	5,448	5,557	5,535
Other Utilities	5,388	5,394	5,351	4,771
Streetlighting and Railroads	286	288	288	282
Total	29,300	29,611	29,547	28,585
Customers: (average)				
Residential	1,150,357	1,145,142	1,134,588	1,117,356
Commercial	102,867	102,900	101,301	98,095
Industrial	5,067	5,114	5,090	5,063
Other	3,305	3,283	3,277	3,222
Total	1,261,596	1,256,439	1,244,256	1,223,736
Average Annual Use Per Residential Customer (kWh)	8,285	8,304	8,460	8,418
Average Annual Bill Per Residential Customer	$ 866.20	$ 819.94	$ 792.28	$ 749.54
Average Revenue Per kWh:				
Residential	10.45¢	9.87¢	9.36¢	8.90¢
Commercial	9.30	8.78	8.39	7.85
Industrial	8.05	7.53	7.05	6.62

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

1987	1986	1985	1984	1983	1982
18,019	16,624	11,453	13,711	10,898	12,343
7,912	9,048	8,325	9,065	7,963	7,503
866	895	726	840	833	791
973	950	925	875	897	795
39	33	16	34	13	15
(1,322)	(1,293)	(1,287)	(1,199)	(1,244)	(1,108)
26,487	26,257	20,158	23,326	19,360	20,339
2,585	3,328	5,398	2,916	4,648	2,743
(2,082)	(2,050)	(1,859)	(1,793)	(1,801)	(1,631)
26,990	27,535	23,697	24,449	22,207	21,451
$ 780,866	$ 741,838	$ 750,076	$ 754,075	$ 668,794	$ 633,124
630,678	602,924	606,414	589,898	515,750	479,976
353,394	350,310	371,079	381,289	332,460	314,420
203,642	234,222	165,071	216,227	151,800	150,357
32,318	34,741	34,899	32,252	26,456	23,767
(18,146)	(2,464)	9,698	29,340	28,413	23,114
1,982,752	1,961,571	1,937,237	2,003,081	1,723,673	1,624,758
55,802	45,271	31,988	27,476	22,752	16,550
$2,038,554	$2,006,842	$1,969,225	$2,030,557	$1,746,425	$1,641,308
8,825	8,274	7,837	7,804	7,554	7,342
8,151	7,676	7,185	6,904	6,493	6,166
5,449	5,394	5,286	5,374	5,046	4,871
4,284	5,883	3,094	4,113	2,910	2,895
281	308	295	254	204	177
26,990	27,535	23,697	24,449	22,207	21,451
1,091,539	1,063,998	1,041,254	1,021,871	1,005,005	991,069
94,164	90,924	88,031	85,658	83,955	88,315
5,084	5,102	5,087	5,022	4,979	5,004
3,120	3,096	3,067	3,025	3,010	2,428
1,193,907	1,163,120	1,137,439	1,115,576	1,096,949	1,086,816
8,061	7,746	7,492	7,596	7,472	7,361
$ 713.24	$ 694.51	$ 717.06	$ 734.00	$ 661.57	$ 634.71
8.85¢	8.97¢	9.57¢	9.66¢	8.85¢	8.62¢
7.74	7.85	8.44	8.54	7.94	7.78
6.49	6.49	7.02	7.10	6.59	6.45

SHAREHOLDER INFORMATION

Shareholders

As of January 31, 1992, there were 146,765 common shareholders of record of Northeast Utilities holding an aggregate of 119,624,077 common shares.

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. 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
1991	First	$21 1/2	$19	$0.44
	Second	21 1/2	19 3/4	0.44
	Third	22 3/8	20 1/8	0.44
	Fourth	24 3/8	21 3/4	0.44
1990	First	$22 5/8	$20 1/8	$0.44
	Second	21 1/4	19	0.44
	Third	20 3/8	17 7/8	0.44
	Fourth	20 7/8	18 1/8	0.44

Dividend Reinvestment Plan

The company has a Dividend Reinvestment Plan under which all common shareholders may use their dividends to purchase additional common shares. The company absorbs all brokerage fees for purchases under the plan.

Northeast Utilities Service Company, Shareholder Services, P.O. Box 5006, Hartford, Connecticut 06102-5006, is the company's dividend-paying agent and administers the company's Dividend Reinvestment Plan.

Annual Meeting

The annual meeting of shareholders of Northeast Utilities will be held on Tuesday, May 19, 1992, at 10 a.m., at La Renaissance, East Windsor, Connecticut, which is located at Exit 44 (East Windsor) of Interstate 91.

Transfer Agents and Registrars

Northeast Utilities Service Company
Shareholder Services
P.O. Box 5006
Hartford, Connecticut 06102-5006

State Street Bank and Trust Company
Corporate Stock Transfer Department
P.O. Box 8200
Boston, Massachusetts 02266-8200

Form 10-K

Northeast Utilities will provide shareholders a copy of its 1991 Annual Report to the Securities and Exchange Commission on Form 10-K, including the financial statements and schedules thereto, without charge, upon receipt of a written request sent to:

Theresa H. Allsop
Assistant Secretary
Northeast Utilities
P.O. Box 270
Hartford, Connecticut 06141-0270

OFFICERS

Chairman and Chief Executive Officer

William B. Ellis

President and Chief Operating Officer

Bernard M. Fox

Executive Vice President

John F. Opeka
Nuclear

Senior Vice Presidents

Robert E. Busch
Chief Financial Officer

John P. Cagnetta
Corporate Planning and Regulatory Relations

Frank R. Locke
Chief Administrative Officer–New Hampshire

Hugh C. MacKenzie
Customer Service Operations

*Lawrence H. Shay
Administrative Services

*Walter F. Torrance, Jr.
Secretary and General Counsel

Vice Presidents

C. Thayer Browne
Treasurer

Eric A. DeBarba
Nuclear, Engineering Services

Tod O. Dixon
Information Resources

Cheryl W. Grisé
Human Resources

Barry Ilberman
Corporate Planning

Francis L. Kinney
Public Affairs

Keith R. Marvin
Purchasing and Materials Management

John W. Noyes
Regulatory Relations

*Richard A. Reckert
Fossil/Hydro Engineering and Operations

Wayne D. Romberg
Nuclear, Operations Services

Frank P. Sabatino
Marketing

C. Frederick Sears
Environmental

*George D. Uhl
Controller

Roger C. Zaklukiewicz
Transmission and Distribution

Regional Vice Presidents

Robert G. Abair
Western Massachusetts

Richard R. Carella
Eastern

Lesley C. Gerould
Southern

*Roy C. J. Normen
Northern

Alfred R. Rogers
Central

*Robert W. Zonghetti
Western

Assistant Controllers

Patricia R. McLaughlin
*S. James Morneault

Assistant Secretaries

Theresa H. Allsop
*Douglas R. Teece
Karen G. Valenti

Assistant Treasurers

Robert C. Aronson
Arthur H. Hierl
Eugene G. Vertefeuille

**Have elected to participate in a voluntary early retirement plan and will retire in 1992.*

Executive Changes—**Robert E. Busch** *was elected executive vice president and chief financial officer, effective April 1, 1992;* **John F. Opeka** *was elected executive vice president—Nuclear, effective November 1, 1991;* **Eric A. DeBarba** *was elected vice president—Nuclear, Engineering Services, effective March 1, 1992;* **Cheryl W. Grisé** *was elected vice president—Human Resources, effective June 1, 1991;* **Barry Ilberman** *was elected vice president—Corporate Planning, effective January 29, 1992;* **Keith R. Marvin** *was elected vice president—Purchasing and General Services, effective April 1, 1992;* **John W. Noyes** *was elected vice president and controller, effective April 1, 1992;* **Wayne D. Romberg** *was elected vice president—Nuclear, Operations Services, effective March 1, 1992;* **C. Frederick Sears** *was elected vice president—Environmental, effective March 1, 1992; and* **George D. Uhl** *was elected vice president, effective April 1, 1992.* **Edward J. Mroczka,** *senior vice president—Nuclear Engineering and Operations, resigned in 1991 after 24 years of service.*

Retirements—**Albert J. Hajek,** *vice president—Corporate Performance Services and Organizational Control, retired in 1991 after 44 years of service; and* **Winslow C. Wentworth, Jr.,** *Assistant Controller, retired in 1991 after 32 years of service.*

In Memoriam—*We note with sadness, the passing, during the year, of* **Warren A. Greten,** *retired vice president—Fossil and Hydro Production.*

As of March 1, 1992

OFFICERS

William B. Ellis
Chairman of the Board and Chief Executive Officer

Bernard M. Fox
President and Chief Operating Officer

Robert E. Busch
Senior Vice President and Chief Financial Officer

Walter F. Torrance, Jr.
Senior Vice President, Secretary, and General Counsel

C. Thayer Browne
Vice President and Treasurer

George D. Uhl
Vice President and Controller

Theresa H. Allsop
Assistant Secretary

Karen G. Valenti
Assistant Secretary

Robert C. Aronson
Assistant Treasurer

Arthur H. Hierl
Assistant Treasurer

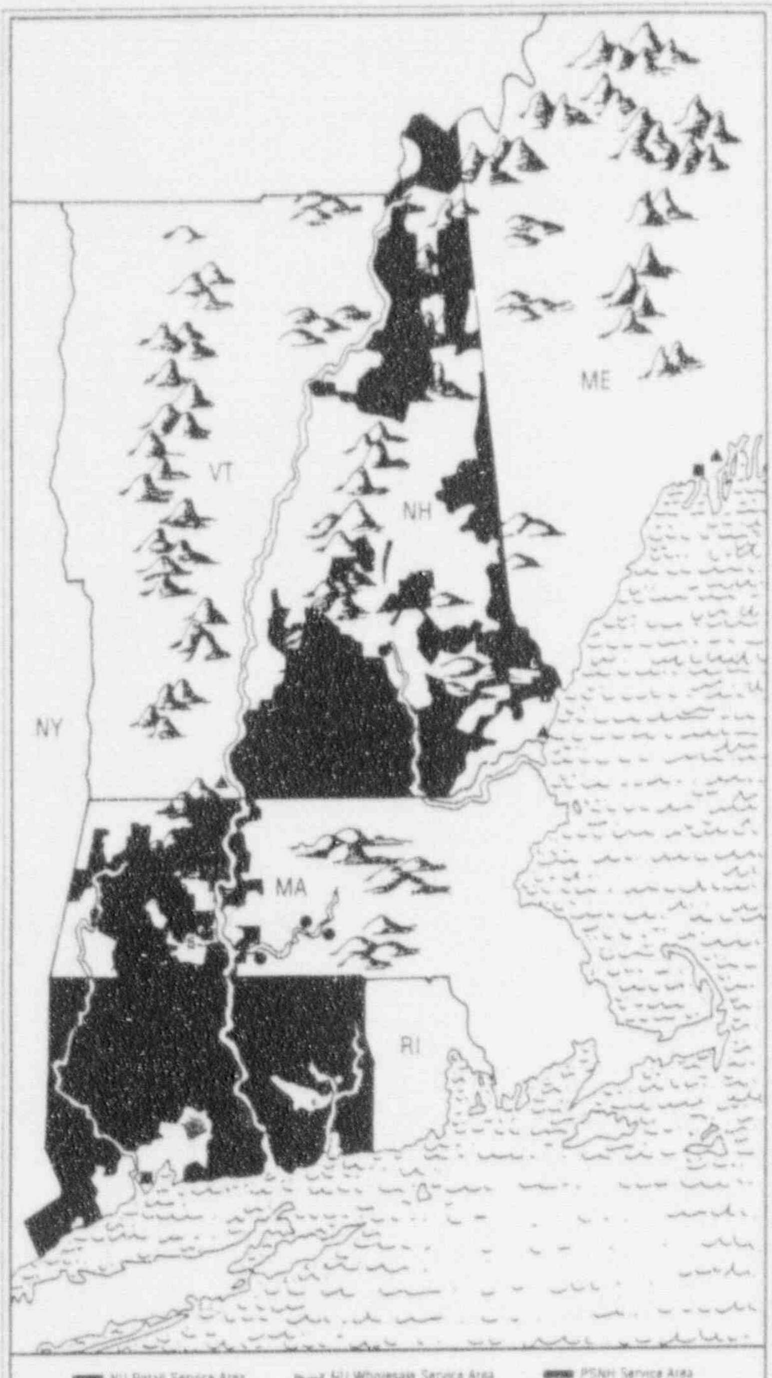
Eugene G. Vertefeuille
Assistant Treasurer

TRUSTEES

* Executive Committee
\+ Finance Committee
\# Audit Committee
† Committee on Organization, Compensation and Board Affairs
° Corporate Responsibility Committee

***Kathryn S. Fuller** resigned as a Trustee in 1991*

As of March 1, 1992



Northeast Utilities (NU) is in the process of acquiring the assets and operating business of Public Service Company of New Hampshire (PSNH).

NU serves 1,264,928 customers in a service area that stretches from the Connecticut shore to the Berkshires in Massachusetts. The service area covers approximately 5,890 square miles (4,400 in Connecticut and 1,490 in Massachusetts) in 208 communities (149 in Connecticut and 59 in Massachusetts). Addition of PSNH to the NU system would add 389,576 customers in 198 communities. The northern bounda: would stretch to Canada and the combined system would add 5,445 squa·e miles.

Net Generating Capacity*
In Megawatts (MW)
As Of January 1, 1992

	NU	PSNH
Nuclear	2,500	567
Fossil-Steam	1,712	888
Hydroelectric	1,083	68
Other Units	454	110
Cogeneration	475	158
Total	6,224	1,791

*Does not include purchases and sales of less than six months.

▲ **Nuclear** NU wholly owns two nuclear units and shares in six others. PSNH shares in six units. Capacities above reflect entitlements from the plants.

■ **Fossil-Steam** NU has 11 units at six locations: 8 oil-fired, one coal-burning, and two with dual oil-gas capabilities. PSNH has 7 units (one jointly owned) at four locations.

● **Hydroelectric** NU has 64 conventional and seven pumped-storage units at 25 plant sites. PSNH has 13 conventional units at 9 sites.

⬬ **Other Units** NU has 24 internal combustion units (not shown on map) for use during periods of high demand. Two turbines at a trash-to-energy unit in Hartford are owned by NU. PSNH has 8 internal combustion units (also not shown).

Cogeneration Independent cogenerators and small power producers under long-term contracts operate in the NU service territory and have a total capacity of about 475 MW. Comparable independents in the PSNH service area have about 160 MW of capacity.

NORTHEAST UTILITIES

P.O. Box 270
Hartford, Connecticut 06141-0270
(203) 665-5000

SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549-1004

Form 10-K

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

(Mark One)

_X_ ANNUAL REPORT PURSUANT TO SECTION 1 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [FEE REQUIRED]

For the fiscal year ended December 31, 1991

OR

___ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

For the transition period from ______________ to ______________

Commission file number 1-7316

COMMONWEALTH ENERGY SYSTEM
(Exact name of registrant as specified in its Declaration of Trust)

Massachusetts (State or other jurisdiction of incorporation or organization)	04-1662010 (I.R.S. Employer Identification No.)
One Main Street, Cambridge, Massachusetts (Address of principal executive offices)	02142-9150 (Zip Code)

(Registrant's telephone number, including area code) (617) 225-4000

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

Title of each class	Name of each exchange on which registered
Common Shares of Beneficial Interest $4 par value	New York Stock Exchange, Inc. Boston Stock Exchange, Inc. Pacific Stock Exchange, Inc.

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

Title of Class
None

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. _x_

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 ___

Aggregate market value of the voting stock held by non-affiliates of the registrant as of March 16, 1992: $385,403,886

Common Shares outstanding at March 16, 1992: 10,043,098 shares

Document Incorporated by Reference	Part in Form 10-K
Notice of 1992 Annual Meeting, Proxy Statement and 1991 Financial Information, dated April 3, 1992 (pages as specified herein)	Parts I, II and III

List of Exhibits begins on page 26 of this report.

COMMONWEALTH ENERGY SYSTEM
FORM 10-K DECEMBER 31, 1991
TABLE OF CONTENTS

PART I

Item 1. Business

General

Commonwealth Energy System, a Massachusetts trust, is an unincorporated business organization with transferable shares. It is organized under a Declaration of Trust dated December 31, 1926, as amended, pursuant to the laws of Massachusetts. It is an exempt public utility holding company under the provisions of the Public Utility Holding Company Act of 1935, holding all of the stock of four operating public utility companies. 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 operating utility subsidiaries of the System are engaged in the generation, transmission and distribution of electricity and the distribution of natural gas, all within Massachusetts. These subsidiaries are:

Electric	Gas
Cambridge Electric Light Company	Commonwealth Gas Company
Canal Electric Company	
Commonwealth Electric Company	

In addition to the utility companies, the System also owns all of the stock of a steam distribution company (COM/Energy Steam Company), five real estate trusts and a liquefied natural gas (LNG) and vaporization facility (Hopkinton LNG Corp.). Subsidiaries of the System have common executive and financial management and receive technical assistance as well as financial, data processing, accounting, legal and other services from a wholly-owned services company subsidiary (COM/Energy Services Company).

The five real estate subsidiaries are: Darvel Realty Trust, which is a joint-owner of the Riverfront Office Park complex in Cambridge; COM/Energy Acushnet Realty, which leases land to Hopkinton LNG Corp.; COM/Energy Research Park Realty, which was organized to develop a research building in Cambridge; COM/Energy Cambridge Realty, which was organized to hold various properties; and COM/Energy Freetown Realty (Freetown), which was organized in 1986 to purchase and develop 596 acres of land in Freetown, Massachusetts.

Freetown's preliminary plans called for the development of an energy park, the first phase of which included the construction of a 440 megawatt (MW) generating unit, through the joint efforts of Freetown and Texaco Syngas, Inc. and a subsidiary of General Electric Company (the co-developers).

Effective November 30, 1991, the co-developers notified Freetown of their intent not to continue with the project due to poor economic conditions and significant declines in regional load forecasts which

Item 1. Business (Continued)

General (Continued)

pushed the need for power out to the late 1990s. Subsequent efforts by the System to generate interest in alternative uses of the site were hampered by continuing difficulties in the regional economy, particularly in the real estate market. On January 23, 1992, the System announced its decision to write-down its investment in the Freetown project. This action resulted in the recognition of a one-time (net of tax) charge of $14.8 million. For additional information, refer to Note 11(a) of the Notes to Consolidated Financial Statements filed under Item 8 of this report.

Each of the operating utility subsidiaries previously listed serves retail customers except for Canal Electric Company (Canal) which operates an electric 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 1, with a rated capacity of 569 MW, wholly-owned by Canal; and Canal Unit 2, with a rated capacity of 580 MW, jointly-owned by Canal and Montaup Electric Company (Montaup) (an unaffiliated company). Canal Unit 2 is operated under an agreement with Montaup which provides for the equal sharing of output, fixed charges and operating expenses.

Electric service is furnished by Cambridge Electric Light Company (Cambridge Electric) and Commonwealth Electric Company (Commonwealth Electric) at retail to approximately 304,000 year-round customers in 41 communities in eastern Massachusetts covering 1,112 square miles and having an aggregate population of 645,000. The system also serves approximately 49,000 seasonal retail customers. The territory served includes the communities of Cambridge, New Bedford and Plymouth and the geographic area comprising Cape Cod and Martha's Vineyard. Cambridge Electric also sells power at wholesale to the Town of Belmont, Massachusetts.

Natural gas is distributed by Commonwealth Gas to approximately 228,000 customers in 49 communities in central and eastern Massachusetts covering 1,067 square miles and having an aggregate population of 1,128,000. Twelve of these communities are also served by system companies with electricity. Some of the larger communities served by Commonwealth Gas include Cambridge, Somerville, New Bedford, Plymouth, Worcester, Framingham, Dedham and the Hyde Park area of Boston.

The population in the system's electric service area increased by 15.2% while the population in the gas service area increased by 12% since the last federal census was taken in 1980.

Steam, which is produced by Cambridge Electric in connection with the generation of electricity, is purchased by COM/Energy Steam and, together with its own production, is distributed to 19 customers in Cambridge and 1 customer (Massachusetts General Hospital) in Boston. Steam is used for space heating and other purposes. A major new customer, New England Confectionary Company (Necco), is scheduled to

Item 1. Business (Continued)

General (Continued)

begin receiving steam service in June 1992. Necco will become the fourth largest customer of COM/Energy Steam.

Industry in the territories served is highly diversified. The larger industrial customers include high-technology firms and manufacturers of such products as photographic equipment and supplies, rubber products, textiles, wire and other fastening devices, abrasives and grinding wheels, candy, copper and alloys, and chemicals. Among customers served are several major educational institutions, including Harvard University and the Massachusetts Institute of Technology.

Electric Power Supply

System companies own generating facilities with a capability totaling 1,078.4 MW. Included in this amount is 572 MW provided by Canal Unit 1, of which three-quarters (429 MW) is sold to neighboring utilities under long-term contracts, and 292 MW provided by Canal Unit 2. In 1991, Canal executed an exchange transaction with Central Vermont Public Service Corporation (CVPS) whereby 50 MW of Canal Unit 2 was exchanged for 25 MW each of CVPS's entitlement in the Vermont Yankee nuclear power plant and the Merrimack 2 coal-fired unit through October 1995 in order to reduce the system's reliance on oil. Another 214.4 MW is provided by various smaller system units. Of the 649.4 MW available to the system, 66.4 MW is used principally for peaking purposes. Seabrook 1 provides 40.5 MW of capability to the system and Central Maine Power Company's Wyman Unit 4, an oil-fired facility in which the system has a 1.4% joint-ownership interest, provides 8.9 MW.

In addition, the system has available 77.7 MW from four (4) nuclear units in which the distribution companies have ownership interests. Information with respect to these units is as follows:

	Connecticut Yankee	Maine Yankee	Vermont Yankee	Yankee Atomic
Location	Haddam Neck, Connecticut	Wiscasset, Maine	Vernon, Vermont	Rowe, Mass.
Year of Initial Operation	1968	1972	1972	1961
Contract Expiration Date	1998	2008	2012	2000
System Percent of Equity Ownership	4.50%	4.00%	2.50%	4.50%
System Percent of Plant Entitlement	4.50%	3.59%	2.25%	4.50%
Plant Capability (MW)	591.1	880.0	520.0	173.6
System Entitlement (MW)	26.6	31.6	11.7	7.8
1991 Actual Cost ($000)	$9,692	$5,900	$3,383	$3,210
1992 Estimated Cost ($000)	$9,127	$7,484	$3,972	$3,891

Item 1. Business (Continued)

Electric Power Supply (Continued)

On February 26, 1992, the Board of Directors of the Yankee Atomic unit decided to permanently close the plant and, in time, decommission the facility. For additional information, refer to Note 4(f) of the Notes to Consolidated Financial Statements filed under Item 8 of this report.

To satisfy demand requirements and provide required reserve capacity, the system supplements its generating capacity by purchasing power on a long and short-term basis through capacity entitlements under power contracts with other New England and Canadian utilities and with Qualifying Facilities through a competitive bidding process which is regulated by the Massachusetts Department of Public Utilities and also with other non-utility generators.

Long-term purchase arrangements include a 73.7 MW entitlement from a nuclear unit in Plymouth, Massachusetts (Pilgrim) under a life-of-the-unit contract with Boston Edison Company. In addition, through Canal's equity ownership in Hydro-Quebec Phase II, the system has an entitlement of 67.9 MW. Long-term purchase arrangements are in place with the following natural gas-fired cogenerating units in Massachusetts: 26.8 MW from the Consolidated Power Company, 37.2 MW from Pepperell Power Associates and 53 MW from Northeast Energy Associates. Additionally, the system receives 46.2 MW from the SEMASS waste-to-energy plant in Rochester, Massachusetts, and has entitlements totaling 24.7 MW through contracts with five (5) hydroelectric suppliers, including 20 MW from Boott Hydropower, Inc., in Lowell, Massachusetts. The system anticipates providing for future peak load plus reserve requirements through existing and planned system generation, including purchasing excess capacity from neighboring utilities and/or non-utility generators.

Cambridge Electric, Canal and Commonwealth Electric, together with other electric utility companies in the New England area, are members of the New England Power Pool (NEPOOL), which was formed in 1971 to provide for the joint planning and operation of electric systems throughout New England.

NEPOOL operates a centralized dispatching facility to ensure reliability of service and to dispatch the most economically available generating units of the member companies to fulfill the region's energy requirement. This concept is accomplished by use of computers to monitor and forecast load requirements and provide for the economic dispatching of generation.

NEPOOL, on behalf of its members entered into an Interconnection Agreement with Hydro-Quebec, a Canadian utility operating in the Province of Quebec. The agreement provided for construction of an interconnection (Phase I) between the electrical systems of New England and Quebec. These parties have also entered into an Energy

Item 1. Business (Continued)

Electric Power Supply (Continued)

Contract and an Energy Banking Agreement; the former obligates Hydro-Quebec to offer NEPOOL participants up to 33 million MWH of surplus energy during an eleven-year term commencing September 1, 1986 and the latter provides for energy transfers between the two systems. The Phase I Interconnection began operation in October 1986. NEPOOL has also entered into Phase II agreements for an additional purchase from Hydro-Quebec of 7 million MWH per year for a twenty-five year period which began in late 1990.

The System's electric subsidiaries are also members of the Northeast Power Coordinating Council (NPCC), an advisory organization which includes the major power systems in New England and New York plus the provinces of Ontario and New Brunswick in Canada. NPCC establishes criteria and standards for reliability and serves as a vehicle for coordination in the planning and operation of these systems in enhancing reliability.

The reserve requirements used by the NEPOOL participants in planning future additions are determined by NEPOOL to meet the reliability criteria recommended by NPCC. The system estimates that, during the next ten years, reserve requirements so determined will be in the range of 23% to 29% of peak load.

Power Supply Commitments and Support Agreements

Cambridge Electric and Commonwealth Electric, through Canal, secure cost savings for their respective customers by planning for bulk power supply on a single system basis.

The system's 3.52% interest in the Seabrook nuclear power plant is owned by Canal to provide for a portion of the capacity and energy needs of Cambridge Electric and Commonwealth Electric. Seabrook was originally designed to have two pressurized water reactors, each with a rated capacity of 1,150 MW. Seabrook 1 has been completed since mid-1986. The second reactor, however, was abandoned in 1984.

Upon the plant's commercial operation in 1990, Canal began recovering 100% of its Seabrook 1 investment through power contracts with Cambridge Electric and Commonwealth Electric, subject to refund pending a full review of Canal's investment in the unit by the FERC. For additional information concerning Seabrook 1, refer to Note 4(b) of Notes to Consolidated Financial Statements filed under Item 8 of this report.

In response to solicitations made to NEPOOL members by Northeast Utilities (NU) Canal, on behalf of Commonwealth Electric and Cambridge Electric, agreed to purchase entitlements through short and long-term contracts in various selected generating units. The length of these separate agreements range up to a five-year period.

Item 1. Business (Continued)

Power Supply Commitments and Support Agreements (Continued)

The terms of the five-year agreement stipulate the purchase of 50 MW, on average, from NU annually from November 1989 through October 1994. Commonwealth Electric and Cambridge Electric are each appropriated a portion of the power received from NU based on need. These and other bulk electric power purchases are necessary in order to fulfill the system's NEPOOL obligation and to meet Commonwealth Electric and Cambridge Electric capacity requirements.

Canal participated with other electric utilities in the construction and operation of Hydro-Quebec Phase I transmission facilities in northeastern Vermont, which were completed in 1986 at a cost of approximately $140 million. Upon commercial operation of Phase II and per the Phase I Support Agreements, Canal's share of Phase I was reduced to 3.7% to allow for greater participating interest of two other utilities. Canal has also entered into a support agreement for 3.8% of Hydro-Quebec Phase II facilities which were completed in November 1990 at a cost of $487 million. For additional information relating to Canal's interest in Hydro-Quebec Phases I and II, refer to Note 4(e) of Notes to Consolidated Financial Statements filed under Item 8 of this report.

Price-Anderson Act

The Price-Anderson Act (the Act) is a federal statute that includes among its provisions a requirement for licensees of nuclear electric generating units to maintain financial protection to cover public liability claims resulting from a nuclear incident or precautionary evacuation and a restriction on the maximum liability exposure resulting from any single nuclear incident. In 1988, Congress enacted a fifteen-year extension of the Act and increased the available insurance and the maximum liability. The higher coverage is provided by existing private insurance and retrospective assessments for costs in excess of that covered by insurance, up to $66.2 million for each nuclear reactor which is licensed to operate with a maximum assessment of $10 million per incident within one calendar year. Based on the system's equity ownership in the corporations owning four nuclear generating facilities and its 3.52% ownership interest in Seabrook 1, the system's retrospective premium could be as high as $1.9 million yearly or a cumulative total of $12.6 million, exclusive of the effect of inflation indexing (at five-year intervals) and a 5% surcharge ($3.3 million) in the event that total public liability claims from a nuclear incident exceed the funds available to pay such claims.

Item 1. Business (Continued)

Electric Fuel Supply

(a) Oil

Imported residual oil is the primary fuel used in the generation of power in system generating plants. Approximately 42% of the system's current energy requirements for retail sales are from oil producing plants.

Effective July 1, 1991, Canal executed a two-year contract with Coastal Oil New England, Inc. (Coastal) for the purchase of residual fuel oil. The contract provides for the delivery of a set percentage of Canal's fuel requirement, the balance to be met by spot purchases or by Coastal at the discretion of Canal.

Energy Supply and Credit Corporation (ESCO) operates Canal's oil terminal for the purchase, receipt and payment of oil under assignment of Canal's supply contracts to ESCO (Massachusetts), Inc. Oil in the terminal's tanks is held in inventory by ESCO and delivered upon demand to Canal's tanks.

Fuel oil storage facilities at the Canal site have a capacity of 1,199,000 barrels, representing 34 days of normal operation of the two units. During 1991, ESCO maintained an average daily inventory of 623,000 barrels of fuel oil which represents 18 days of normal operation of the two units. This supply is maintained by tanker deliveries approximately every ten to fifteen days.

Reference is made to Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," for a discussion of the cost of fuel oil.

(b) Nuclear Fuel Supply and Disposal

Approximately 31% of the system's 1991 energy requirements for retail sales was generated by nuclear plants. The supply of fuel for nuclear generating plants generally involves the acquisition of uranium concentrate, its conversion to uranium hexafluoride, enrichment, fabrication of the nuclear fuel assemblies and disposition through reprocessing or storage of spent fuel.

The contract and inventory information which follows for Seabrook 1 has been furnished to Canal by New Hampshire Yankee (NHY), the plant manager responsible for operation of the unit. With respect to uranium and converted uranium requirements, there is existing inventory for the second reload and 100% coverage for the third reload. Uranium requirements are 65% covered through 1996 and converted uranium requirements are up to 100% covered through 1999. The contract for fabrication services is fully covered through 1998.

With respect to enrichment services, Seabrook 1 has 100% coverage

Item 1. Business (Continued)

(b) Nuclear Fuel Supply and Disposal (Continued)

for the second reload and 70% coverage for the third reload. During the 1995-2014 period, there is full coverage.

There are no spent fuel reprocessing facilities currently operating in the United States. Instead, United States operating nuclear generating units are required to retain high level wastes and spent fuel on-site or make long-term arrangements for their storage. As required by the Nuclear Waste Policy Act of 1982 (the Act), as amended, the joint-owners entered into a contract with the Department of Energy for the transport and disposal of spent fuel and high level radioactive waste at a national nuclear waste repository. Owners or generators of spent nuclear fuel or its associated wastes are required to bear all of the costs for such transportation and disposal through payment of a fee of approximately 1 mill/KWH based on net electric generation to the Nuclear Waste Fund. Under the Act, a temporary national repository for nuclear waste was anticipated to be in operation by 1998; however, a reassessment of the project's schedule requires extending the completion date of the permanent facility until at least 2010. Seabrook 1 is currently licensed for enough on-site storage to accommodate all spent fuel expected to be accumulated through the year 2010. Furthermore, NHY will be evaluating options for extending on-site spent fuel storage capacity beyond this time.

Gas Supply

General

The system obtains its natural gas supplies under long-term contracts with two pipeline companies, Tennessee Gas Pipeline Company (Tennessee), a division of Tenneco, Inc., and Algonquin Gas Transmission Company (Algonquin), a wholly-owned subsidiary of Texas Eastern Transmission Corporation. The principal Algonquin contracts extend through 1996 and the Tennessee contract through the year 2000. These contracts provide for specified quantities of natural gas, which constitute the system's principal sources of supply to meet its requirements for firm gas (i.e., gas sales which are not contractually subject to interruption). The system also purchases gas on the spot market. In addition, LNG facilities, described below, are used to liquefy and store pipeline gas during the warmer months for use during the heating season. During 1991, all of the system's firm gas requirements were supplied by pipeline gas. Approximately 57% of these supplies were purchased on the spot market.

In 1990, the system exercised its right to convert a portion of its firm sales contract with Algonquin to firm transportation. Effective November 1, 1990, the system converted 17,285 MMBTU/day out of its 87,207 MMBTU/day contract. The gas will be purchased under long-term firm contracts (five to six years) from four separate suppliers and transportation will be provided by Texas Eastern and Algonquin on

Item 1. Business (Continued)

Gas Supply (Continued)

a firm basis from the supply area to our city gate stations. Approximately 87% of this gas is covered by three contracts that were approved by the DPU on January 11, 1991. These contracts allow for increased reliability and the ability to purchase gas at a cost lower than the prior firm sales arrangements with Algonquin. The remaining contract has been signed and submitted to the DPU for its review and approval.

In 1991, the system converted a portion of its existing firm gas supply contract with Tennessee Gas Pipeline to firm transportation. The conversion became effective on September 1, 1991 with a maximum daily quantity (MDQ) of 10,000 MMBTU representing approximately 18% of the then existing sales MDQ of 56,826 MMBTU. The purchase contract associated with the conversion has been submitted to the DPU for its review and approval

Commonwealth Gas began transporting gas in 1990 for end-users on its system. There are currently only three customers using this transportation service. Total end-user transportation accounted for only 299,760 MMBTU of throughput in 1991 which represented approximately 0.7% of system throughput.

Hopkinton LNG Facility

A portion of the system's gas requirements during the heating season are provided by Hopkinton LNG Corp. (Hopkinton), a wholly-owned subsidiary of the System. The facility consists of a liquefaction and vaporization plant and three above-ground cryogenic storage tanks having an aggregate capacity of 3 million MCF of natural gas.

In addition, Hopkinton owns a satellite vaporization plant and two above-ground cryogenic storage tanks located in Acushnet, Massachusetts. These storage tanks have an aggregate capacity of 500,000 MCF of natural gas and are filled with LNG trucked from the tanks in Hopkinton.

Commonwealth Gas Company has a contract for LNG service with Hopkinton extending through 1996, thereafter renewable year to year with notice of termination due five years in advance. Contract payments include a demand charge sufficient to cover Hopkinton's fixed charges and an operating charge which covers liquefaction and vaporization expenses. Commonwealth Gas furnishes pipeline gas during the period April 15 to November 15 each year for liquefaction and storage. As the need arises, LNG is vaporized and placed in the distribution system of Commonwealth Gas.

Item 1. Business (Continued)

Hopkinton LNG Facility (Continued)

Based upon information presently available regarding projected growth in demand and estimates of availability of future supplies of pipeline gas, the System believes that its present sources of gas supply are adequate to meet existing load and allow for future growth in sales.

Rates, Regulation and Legislation

Certain of the System's utility subsidiaries operate under the jurisdiction of the DPU, which regulates retail rates, accounting, issuance of securities and other matters. In addition, Canal Electric and Cambridge Electric file their respective wholesale rates with the Federal Energy Regulatory Commission (FERC).

(a) Wholesale Rate Proceedings

Cambridge Electric needs FERC approval to increase its wholesale rates to the Town of Belmont, Massachusetts (Belmont), a "partial requirements" customer of Cambridge Electric since 1986. These rates include a fuel adjustment clause which reflects changes in costs of fuels and purchased power used to supply Belmont. On March 23, 1990, Cambridge Electric filed a request with the FERC to increase its wholesale rates to Belmont by $2,252,000 annually. The request was largely due to increased purchased power costs and major additions to plant-in-service since the last filing in 1985. Cambridge Electric proposed rates, subsequently accepted by the FERC, which went into effect, subject to refund, on August 1, 1990. On September 19, 1990, Cambridge Electric and Belmont filed an uncontested Offer of Settlement which the FERC approved on December 6, 1990. This settlement resolved all issues with the exception of Seabrook 1 costs which are subject to change based upon the results of the FERC's final review of Canal's investment in the unit. This settlement required Cambridge Electric to adjust its Belmont rate to reflect the final allocation of power purchased by Canal on behalf of Cambridge Electric and Commonwealth Electric. Cambridge Electric made a refund to Belmont in August 1991 and filed the requisite compliance report with the FERC on September 16, 1991.

A settlement agreement between Canal and Belmont addressing all Seabrook cost-of-service issues (except rate of return on common equity) was filed with the FERC on April 16, 1991 and subsequently approved by the FERC on November 13, 1991. This settlement resulted in refunds to Cambridge Electric and Commonwealth Electric by Canal and further resulted in changes to Belmont's rate. In addition, this settlement changed the effective date of the Belmont Service Agreement from August 1, 1990 to June 30, 1990. The charges and refunds resulting from this settlement were applied to Belmont's bill in January 1992.

Item 1. Business (Continued)

Rates, Regulation and Legislation (Continued)

(b) Automatic Adjustment Clauses

Electric

Both Commonwealth Electric and Cambridge Electric have Fuel Charge rate schedules (formerly the Power Cost Charge or PCC) which allow for current recovery, from retail customers, of fuel used in electric generation and a substantial portion of purchased power, demand and transmission costs. Such schedules require a quarterly computation and DPU approval of a Fuel Charge decimal. The computation is based upon forecasts of fuel, purchased power and transmission costs and billed unit sales for each period. To the extent that collections under the rate schedule do not match actual costs for that period, an appropriate adjustment is reflected in the calculation of the decimal for the next subsequent calendar quarter. Amounts recoverable under these clauses are subject to review and approval by the DPU. Cambridge Electric collects the capacity-related portion of its purchased power costs associated with certain long-term power arrangements through its base rates. The DPU ordered Commonwealth Electric, effective July 1, 1991, to collect its capacity-related costs associated with certain long-term power arrangements through its base rates. Prior to July 1, Commonwealth Electric was recovering the entire capacity-related portion of purchased power through its Fuel Charge. This was the same method of recovery used by Commonwealth Electric prior to its January 1989 retail rate increase.

On July 30, 1990, Cambridge Electric and Commonwealth Electric received DPU approval to recover conservation and load management (C&LM) costs through their respective Fuel Charge. The C&LM programs were developed in 1988 in collaboration with other Massachusetts electric utilities as well as the Conservation Law Foundation of New England, Inc., the Massachusetts Attorney General and other public interest groups and offer opportunities to all customers to save energy by investing in C&LM measures. The overall benefit of the programs will be to reduce capacity and energy requirements which thereby reduce the cost of providing service. For further information, refer to Note 8 of the Notes to Consolidated Financial Statements filed under Item 8 of this report.

Upon the declaration of commercial operation in 1990, Canal began recovering 100% of its Seabrook 1 investment through power contracts with Commonwealth Electric and Cambridge Electric, subject to refund pending a full FERC review of Canal's investment in the unit by the FERC. On December 6, 1991, a FERC Administrative Law Judge (ALJ) issued an initial ruling affirming the prudence of Canal's oversight of emergency response planning for Seabrook. The ALJ further agreed with Canal that all costs were prudently incurred and therefore just and reasonable. Although a final FERC order has not been received, it is expected that the FERC will uphold the ALJ's ruling. Commonwealth

Item 1. Business (Continued)

Rates, Regulation and Legislation (Continued)

(b) Automatic Adjustment Clauses (Continued)

Electric and Cambridge Electric have been billing, subject to refund, Seabrook 1 charges to their retail customers since August 1, 1990 through Fuel Charge decimals approved by the DPU.

Prior to commercial operation, Cambridge Electric and Commonwealth Electric collected, subject to refund, approximately 50% of pre-commercial financing costs related to Seabrook 1.

Cambridge Electric and Commonwealth Electric are collecting, through their respective Fuel Charge, amounts being billed to them by Canal Electric for costs associated with Seabrook 2 (over a ten-year period) pursuant to a Capacity Acquisition Agreement and both FERC and DPU approval.

Gas

Commonwealth Gas has a standard seasonal cost of gas adjustment rate schedule which provides for the recovery, from firm customers, of purchased gas costs not collected through base rates. These adjustment charges, which require DPU approval, are estimated semi-annually and include credits for gas pipeline refunds and profit margins applicable to interruptible sales. Actual gas costs are reconciled annually as of October 31 and any difference is included as an adjustment in the calculation of the decimals for the two subsequent six-month periods.

Periodically, Commonwealth Gas is required to file a long-range forecast of the needs and requirements of its market area and annual supplements thereto with the Massachusetts Energy Facilities Siting Council (the Council). To approve a long-range forecast, the Council must find, among other things, that Commonwealth Gas's plans for construction of new gas manufacturing or storage facilities and certain high-pressure gas pipelines are consistent with current health, environmental protection and resource use and development policies as adopted by the Commonwealth of Massachusetts. Commonwealth Gas filed a long-range forecast with the Council on July 20, 1990 and updated aspects of the filing in March 1991. This forecast remains pending before the Council.

(c) Gas Demand and Take-or-Pay Costs

Commonwealth Gas is obligated to pay demand charges pursuant to long-term firm contracts with its principal suppliers which are recovered from customers through a cost of gas adjustment clause (CGA).

Item 1. Business (Continued)

Rates, Regulation and Legislation (Continued)

(c) Gas Demand and Take-or-Pay Costs (Continued)

In June 1991, Tennessee Gas Pipeline Company (Tennessee), one of Commonwealth Gas Company's principal suppliers, filed a comprehensive settlement with the Federal Energy Regulatory Commission (FERC) dealing with a variety of contract restructuring issues, including the allocation of take-or-pay costs to Tennessee's customers. The settlement was partly in response to recent court cases which rejected the FERC's approval of the purchase deficiency basis for allocating pipeline take-or-pay costs. The settlement, if approved by the FERC, would modify the manner in which the Tennessee take-or-pay costs are allocated to customers, increasing Commonwealth Gas Company's cost compared to the purchase deficiency basis rejected by the courts. The settlement would also create a mechanism for recovering prospective take-or-pay costs.

Algonquin Gas Transmission Company (Algonquin) has made a series of filings with the FERC to recover from its customers take-or-pay charges imposed on it from its upstream suppliers. As a result, Commonwealth Gas has been allocated a share of these costs. Algonquin is currently billing Commonwealth Gas for gas supply inventory charges from Texas Eastern Transmission Company (Texas Eastern) through the Algonquin commodity rate. Both the Texas Eastern and Algonquin contracts are being restructured which will likely result in additional costs to Commonwealth Gas.

Commonwealth Gas is collecting take-or-pay and other contract restructuring costs imposed by Algonquin and Tennessee from its customers through the CGA as permitted by the DPU.

(d) Most Recent Rate Case Proceedings

On April 16, 1991, Commonwealth Gas requested a $27.7 million (11.3%) revenue increase in a filing with the DPU using a test year ended December 31, 1990. This was the first rate increase request since May 1987.

On September 16, 1991, the DPU approved a settlement of the revenue requirements portion of the Commonwealth Gas filing. The $22.8 million increase in annual revenues represented approximately 82% of the original request and included a return on equity, for accounting purposes, of 13%. The DPU later ruled on the rate design portion of the request and the new rates went into effect on November 1, 1991. The increase was necessitated by the rising costs of providing service to customers and substantial expenditures to upgrade, improve and maintain the Commonwealth Gas distribution system.

Item 1. Business (Continued)

Rates, Regulation and Legislation (Continued)

(d) Most Recent Rate Case Proceedings (Continued)

On December 31, 1987, Commonwealth Gas received authorization from the DPU to increase base revenues by $12.5 million or 5.6% of total test-year revenues and approximately 80% of the $15.6 million originally requested. The overall rate of return was set at 11.2%, including an allowed return on common equity of 13.25%. This was the first increase for Commonwealth Gas since 1982. In the order, the DPU endorsed Commonwealth Gas's proposal to offer cost-based firm transportation services to its industrial customers.

On May 17, 1989, Cambridge Electric filed for an increase in its base rates using a 1988 test year. On August 31, 1989, the DPU approved an Offer of Settlement between the parties which resolved all issues involving revenue requirement. Cambridge Electric was allowed to increase annual revenues by $4,438,000 or 5.5% of total test-year revenue, approximately 73% of the $6,111,000 originally requested. The new rates became effective on December 18, 1989 and represent the first increase in Cambridge Electric's rates since 1982.

On May 31, 1988, Cambridge Electric received authorization from the DPU to implement the final stage in its move to equalization of rates of return across rate classes. The revised rates reflect a settlement agreement which reduced base revenue by $300,000, effective March 1, 1988.

In January 1989, Commonwealth Electric received authorization from the DPU to increase base revenues by $18 million or 6.6% of total test-year revenues. This increase represented approximately 77% of its original $23.3 million request and included an overall rate of return of 10.89% and return on common equity of 13% and represented the first increase in Commonwealth Electric's base rates since 1982.

As part of this proceeding, the DPU ordered a restructuring of Commonwealth Electric's rates which resulted in significant increases to certain customer rate classes. Subsequently, as a result of customer pressure, the Massachusetts state legislature passed, and the Governor signed, precedent-setting legislation which required that the increase to any ratepayer or class of ratepayers not exceed 7% per year. This legislation became effective February 1, 1990 and specified that the revision would not reduce the amount of annual revenues allowed in that January 1989 order.

On July 1, 1991, the DPU issued an order increasing Commonwealth Electric's retail electric revenues by $10.9 million, or 3.1%. The requested increase was $17.3 million. The order, based on a June 30, 1990 test year, provides an overall return of 10.49%, including a return on equity of 12%. The DPU also ordered the restructuring of the Company's rates to more closely reflect the actual cost of

Item 1. Business (Continued)

Rates, Regulation and Legislation (Continued)

(d) Most Recent Rate Case Proceedings (Continued)

providing service to each customer class. Further, the DPU ordered Commonwealth Electric to undertake an independent management audit in 1992 to address, among other areas, its management, planning and control practices. On February 14, 1992, Ernst & Young was selected by the DPU from three qualified management consulting firms submitted by Commonwealth Electric to perform the audit. The audit began on March 6, 1992.

(e) Economic Development Rate

In an effort to foster industrial development in its service area, Commonwealth Electric filed a new Economic Development Rate with the DPU in mid-September. The rate, which was approved by the DPU, became effective on October 1, 1991 and is being offered to new or existing industrial customers who have an electric demand of 500 kilowatts or more and meet specific financial criteria. Eligible customers must also be one of the 20 largest industrial employers in the city or town or recognized as a major employer in the smaller towns. The rate is available for a six-year term. Nineteen industrial customers are presently benefiting from this special rate.

(f) Other

As a result of the Tax Reform Act of 1986, the DPU issued an order on June 1, 1987 requiring essentially all utilities under its jurisdiction to file new rates, effective July 1, 1987, to reflect the lower revenue requirement caused by the tax rate reduction. As a result, Cambridge Electric, Commonwealth Gas and Commonwealth Electric filed revised rates that reduce annual revenues by $787,000, $3,201,000 and $4,006,000, respectively. Subsequently, as discussed above, all three companies completed base rate proceedings affecting their total costs of providing service, including income taxes.

Replacement Power Costs

In connection with its ongoing review of the fuel and purchased power costs of certain Massachusetts electric companies, the DPU reviews the operating performance of all plants from which power is obtained. For additional information concerning replacement power costs, refer to Note 4(d) of Notes to Consolidated Financial Statements filed under Item 8 of this report.

Item 1. Business (Continued)

Storm Damage

In August 1991, Commonwealth Electric's service territory was particularly hard hit by Hurricane Bob. Its transmission and distribution system suffered such extensive damage that its entire service territory (with minor exceptions) was without power at one point. Commonwealth Electric's franchise is located entirely within four of the ten Massachusetts counties which were declared federal disaster zones. For further information on costs and recovery options, refer to Note 4(h) of Notes to Consolidated Financial Statements filed under Item 8 of this report.

Segment Information

System companies provide electric, gas and steam services to retail customers in service territories located in central and eastern Massachusetts and, in addition, sell electricity at wholesale to Massachusetts customers. Other operations of the system include the development and management of new real estate ventures and operation of rental properties and other investment activities which do not presently contribute significantly to either revenues or operating income.

Reference is made to additional industry segment information in Note 10 of Notes to Consolidated Financial Statements filed under Item 8 of this report.

Environmental Matters

The system, as with all other utility companies, is subject to regulations administered by federal, state and local authorities relating to the quality of the environment. Compliance with these regulations has required capital expenditures by the system for the period 1968 through 1991 of approximately $50.3 million, $29.7 million of which was for facilities and studies at Seabrook. Additional capital expenditures through 1996 will require an estimated $1.1 million including $295,000 relating to Seabrook.

For additional information concerning these and other environmental issues relating to former gas manufacturing sites, refer to the "Environmental Matters" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" filed under Item 7 of this report.

Construction and Financing

For information concerning the system's financing and construction programs refer to Management's Discussion and Analysis of Financial Condition and Results of Operations filed under Item 7 and Note 4(a) of the Notes to Consolidated Financial Statements filed under Item 8 of this report.

Item 1. Business (Continued)

Employees

There were 2,510 regular employees of the system at December 31, 1991, 1,500 (60%) of whom are represented by various collective bargaining units. Existing agreements are for varying periods and expire in 1993 and thereafter. Employee relations have generally been satisfactory.

Item 2. Properties

The system's principal electric properties consist of Canal Unit 1, a 569 MW oil-fired steam electric generating unit, and its one-half ownership in Canal Unit 2, a 580 MW oil-fired steam electric generating unit, both located at Canal Electric's facility in Sandwich, Massachusetts. Other electric properties include an integrated system of distribution lines and substations together with Commonwealth Electric's 59 MW steam electric generating station located in New Bedford, Massachusetts, and Cambridge Electric's two steam electric generating stations with a net capability of 78.5 MW located in Cambridge, Massachusetts. In addition, the system has a 1.4% or 8.9 MW joint-ownership interest in Central Maine Power Company's Wyman Unit 4 and a 3.52% interest (40.5 MW of capacity) in Seabrook 1. The system also owns smaller generating units totaling 51.8 MW used primarily for peaking and emergency purposes.

In addition, the system's other principal properties consist of an electric division office building in Wareham, Massachusetts and other structures such as garages and service buildings. The system's gas division owns a central headquarters and service building in Southborough, Massachusetts, five district office buildings and several natural gas receiving and take stations.

At December 31, 1991, the electric transmission and distribution system consisted of 5,790 pole miles of overhead lines, 3,938 cable miles of underground line, 369 substations and 367,207 active customer meters.

The principal natural gas properties consist of distribution mains, services and meters necessary to maintain reliable service to customers. At the end of 1991, the gas system included 2,686 miles of gas distribution lines, 156,271 services and 228,520 customer meters together with the necessary measuring and regulating equipment. In addition, the system owns a liquefaction and vaporization plant, a satellite vaporization plant and above-ground cryogenic storage tanks having an aggregate storage capacity equivalent to 3.5 million MCF of natural gas.

Item 3. Legal Proceedings

Refer to the "Environmental Matters" section of "Management's Discussion and Analysis of Financial Condition and Results of Operations" section of the Notice of 1992 Annual Meeting, Proxy Statement and 1991 Financial Information dated April 3, 1992, pages A-9 and A-10.

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

None

PART II.

Item 5. Market for the Registrant's Securities and Related Stockholder Matters

(a) Principal Markets

The System's common shares are listed on the New York, Boston and Pacific Stock Exchanges. The table below sets forth the high and low closing prices as reported on the New York Stock Exchange composite transactions tape.

	1991 by Quarter				1990 by Quarter			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
High	33	34 7/8	36 3/4	39 3/4	38 7/8	37 3/8	35 1/8	33 1/4
Low	30	30 7/8	32	35 1/4	34 5/8	33 1/2	29 3/8	29 1/2

(b) Number of Shareholders at December 31, 1991

16,699 shareholders

(c) Frequency and Amount of Dividends Declared in 1991 and 1990

1991		1990	
Declaration Date	Per Share Amount	Declaration Date	Per Share Amount
March 28, 1991	$ .73	March 22, 1990	$ .73
June 26, 1991	.73	June 28, 1990	.73
September 26, 1991	.73	September 27, 1990	.73
December 19, 1991	.73	December 13, 1990	.73
	$2.92		$2.92

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

Item 6. Selected Financial Data

Information required by this item is incorporated herein by reference to Exhibit A to the Notice of 1992 Annual Meeting, Proxy Statement and 1991 Financial Information dated April 3, 1992, page A-32.

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

Information required by this item is incorporated herein by reference to Exhibit A to the Notice of 1992 Annual Meeting, Proxy Statement and 1991 Financial Information dated April 3, 1992, pages A-3 through A-12.

Item 8. Financial Statements and Supplementary Data

The following consolidated financial statements and supplementary data of the System and its subsidiaries are incorporated herein by reference to Exhibit A to the Notice of 1992 Annual Meeting, Proxy Statement and 1991 Financial Information dated April 3, 1992 on pages A-12 through A-32.

	Proxy Page Reference
Management's Report	A-12
Report of Independent Public Accountants	A-13
Consolidated Balance Sheets - At December 31, 1991 and 1990	A-14/A-15
Consolidated Statements of Income - Years Ended December 31, 1991, 1990 and 1989	A-16
Consolidated Statements of Cash Flows - Years Ended December 31, 1991, 1990 and 1989	A-17
Consolidated Statements of Capitalization - At December 31, 1991 and 1990	A-18
Consolidated Statements of Changes in Common Shareholders' Investment and in Redeemable Preferred Shares - Years Ended December 31, 1991, 1990 and 1989	A-19
Notes to Consolidated Financial Statements	A-20/A-31
Quarterly Information pertaining to the results of operations for the years ended December 31, 1991 and 1990	A-32

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None

Item 10. Trustees and Executive Officers of the Registrant

a. Trustees of the Registrant:

Information required by this item is incorporated herein by reference to the Notice of 1992 Annual Meeting, Proxy Statement and 1991 Financial Information dated April 3, 1992, pages 3, 4 and 5.

b. Executive Officers of the Registrant:

Name of Officer	Position and Business Experience	Age at December 31, 1991
Gerald E. Anderson	Trustee, President and Chief Executive Officer of the System and Chairman and Chief Executive Officer of its principal subsidiary companies since 1975 (retired effective January 1, 1992).	60
William G. Poist	President and Chief Operating Officer of Commonwealth Gas Company* from 1983 to 1991 and Hopkinton LNG Corp.* from 1985 to 1991; Vice President of the System and COM/Energy Services Company* effective September 1, 1991; Trustee, President and Chief Executive Officer of the System and Chairman and Chief Executive Officer of its principal subsidiary companies (effective January 1, 1992).	58
Russell D. Wright	Financial Vice President and Treasurer of the System and Financial Vice President of its subsidiary companies since 1987, Treasurer of System subsidiary companies (December 1989 to December 1990), Assistant Vice President-Finance of System subsidiary companies 1986.	45
Harold N. Scherer, Jr.	President and Chief Operating Officer of Cambridge Electric Light Company*, Canal Electric Company*, COM/Energy Steam Company* and Commonwealth Electric Company* since November 26, 1990; Senior Vice President of Electrical Engineering for American Electric Power, Columbus, Ohio 1982 to November 1990.	62
Kenneth M. Margossian	Vice President of Human Resources and Administration of Commonwealth Gas Company from 1985 to 1987; Vice President of Facilities Development from 1987 to 1988; Vice President of Operations from 1988 to 1991; President and Chief Operating Officer of Commonwealth Gas Company and Hopkinton LNG Corp. effective September 1, 1991.	43
Michael P. Sullivan	Vice President, Secretary and General Attorney of the System and subsidiary companies since 1981.	43
John A. Whalen	Comptroller of the System and subsidiary companies since 1978.	44

*Subsidiary of the System.

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

The term of office for System officers expires May 7, 1992, the date of the next Annual Organizational Meeting.

There are no family relationships between any trustee and executive officer and any other trustee or executive of the System. There were no arrangements or understandings between any officer or trustee and any other person pursuant to which he was or is to be selected as an officer, trustee 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 trustee or executive officer during the past five years.

Item 11. Executive Compensation

Information required by this item is incorporated herein by reference to the Notice of 1992 Annual Meeting, Proxy Statement and 1991 Financial Information dated April 3, 1992, pages 5, 6 and 7.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Information required by this item is incorporated herein by reference to the Notice of 1992 Annual Meeting, Proxy Statement and 1991 Financial Information dated April 3, 1992, pages 3, 4 and 5.

Item 13. Certain Relationships and Related Transactions

Information required by this item is incorporated herein by reference to the Notice of 1992 Annual Meeting, Proxy Statement and 1991 Financial Information dated April 3, 1992, pages 3, 4 and 5.

PART IV.

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

(a) 1. Index to Financial Statements

Consolidated financial statements and notes thereto of Commonwealth Energy System and Subsidiary Companies together with the Report of Independent Public Accountants, as detailed on page 22 in Item 8 of this Form 10-K, have been incorporated herein by reference to Exhibit A to the Notice of 1992 Annual Meeting, Proxy Statement and 1991 Financial Information dated April 3, 1992.

(a) 2. Index to Financial Statement Schedules

Commonwealth Energy System and Subsidiary Companies

Filed herewith at page(s) indicated -

Report of Independent Public Accountants on Schedules (page 51).

Schedule III - Investments in, Equity in Earnings of, and Dividends Received from Related Parties - Years Ended December 31, 1991, 1990 and 1989 (pages 52-54).

Schedule V - Property, Plant and Equipment - Years Ended December 31, 1991, 1990 and 1989 (pages 55-57).

Schedule VI - Accumulated Depreciation and Amortization of Property, Plant and Equipment - Years Ended December 31, 1991, 1990 and 1989 (page 58).

Schedule VIII - Valuation and Qualifying Accounts - Years Ended December 31, 1991, 1990 and 1989 (page 59).

Schedule IX - Short-Term Borrowings - Years Ended December 31, 1991, 1990 and 1989 (page 60).

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

Subsidiaries not Consolidated and Fifty-Percent or Less Owned Persons

Financial statements of 50% or less owned persons accounted for by the equity method have been omitted because they do not, considered individually or in the aggregate, constitute a significant subsidiary.

Form 11-K, Annual Reports of Employee Stock Purchases, Savings and Similar Plans

Pursuant to Rule 15(d)-21 of the Securities and Exchange Act of 1934, the information, financial statements and exhibits required

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

by Form 11-K with respect to the Employees Savings Plan of Commonwealth Energy System and Subsidiary Companies will be filed as an amendment to this report under cover of Form 8 not later than April 30, 1992.

(a) 3. Exhibits:

Notes to Exhibits -

a. Unless otherwise designated, the exhibits listed below are incorporated by reference to the appropriate exhibit numbers and the Securities and Exchange Commission file numbers indicated in parentheses.

b. If applicable, as designated by an asterisk, certain documents previously filed by the System or its subsidiary companies have been disposed of by the Commission pursuant to its Records Control Schedule and are hereby being refiled by the appropriate registrant and to the appropriate file number.

c. During 1981, New Bedford Gas and Edison Light Company sold its gas business and properties to Commonwealth Gas Company and changed its corporate name to Commonwealth Electric Company.

d. The following is a glossary of Commonwealth Energy System and subsidiary companies' acronyms that are used throughout the following Exhibit Index:

CES	Commonwealth Energy System
CE	Commonwealth Electric Company
CEL	Cambridge Electric Light Company
CEC	Canal Electric Company
CG	Commonwealth Gas Company
NBGEL	New Bedford Gas and Edison Light Company
HOPCO	Hopkinton LNG Corp.

Exhibit Index

Exhibit 3. Declaration of Trust

Commonwealth Energy System (Registrant)

3.1.1 Declaration of Trust of CES dated December 31, 1926, as amended by vote of the shareholders and trustees May 7, 1987 (Exhibit 1 to the CES Form 10-Q (March 1987), File No. 1-7316).

Item 14. Exhibits, Financial Statement Sch dules and Reports on Form 8-K (Continued)

Exhibit 4. Instruments defining the rights of security holders, including indentures

Commonwealth Energy System (Registrant)

Debt Securities -

4.1.1 CES Note Agreement ($40 Million Privately Placed Senior Notes) dated June 28, 1989 (Exhibit 1 to the CES Form 10-Q (September 1989), File No. 1-7316).

Subsidiary Companies of the Registrant

Cambridge Electric Light Company

Indenture of Trust or Supplemental Indenture of Trust -

4.2.1 Original Indenture on Form S-1 (April, 1949) (Exhibit 7(a), File No. 2-7909)

4.2.2 First Supplemental on Form S-9 (Jan., 1958) (Exhibit 2(b)2, File No. 2-13783)

4.2.3 Second Supplemental on Form 8-K (Feb., 1962) (Exhibit A, File No. 2-7909)

4.2.4 Third Supplemental on Form 10-K (1984) (Exhibit 1, File No. 2-7909)

4.2.5 Fourth Supplemental on Form 10-K (1984) (Exhibit 2, File No. 2-7909)

4.2.6 Fifth Supplemental on Form 10-K (1983) (Exhibit 1, File No. 2-7909)

4.2.7 Sixth Supplemental on Form 10-Q (June 1989) (Exhibit 1, File No. 2-7909)

Canal Electric Company

Indenture of Trust and First Mortgage or Supplemental Indenture of Trust and First Mortgage -

4.3.1 Indenture of Trust and First Mortgage with State Street Bank and Trust Company, Trustee, dated October 1, 1968 (Exhibit 4(b) to Form S-1, File No. 2-30057).

4.3.2 First and General Mortgage Indenture with Citibank, N.A., Trustee, dated September 1, 1976 (Exhibit 4(b)2 to Form S-1, File No. 2-56915).

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

Canal Electric Company (Continued)

4.3.3 First Supplemental dated October 1, 1968 with State Street Bank and Trust Company, Trustee, dated September 1, 1976 (Exhibit 4(b)3 to Form S-1, File No. 2-56915).

4.3.4 Second Supplemental dated September 1, 1976 with Citibank, N.A., New York, N.Y., Trustee, dated December 1, 1983 (Exhibit 1 to 1983 Form 10-K, File No. 2-30057).

4.3.5 Third Supplemental dated September 1, 1976 with Citibank, N.A., New York, NY, Trustee, dated December 1, 1990 (Exhibit 3 to 1990 Form 10-K, File No. 2-30057).

4.3.6 Fourth Supplemental dated September 1, 1976 with Citibank, N.A., New York, NY, Trustee, dated December 1, 1990 (Exhibit 4 to 1990 Form 10-K, File No. 2-30057).

Commonwealth Gas Company

Indenture of Trust or Supplemental Indenture of Trust -

4.4.1 Original Indenture on Form S-1 (Feb., 1949) (Exhibit 7(a), File No. 2-7820)

4.4.2 First Supplemental on Form S-1 (Mar., 1950) (Exhibit 7(a), File No. 2-8418)

4.4.3 Second and Third Supplemental on Form S-1 (Nov., 1952) (Exhibits 4(a)(2) and 4(a)(3), File No. 2-10445)

4.4.4 Fourth Supplemental on Form S-9 (Oct., 1954) (Exhibit 2(b)(5), File No. 2-15089)

4.4.5 Fifth Supplemental on Form S-9 (Mar., 1956) (Exhibit 2(b)(6), File No. 2-15089)

4.4.6 Sixth Supplemental on Form S-9 (April, 1957) (Exhibit 2(b)(7), File No. 2-15089)

4.4.7 Seventh Supplemental on Form S-9 (June 1959) (Exhibit 2(b)(8), File No. 2-20532)

4.4.8 Eighth Supplemental on Form S-9 (Sept., 1961) (Exhibit 2(b)(9), File No. 2-20532)

4.4.9 Ninth Supplemental on Form 8-K (Aug., 1962) (Exhibit A, File No. 2-1647)

4.4.10 Tenth Supplemental on Form 10-K (1970) (Exhibit 2, File No. 2-1647)

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

Commonwealth Gas Company (Continued)

4.4.11 Eleventh Supplemental on Form S-1 (June, 1972) (Exhibit 4(b)(2), File No. 2-48556)

4.4.12 Twelfth Supplemental on Form S-1 (Aug., 1973) (Exhibit 4(b)(3), File No. 2-48556)

4.4.13 Thirteenth Supplemental on Form 10-K (1980) (Exhibit 3, File No. 2- 1647)

4.4.14 Fourteenth Supplemental on Form 10-K (1990) (Exhibit 1, File No. 2-1647)

4.4.15 Fifteenth Supplemental on Form 10-K (1982) (Exhibit 1, File No. 2-1647)

4.4.16 Sixteenth Supplemental on Form 10-K (1986) (Exhibit 1, File No. 2-1647)

4.4.17 Seventeenth Supplemental on Form 10-K (1990) (Exhibit 2, File No. 2-1647)

Commonwealth Electric Company

Indenture of Trust or Supplemental Indenture of Trust -

4.5.1 Original Indenture on Form S-1 (Nov., 1948) (Exhibit 7(a), File No. 2-7749)

4.5.2 First Supplemental on Form S-1 (Oct., 1950) (Exhibit 7(a-1), File No. 2-8605)

4.5.3 Second Supplemental on Form 10-K (1984) (Exhibit 1, File No. 2-7749)

4.5.4 Third Supplemental on Form 8-K (Feb., 1962) (Exhibit A, File No. 2-7749)

4.5.5 Fourth Supplemental on Form 10-K (1984) (Exhibit 2, File No. 2-7749)

4.5.6 Fifth Supplemental on Form 10-K (1984) (Exhibit 3, File No. 2-7749)

4.5.7 Sixth Supplemental on Form 0-K (1984) (Exhibit 4, File No. 2-7749)

4.5.8 Seventh Supplemental on Form S-1 (Dec., 1975) (Exhibit 4(b)2, File No. 2-54955)

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

Cape & Vineyard Electric Company**

4.5.9 Original Indenture on Form S-1 (Apr., 1957) (Exhibit 4(b)1, File No. 2-26429)

4.5.10 First Supplemental on Form 10-K (1984) (Exhibit 5, File No. 2-7749)

4.5.11 Second Supplemental on Form 10-K (1984) (Exhibit 6, File No. 2-7749)

** Merged with Commonwealth Electric Company January 1, 1971.

Exhibit 10. Material Contracts

10.1 Power contracts.

10.1.1 Power contracts between CEC (Unit 1) and NBGEL and CEL dated December 1, 1965 (Exhibit 13(a)(1-4) to the CEC Form S-1, File No. 2-30057).

10.1.2* Power contract between Yankee Atomic Electric Company (YAEC) and CEL dated June 30, 1959, as amended April 1, 1975 (Refiled as Exhibit 1 to the 1991 CEL Form 10-K, File No. 2-7909).

10.1.2.1 Second, Third and Fourth Amendments to 10.1.2 as amended October 1, 1980, April 1, 1985 and May 6, 1988, respectively (Exhibit 2 to the CEL Form 10-Q (June 1988), File No. 2-7909).

10.1.2.2 Fifth and Sixth Amendments to 10.1.2 as amended June 26, 1989 and July 1, 1989, respectively (Exhibit 1 to the CEL Form 10-Q (September 1989), File No. 2-7909).

10.1.3* Power Contract between YAEC and NBGEL dated June 30, 1959, as amended April 1, 1975 (Refiled as Exhibit 2 to the 1991 CE Form 10-K, File No. 2-7749).

10.1.3.1 Second, Third and Fourth Amendments to 10.1.3 as amended October 1, 1980, April 1, 1985 and May 6, 1988, respectively (Exhibit 1 to the CE Form 10-Q (June 1988), File No. 2-7749).

10.1.3.2 Fifth and Sixth Amendments to 10.1.3 as amended June 26, 1989 and July 1, 1989, respectively (Exhibit 3 to the CE Form 10-Q (September 1989), File No. 2-7749).

10.1.4 Power Contract between Connecticut Yankee Atomic Power Company (CYAPC) and CEL dated July 1, 1964 (Exhibit 13-K1 to the System's Form S-1, (April 1967) File No. 2-25597).

10.1.4.1 Additional Power Contract providing for extension on contract term between CYAPC and CEL dated April 30, 1984 (Exhibit 5 to the CEL Form 10-Q (June 1984), File No. 2-7909).

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

10.1.4.2 Second Supplementary Power Contract providing for decommissioning financing between CYAPC and CEL dated April 30, 1984 (Exhibit 6 to the CEL Form 10-Q (June 1984), File No. 2-7909).

10.1.5 Power contract between Vermont Yankee Nuclear Power Corporation (VYNPC) and CEL dated February 1, 1968 (Exhibit 3 to the CEL 1984 Form 10-K, File No. 2-7909).

10.1.5.1 First Amendment dated June 1, 1972 (Section 7) and Second Amendment dated April 15, 1983 (decommissioning financing) to 10.1.5 (Exhibits 1 and 2, respectively, to the CEL Form 10-Q (June 1984), File No. 2-7909).

10.1.5.2 Third Amendment dated April 1, 1985 and Fourth Amendment dated June 1, 1985 to 10.1.5 (Exhibits 1 and 2, respectively, to the CEL Form 10-Q (June 1986), File No. 2-7909).

10.1.5.3 Fifth and Sixth Amendments to 10.1.5 dated February 1, 1968, both as amended May 6, 1988 (Exhibit 1 to the CEL Form 10-Q (June 1988), File No. 2-7909).

10.1.5.4 Seventh Amendment to 10.1.5 dated February 1, 1968, as amended June 15, 1989 (Exhibit 2 to the CEL Form 10-Q (September 1989), File No. 2-7909).

10.1.5.5 Additional Power Contract dated February 1, 1984 between CEL and VYNPC providing for decommissioning financing and contract extension (Exhibit 2 to CEL 1983 Form 10-K, File No. 2-7909).

10.1.6 Power contract between Maine Yankee Atomic Power Company (MYAPC) and CEL dated May 20, 1968 (Exhibit 5 to the System's Form S-7, File No. 2-38372).

10.1.6.1 First Amendment dated March 1, 1984 (decommissioning financing) and Second Amendment dated January 1, 1984 (supplementary payments) to 10.1.6 (Exhibits 3 and 4 to the CEL Form 10-Q (June 1984), File No. 2-7909).

10.1.6.2 Third Amendment to 10.1.6 dated October 1, 1984 (Exhibit 1 to the CEL Form 10-Q (September 1984), File No. 2-7909).

10.1.7 Agreement between NBGEL and Boston Edison Company (BECO) for the purchase of electricity from BECO's Pilgrim Unit No. 1 dated August 1, 1972 (Exhibit 7 to the CE 1984 Form 10-K, File No. 2-7749).

10.1.7.1 Service Agreement between NBGEL and BECO for purchase of stand-by power for BECO's Pilgrim Station dated August 16, 1978 (Exhibit 1 to the CE 1988 Form 10-K, File No. 2-7749).

10.1.7.2 System Power Sales Agreement by and between CE and BECO dated July 12, 1984 (Exhibit 1 to the CE Form 10-Q (September 1984), File No. 2-7749).

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

10.1.7.3 Power Exchange Agreement by and between BECO and CE dated December 1, 1984 (Exhibit 16 to the CE 1984 Form 10-K, File No. 2-7749).

10.1.7.4 Power Exchange Agreement by and between BECO and CEL dated December 1, 1984 (Exhibit 5 to the CEL 1984 Form 10-K, File No. 2-7909).

10.1.7.5 Service Agreement for Non-Firm Transmission Service between BECO and CEL dated July 5, 1984 (Exhibit 4 to the CEL 1984 Form 10-K, File No. 2-7909).

10.1.8 Agreement for Joint-Ownership, Construction and Operation of New Hampshire Nuclear Units (Seabrook) dated May 1, 1973 (Exhibit 13(N) to the NBGEL Form S-1 dated October 1973, File No. 2-49013 and as amended below:

10.1.8.1 First through Fifth Amendments to 10.1.8 as amended May 24, 1974, June 21, 1974, September 25, 1974, October 25, 1974 and January 31, 1975, respectively (Exhibit 13(m) to the NBGEL Form S-1 (November 7, 1975), File No. 2-54995).

10.1.8.2 Sixth through Eleventh Amendments to 10.1.8 as amended April 18, 1979, April 25, 1979, June 8, 1979, October 11, 1979 and December 15, 1979, respectively (Refiled as Exhibit 1 to the CEC 1989 Form 10-K, File No. 2-30057).

10.1.8.3 Twelfth through Fourteenth Amendments to 10.1.8 as amended May 16, 1980, December 31, 1980 and June 1, 1982, respectively (Exhibits 1, 2, and 3 to the CE Form 10-Q (June 1982), File No. 2-7749).

10.1.8.4 Fifteenth and Sixteenth Amendments to 10.1.8 as amended April 27, 1984 and June 15, 1984, respectively (Exhibit 1 to the CEC Form 10-Q (June 1984), File No. 2-30057).

10.1.8.5 Seventeenth Amendment to 10.1.8 as amended March 8, 1985 (Exhibit 1 to the CEC Form 10-Q (March 1985), File No. 2-30057).

10.1.8.6 Eighteenth Amendment to 10.1.8 as amended March 14, 1986 (Exhibit 1 to the CEC Form 10-Q (March 1986), File No. 2-30057).

10.1.8.7 Nineteenth Amendment to 10.1.8 as amended May 1, 1986 (Exhibit 1 to the CEC Form 10-Q (June 1986), File No. 2-30057).

10.1.8.8 Twentieth Amendment to 10.1.8 as amended September 19, 1986 (Exhibit 1 to the CEC 1986 Form 10-K, File No. 2-30057).

10.1.8.9 Twenty-First Amendment to 10.1.8 as amended November 12, 1987 (Exhibit 1 to the CEC 1987 Form 10-K, File No. 2-30057).

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

10.1.8.10 Settlement Agreement and Twenty-Second Amendment to 10.1.8, both dated January 13, 1989 (Exhibit 4 to the CEC 1988 Form 10-K, File No. 2-30057).

10.1.9 Interim Agreement to Preserve and Protect the Assets of and Investment in the New Hampshire Nuclear Units dated April 27, 1984 (Exhibit 2 to the CEC Form 10-Q (June 1984), File No. 2-30057).

10.1.10 Resolutions proposed by Merrill Lynch Capital Markets and adopted by the Joint-Owners of the Seabrook Nuclear Project regarding Project financing, dated May 14, 1984 (Exhibit 1 to the CEC Form 10-Q (March 1984), File No. 2-30057).

10.1.11 Agreement for Seabrook Project Disbursing Agent establishing YAEC as the disbursing agent under the Joint-Ownership Agreement, dated May 23, 1984 (Exhibit 4 to the CEC Form 10-Q (June 1984), File No. 2-30057).

10.1.11.1 First Amendment to 10.1.11 as amended March 8, 1985 (Exhibit 2 to the CEC Form 10-Q (March 1985), File No. 2-30057).

10.1.11.2 Second through Fifth Amendments to 10.1.11 as amended May 20, 1985, June 18, 1985, January 2, 1986 and November 12, 1987, respectively (Exhibit 4 to the CEC 1987 Form 10-K, File No. 2-30057).

10.1.12 Agreement to Share Certain Costs Associated with the Tewksbury-Seabrook Transmission Line dated May 8, 1986 (Exhibit 2 to the CEC 1986 Form 10-K, File No. 2-30057).

10.1.13 Purchase and Sale Agreement together with an implementing Addendum dated December 31, 1981, between CE and CEC, for the purchase and sale of the CE 3.52% joint-ownership interest in the Seabrook units, dated January 2, 1981 (Exhibit 1 to the CEC and CE Form 8-K (January 13, 1982), File Nos. 2-30057 and 2-7749).

10.1.14* Agreement to transfer ownership, construction and operational interest in the Seabrook Units 1 and 2 from CE to CEC dated January 2, 1981 (Refiled as Exhibit 3 to the 1991 CE Form 10-K, File No. 2-7749).

10.1.15 Termination Supplement between CEC, CE and CEL for Seabrook Unit 2, dated December 8, 1986 (Exhibit 3 to the CEC 1986 Form 10-K, File No. 2-30057).

10.1.16 Power Contract, as amended to Februar[illegible], 1990, superceding the Power Contract dated September 1, [illegible]6 and amendment dated June 1, 1988, between CEC (seller) and CE and CEL (purchasers) for seller's entire share of the Net Unit Capability of Seabrook 1 and related energy (Exhibit 1 to the CEC Form 10-Q (March 1990), File No. 2-30057).

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

10.1.17 Agreement between NBGEL and Central Maine Power Company (CMP), for the joint-ownership, construction and operation of William F. Wyman Unit No. 4 dated November 1, 1974 together with Amendment No. 1 dated June 30, 1975 (Exhibit 13(N) to the NBGEL Form S-1, File No. 2-54955).

10.1.17.1 Amendments No. 2 and 3 to 10.1.17 as amended August 16, 1976 and December 31, 1978 (Exhibit 5(a) 14 to the System's Form S-16 (June 1979), File No. 2-64731).

10.1.18 Agreement between the registrant and Montaup Electric Company (MEC) for use of common facilities at Canal Units I and II and for allocation of related costs, executed October 14, 1975 (Exhibit 1 to the CEC 1985 Form 10-K, File No. 2-30057).

10.1.18.1 Agreement between the registrant and MEC for joint-ownership of Canal Unit II, executed October 14, 1975 (Exhibit 2 to the CEC 1985 Form 10-K, File No. 2-30057).

10.1.18.2 Agreement between the registrant and MEC for lease relating to Canal Unit II, executed October 14, 1975 (Exhibit 3 to the CEC 1985 Form 10-K, File No. 2-30057).

10.1.19 Contract between CEC and NBGEL and CEL, affiliated companies, for the sale of specified amounts of electricity from Canal Unit 2 dated January 12, 1976 (Exhibit 7 to the System's 1985 Form 10-K, File No. 1-7316).

10.1.20* Capacity Acquisition Agreement between CEC,CEL and CE dated September 25, 1980 (Refiled as Exhibit 1 to the 1991 CEC Form 10-K, File No. 2-30057).

10.1.20.1 Supplement to 10.1.20 consisting of three Capacity Acquisition Commitments each dated May 7, 1987, concerning Phases I and II of the Hydro-Quebec Project and electricity acquired from Connecticut Light and Power Company CL&P) (Exhibit 1 to the CEC Form 10-Q (September 1987), File No. 2-30057).

10.1.20.2 Supplements to 10.1.20 consisting of two Capacity Acquisition Commitments each dated October 31, 1988, concerning electricity acquired from Western Massachusetts Electric Company and/or CL&P for periods ranging from November 1, 1988 to October 31, 1994 (Exhibit 2 to the CEC Form 10-Q (September 1989), File No. 2-30057).

10.1.21 Phase 1 Vermont Transmission Line Support Agreement and Amendment No. 1 thereto between Vermont Electric Transmission Company, Inc. and certain other New England utilities, dated December 1, 1981 and June 1, 1982, respectively (Exhibits 1 and 2 to the CE 1982 Form 10-K, File No. 2-7749).

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

10.1.21.1 Amendment No. 2 to 10.1.21 as amended November 1, 1982 (Exhibit 5 to the CE Form 10-Q (June 1984), File No. 2-7749).

10.1.21.2 Amendment No. 3 to 10.1.21 as amended January 1, 1986 (Exhibit 2 to the CE 1986 Form 10-K, File No. 2-7749).

10.1.22 Transmission Contract between Maine Electric Power Company (MEPCO) and CE dated November 1, 1988 for terms and conditions MEPCO wheels CE's entitlement in Point Lepreau Unit 1 (Exhibit 2 to the CE Form 10-Q (September 1989), File No. 2-7749).

10.1.23 Transmission Service Agreement between CMP and CE dated November 1, 1988 for terms and conditions CMP wheels CE's entitlement in Point Lepreau Unit 1 (Exhibit 1 to CE Form 10-Q (September 1989), File No. 2-7749).

10.1.23.1 First Amendment to 10.1.23 dated November 1, 1988, as amended June 1, 1991 (Exhibit 1 to CE Form 10-Q (September 1991), File No. 2-7749).

10.1.24 Participation Agreement between MEPCO and CEL and/or NBGEL dated June 20, 1969 for construction of a 345 KV transmission line between Wiscasset, Maine and Mactaquac, New Brunswick, Canada and for the purchase of base and peaking capacity from the NBEPC (Exhibit 13 to the CES 1984 Form 10-K, File No. 1-7316).

10.1.24.1 Supplement Amending 10.1.24 as amended June 24, 1970 (Exhibit 8 to the CES Form S-7, Amendment No. 1, File No. 2-38372).

10.1.25 Power Purchase Agreement between Weweantic Hydro Associates and CE for the purchase of available hydro-electric energy produced by a facility located in Wareham, Massachusetts, dated December 13, 1982 (Exhibit 1 to the CE 1983 Form 10-K, File No. 2-7749).

10.1.26 Power Purchase Agreement between Pioneer Hydropower, Inc. and CE for the purchase of available hydro-electric energy produced by a facility located in Ware, Massachusetts, dated September 1, 1983 (Exhibit 2 to the CE 1983 Form 10-K, File No. 2-7749).

10.1.27 Power Purchase Agreement between Corporation Investments, Inc. (CI), and CE for the purchase of available hydro-electric energy produced by a facility located in Lowell, Massachusetts, dated January 10, 1983 (Exhibit 3 to the CE 1983 Form 10-K, File No. 2-7749).

10.1.27.1 Amendment to 10.1.27 between CI and Boott Hydropower, Inc., an assignee therefrom, and CE, as amended March 6, 1985 (Exhibit 8 to the CE 1984 Form 10-K, File No. 2-7749).

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

10.1.28 Phase 1 Terminal Facility Support Agreement dated December 1, 1981, Amendment No. 1 dated June 1, 1982 and Amendment No. 2 dated November 1, 1982, between New England Electric Transmission Corporation (NEET), other New England utilities and CE (Exhibit 1 to the CE Form 10-Q (June 1984), File No. 2-7749).

10.1.28.1 Amendment No. 3 to 10.1.28 (Exhibit 2 to the CE Form 10-Q (June 1986), File No. 2-7749).

10.1.29 Preliminary Quebec Interconnection Support Agreement dated May 1, 1981, Amendment No. 1 dated September 1, 1981, Amendment No. 2 dated June 1, 1982, Amendment No. 3 dated November 1, 1982, Amendment No. 4 dated March 1, 1983 and Amendment No. 5 dated June 1, 1983 among certain New England Power Pool (NEPOOL) utilities (Exhibit 2 to the CE Form 10-Q (June 1984), File No. 2-7749).

10.1.30 Agreement with Respect to Use of Quebec Interconnection dated December 1, 1981, Amendment No. 1 dated May 1, 1982 and Amendment No. 2 dated November 1, 1982 among certain NEPOOL utilities (Exhibit 3 to the CE Form 10-Q (June 1984), File No. 2-7749).

10.1.30.1 Amendatory Agreement No. 3 to 10.1.30 as amended June 1, 1990, among certain NEPOOL utilities (Exhibit 1 to the CEC Form 10-Q (September 1990), File No. 2-30057).

10.1.31 Phase I New Hampshire Transmission Line Support Agreement between NEET and certain other New England Utilities dated December 1, 1981 (Exhibit 4 to the CE Form 10-Q (June 1984), File No. 2-7749).

10.1.32 Agreement, dated September 1, 1985, with Respect To Amendment of Agreement With Respect To Use Of Quebec Interconnection, dated December 1, 1981, among certain NEPOOL utilities to include Phase II facilities in the definition of "Project" (Exhibit 1 to the CEC Form 10-Q (September 1985), File No. 2-30057).

10.1.33 Agreement to Preliminary Quebec Interconnection Support Agreement - Phase II among Public Service Company of New Hampshire (PSNH), New England Power Co. (NEP), BECO and CEC whereby PSNH assigns a portion of its interests under the original Agreement to the other three parties, dated October 1, 1987 (Exhibit 2 to the CEC 1987 Form 10-K, File No. 2-30057).

10.1.34 Preliminary Quebec Interconnection Support Agreement - Phase II among certain New England electric utilities dated June 1, 1984 (Exhibit 6 to the CE Form 10-Q (June 1984), File No. 2-7749).

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

10.1.34.1 First, Second and Third Amendments to 10.1.34 as amended March 1, 1985, January 1, 1986 and March 1, 1987, respectively (Exhibit 1 to the CEC Form 10-Q (March 1987), File No. 2-30057).

10.1.34.2 Fifth, Sixth and Seventh Amendments to 10.1.34 as amended October 15, 1987, December 15, 1987 and March 1, 1988, respectively (Exhibit 1 to the CEC Form 10-Q (June 1988), File No. 2-30057).

10.1.34.3 Fourth and Eighth Amendments to 10.1.34 as amended July 1, 1987 and August 1, 1988, respectively (Exhibit 3 to the CEC Form 10-Q (September 1988), File No. 2-30057).

10.1.34.4 Ninth and Tenth Amendments to 10.1.34 as amended November 1, 1988 and January 15, 1989, respectively (Exhibit 2 to the CEC 1988 Form 10-K, File No. 2-30057).

10.1.34.5 Eleventh Amendment to 10.1.34 as amended November 1, 1989 (Exhibit 4 to the CEC 1989 Form 10-K, File No. 2-30057).

10.1.34.6 Twelfth Amendment to 10.1.34 as amended April 1, 1990 (Exhibit 1 to the CEC Form 10-Q (June 1990), File No. 2-30057).

10.1.35 Phase II Equity Funding Agreement for New England Hydro-Transmission Electric Company, Inc. (New England Hydro) (Massachusetts), dated June 1, 1985, between New England Hydro and certain NEPOOL utilities (Exhibit 2 to the CEC Form 10-Q (September 1985), File No. 2-30057).

10.1.36 Phase II Massachusetts Transmission Facilities Support Agreement dated June 1, 1985, refiled as a single agreement incorporating Amendments 1 through 7 dated May 1, 1986 through January 1, 1989, respectively, between New England Hydro and certain NEPOOL utilities (Exhibit 2 to the CEC Form 10-Q (September 1990), File No. 2-30057).

10.1.37 Phase II New Hampshire Transmission Facilities Support Agreement dated June 1, 1985, refiled as a single agreement incorporating Amendments 1 through 8 dated May 1, 1986 through January 1, 1990, respectively, between New England Hydro-Transmission Corporation (New Hampshire Hydro) and certain NEPOOL utilities (Exhibit 3 to the CEC Form 10-Q (September 1990), File No. 2-30057).

10.1.38 Phase II Equity Funding Agreement for New Hampshire Hydro, dated June 1, 1985, between New Hampshire Hydro and certain NEPOOL utilities (Exhibit 3 to the CEC Form 10-Q (September 1985), File No. 2-30057).

10.1.38.1 Amendment No. 1 to 10.1.38 dated May 1, 1986 (Exhibit 6 to the CEC Form 10-Q (March 1987), File No. 2-30057).

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

10.1.38.2 Amendment No. 2 to 10.1.38 as amended September 1, 1987 (Exhibit 3 to the CEC Form 10-Q (September 1987), File No. 2-30057).

10.1.39 Phase II New England Power AC Facilities Support Agreement, dated June 1, 1985, between NEP and certain NEPOOL utilities (Exhibit 6 to the CEC Form 10-Q (September 1985), File No. 2-30057).

10.1.39.1 Amendments Nos. 1 and 2 to 10.1.39 as amended May 1, 1986 and February 1, 1987, respectively (Exhibit 5 to the CEC Form 10-Q (March 1987), File No. 2-30057).

10.1.39.2 Amendments Nos. 3 and 4 to 10.1.39 as amended June 1, 1987 and September 1, 1987, respectively (Exhibit 5 to the CEC Form 10-Q (September 1987), File No. 2-30057).

10.1.40 Phase II Boston Edison AC Facilities Support Agreement, dated June 1, 1985, between BECO and certain NEPOOL utilities (Exhibit 7 to the CEC Form 10-Q (September 1985), File No. 2-30057).

10.1.40.1 Amendments Nos. 1 and 2 to 10.1.40 as amended May 1, 1986 and February 1, 1987, respectively (Exhibit 2 to the CEC Form 10-Q (March 1987), File No. 2-30057).

10.1.40.2 Amendments Nos. 3 and 4 to 10.1.40 as amended June 1, 1987 and September 1, 1987, respectively (Exhibit 4 to the CEC Form 10-Q (September 1987), File No. 2-30057).

10.1.41 Agreement Authorizing Execution of Phase II Firm Energy Contract, dated September 1, 1985, among certain NEPOOL utilities in regard to participation in the purchase of power from Hydro-Quebec (Exhibit 8 to the CEC Form 10-Q (September 1985), File No. 2-30057).

10.1.42 System Power Sales Agreement by and between CE, as seller, and Central Vermont Public Service Corporation (CVPS), as buyer, dated September 15, 1984 (Exhibit 2 to the CE Form 10-Q (September 1984), File No. 2-7749).

10.1.42.1 System Sales Agreement by CVPS, as seller, and CE, as buyer, dated September 15, 1984 (Exhibit 9 to the CE 1984 Form 10-K, File No. 2-7749).

10.1.42.2 System Sales and Exchange Agreement by and between CVPS and CE on energy transactions, dated September 15, 1984 (Exhibit 10 to the CE 1984 Form 10-K, File No. 2-7749).

10.1.42.3 System Exchange Agreement by and between CE and CVPS for the exchange of capacity and associated energy, dated September 3, 1985 (Exhibit 1 to the CE 1985 Form 10-K, File No. 2-7749).

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

10.1.42.4 Purchase Agreement by and between CEC and CVPS for the purchase of capacity from CEC for the term March 1, 1991 to October 31, 1995, dated March 1, 1991 (Exhibit 1 to CEC Form 10-Q (June 1991), File No. 2-30057).

10.1.42.5 Power Sale Agreement by and between CEC and CVPS for the purchase of 50 MW of capacity from CVPS's units (25 MW from Vermont Yankee and 25 MW from Merrimack 2) for the term of March 1, 1991 to October 31, 1995, dated March 1, 1991 (Exhibit 2 to CEC Form 10-Q (June 1991), File No. 2-30057).

10.1.43 Agreements by and between Swift River Company and CE for the purchase of available hydro-electric energy to be produced by units located in Chicopee and North Willbraham, Massachusetts, both dated September 1, 1983 (Exhibits 11 and 12 to the CE 1984 Form 10-K, File No. 2-7749).

10.1.43.1 Transmission Service Agreement between Northeast Utilities' companies (NU) - The Connecticut Light and Power Company (CL&P) and Western Massachusetts Electric Company (WMECO), and CE for NU companies to transmit power purchased from Swift River Company's Chicopee Units to CE, dated October 1, 1984 (Exhibit 14 to the CE 1984 Form 10-K, File No. 2-7749).

10.1.43.2 Transformation Agreement between WMECO and CE whereby WMECO is to transform power to CE from the Chicopee Units, dated December 1, 1984 (Exhibit 15 to the CE 1984 Form 10-K, File No. 2-7749).

10.1.44 System Power Sales Agreement by and between CL&P and WMECO, as buyers, and CE, as seller, dated January 13, 1984 (Exhibit 13 to the CE 1984 Form 10-K, File No. 2-7749).

10.1.45 System Power Sales Agreement by and between CL&P, WMECO, as sellers, and CEL, as buyer, of power in excess of firm power customer requirements from the electric systems of the NU Companies, dated June 1, 1984, as effective October 25, 1985 (Exhibit 1 to CEL 1985 Form 10-K, File No. 2-7909).

10.1.46 Power Purchase Agreement with Respect to South Meadow Unit Nos. 11, 12, 13, and 14 of the NU system company of CL&P (seller) and CE (buyer), dated November 1, 1985 (Exhibit 1 to the CE Form 10-Q (June 1986), File No. 2-7749).

10.1.47 Power Purchase Agreement by and between SEMASS Partnership, as seller, to construct, operate and own a solid waste disposal facility at its site in Rochester, Massachusetts and CE, as buyer of electric energy and capacity, dated September 8, 1981 (Exhibit 17 to the CE 1984 Form 10-K, File No. 2-7749).

10.1.47.1 Power Sales Agreement to 10.1.47 for all capacity and related energy produced, dated October 31, 1985 (Exhibit 2 to the CE 1985 Form 10-K, File No. 2-7749).

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

10.1.47.2 Amendment to 10.1.47 for all additional electric capacity and related energy to be produced by an addition to the Original Unit, dated March 14, 1990 (Exhibit 1 to the CE Form 10-Q (June 1990), File No. 2-7749).

10.1.47.3 Amendment to 10.1.47 for all additional electric capacity and related energy to be produced by an addition to the Original Unit, dated May 24, 1991 (Exhibit 1 to CE Form 10-Q (June 1991), File No. 2-7749).

10.1.48 System Power Sales Agreement by and between CE (seller) and NEP (buyer), dated January 6, 1984 (Exhibit 1 to the CE Form 10-Q (June 1985), File No. 2-7749).

10.1.49 Service Agreement by and between CE and NEP dated March 24, 1984, whereas CE agrees to purchase short-term power applicable to NEP'S FERC Electric Tariff Number 5 (Exhibit 1 to the CE Form 10-Q (June 1987), File No. 2-7749).

10.1.50 Power Sale Agreement by and between CE (buyer) and Northeast Energy Associated, Ltd. (NEA) (seller) of electric energy and capacity, dated November 26, 1986 (Exhibit 1 to the CE Form 10-Q (March 1987), File No. 2-7749).

10.1.50.1 First Amendment to 10.1.50 as amended August 15, 1988 (Exhibit 1 to the CE Form 10-Q (September 1988), File No. 2-7749).

10.1.50.2 Second Amendment to 10.1.50 as amended January 1, 1989 (Exhibit 2 to the CE 1988 Form 10-K, File No. 2-7749).

10.1.50.3 Power Sale Agreement dated August 15, 1988 between NEA and CE for the purchase of 21 MW of electricity (Exhibit 2 to the CE Form 10-Q (September 1988), File No. 2-7749).

10.1.50.4 Amendment to 10.1.50.3 as amended January 1, 1989 (Exhibit 3 to the CE 1988 Form 10-K, File No. 2-7749).

10.1.51 Power Sale Agreement by and between CE (buyer) and CPC Lowell Cogeneration Corp.(seller) of all capacity and related energy produced, dated September 29, 1986 (Exhibit 2 to the CE Form 10-Q (March 1987), File No. 2-7749).

10.1.51.1 Restatement of 10.1.51 as restated March 30, 1987 (Exhibit 2 to the CE Form 10-Q (June 1987), File No. 2-7749).

10.1.52 Power Sale Agreement by and between CE (buyer) and Pepperell Power Associates Limited Partnership (seller) of all electricity produced from a 38 KW generating unit, dated April 13, 1987 (Exhibit 3 to the CE Form 10-Q (March 1987), File No. 2-7749).

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

10.1.53 Power Sale Agreement by and between CE (buyer) and Tondu Energy Systems, Inc. (Tondu) (seller) of all of the electricity produced at a unit to be constructed at a site in Lee, MA, Lee Mills Cogeneration Project, dated April 28, 1987 (Exhibit 3 to CE Form 10-Q (June 1987), File No. 2-7749).

10.1.53.1 Assignment and Assumption Agreement by and between Lee Mills Cogeneration Co. (LMC) and Tondu and as consented to by CE, whereby Tondu conveyed its rights in the Lee Mills Cogeneration Project to LMC, dated June 11, 1987 (Exhibit 4 to the CE Form 10-Q (June 1987), File No. 2-7749).

10.1.54 Power Contract between CEC (seller) and CE and CEL (purchasers) dated August 14, 1989 whereby purchasers agree to purchase the capacity and energy from seller's "Slice-of-System" entitlement from CL&P for the term of November 1, 1989 to October 31, 1994 (Exhibit 1 to the CEC Form 10-Q (September 1989), File No. 2-30057).

10.1.54.1 Power Sale Agreement dated November 1, 1988, by and between CEC (buyer) and CL&P (seller), whereby buyer will purchase generating capacity totaling 250 MW from various seller's units ("Slice of System") for the term November 1, 1989 to October 31, 1994 (Exhibit 3 to the CEC 1988 Form 10-K, File No. 2-30057).

10.1.55 Power Contract between CEC (seller) and CE and CEL (buyers) to resell and purchase, respectively, varying amounts of capacity and energy equal to buyer's share from certain units owned by CL&P and WMECO for the term May 1, 1987 to April 30, 1993, dated May 1, 1987 (Exhibit 5 to the CEC 1988 Form 10-K, File No. 2-30057).

10.1.55.1 Sales Agreement with Respect to the Retirement Package dated May 1, 1987 between Northeast Utilities Service Company (NUSC), acting as agent for CL&P and WMEC and CEC whereby CEC will purchase capacity and energy from certain fossil steam and gas turbine units for the term May 1, 1987 to April 30, 1993 (Exhibit 3 to the CEC Form 10-Q (September 1989), File No. 2-30057).

10.1.56 Unit Sales Agreement between CL&P and CEC from CL&P's Middletown Units 3 and 4 through April 30, 1993, dated August 26, 1991 (Exhibit 1 to CEC Form 10-Q (September 1991), File No. 2-30057).

10.1.56.1 Power Contract between CEC, CEL and CE for CEC's entitlement in CL&P's Middletown Units 3 and 4 through April 30, 1993, dated August 27, 1991 (Exhibit 2 to CEC Form 10-Q (September 1991), File No. 2-30057).

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

10.1.57 Power Contract between CEC (seller) and CE and CEL (buyers) to resell and purchase, respectively, varying amounts of capacity and energy equal to buyer's share from certain units owned by the CL&P and WMECO for the term November 1, 1988 to April 30, 1993, dated November 1, 1988 (Exhibit 1 to the CEC 1988 Form 10-K, File No. 2-30057).

10.1.57.1 Supplemental Sales Agreement with Respect to Retirement Package dated November 1, 1988 between NUSC, acting as agent for the CL&P and WMEC, and CEC whereby CEC will purchase capacity and energy from certain fossil steam and gas turbine units for the term November 1, 1988 to April 30, 1993 (Exhibit 4 to the CEC Form 10-Q (September 1989), File No. 2-30057).

10.1.58 Transmission Agreement dated November 1, 1988 by and between CE and PSNH whereby power purchased by CE from the New Brunswick Electric Commission is agreed to be routed through the transmission facilities of PSNH for the term November 1, 1988 through October 31, 1991 (Exhibit 1 to the CE 1989 Form 10-K, File No. 2-7749).

10.1.59 Exchange of Power Agreement between Montaup Electric Company and CE dated January 17, 1991 (Exhibit 2 to CE Form 10-Q (September 1991) File No. 2-7749).

10.2 Natural gas purchase contracts.

10.2.1 Natural gas purchase contracts between Algonquin Gas Transmission Company (AGT) and the gas subsidiaries of the System: Firm Service contracts dated October 28, 1969 and July 10, 1972; Winter Service contracts dated August 14, 1968 and July 10, 1972 (Exhibits 1, 2, 3, and 4, respectively, to the CG 1984 Form 10-K, File No. 2-1647).

10.2.2 Service Agreement Applicable to Rate Schedule F-1 between AGT and CG for Firm natural gas services, dated January 28, 1981 (Exhibit 1 to the CG Form 10-Q (March 1987), File No. 2-1647).

10.2.3 Service Agreement Applicable to Rate Schedule F-2 between AGT and CG for the purchase of certain quantities of natural gas acquired by AGT from CGS, dated April 11, 1985 (Exhibit 2 to the CG Form 10-Q (March 1987), File No. 2-1647).

10.2.4 Service Agreement Applicable to Rate Schedule F-3 between AGT and CG for the purchase of certain quantities of natural gas acquired by AGT from National Fuel Gas Supply Corporation, dated April 11, 1985 (Exhibit 3 to the CG Form 10-Q (March 1987), File No. 1-1647).

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

10.2.5 Service Agreement Applicable to Rate Schedule F-4 between AGT and CG for the purchase of certain quantities of natural gas acquired by AGT from Texas Eastern Transmission Company, dated December 26, 1985 (Exhibit 4 to the CG Form 10-Q (March 1987), File No. 2-1647).

10.2.6 Gas Service Contract between HOPKO and NBGEL for the performance of liquefaction, storage and vaporization service and the operation and maintenance of an LNG facility located at Acushnet, MA dated September 1, 1971 (Exhibit 8 to the CG 1984 Form 10-K, File No. 2-1647).

10.2.6.1 Gas Service Contract between HOPKO and CG for the performance of liquefaction, storage and vaporization services and the operation of LNG facilities located in Hopkinton, MA dated September 1, 1971 (Exhibit 9 to the CG 1984 Form 10-K, File No. 2-1647).

10.2.6.2 Amendments to 10.2.6 and 10.2.6.1 as amended December 1, 1976 (Exhibits 2 and 3 to the CG 1986 Form 10-K, File No. 2-1647).

10.2.6.3 Supplement 1 to Gas Service Contract between HOPKO and NBGEL dated September 1, 1973 and September 14, 1977 (Exhibit 5(c)5 to the CES Form S-16 (June 1979), File No. 2-64731).

10.2.6.4 Supplement 1 to 10.2.6.1 dated September 14, 1977 (Exhibit 5(c)6 to the CG Form S-16 (June 1979), File No. 2-64731).

10.2.6.5 Supplement 2 to 10.2.6.1 dated September 30, 1982 (Exhibit 2 to the CG 1982 Form 10-K, File No. 2-1647).

10.2.6.6 1986 Consolidating Supplement to CG Service Contract and NBGEL Service Contract by and between CG and HOPKO dated December 31, 1986 amending and consolidating the CG Service Contract and the NBGEL Service Contract both as amended December 1, 1976 and supplemented September 14, 1977 (Exhibit 2 to CG Form 10-Q (March 1988), File No. 2-1647).

10.2.7 Operating Agreement between Air Products and Chemicals, Inc., (APC) and HOPKO, dated as of September 1, 1971, as supplemented by Supplements No. 1, No. 2 and No. 3 dated as of July 1, 1974, August 1, 1975 and January 1, 1985, respectively, with respect to the operation and maintenance by APC of HOPKO's liquefied natural gas facilities located at Hopkinton, MA (Exhibit 11 to the CES 1984 Form 10-K, File No. 1-7316).

10.2.7.1 Engineering and Prime Contracting Agreement between APC and HOPKO for performance of engineering services and capital project construction at LNG facility in Hopkinton, MA (Exhibit 12 to the CES 1984 Form 10-K, File No. 1-7316).

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

10.2.8 Firm Storage Service Transportation Contract by and between TGP and CG providing for firm transportation of natural gas from CGT, dated December 15, 1985 (Exhibit 1 to the CG 1985 Form 10-K, File No. 2-1647).

10.2.9 Agency Agreement for Certain Transportation Arrangements by and between CG and Citizens Resources Corporation (CRC) whereby CRC arranges for a third party transportation of natural gas acquired by CG, dated April 14, 1986 (Exhibit 1 to the CG Form 10-Q (June 1986), File No. 2-1647).

10.2.9.1 Natural Gas Sales Agreement between CG and CRC, dated April 14, 1986 (Exhibit 2 to CG Form 10-Q (June 1986), File No. 2-1647).

10.2.10 Gas Sales Agreement by and between Enron Gas Marketing, Inc. and CG relating to the sale and purchase of natural gas on an interruptible basis, dated June 17, 1986 (Exhibit 3 to the CG Form 10-Q (June 1986), File No. 2-1647).

10.2.11 Agency Agreement for Certain Transportation Arrangements, dated June 18, 1985 and Gas Purchase and Sales Agreement dated August 6, 1985 by and between CG and Tenngasco Corporation and other related entities (Exhibit 4 to the CG Form 10-Q (June 1986), File No. 2-1647).

10.2.12 Service Agreement dated December 14, 1985 and an amendment thereto dated May 15, 1986 by and between Texas Eastern Transmission Corporation (TET) and CG to receive, transport and deliver to points of delivery natural gas for the account of CG, dated December 14, 1985 (Exhibit 5 to the CG Form 10-Q (June 1986), File No. 2-1647).

10.2.13 Gas Transportation Agreement by and between TET and CG to receive, transport and deliver on an interruptible basis, certain quantities of natural gas for the account of CG, dated January 31, 1986 (Exhibit 6 to the CG Form 10-Q (June 1986), File No. 2-1647).

10.2.14 Service Agreement dated May 19, 1988, by and between TET and CG, whereby TET agrees to receive, transport and deliver natural gas to CG (Exhibit 1 to the CG Form 10-Q (September 1988), File No. 2-1647).

10.2.15 Gas Sales Agreement by and between Texas Eastern Gas Trading Company and CG providing for the sale of certain quantities of natural gas to CG, dated May 15, 1986 (Exhibit 7 to the CG Form 10-Q (June 1986), File No. 2-1647).

10.2.16 Service Agreement applicable to Rate Schedule TS-3 between TET and CG for Firm natural gas service, dated April 16, 1987 (Exhibit 1 to the CG Form 10-Q (June 1987), File No. 2-1647).

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

10.2.17 Natural Gas Sales Agreement between Summit Pipeline and Producing Company and CG, dated April 16, 1987 (Exhibit 2 to the CG Form 10-Q (June 1987), File No. 2-1647).

10.2.18 Natural Gas Sales Agreement between Natural Gas Supply Company and CG, dated May 12, 1987 (Exhibit 3 to the CG Form 10-Q (June 1987), File No. 2-1647).

10.2.19 Natural Gas Sales Agreement between Stellar Gas Company and CG, dated April 15, 1988 (Exhibit 1 to the CG Form 10-Q (March 1988), File No. 2-1647).

10.2.20 Natural Gas Sales Agreement between Amalgamated Gas Pipeline Company and CG dated April 5, 1988 (Exhibit 1 to the CG Form 10-Q (June 1988), File No. 2-1647).

10.2.21 Natural Gas Sales Agreement between Gulf Ohio Pipeline Corporation and CG dated May 18, 1988 (Exhibit 2 to the CG Form 10-Q (June 1988), File No. 2-1647).

10.2.22 Natural Gas Sales Agreement between Phillips Petroleum Company and CG dated May 18, 1988 (Exhibit 3 to the CG Form 10-Q (June 1988), File No. 2-1647).

10.2.23 Natural Gas Sales Agreement between TXO Gas Marketing Corp. and CG dated April 25, 1988 (Exhibit 1 to the CG 1988 Form 10-K, File No. 2-1647).

10.2.24 Gas Transportation Agreement by and between AGT and CG to receive, transport and deliver certain quantities of natural gas on a firm basis for the account of CG dated December 1, 1988 (Exhibit 2 to the CG 1988 Form 10-K, File No. 2-1647).

10.2.25 Natural Gas Sales Agreement between Enermark Gas Gathering Corporation and CG dated January 6, 1989 (Exhibit 3 to the CG 1988 Form 10-K, File No. 2-1647).

10.2.26 Gas Sales Agreement between BP Gas Inc. (seller) and CG (purchaser) for the purchase of spot market gas, dated March 31, 1989 with a contract term of at least one year (Exhibit 1 to the CG Form 10-Q (March 1989), File No. 2-1647).

10.2.27 Gas Sales Agreement between Tejas Power Corporation (seller) and CG (purchaser) for the purchase of spot market gas, dated February 21, 1989 with a contract term of at least one year (Exhibit 2 to the CG Form 10-Q (March 1989), File No. 2-1647).

10.2.28 Gas Sales Agreement between Catamount Natural Gas, Inc. (seller) and CG (purchaser) for the purchase of spot market gas, dated April 5, 1988, with a contract term of at least one year (Exhibit 1 to the CG Form 10-Q (June 1989), File No. 2-1647).

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

10.2.29 Gas Sales Agreement between Transco Energy Marketing Company (seller) and CG (purchaser) for the purchase of spot market gas, dated March 1, 1989, with a contract term of at least one year (Exhibit 2 to the CG Form 10-Q (June 1989), File No. 2-1647).

10.2.30 Gas Sales Agreement between V.H.C. Gas Systems, L.P. (seller) and CG (purchaser) for the purchase of spot market gas, dated June 2, 1989, with a contract term of at least one year (Exhibit 3 to the CG Form 10-Q (June 1989), File No. 2-1647).

10.2.31 Gas Sales Agreement between End-Users Supply System (seller) and CG (purchaser) for the purchase of spot market gas, dated June 29, 1989, with a contract term of at least one year (Exhibit 1 to the CG Form 10-Q (September 1989), File No. 2-1647).

10.2.32 Gas Sales Agreement between Entrade Corporation (seller) and CG (purchaser) for the purchase of spot market gas, dated August 14, 1989, with a contract term of at least one year (Exhibit 2 to the CG Form 10-Q (September 1989), File No. 2-1647).

10.2.33 Gas Sales Agreement between Fina Oil and Chemical Company (seller) and CG (purchaser) for the purchase of spot market gas, dated July 10, 1989, with a contract term of at least one year (Exhibit 3 to the CG Form 10-Q (September 1989), File No. 2-1647).

10.2.34 Gas Sales Agreement between Mobil Natural Gas Inc. (seller) and CG (purchaser) for the purchase of spot market gas, dated August 14, 1989, with a contract term of at least one year (Exhibit 4 to the CG Form 10-Q (September 1989), File No. 2-1647).

10.2.35 Gas Storage Agreement between Steuben Gas Storage Company (Steuben) and CG (customer) for the storage and delivery of customer's natural gas to and from underground gas storage facilities, dated May 23, 1989, with a contract term of at least one year (Exhibit 4 to the CG Form 10-Q (June 1989), File No. 2-1647).

10.2.35.1 Amendment, dated August 28, 1989, to 10.2.35 dated May 23, 1989 (Exhibit 5 to the CG Form 10-Q (September 1989), File No. 2-1647).

10.2.36 Gas Sales Agreement between PSI, Inc. (seller) and CG (purchaser) for the purchase of spot market gas, dated September 25. 1989, with a term of at least one year (Exhibit 1 to the CG 1989 Form 10-K, File No. 2-1647).

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

10.2.37 Gas Sales Agreement between Hadson Gas Systems (seller) and CG (purchaser) for the purchase of firm gas, dated August 15, 1990, with a contract term of at least six years (Exhibit 1 to the CG Form 10-Q (September 1990), File No. 2-1647).

10.2.38 Gas Sales Agreement between Odeco Oil Company (seller) and CG (purchaser) for the purchase of firm gas, dated August 15, 1990, with a contract term of at least five years (Exhibit 2 to the CG Form 10-Q (September 1990), File No. 2-1647).

10.2.39 Operating Agreement between AGT, CG and Distrigas of Massachusetts Corporation in connection with the deliveries of regasified liquified natural gas into the Algonquin J-system, dated August 1, 1990 (Exhibit 3 to the CG Form 10-Q (September 1990), File No.2-1647).

10.2.40 Gas Sales Agreement between TEX/CON Marketing Gas Company (seller) and CG (purchaser) for the purchase of firm gas, dated September 12, 1990, with a contract term of five years (Exhibit 3 to the CG 1990 Form 10-K, File No. 2-1647).

10.2.41 Transportation Agreement between AGT and CG to provide for firm transportation of natural gas on a daily basis, dated December 1, 1988 (Exhibit 3 to the CG 1991 Form 10-K, File No. 2-1647).

10.2.42 Transportation Assignment Agreement between AGT and CG regarding Rate Schedule ATAP Agreement No. 9020016 which provides for the assignment, on an interruptible basis, of firm service rights on TET's system under Rate Schedule FT-1, dated January 3, 1990, for a term ending October 31, 1999 (Exhibit 4 to the CG 1991 Form 10-K, File No. 2-1647).

10.2.43 Gas Sales Agreement between AFT and CG to reduce the volume of Rate Schedule F-1, dated October 15, 1990 (Exhibit 5 to the CG 1991 Form 10-K, File No. 2-1647).

10.2.44 Transportation Agreement between AFT and CG for Rate Schedule AFT-1, dated November 1, Agreement No. 90103, 1990 (Exhibit 6 to the CG 1991 Form 10-K, File No. 2-1647).

10.2.45 Transportation Assignment Agreement between AFT and CG regarding Rate Schedule ATAP Agreement No. 90202, which provides for the assignment, on a firm basis, of firm service rights on TET's system under Rate Schedule FT-1 dated November 1, 1990 (Exhibit 7 to the CG 1991 Form 10-K, File No. 2-1647).

10.2.46 Gas Sales Agreement between TGP and CG under TGP's CD-6 Rate Schedules dated September 1, 1991 (Exhibit 8 to the CG 1991 Form 10-K, File No. 2-1647).

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

10.2.47 Transportation Agreement between TGP and CG dated September 1, 1991 (Exhibit 9 to the CG 1991 Form 10-K, File No. 2-1647).

10.2.48 Transportation Agreement between CNG and CG to provide for transportation of natural gas on a daily basis from Steuben Gas Storage Company to TGP (Exhibit 10 to the CG 1991 Form 10-K, File No. 2-1647).

10.3 Other agreements.

10.3.1 Pension Plan for Employees of CES and Subsidiary Companies as amended January 1, 1989 (Exhibit 1 to CES Form 10-Q (June 1991), File No. 1-7316).

10.3.2 Employees Savings Plan of Commonwealth Energy System and Subsidiary Companies restated as of January 1, 1989 (Exhibit 1 to the CES Form 10-Q (June 1989), File No. 1-7316).

10.3.3 New England Power Pool Agreement (NEPOOL) dated September 1, 1971 as amended through August 1, 1977, between NEGEA Service Corporation, as agent for CEL, CEC, NBGEL, and various other electric utilities operating in New England together with amendments dated August 15, 1978, January 31, 1979 and February 1, 1980. (Exhibit 5(c)13 to New England Gas and Electric Association's Form S-16 (April 1980), File No. 2-64731).

10.3.3.1* Thirteenth Amendment to 10.3.3 as amended September 1, 1981 (Refiled herewith as Exhibit 3 at page 138).

10.3.3.2 Fourteenth through Twentieth Amendments to 10.3.3 as amended December 1, 1981, June 1, 1982, June 15, 1983, October 1, 1983, August 1, 1985, August 15, 1985 and September 1, 1985, respectively (Exhibit 4 to the CES Form 10-Q (September 1985), File No. 1-7316).

10.3.3.3 Twenty-first Amendment to 10.3.3 as amended to January 1, 1986 (Exhibit 1 to the CES Form 10-Q (March 1986), File No. 1-7316).

10.3.3.4 Twenty-second Amendment to 10.3.3 as amended to September 1, 1986 (Exhibit 1 to the CES Form 10-Q (September 1986), File No. 1-7316).

10.3.3.5 Twenty-third Amendment to 10.3.3 as amended to April 30, 1987 (Exhibit 1 to the CES Form 10-Q (June 1987), File No. 1-7316).

10.3.3.6 Twenty-fourth Amendment to 10.3.3 as amended March 1, 1988 (Exhibit 1 to the CES Form 10-Q (March 1989), File No. 1-7316).

10.3.3.7 Twenty-fifth Amendment to 10.3.3. as amended to May 1, 1988 (Exhibit 1 to the CES Form 10-Q (March 1988), File No. 1-7316).

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

10.3.3.8 Twenty-sixth Agreement to 10.3.3 as amended March 15, 1989 (Exhibit 1 to the CES Form 10-Q (March 1989), File No. 1-7316).

10.3.3.9 Twenty-seventh Agreement to 10.3.3 as amended October 1, 1990 (Exhibit 3 to the CES 1990 Form 10-K, File No. 1-7316)

10.3.4 Facilities Lease and Operating Agreement between CE and Global Petroleum Corporation, dated November 12, 1983, covering CE's lease of a New Bedford oil terminal to Global for Global to operate and maintain for the joint benefit of the companies (Exhibit 1 to the CE Form 10-Q (June 1989), File No. 2-7749).

10.3.5 Fuel Supply, Facilities Lease and Operating Contract by and between, on the one side, ESCO (Massachusetts), Inc. and Energy Supply and Credit Corporation, and on the other side, CEC, dated as of February 1, 1985 (Exhibit 1 to the CEC 1984 Form 10-K, File No. 2-30057

10.3.5.1 Amendments Nos. 1 and 2 to 10.3.5 as amended July 1, 1986 and November 15, 1989, respectively (Exhibit 3 to the CEC 1989 Form 10-K, File No. 2-30057).

10.3.6 Assignment and Sublease Agreement and Canal's Consent of Assignment thereto whereby ESCO-Mass assigns its rights and obligations under Part II of the Resupply Agreement dated February 1, 1985 to ESCO Terminals Inc., dated June 4, 1985 (Exhibit 4 to CEC Form 10-Q (June 1985), File No. 2-30057).

10.3.7 Oil Supply Contract by and between CEC (buyer) and Coastal Oil New England, Inc. (seller) for a portion of CEC's requirements of No. 6 residual fuel oil, dated July 1, 1991 (Exhibit 3 to CEC Form 10-Q (June 1991), File No. 2-30057).

10.3.7.1 Assignment Agreement between CEC and ESCO (Massachusetts), Inc. (ESCO-Mass) and Energy Supply and Credit Corporation whereby CEC assigns to ESCO-Mass rights and obligations under 10.3.7 (above) dated July 1, 1991 (Exhibit 4 to CEC Form 10-Q (June 1991), File No. 2-30057).

10.3.8 Guarantee Agreement by CEL (as guarantor) and MYA Fuel Company (as initial lender) covering the unconditional guarantee of a portion of the payment obligations of Maine Yankee Atomic Power Company under a loan agreement and note initially between Maine Yankee and MYA Fuel Company (Exhibit 3 to the CEL Form 10-K for 1985, File No. 2-7909).

10.3.9 Stock Purchase Agreement by and among Texas Eastern Corporation (purchaser) and Eastern Gas and Fuel Associates, Commonwealth Energy System and Providence Energy Corporation (sellers) for the purchase and sale of ownership interests in Algonquin Energy, Inc., dated June 10, 1986 (Exhibit 1 to the CEC Form 10-Q (June 1986), File No. 1-7316).

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

Exhibit 13. Annual Report To Security Holders

Filed herewith as Exhibit 1 is the 1991 Summary Annual Report of Commonwealth Energy System (page 64).

Exhibit 22. Subsidiaries of the Registrant

Incorporated by reference to Exhibit 2 (page 101) to the System's 1988 Annual Report on Form 10-K, File No. 1-7316.

Exhibit 28. Additional Exhibit

Filed herewith as Exhibit 2 is a copy of the Notice of 1992 Annual Meeting, Proxy Statement and 1991 Financial Information dated April 3, 1992 (page 92).

(b) Reports on Form 8-K

A report on Form 8-K was filed with the Commission on December 24, 1991, relating to issuance of an initial ruling by an Administrative Law Judge affirming the prudence of Canal Electric Company's oversight of emergency response planning for the Seabrook nuclear power plant. Also disclosed was the FERC approval of a settlement agreement on November 13, 1991 which resolved all Seabrook cost-of-service issues and the filing of a settlement proposal with FERC on Canal's rate of return on equity for its Seabrook investment.

A second report on Form 8-K was filed with the Commission on January 24, 1992 relating to the System's decision to write down its investment in the Freetown Energy Park project.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS ON SCHEDULES

To Commonwealth Energy System:

We have audited in accordance with generally accepted auditing standards, the consolidated financial statements of Commonwealth Energy System appearing in Exhibit A to the proxy statement for the 1992 annual meeting of shareholders incorporated by reference in this Form 10-K, and have issued our report thereon dated February 26, 1992. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedules listed in Part IV, Item 14 of this Form 10-K are the responsibility of the System and subsidiary companies' management and 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 our audits 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 26, 1992.

SCHEDULE III

COMMONWEALTH ENERGY SYSTEM AND SUBSIDIARY COMPANIES

INVESTMENTS IN, EQUITY IN EARNINGS OF, AND DIVIDENDS RECEIVED FROM RELATED PARTIES
FOR THE YEAR ENDED DECEMBER 31, 1991

(Dollars in Thousands)

	Balance at Beginning of Year		Additions	Deductions		Balance at End of Year		
	Number of Shares	Investment	Equity in Earnings	Distribution of Earnings	Other	Number of Shares	Investment	Notes Receivable (A)
SUBSIDIARIES CONSOLIDATED:								
(All issues are common stock)								
Cambridge Electric Light Company	304 600	$ 37 972	$ 4 039	$ 4 066	$ -	304 600	$ 37 945	$ 655
COM/Energy Steam Company	25 500	2 708	1 125	727	-	25 500	3 106	-
Canal Electric Company	1 523 200	106 846	18 978	16 755	-	1 523 200	109 069	2 570
Commonwealth Gas Company	2 407 000	85 226	3 120	5 416	-	2 407 000	82 930	3 725
Darvel Realty Trust	28	1 307	360	110	-	28	1 557	-
COM/Energy Freetown Realty	1	478	(15,795)	-	-	1	(15 317)	-
COM/Energy Research Park Realty	1	790	450	-	-	1	1 240	-
COM/Energy Cambridge Realty	1	90	(8)	-	-	1	82	-
COM/Energy Acushnet Realty	1	488	70	-	-	1	558	-
COM/Energy Services Company	3 250	325	49	37	-	3 250	337	-
Commonwealth Electric Company	1 606 472	125 457	9 857	7 952	-	1 606 472	127 362	5 950
Hopkinton LNG Corp.	5 000	3 747	548	-	-	5 000	4 295	-
		$365 434	$22 793	$35 063	$ -		$353 164	$12 900
OTHER INVESTMENTS:								
(Accounted for by the equity method)								
Nuclear Electric Power Companies	52 654	$ 9 475	$ 1 504	$ 1 330	$20(B)	52 454	$ 9 629	
Hydro-Quebec Phase II	137 442	3 453	1 195	276	-	137 442	4 372	
Other Investments	-	713	(685)	-	-	-	28	
		$ 13 641	$ 2 014	$ 1 606	$20		$ 14 029	

NOTES: (A) Notes are written for eleven months and twenty-nine days. Interest is at the prime interest rate and is adjusted for changes in the rate during the term of the notes.

(B) In 1991, Vermont Yankee repurchased 2% of its common stock at $150 per share from Cambridge Electric. Cambridge Electric's original cost was $100 per share. As of December 31, 1991, Cambridge Electric held 8,801 shares in Vermont Yankee. There were no other changes in the number of shares held during the three-year peri[illegible] ending December 31, 1991.

SCHEDULE III

COMMONWEALTH ENERGY SYSTEM AND SUBSIDIARY COMPANIES

INVESTMENTS IN, EQUITY IN EARNINGS OF, AND DIVIDENDS RECEIVED FROM RELATED PARTIES
FOR THE YEAR ENDED DECEMBER 31, 1990

(Dollars in Thousands)

	Balance at Beginning of Year		Additions		Deductions	Balance at End of Year		
	Number of Shares	Investment	Equity in Earnings	Other	Distribution of Earnings	Number of Shares	Investment	Notes Receivable (A)
SUBSIDIARIES CONSOLIDATED:								
(All issues are common stock)								
Cambridge Electric Light Company	304 600	$ 38 424	$ 1 984	$ -	$ 2 436	304 600	$ 37 972	$ 1 275
COM/Energy Steam Company	25 500	3 219	1 096	-	1 607	25 500	2 708	-
Canal Electric Company	1 523 200	117 837	16 807	-	27 798	1 523 200	106 846	350
Commonwealth Gas Company	1 832 000	66 501	(2 542)	23 000(B)	1 733	2 407 000	85 226	-
Dervel Realty Trust	26	1 291	480	-	464	26	1 307	-
COM/Energy Freetown Realty	1	550	(72)	-	-	1	478	-
COM/Energy Research Park Realty	1	790	515	-	515	1	790	-
COM/Energy Cambridge Realty	1	95	(5)	-	-	1	90	-
COM/Energy Acushnet Realty	1	488	74	-	74	1	488	-
COM/Energy Services Company	3 250	325	49	-	49	3 250	325	-
Commonwealth Electric Company	1 606 472	127 343	6 162	-	8 048	1 606 472	125 457	-
Hopkinton LNG Corp.	5 000	3 743	548	-	544	5 000	3 747	-
		$360 606	$25 096	$23 000	$43 268		$365 434	$ 1 625
OTHER INVESTMENTS:								
(Accounted for by the equity method)								
Nuclear Electric Power Companies	52 654	$ 9 384	$ 1 432	$ -	$ 1 341	52 654	$ 9 475	
Hydro-Quebec Phase II	137 442	3 359	94	-	-	137 442	3 453	
Other Investments	-	1 060	(347)	-	-	-	713	
		$ 13 803	$ 1 179	$ -	$ 1 341		$ 13 641	

NOTES: (A) Notes are written for eleven months and twenty-nine days. Interest is at the prime interest rate and is adjusted for changes in the rate during the term of the notes.

(B) Additional investment.

SCHEDULE III

COMMONWEALTH ENERGY SYSTEM AND SUBSIDIARY COMPANIES

INVESTMENTS IN, EQUITY IN EARNINGS OF, AND DIVIDENDS RECEIVED FROM RELATED PARTIES
FOR THE YEAR ENDED DECEMBER 31, 1989

(Dollars in Thousands)

	Balance at Beginning of Year		Additions		Deductions	Balance at End of Year		
	Number of Shares	Investment	Equity in Earnings	Other	Distribution of Earnings	Number of Shares	Investment	Notes Receivable (A)
SUBSIDIARIES CONSOLIDATED:								
(All issues are common stock)								
Cambridge Electric Light Company	200 600	$ 25 417	$ 1 911	$13 000(B)	$ 1 904	304 600	$ 38 424	$ -
COM/Energy Steam Company	25 500	3 211	1 053	-	1 045	25 500	3 219	-
Canal Electric Company	1 523 200	103 987	13 850	-	-	1 523 200	117 837	7 900
Commonwealth Gas Company	1 832 000	66 939	12 386	-	12 824	1 832 000	66 501	-
Dervel Realty Trust	26	1 698	411	-	818	26	1 291	-
COM/Energy Freetown Realty	1	646	(96)	-	-	1	550	-
COM/Energy Research Park Realty	1	787	473	-	470	1	790	-
COM/Energy Cambridge Realty	1	66	29	-	-	1	95	-
COM/Energy Acushnet Realty	1	467	74	-	53	1	488	-
COM/Energy Services Company	3 250	325	49	-	49	3 250	325	-
Commonwealth Electric Company	1 106 472	85 678	11 214	40 000(B)	9 549	1 606 472	127 343	-
Hopkinton LNG Corp.	5 000	3 678	615	-	550	5 000	3 743	-
		$292 899	$41 969	$53 000	$27 262		$360 606	$ 7 900
OTHER INVESTMENTS:								
(Accounted for by the equity method)								
Nuclear Electric Power Companies	52 654	$ 9 426	$ 1 367	$ -	$ 1 409	52 654	$ 9 384	
Hydro-Quebec Phase II	-	-	-	3 359(C)	-	137 442	3 359	
Other Investments	-	1 409	(349)	-	-	-	1 060	
		$ 10 835	$ 1 018	$ 3 359	$ 1 409		$ 13 803	

NOTES: (A) Notes are written for eleven months and twenty-nine days. Interest is at the prime interest rate and is adjusted for changes in the rate during the term of the notes.

(B) Additional investment.

(C) Initial investment.

COMMONWEALTH ENERGY SYSTEM AND SUBSIDIARY COMPANIES
PROPERTY, PLANT AND EQUIPMENT (A)
FOR THE YEAR ENDED DECEMBER 31, 1991

Classification	Balance Beginning of Year	Additions at Cost	Retirements Charged to Reserve	Retirements Charged to Other	Transfers	Balance End of Year
	(Dollars in Thousands)					
ELECTRIC						
Intangible plant	$ 2 208	$ 179	$ -	$ -	$ -	$ 2 387
Land and rights of way	9 947	12	-	1	163	10 121
Structures and leasehold improvements	133 436	675	(16)	-	(50)	134 077
Production equipment	310 464	3 861	1 054	-	(75)	313 196
Transmission equipment	103 466	3 157	336	-	1	106 288
Distribution equipment	363 728	31 233	4 123	-	(28)	390 810
Nuclear fuel in reactor	8 598	4 182	-	-	-	12 780
General equipment, vehicles, and other	11 434	472	238	-	(4)	11 664
Total plant in service	943 281	43 771	5 735	1	7	981 323
Construction work in progress	10 623	1 211	-	-	(95)	11 739
Nuclear fuel in process	5 655	(3 341)	-	-	247	2 561
Total electric	959 559	41 641	5 735	1	159	995 623
GAS						
Intangible plant	1 392	-	-	-	-	1 392
Land and rights of way	979	-	-	-	-	979
Structures and leasehold improvements	12 463	598	131	-	1	12 931
Production equipment	-	-	-	-	-	-
Distribution equipment	253 021	16 606	1 772	-	-	267 855
General equipment and vehicles	1 918	72	120	-	(1)	1 869
Total plant in service	269 773	17 276	2 023	-	-	285 026
Construction work in progress	678	(165)	-	-	-	513
Total gas	270 451	17 111	2 023	-	-	285 539
OTHER						
Steam heating equipment	4 727	305	6	-	-	5 026
Gas liquefaction facility	34 112	1 098	50	-	-	35 160
Miscellaneous physical property (B)	35 321	891	18	9	(21 981)	14 204
Total plant in service	74 160	2 294	74	9	(21 981)	54 390
Construction work in progress	271	(28)	-	-	-	243
Total other	74 431	2 266	74	9	(21 981)	54 633
Total Property, Plant and Equipment	$1 304 441	$ 61 018	$7 832	$ 10	$(21 822) (C)	$1 335 795

(A) Refer to Note 1 of Notes to Financial Statements for depreciation method and rates.
(B) Principally real estate.
(C) Freetown project write-down.

SCHEDULE V

COMMONWEALTH ENERGY SYSTEM AND SUBSIDIARY COMPANIES
PROPERTY, PLANT AND EQUIPMENT (A)
FOR THE YEAR ENDED DECEMBER 31, 1990

Classification	Balance Beginning of Year	Additions at Cost	Retirements Charged to Reserve	Retirements Charged to Other	Transfers	Balance End of Year
	(Dollars in Thousands)					
ELECTRIC						
Intangible plant	$ -	$ 2 208	$ -	$ -	$ -	$ 2 208
Land and rights of way	9 689	255	-	1	4	9 947
Structures and leasehold improvements	57 676	76 258	507	-	9	133 436
Production equipment	155 163	156 975	1 653	-	(21)	310 464
Transmission equipment	96 617	6 843	133	-	139	103 466
Distribution equipment	334 292	36 593	7 030	-	(127)	363 728
Nuclear fuel in reactor	-	8 598	-	-	-	8 598
General equipment, vehicles, and other	8 430	3 085	81	-	-	11 434
Total plant in service	661 867	290 815	9 404	1	4	943 281
Construction work in progress	252 209	(241 586)	-	-	-	10 623
Nuclear fuel in process	-	5 655	-	-	-	5 655
Total electric	914 076	54 884	9 404	1	4	959 559
GAS						
Intangible plant	-	1 392	-	-	-	1 392
Land and rights of way	979	-	-	-	-	979
Structures and leasehold improvements	12 063	444	44	-	-	12 463
Production equipment	357	-	357	-	-	-
Distribution equipment	228 219	27 275	2 473	-	-	253 021
General equipment and vehicles	1 892	162	136	-	-	1 918
Total plant in service	243 510	29 273	3 010	-	-	269 773
Construction work in progress	2 888	(2 210)	-	-	-	678
Total gas	246 398	27 063	3 010	-	-	270 451
OTHER						
Steam heating equipment	4 524	244	41	-	-	4 727
Gas liquefaction facility	33 117	1 487	492	-	-	34 112
Miscellaneous physical property (B)	33 452	2 063	83	107	(4)	35 321
Total plant in service	71 093	3 794	616	107	(4)	74 160
Construction work in progress	(3)	274	-	-	-	271
Total other	71 090	4 068	616	107	(4)	74 431
Total Property, Plant and Equipment	$1 231 564	$ 86 015	$13 030	$ 108	$ -	$1 304 441

(A) Refer to Note 1 of Notes to Financial Statements for depreciation method and rates.

(B) Principally real estate.

COMMONWEALTH ENERGY SYSTEM AND SUBSIDIARY COMPANIES
PROPERTY, PLANT AND EQUIPMENT (A)
FOR THE YEAR ENDED DECEMBER 31, 1989

Classification	Balance Beginning of Year	Additions at Cost	Retirements Charged to Reserve	Retirements Charged to Other	Transfers	Balance End of Year
	(Dollars in Thousands)					
ELECTRIC						
Land and rights of way	$ 9 526	$ 144	$ -	$ -	$ 19	$ 9 689
Structures and leasehold improvements	50 728	7 046	98	-	-	57 676
Production equipment	154 257	1 145	239	-	-	155 163
Transmission equipment	88 009	28 798	223	-	33	96 617
Distribution equipment	299 741	38 841	4 057	-	(33)	334 292
General equipment, vehicles, and other	7 812	651	31	-	(2)	8 430
Total plant in service	590 073	76 425	4 648	-	17	661 867
Construction work in progress	252 517	(308)	-	-	-	252 209
Total electric	842 590	76 117	4 648	-	17	914 076
GAS						
Land and rights of way	979	-	-	-	-	979
Structures and leasehold improvements	9 158	2 933	28	-	-	12 063
Production equipment	357	-	-	-	-	357
Distribution equipment	207 513	22 342	1 636	-	-	228 219
General equipment and vehicles	1 706	216	30	-	-	1 892
Total plant in service	219 713	25 491	1 694	-	-	243 510
Construction work in progress	3 990	(1 102)	-	-	-	2 888
Total gas	223 703	24 389	1 694	-	-	246 398
OTHER						
Steam heating equipment	4 246	319	41	-	-	4 524
Gas liquefaction facility	32 516	603	2	-	-	33 117
Miscellaneous physical property (B)	30 703	2 859	86	7	(17)	33 452
Total plant in service	67 465	3 781	129	7	(17)	71 093
Construction work in progress	9	(12)	-	-	-	(3)
Total other	67 474	3 769	129	7	(17)	71 090
Total Property, Plant and Equipment	$1 133 767	$104 275	$6 471	$ 7	$ -	$1 231 564

(A) Refer to Note 1 of Notes to Financial Statements for depreciation method and rates.
(B) Principally real estate.

COMMONWEALTH ENERGY SYSTEM AND SUBSIDIARY COMPANIES

ACCUMULATED DEPRECIATION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT

FOR THE YEARS ENDED DECEMBER 31, 1991, 1990 AND 1989

(Dollars in Thousands)

		Provision							
Classification	Balance at Beginning of Year	Charged to Operations	Nuclear Fuel Expense	Clearing Accounts and Other Income	Amortization of Leasehold Improvements	Retirements	Removal Cost	Salvage	Balance at End of Year
				YEAR ENDED DECEMBER 31, 1991					
Electric	$251 742	$32 869	$3 823	$ -	$ 481	$5 735	$3 439	$ 270	$280 011
Gas	60 720	7 910	-	-	835	2 023	1 084	31	66 389
Other	25 592	1 172	-	300	-	74	403	-	26 587
Total Accumulated Depreciation and Amortization	$338 054	$41 951	$3 823	$300	$1 316	$7 832	$4 926	$ 301	$372 987
				YEAR ENDED DECEMBER 31, 1990					
Electric	$232 407	$26 210	$2 251	$ -	$ 219	$ 9 404	$3 327	$3 386	$251 742
Gas	57 744	7 340	-	-	608	3 010	1 918	(44)	60 720
Other	25 856	1 099	-	228	-	616	975	-	25 592
Total Accumulated Depreciation and Amortization	$316 007	$34 649	$2 251	$228	$ 827	$13 030	$6 220	$3 342	$338 054
				YEAR ENDED DECEMBER 31, 1989					
Electric	$217 037	$22 023	$ -	$ 15	$ 39	$4 648	$3 083	$1 024	$232 407
Gas	53 666	6 686	-	-	460	1 694	1 309	(65)	57 744
Other	24 971	1 060	-	172	-	129	218	-	25 856
Total Accumulated Depreciation and Amortization	$295 674	$29 769	$ -	$187	$ 499	$6 471	$4 610	$ 959	$316 007

COMMONWEALTH ENERGY SYSTEM AND SUBSIDIARY COMPANIES

VALUATION AND QUALIFYING ACCOUNTS

FOR THE YEARS ENDED DECEMBER 31, 1991, 1990 AND 1989

Description	Balance Beginning of Year	Additions: Provision Charged to Operations	Additions: Recoveries	Deductions: Accounts Written-Off	Balance at End of Year
Allowance for Doubtful Accounts		Year Ended December 31, 1991			
	$4 506	$10 943	$2 042	$12 258	$5 233
		Year Ended December 31, 1990			
	$4 278	$ 8 823	$1 256	$ 9 851	$4 506
		Year Ended December 31, 1989			
	$2 455	$ 7 506	$1 753	$ 7 436	$4 278

SCHEDULE IX

COMMONWEALTH ENERGY SYSTEM
AND SUBSIDIARY COMPANIES

SHORT-TERM BORROWINGS (A)

FOR THE YEARS ENDED DECEMBER 31, 1991, 1990 and 1989

(Dollars in Thousands)

Category of Aggregate Short-Term Borrowings	Balance at End of Period	Weighted Average Interest Rate at End of Period	Maximum Amount Outstanding During the Period	Average Amount Outstanding During the Period (B)	Weighted Average Interest Rate During the Period (C)
Notes Payable to Banks					
	Year Ended December 31, 1991				
	$145 800	5.5%	$150 875	$120 567	6.3%
	Year Ended December 31, 1990				
	$118 425	8.9%	$194 650	$162 563	8.5%
	Year Ended December 31, 1989				
	$153 275	9.3%	$213 275	$186 360	9.6%

(A) Refer to Note 5 of Notes to Financial Statements filed under Item 8 of this report for the general terms of notes payable to banks.

(B) The average amount outstanding during the period is determined by averaging the level of month-end principal balances outstanding using a rolling thirteen-month period through December 31.

(C) The weighted average interest rate during the period is determined by averaging the interest rates in effect on all loans transacted for the twelve-month period ended December 31.

COMMONWEALTH ENERGY SYSTEM

FORM 10-K DECEMBER 31, 1991

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.

COMMONWEALTH ENERGY SYSTEM
(Registrant)

By: WILLIAM G. POIST
William G. Poist, President 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 date indicated.

Principal Executive Officer:

WILLIAM G. POIST — March 26, 1992
William G. Poist,
President and Chief Executive Officer

Principal Financial Officer:

R. D. WRIGHT — March 26, 1992
Russell D. Wright,
Financial Vice President and Treasurer

Principal Accounting Officer:

JOHN A. WHALEN — March 26, 1992
John A. Whalen,
Comptroller

A majority of the Board of Trustees:

R. E. SIEGFRIED — March 26, 1992
Robert E. Siegfried, Chairman of the Board

WILLIAM G. POIST — March 26, 1992
William G. Poist, Trustee

B. L. FRANCIS — March 26, 1992
Betty L. Francis, Trustee

SIGNATURES
(Continued)

HENRY DORMITZER Henry Dormitzer, Trustee	March 26, 1992
SHELDON A. BUCKLER Sheldon A. Buckler, Trustee	March 26, 1992
FRANKLIN M. HUNDLEY Franklin M. Hundley, Trustee	March 26, 1992
CALVIN SIEGAL Calvin Siegal, Trustee	March 26, 1992
SINCLAIR WEEKS, JR. Sinclair Weeks, Jr., Trustee	March 26, 1992
G. L. WILSON Gerald L. Wilson, Trustee	March 26, 1992

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation by reference in this Form 10-K of our report dated February 26, 1992 appearing in Exhibit A to the proxy statement for the 1992 annual meeting of shareholders and the incorporation of our reports included and incorporated by reference in this Form 10-K into the System's previously filed Registration Statements on Form S-8 File No. 33-28435 and on Form S-3 File No. 33-44161.

ARTHUR ANDERSEN & CO.

Boston, Massachusetts,
March 27, 1992.