COMMONWEALTH ENERGY SYSTEM

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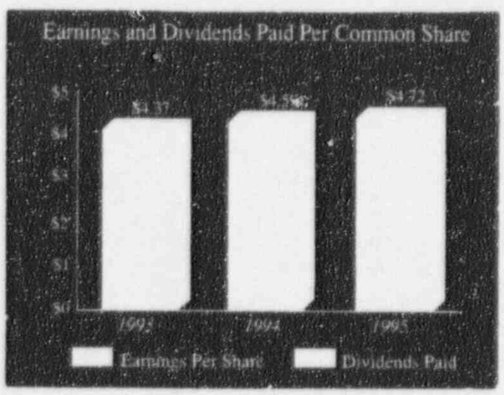
Summary Annual Report



COMEnergy®

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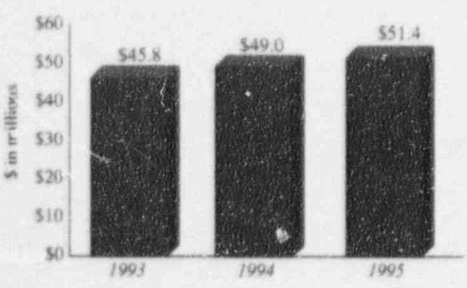
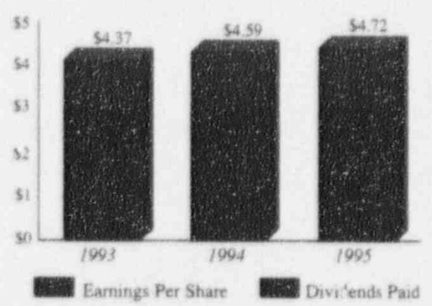
Comparative Highlights

	1995	1994	%
FINANCIAL DATA (in millions)			
Operating Revenue	**$931.4**	$979.2	(4.9)
Other Operation and Maintenance	**$238.8**	$244.0	(2.2)
Operating Income	**$96.6**	$93.5	3.4
Net Income	**$51.4**	$49.0	5.0
OPERATING DATA			
Customers Served			
Electric	**359,000**	357,000	0.5
Gas	**233,000**	232,000	0.4
Unit Sales			
Electric (MWH)			
Retail	**4,647,840**	4,621,209	0.6
Wholesale	**1,973,543**	3,803,786	(48.1)
Gas (MMBTU)			
Firm	**38,458**	38,539	(0.2)
Interruptible and Other	**7,164**	8,815	(18.7)
Transportation Volume	**4,024**	2,208	2.2
Regular Employees	**2,096**	2,169	(3.4)
COMMON SHARE DATA			
Earnings	**$4.72**	$4.59	2.8
Dividends Paid	**$3.00**	$2.98	0.7
Dividend Rate at End of Year	**$3.00**	$3.00	—
Closing Price Range	**$47⅛–$35⅜**	$45½–$35⅛	—
Closing Price at End of Year	**$44¾**	$36⅛	23.0
Average Shares Outstanding	**10,655,918**	10,413,781	2.3
Book Value	**$36.30**	$34.49	5.2
Dividend Payout Ratio	**63.6**	64.9	(2.0)
Price/Earnings Ratio	**9.5**	7.9	20.3

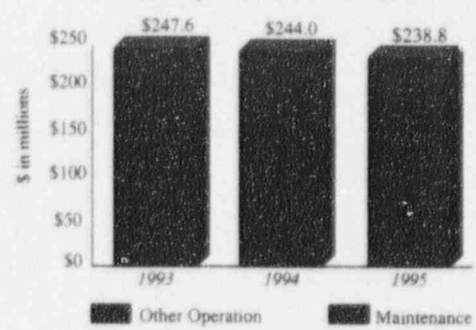
Net Income



Earnings and Dividends Paid Per Common Share



Other Operation and Maintenance



Please note that detailed financial statements and other information, prepared in accordance with the rules and regulations of the Securities and Exchange Commission, are included in Exhibit A of the 1996 Proxy Statement.

Printed with soybean ink on recycled paper to preserve our environment and natural resources.

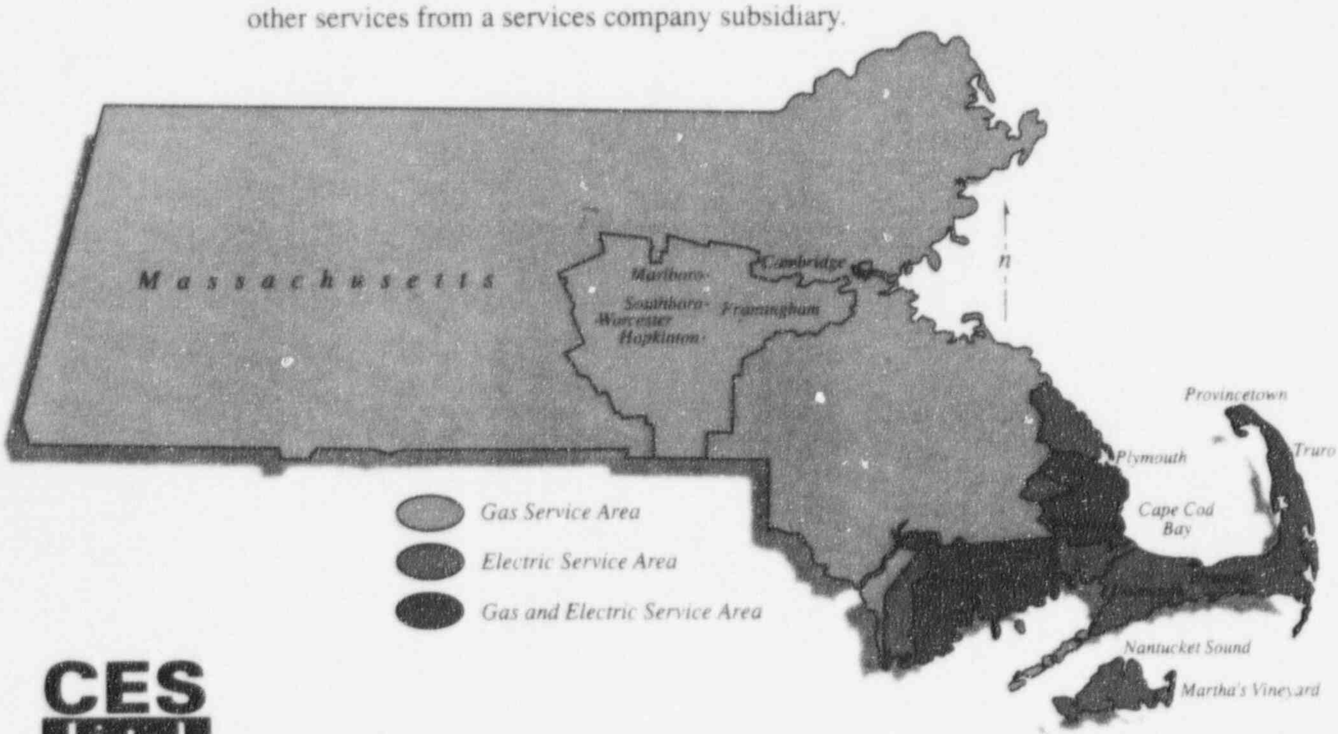
System Profile

Commonwealth Energy System is an exempt public utility holding company with investments in four operating public utility companies located in central, eastern and southeastern Massachusetts.

System electric operations are involved in the production and sale of electricity in 41 communities including New Bedford, Plymouth, Cambridge and the geographic area comprising Cape Cod. Gas operations serve 49 communities including New Bedford, Cambridge, Plymouth and Worcester.

In addition to the utility companies, the system includes a steam distribution company, five real estate trusts and a company engaged in the operation of LNG facilities. The retail electric subsidiaries receive a portion of their capacity and energy requirements from the system's ownership interests in four operating nuclear electric generating facilities and one oil-fired unit.

The System is a business trust organized in 1926 under the laws of Massachusetts. 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 services company subsidiary.



CES Listed NYSE
THE NEW YORK STOCK EXCHANGE

To Our Shareholders

We are pleased to report to you that 1995 was another excellent year for Commonwealth Energy System.

In this summary annual report for 1995, we will be using a new format of questions and answers that address the issues and concerns most often raised throughout the year by shareholders and the investment community.

Q. How did COM/Energy do in 1995?

A. The year 1995 was very positive for Commonwealth Energy System and I am proud of the results we achieved:

> "The results of our efforts will be a stronger Commonwealth Energy System that will truly prosper through change."
>
> William G. Poist
> President and CEO

- Earnings per common share for 1995 were $4.72, an increase of 13 cents or 2.8% from the $4.59 attained in 1994 and the highest year-end level since 1984.

- Net income for the year was $51.4 million, the highest we have ever reported.

- Return on average common equity was 13.3%, far exceeding the average for the industry.

- The market price per common share closed 1995 at $44.75 per share, an increase of 23% when compared to a $36.38 close in 1994. This price appreciation together with the $3.00 annualized common dividend per share resulted in a total return to shareholders of approximately 33% assuming the reinvestment of dividends.

- Our cash flow per share of $9.75 for the year exceeded the dividend payment by more than three times.

- The system's capital structure continued to improve as long-term debt was reduced to 47% of total capitalization, compared to 51% last year.

- COM/Energy Services Company is being redesigned to offer market-priced services to our operating companies and external clients.

- The first of a number of planned new alliances was developed with A&C Enercom, Inc. to provide residential customers in a broad geographical area appliance service and replacement contracts, energy management and a host of related products and services.

Beyond these strong achievements, COM/Energy made important strides in the regulatory and environmental arenas in 1995, both of which will be discussed in our report on our gas and electric divisions.

Q. What is COM/Energy's policy on common dividends?

A. During 1995 COM/Energy paid a quarterly dividend of 75 cents per share, which equates to an annual dividend rate of $3.00, and a dividend payout ratio of 63.3%. In fact, COM/Energy has been rock-solid in paying dividends...without a decrease...in every quarter since 1947. The most recent dividend paid to shareholders, on February 1, 1996, was the

195th in a row, which I believe is quite an accomplishment considering the changes the utility industry has gone through over the past 50 years.

Over the last five years, the dividend has been increased twice, earnings have continued to increase and the system's overall financial condition has improved. Although past financial performance is no guarantee for the future, it does lay a solid foundation for progress and growth. The Board of Trustees will continue to review the system's financial performance and other factors influencing the rate of dividends paid and is committed to dividend growth and enhanced shareholder value.

William G. Poist
President and Chief Executive Officer

Q. How will COM/Energy be affected by the restructuring of the electric industry?

A. Efforts now underway to restructure the electric industry in Massachusetts may have a significant impact on the way our electric division does business. The electric division contributed roughly 60 percent of the system's net profit in 1995. Despite these potential changes, I believe that we will be a stronger and better managed business because of it, providing even greater value to our shareholders.

Through March 1996 (when this report was published) the Massachusetts Department of Public Utilities had received restructuring plans or comments from five electric utilities, although it had requested plans from only the three largest companies by February 16, 1996. COM/Electric's plan is required for submission by late summer 1996.

In this process, our electric division, COM/Electric, submitted brief comments that we labeled the "Competitive Challenge," that suggested a concept for our companies that would allow us to sell 100 percent of our 21 power capacity entitlements (including entitlements with our own Canal Electric Company). In turn, our customers would be free to buy their power in a fully competitive market from whomever they chose, and we would focus our efforts as a local electric distribution company to provide top-notch distribution, customer services, and a host of new energy-related products and services.

In selling our entitlements through an auction, a true market-based value would be established for the contracts, with any difference treated as a "stranded cost" that would be assumed by the electric customer.

This proposal would make us the first utility in the state to voluntarily provide customers with the type of competitive choice Massachusetts hopes to ultimately achieve in its utility regulations. At the same time, it allows the opportunity to remove ourselves from a portion of the business which provides only a pass-through of costs from power generator to customers and returns nothing to shareholders.

By selling our entitlements, we will become a stronger system because we shed billions of dollars in long-term contractual obligations for the years that some of these contracts are in effect.

A more detailed description of our "Competitive Challenge" is included in our discussion of the electric division.

Q. What is your experience with stranded costs?

A. In 1995, the DPU ruled that one of Cambridge Electric Light Company's largest customers, the Massachusetts Institute of

Technology, was obligated to pay for the costs and obligations we incurred on MIT's behalf, when its on-site cogeneration unit went on line and it substantially left the Cambridge Electric system.

The DPU's decision requires that we further address the issue of MIT's stranded costs in our restructuring plan, required for submission by late summer and that we explain the steps we have taken to mitigate the loss of MIT as a customer.

In the meantime, MIT took the issue to the Federal Energy Regulatory Commission (which ruled in February that the state had the right to impose a customer transition charge) and to the Massachusetts Supreme Judicial Court.

We are very heartened that the FERC upheld the DPU's ruling regarding recovery of stranded costs and are optimistic that its decision will be upheld in the appeals process. In our view, the DPU has clearly recognized the rights of host utilities and the regulatory compact which has existed and it has set the stage for the recovery of all stranded costs.

Q. Where are we going and what are we doing to get us there?

A. At last year's annual meeting we talked about our plans to embark on a program we called "Prosperity Through Change." It is an aggressive program which will both strengthen the competitive position of our regulated core companies and create new opportunities in the unregulated arena that will provide greater shareholder value.

Our core businesses—gas and electric—are working hard to meet the needs of their customers, develop new products and services, cut operating costs, improve their competitive position, and prepare to take advantage of regulatory changes.

In developing new businesses, we are pursuing opportunities in the industry we know best—energy—and our focus is on unregulated energy endeavors. To aid us in this effort, this year we established a new corporate structure that allows us to take full advantage of our experience in the gas and electric business while better supporting the creation of new, fully-competitive, market-driven companies. Our aim is to ensure that everything we do is profitable in its own right and can contribute to the profitability of other System companies.

Our approach to new business development is to forge alliances with other companies. The first of these new alliances, I am pleased to report to you, is with A&C Enercom, Inc., a subsidiary of Virginia Power and Light, to provide customers in a wide geographic area with service contracts, energy management, power quality and reliability services, and a host of other related products and services. The development of other strategic alliances are in the works.

Also in the category of new business development is the re-design of COM/Energy Services Company. Over the years it has done outstanding work on behalf of our regulated businesses, but like those businesses, if it is to survive, it too must now redefine itself to become more cost-effective, more competitive and smarter in the way it does business. Our goal is to reshape the Services Company to provide high-quality, market-priced services both to our operating companies as well as to a host of external clients.

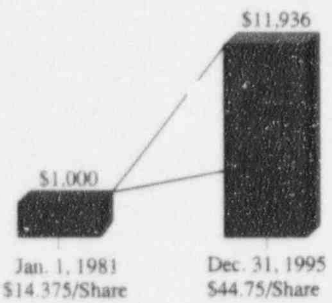
Michael P. Sullivan (left), vice president, secretary and general counsel; Leonard R. Devanna (center), vice president systems, planning and development; and James D. Rappoli (right), financial vice president and treasurer; are part of the policy-setting Management Committee. Other members of the committee are William G. Poist, president and chief executive officer; Russell D. Wright, president and chief operating officer, COM/Electric; and Kenneth M. Margossian, president and chief operating officer, COM/Gas.

Our efforts are getting results. We have restructured the Services Company appointing Mr. John Whalen as Vice President and General Manager. Mr. Whalen was formerly the System comptroller. We have started to seek an array of contracts in the unregulated arena. Our work has just begun but we envision that the Services Company will be able to provide a valuable resource to our companies and enhance value to our shareholders.

We believe that the results of our efforts in the regulated and unregulated environments will be a stronger, more valuable Commonwealth Energy System.

Q. Why should an investor consider COM/Energy?

CES Stock Performance
Fifteen-Year Result of a $1,000 Investment



Assumes investment on the last trading day of 1980 and reinvestment of dividends

A. One of the major attractions an investor may consider when looking at COM/Energy is our tremendous track record of quarterly dividend payments. Our overall total return has also been quite impressive.

As an example, an investor who purchased $1,000 in COM/Energy common shares at the close of 1980 has benefited from a fifteen-year compounded annual rate of return of nearly 18%. Assuming the reinvestment of quarterly dividends, at the end of 1995, that $1,000 investment has grown to be worth nearly $12,000.

We believe that a shareholder should consider the diversity of the system as a real strength. Because we operate in three energy markets—electric, gas and steam—an investor in Commonwealth Energy System gets an electric company as well as a gas company to provide stability. Also, an investor should be impressed with our plans and efforts to successfully compete in the ever changing regulated and unregulated energy markets. We are formulating and implementing plans which will not only ensure our successful transition into the new world of competition but strengthen our position in the distribution of gas, electricity, and steam.

In closing, we are confident that as competition comes knocking, our experience and talents are ready for the challenge. We believe that the results of our efforts will be a stronger Commonwealth Energy System...more efficient, better managed, and more diversified than ever...that will truly prosper through change.

We extend our thanks to you, our shareholders, for your confidence and continued support of Commonwealth Energy System.

Sincerely,

William G Poist

William G. Poist
President and Chief Executive Officer

Electric Operations

Q. What is COM/Electric's position on electric industry restructuring?

A. On February 15, we presented our preliminary comments to the Massachusetts Department of Public Utilities (DPU) outlining a vision for restructuring which we called the "Competitive Challenge." This vision is dramatic and is the result of many discussions with industry representatives, government officials and customers.

Our "Competitive Challenge" proposes auctioning all 1,140 megawatts of power capacity entitlements held in 21 contracts by both Commonwealth Electric Company and Cambridge Electric Light Company. The entitlements would be sold on the open market, subsequently allowing our customers to purchase electricity from any supplier of their choice at market prices. We would still continue to provide our service territory with distribution, customer service and marketing activities.

Russell D. Wright
President and Chief Operating Officer

In making this proposal, COM/Electric is in a unique position in relation to other electric utilities in Massachusetts in that nearly 100 percent of the electricity our distribution companies sell to customers is bought from other companies. This "purchased power" is relatively expensive and provides no additional return to shareholders.

We anticipate that our proposal will allow our customers to achieve lower electric rates through the purchase of power on the open market. It will also protect our shareholders by simplifying the issue of stranded costs (see page 11 for additional discussion of deregulation issues). Part of our proposal includes 100 percent recovery of the difference between the current market value of our power contracts and their original costs. Recovery would be made through an access charge paid over time by all customers in our franchise area.

COM/Electric's "Competitive Challenge" has received positive reviews from several state regulators, including Massachusetts Attorney General Scott Harshbarger who praised the company for taking a "bold step." He commended COM/Electric for "stepping up to the plate and proposing that the market determine the amount, if any, of its costs that are stranded by allowing consumers to freely choose suppliers of electric power."

Q. What is COM/Electric doing to lower operating costs to improve its competitive position?

A. Three years ago, COM/Electric began an aggressive cost-cutting program, which to date, has included a reduction in our work force of over 10 percent; the closing of five of our district offices as well as our Cannon Street power station; consolidating management functions; renegotiating or canceling several power purchase contracts; and, stabilizing the fuel charge portion of Commonwealth Electric customers' bills for a three-year period. In May 1995, we received approval to reduce Commonwealth Electric's residential rates by $2.7 million per year through a settlement agreement with the state Attorney General's office.

Other examples of our cost savings measures include:

- Decreasing our annual construction expenditures from approximately $50 million to $25 million.
- Marketing our excess power—saving $2 million per year.
- Receiving approval from the DPU on a settlement agreement that allows reduced spending on conservation measures during the restructuring of the electric utility industry.
- Negotiating cost-saving labor contracts.
- Cutting the total value of our inventories from $8 million to under $4 million through use of advanced computerized inventory control systems and innovative partnerships with suppliers.

In response to a request for help in lowering their electric bills, COM/Electric was able to offer the makers of Chatham Village croutons in Wareham, Massachusetts a money-saving economic development rate.

Q. What growth potential exists in the COM/Electric service area?

A. Recognizing that our fortunes are closely tied to the economy of the regions we serve, we've undertaken a number of initiatives to attract business to the area and help those already here to expand.

These initiatives include working with regional economic development councils to develop a marketing brochure and companion video to promote our area as an ideal place for business to prosper. We are also working closely with local, state and federal officials, civic groups and individual customers to bring additional development to the New Bedford area, which is the heart of our industrial sales. This area has enormous potential and is very receptive to new business. Plans for an expanded airport are being developed to complement the city's free trade zone. A new commuter rail line to Boston is also on the drawing board, along with a new aquarium, and as a major boost to the region, a new casino/entertainment complex and a host of spin-off businesses.

Recently, we successfully completed the first part of a broader program to sell a range of products and services to residential customers. We're also using our expertise in the commercial and industrial area to market products and services such as surge protectors, power factor correction and power system analysis.

Our efforts have also focused on maximizing our existing assets. These efforts have included renting space on our radio towers to communications companies and selling rights, nationwide, to our Work Management Information System (WMIS) which was designed by our employees to streamline our customer work flow.

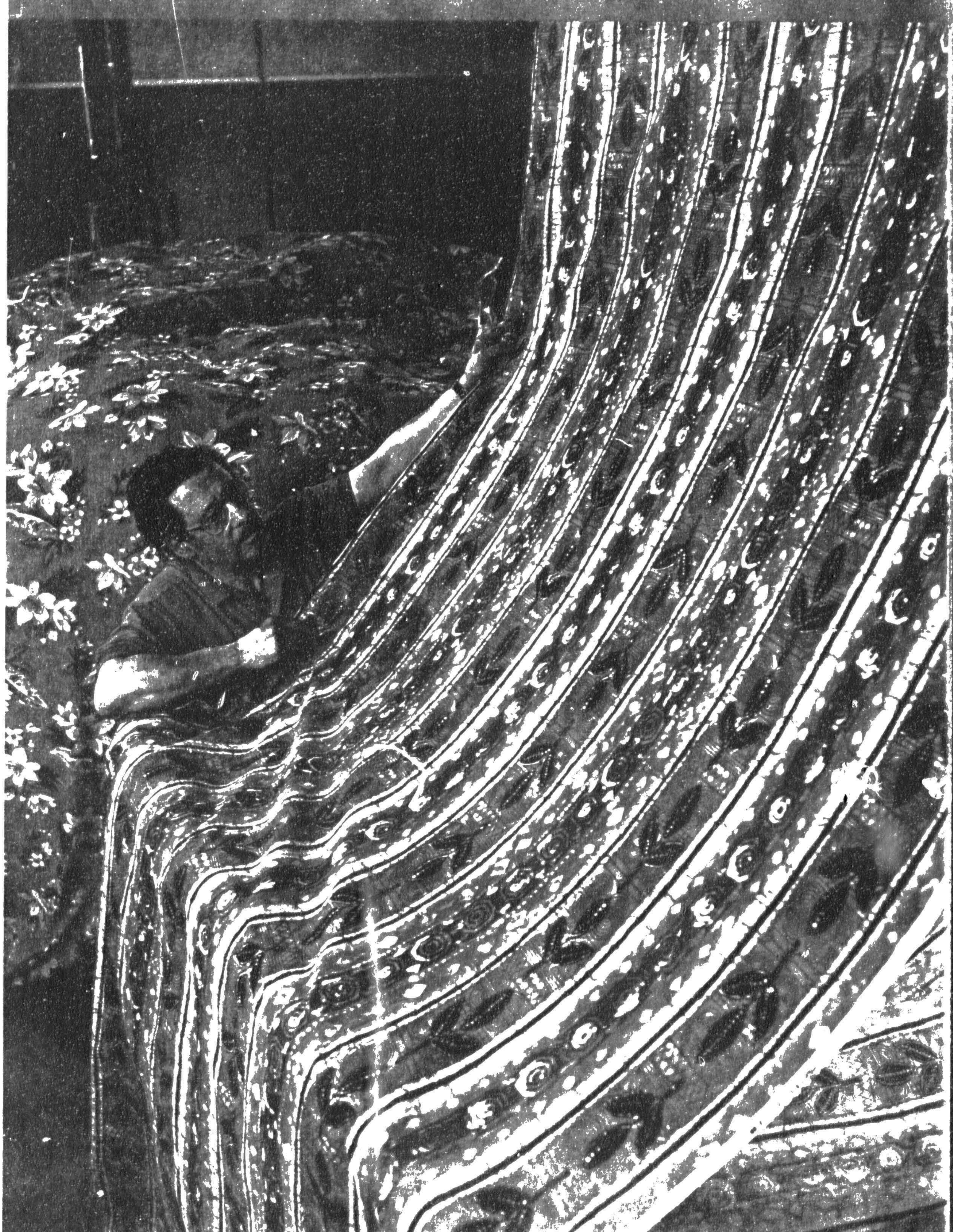
COM/Energy Steam Company, a non-regulated affiliate of COM/Electric, continues to achieve very positive results, enjoying another record year, both in revenue and steam output. We continue to strive to provide high-quality service to our steam customers, and are exploring every opportunity to expand our steam sales into new markets.

Q. What is COM/Electric doing to improve service and reliability for its customers?

A. Despite our continued focus on cost containment, we undertook a number of projects to ensure that our service and reliability continue to excel. Here's what we've done in 1995:

- Increased reliability and capacity of our transmission system with an upgrade of a portion of our 115 KV transmission line. By accelerating our design work, we were able to take full advantage of a lull in construction activities to reduce costs.
- Completely updated our SCADA (System Control and Data Acquisition) control center.

With help from COM/Electric, Brittany Dye & Printing of New Bedford was able to apply for a $500,000 grant from the Department of Energy to explore using new electric technologies in the drying of textiles.



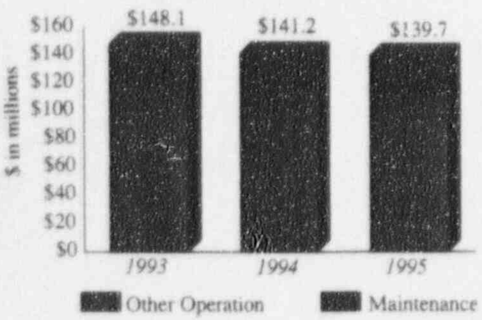
When Sea Watch International, one of the world's largest specialty seafood processors, was considering locating a new plant, COM/Electric provided the technical assistance and competitive rates they needed to come to New Bedford.

All new hardware and software gives us vastly improved flexibility and allows us to be ready for our future needs. A new trouble call system linked with the new SCADA system will be a big help for customer services, identifying outage problems and enabling our line crews to begin repairs faster.

- Redesigned our customers' bills to be easier to understand and show customer-friendly information about rates, usage and temperature comparisons.
- Implemented a convenient automatic monthly direct bill payment system, and an integrated voice response telephone system that will allow us to introduce pay-by-phone and a host of other innovative customer services.

In addition, automatic meter reading devices are now being installed in our high-cost-to-read areas—first in New Bedford and then in Cambridge. Installation of these meters will improve customer service by improving accuracy and eliminating estimated bills, while reducing operating costs.

Other Operation and Maintenance



Q. What is the company's relationship with the communities it serves?

A. Through our involvement with civic and community groups, interaction with elected officials, support of local causes, and employee involvement as community volunteers, we are committed to being the best corporate citizen possible.

A prime example is our Canal Electric plant where by burning lower sulfur oil and installing new burners and emissions monitoring equipment, we made a dramatic difference in sulfur and nitrogen emissions and greatly improved community relations along the way. This past year, we went a step further by starting a conversion process of Canal Unit 2 to clean-burning natural gas.

On the new technology front, we are working with the Union of Concerned Scientists in a research partnership involving a photovoltaic system and special, highly-efficient variable speed motors at its national headquarters in Cambridge. We helped fund a 22-passenger electric shuttle bus for the Martha's Vineyard Transit Authority which went into commercial operation on the island last summer. We are also continuing to monitor the performance of New England's first fuel cell at the U.S. Army's Soldier Systems Command in Natick, Massachusetts.

Our commitment to the community is clearly demonstrated in all our actions. Whether it's partnerships with schools, beach cleanups, seafood festivals or donating money to the United Way, our employees are quick to respond, building relationships and showing the community that we are an integral part of the 41 cities and towns we serve.

Our community support was recognized this past fall by the New Bedford Chamber of Commerce. We were inducted into the Chamber's Hall of Fame for the tremendous strides we have taken to work with our industrial customers, develop solid relationships with civic and community groups, and provide personal attention to individual residents through a wide range of employee volunteer efforts.

Restructuring of the Electric Industry

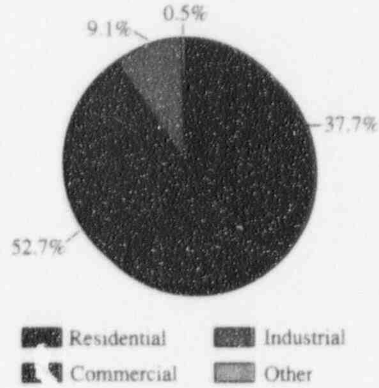
Massachusetts looks to industry restructuring, competitive choice for consumers

With all the talk of the restructuring of the electric utility industry, where does Massachusetts stand? While the debate varies from state to state with about 35 states nationwide having begun the process of revising regulations to promote competition, the DPU dramatically accelerated the process with its August 16, 1995 order outlining a schedule for Massachusetts utilities to submit individual restructuring proposals. Under the order, three utilities were required to submit their proposals by February 16, 1996. Commonwealth Electric and Cambridge Electric's formal plans are not due until the end of the summer, but we submitted comments to the DPU on February 15, 1996, outlining our innovative "Competitive Challenge" proposal.

Deborah McLaughlin, vice president of customer service, is leading COM/Electric's response to the state's electric industry restructuring challenge.

The DPU order outlined seven "Principles" that will guide a future competitive electric industry, consistent with those developed by the nearly 20 groups and agencies in the "Massachusetts Electric Industry Restructuring Roundtable." They are:

- Providing the broadest possible choice for customers;
- Ensuring that all customers share in the benefits of increased competition;
- Ensuring full and fair competition in power generation markets;
- Separating or "unbundling" generation, transmission and distribution services;
- Ensuring that all customers, including low-income customers, receive electric service;
- Supporting and furthering the goals of environmental regulation;
- Providing incentives for better utility performance.



While the principles set the ground rules for competition, there are many issues that still have to be worked out. The one that is central to the entire discussion of restructuring is the so-called "stranded costs" or commitments which utilities made in power plants and related long-term power contracts under a regulated environment to serve new and existing customers. The DPU order indicated that utilities should have a reasonable opportunity to recover stranded costs, probably through a non-bypassable access charge on customer bills.

The DPU affirmed its support of stranded cost recovery with a landmark decision on September 29, 1995 when our Cambridge Electric Light Company received approval of its proposed Customer Transition Charge (CTC) to be applied when large customers discontinue service from the company, yet remain in Cambridge.

Electric Operations

Territory:
1,112 square miles covering [illegible] communities with a population of approximately [illegible]

Electric Plant:
Capability—1,5[illegible]2.5 MW, including sales under long-term contracts with other utilities of [illegible]24.5 MW resulting in a net capability of 1,108.0 MW

Peak demand—[illegible] MW on August [illegible], 1995

On another front, the Massachusetts Legislature's Joint Committees on Energy and Government Regulations have both held hearings on the restructuring issue. As of March 1996, no comprehensive package of legislation has been proposed.

Gas Operations

Q. What were COM/Gas' financial results for 1995?

A. COM/Gas' earnings for the year increased significantly compared to 1994 despite virtually unchanged firm sales and lower revenues. Our strong performance is testimony to the aggressive cost control and improved operating procedures we have undertaken that allowed earnings to grow without the benefit of favorable weather conditions.

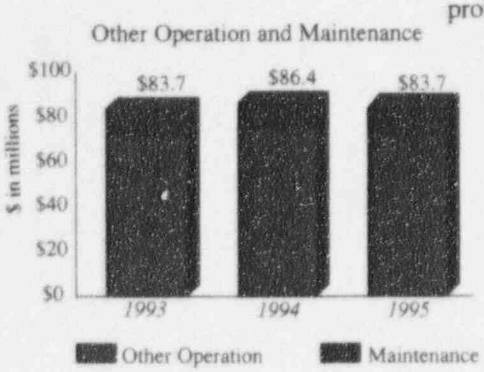
Kenneth M. Margossian
President and Chief Operating Officer

Q. How is COM/Gas reducing costs?

A. Using the customers' perspective as a guide, cross-functional employee teams are exploring every opportunity to control costs and sharpen our competitive position. These efforts include increasing organizational knowledge, streamlining operations, and offering new technologies and innovative services to increase efficiency and reduce costs. In each case, the goal is to maximize profit potential while minimizing costs.

This type of departmental interaction has resulted in meaningful reductions that would not otherwise have been possible and has allowed COM/Gas to stay a step ahead of the competition.

I am very proud of the results we have achieved. Some of our successes include:



- Reduced from ten weeks to ten days the time required to provide gas service to a new customer's home.
- Eliminated warehousing expense for our heating equipment inventory by using direct delivery from the distributor. This allows us to be more competitive in both equipment sales and gas conversions.
- Reduced our distribution and construction crews from four- to two-person crews.

In addition to the continuous improvement of our operations, we are partnering with technology to help reduce costs and enhance service wherever possible. Examples of our use of cost-effective technology include:

- Automated Meter Reading (AMR). The AMR System uses radio technology to enable us to read gas meters from a computer-equipped vehicle. This has dramatically lowered meter reading costs, improved the rate at which meters are read and enhanced customer convenience. To date, 80 percent of our meters are equipped with AMR technology and the monthly read rate has increased from 80 percent to 99.74 percent.
- Interactive Voice Response telephone technology has been put in place to help manage more than 600,000 incoming calls annually by automating certain telephone requests. Approximately 40 percent of our callers are choosing to use the system for convenient access to billing, credit and other account information 24 hours a day.

- New trenchless technologies are being used to maintain or upgrade our distribution system with a minimum of cost and disturbance. One technique employs a device known as the "Bullet" which allows us to replace old gas lines with polyethylene pipe, eliminating the need for costly, disruptive and time-consuming street excavations.

Q. What is COM/Gas doing to increase revenues?

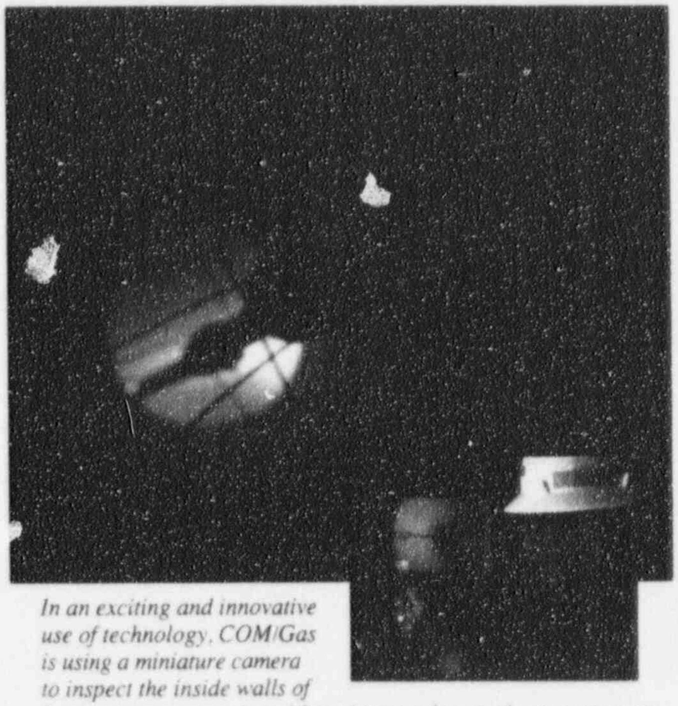
A. As part of the COM/Gas strategic plan, we identified opportunities for revenue growth that take advantage of the unique character of our company and service territory, as well as changes in state and federal regulations.

We have offered expanded service options to our customers. One example is our innovative use of quasi-firm service rates to customers capable of burning alternate fuels. Typically these are former interruptible sales customers who require gas for longer periods than the interruptible selling season allows, but less than year-round firm service. The benefit of this service is twofold: It increases the throughput by lengthening the time a customer burns gas, and, by retaining the same supplies in colder months, ensures that the Company has access to less expensive peak supply.

In another example of accessing new markets by increasing our services, we received DPU approval in December 1995 to offer firm transportation service to all of our commercial and industrial customers. We also received approval to convert our industrial rate into a demand-based rate, providing several of our major transportation rate customers with an important incentive to shift back to firm service.

In November 1995, the DPU approved our effort to scale back demand-side management and phase out non-cost-effective programs. In addition, we collected \$1.4 million for 1995 in lost margins (lost revenue associated with therms saved by conservation programs) and, in 1996, will be collecting \$2.1 million.

We have also expanded existing services such as the merchandising of water heaters and heating systems. In addition, we changed the financing of our merchandising operation, bringing it in-house and offering longer-term financing which provides benefits to our customers and improved returns for the company.



In an exciting and innovative use of technology, COM/Gas is using a miniature camera to inspect the inside walls of low pressure gas mains without interrupting service to customers or disrupting local roadways. This is one of several new trenchless technologies being used by COM/Gas to help reduce costs and improve service.

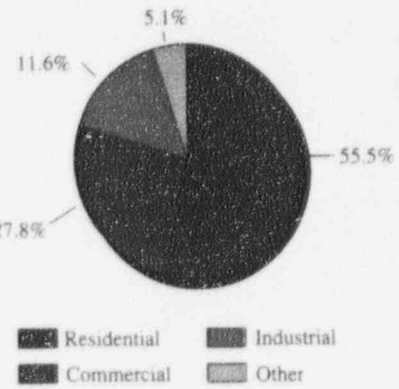
Q. What new opportunities do you see in your market for future growth?

A. The area served by COM/Gas has pockets of strong growth which continue to provide excellent potential. One of these is New England's second largest city–Worcester, Massachusetts–where nearly \$1 billion in development activity is underway including a new exit for Worcester from the Massachusetts Turnpike.

In addition, we see further growth opportunities in new technologies. Improved natural gas engine-driven cooling and absorption chillers are increasing in popularity and are desirable off-peak summer load additions. As an example of this, a team consisting of Worcester city officials and COM/Gas representatives is gradually converting the city's public schools to gas heat and air conditioning.

Natural gas vehicles for fleets

1995 Firm Gas Unit Sales



represent another small but growing market as the Clean Air Act restrictions take effect. The Gas Research Institute (GRI) chose COM/Gas for one of several LNG-to-CNG refueling sites in the country. GRI is providing partial funding of the station which we plan to have operational by the end of the year. When completed, this semi-public station will be the largest capacity station in New England. We are also exploring other opportunities to use LNG as an onboard fuel for heavy-duty commercial vehicles.

Laptop computers help COM/Gas employees streamline the process of providing gas service to a new customer's home and provide flexibility for financing residential appliances.

Last year we worked with the U.S. Army's Soldier Systems Command in Natick, Massachusetts to introduce New England's first fuel cell. Fuel cell technology uses a non-polluting chemical process with natural gas to generate electricity. We are monitoring that installation closely as in the long-term, fuel cells represent a tremendous growth opportunity.

> ***Gas Operations***
>
> **Territory:**
> 1,067 square miles covering 49 communities (including 12 served with electricity supplied by COM/Electric) with a population of approximately 1,128,000
>
> **Gas Plant:**
> *Distribution Lines*—2,778 miles
>
> *Peak day firm send-out*—350,513 MMBTU on February 6, 1995

Q. What is COM/Gas doing to maintain a low cost, reliable gas supply?

A. Our gas costs are among the lowest in Massachusetts. During 1995 we continued to drive costs down by renegotiating a good portion of our gas supply contracts. As part of the renegotiation, we reduced pipeline charges, thereby reducing overall cost.

We continue to benefit from our valuable Hopkinton LNG facility which straddles two major pipelines, giving us the ability to move gas where it is most needed at any given time.

We have added reliability and flexibility to our gas supply by purchasing pipeline capacity that was previously intended for a power plant in Pepperell, Massachusetts. This additional firm capacity allows us to move more storage gas from Steuben County, New York to our customers in a timely and economical way.

We have maintained an active presence at the Federal Energy Regulatory Commission through our participation in Associated Gas Distributors, pipeline customer groups, and by holding a key Executive Committee position on the Gas Industry Standards Board.

Q. How is COM/Gas viewed by its customers and the communities it serves?

A. Our absolute focus on customers has resulted in excellent favorability ratings. For the fifth consecutive year, we have earned the distinction of being the Massachusetts gas utility with the fewest complaints filed with the DPU.

We maintain a high visibility in the communities we serve through school education programs and school/business partnerships and sponsoring programs such as Kids' Fair in Worcester which attracts more than 17,000 parents and children.

In addition, we have a strong emphasis on volunteerism which has earned us wide-spread public recognition. I am very proud of our employees who selflessly and repeatedly donate their time and money to help those in need. Whether it is a food collection for the Salvation Army or a Christmas party for needy children, COM/Gas employees are there, making a difference in the communities where we live and work.

Macy's and COM/Gas worked together to develop the perfect energy solution—natural gas heating and air-conditioning in Macy's new 210,000 square-foot department store in the re-constructed Natick Mall in Natick, Massachusetts.


25¢
25¢

Financial Summary

Commonwealth Energy System and Subsidiary Companies

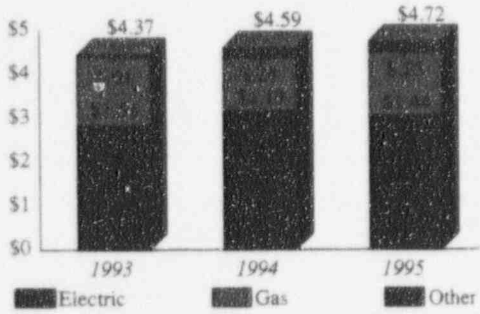
The following is a brief discussion and analysis of financial condition and results of operations for 1995. For a more detailed analysis, please refer to Exhibit A of the 1996 Proxy Statement.

Earnings and Return on Equity

1995 versus 1994

In 1995, earnings applicable to common shares increased $2.5 million or 5.2% surpassing 1994 as the highest year-end level in the System's history. The return on average common equity remained strong at 13.3%, down slightly from the 1994 return of 13.7%. Factors that contributed to the improved earnings were: (1) a $5.2 million reduction in other operation and maintenance; (2) the reversal of a reserve related to the system's electric energy conservation programs; and (3) higher steam unit sales. Partially offsetting these factors was an increase in interest charges related to deferred gas costs and higher short-term interest rates.

Earnings per share by organizational element is presented below:



Electric Operating Revenues, Fuel and Purchased Power

Electric operating revenues decreased $32.8 million (5.1%) due mainly to lower fuel oil costs ($32.6 million) reflecting a combination of scheduled maintenance and other repairs to Canal Electric Company's Unit 1 turbine, which kept the oil-fired unit out of service until August 1995. Also contributing to this decline were lower conservation and load management (C&LM) costs ($3.3 million). Somewhat offsetting these decreases was the recognition in revenues of $5.9 million pertaining to Commonwealth Electric Company's power contract buy-out and fuel charge stabilization deferral.

Retail unit sales increased due to higher sales to commercial customers reflecting increased air-conditioning load during the summer months and the increase in heating degree days during the fourth quarter. Somewhat offsetting these increases was a slight decline in residential sales caused by the extremely mild weather conditions during the first quarter of 1995 compared to the record cold experienced in 1994. The increase in retail unit sales also reflects a modest growth in customers, mainly in the residential and commercial sectors, resulting from more housing units and an improved economy. The decrease in wholesale unit sales reflects the decreased availability of Canal Unit 1. However, fluctuations in the level of wholesale sales have little, if any, impact on net income.

The $27.2 million decrease in the cost of fuel and purchased power reflects a 36% decline in fuel purchases due to the reduced consumption at Unit 1 reflecting maintenance and other repairs discussed previously. The fuel charge stabilization deferral ($3.4 million in 1995 compared to $16 million in 1994), implemented in April 1994, was favorably impacted by the successful renegotiation of a contract with an independent power producer (IPP) in early 1995 that defers power purchases for a six-year period coupled with the termination of a second long-term contract with another IPP through a buy-out arrangement.

Gas Operating Revenues and Cost of Gas Sold

Gas operating revenues decreased $16.6 million (5.1%) due mainly to an $18.3 million (10.3%) decline in the cost of gas sold that reflects a 3.7% reduction in total sales and lower C&LM costs ($910,000). Slightly offsetting these decreases were higher revenues from transportation volume and quasi-firm sales ($917,000). Quasi-firm sales are designed for customers with dual fuel capability who receive interruptible service in peak demand months and firm service in off-peak periods. Presently, these sales have no impact on net income. A portion of the margin realized on quasi-firm sales is used to reduce the cost of gas sold to firm customers and the remaining amount is deferred pending the approval of a margin-sharing proposal filed with the Massachusetts Department of Public Utilities (DPU) in December 1995. A similar proposal for off-system sales is expected to be filed in 1996.

Steam Operating Revenues

Steam operating revenues increased $1.6 million (12%) due primarily to a 10.6% increase in unit sales as a large customer expanded its operations.

Financial Summary

Commonwealth Energy System and Subsidiary Companies

Other Operation and Maintenance

Other operation and maintenance declined $5.2 million (2.2%) reflecting lower liability insurance costs ($5.4 million) resulting from adjustments to insurance accruals attributed to better than anticipated experience. This decrease also reflects lower C&LM costs ($3.3 million) and a decline in the provision for bad debts ($1 million) that resulted from improved collection experience. Somewhat offsetting these decreases were higher postretirement benefit and other labor-related costs ($2.6 million) and an increased level of maintenance costs ($1.9 million).

Depreciation, Amortization and Taxes

Depreciation and amortization increased approximately $4 million (8.1%) due to a higher level of depreciable plant-in-service primarily related to electric operations.

Total taxes declined $4.3 million (7.8%) reflecting a Seabrook-related tax adjustment that resulted from a settlement agreement, discussed later in the "Regulation" section, offset, somewhat, by a higher level of pretax income.

Other Income and Interest Charges

The expense component of other income decreased due primarily to the reversal of a reserve that had been established by Commonwealth Electric which related to certain costs associated with its energy conservation program, the recovery of which was subsequently approved by the DPU. Offsetting this decrease was the recognition of a reserve ($2.7 million, net of tax) related to a generating station that discontinued operations and the absence of the equity component of allowance for funds used during construction ($341,000).

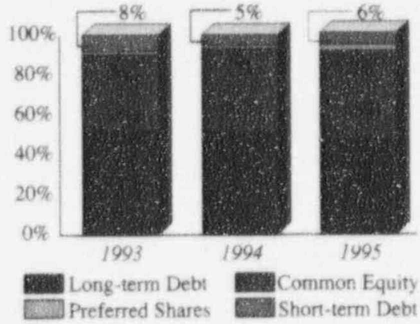
The increase in interest charges was mainly attributed to a higher level of interest on deferred gas costs ($2 million) and a rise in average short-term interest rates (6.1% for 1995 versus 4.4% in 1994). Somewhat offsetting these increases were lower interest costs related to long-term debt ($861,000) reflecting scheduled sinking fund payments and maturing long-term debt.

Capital Resources

Capital resources of the System and its subsidiaries were derived principally from retained earnings and equity funds provided through the System's Dividend Reinvestment and Common Share Purchase Plan (DRP). Effective February 1, 1996, the common share requirements of the DRP were fulfilled through open market purchases rather than the direct issue of new common shares.

Supplemental interim funds are borrowed on a short-term basis and, when necessary, replaced with new equity and/or debt issues through permanent financing secured on an individual company basis. These capital resources provide the funds required for the subsidiary companies' construction programs, current operations, debt service and other capital requirements. System companies also maintain lines of credit with banks. At December 31, 1995, short-term notes payable to banks were $55.6 million, an increase of $10.8 million (24%) over last year. However, the average level of borrowings declined 18.4% during 1995 versus 1994. Bank borrowings were used to temporarily fund construction projects and to repay maturing long-term debt ($25 million and $10 million in 1995 and 1994, respectively). The System's net cash flow from operating activities of approximately $124.7 million reflects a $25.5 million power contract buy-out between Commonwealth Electric and an IPP that will provide future cost savings for customers.

The system's capitalization structure is presented below:



The system anticipates that future capital requirements will be met primarily through internally-generated funds.

Regulation

Rate Settlement Agreements

In May 1995, the DPU approved settlement proposals sponsored jointly by Commonwealth Electric, Cambridge Electric Light Company and the Attorney General of Massachusetts which resolved issues related to cost of service, rates, accounting matters and generating unit performance reviews.

The system's management is encouraged by the support provided through the Office of the Attorney General and believes that these settlements will eliminate the need for potentially costly litigation and regulatory proceedings and, by moderating rate impacts and enabling the system to remain competitive in a changing environment, the settlements are in the best interest of the system and its customers and shareholders.

Electric Industry Restructuring

On August 16, 1995, the DPU issued an order calling for the restructuring of the electric utility industry in Massachusetts. The stated purpose of the restructuring effort is to allow customers flexibility in choosing their electric service provider and to develop an efficient industry structure and regulatory framework that minimizes long-term costs to consumers while maintaining the safety and reliability of electric services with minimum impact on the environment. The electric utility industry could ultimately be functionally separated into three segments to help meet this objective: generation, transmission and distribution.

In February 1996, certain utilities submitted required proposals detailing how they plan to move into a competitive market structure. Since that time, the DPU has given notice of a generic proceeding that will focus on many of the policy issues raised in the DPU's original order. Each of the state's electric utilities, together with other interested parties, will participate in this proceeding. The purpose of this generic proceeding is to establish a set of rules governing the restructuring of the electric industry in Massachusetts. These generic rules would set the basis for the DPU's review of each of the utility-specific restructuring proposals. Commonwealth Electric's and Cambridge Electric's (the Companies) proposal is due in September 1996. Management is unable to predict the ultimate outcome of these proceedings.

Competitive Challenge

On February 15, 1996, in response to the DPU's initial restructuring order, the Companies issued their "Competitive Challenge" by offering to voluntarily put their power generation capacity entitlements (1,140 MW) to a market test in an effort to develop a competitive market whereby customers would have the flexibility to choose their electric supplier. The proposal calls for the auctioning in a competitive market of entitlements in all twenty-one contracts, including contracts held by the Companies involving the System's generating subsidiary. The proposal provides for total recovery of the difference between the current market value of the Companies' power contracts and their original unavoidable costs. This difference, characterized as stranded costs, would be recovered through a non-bypassable access charge paid over an appropriate time period by all customers in the Companies' service area.

The auction approach has received initial positive reviews from the Commonwealth of Massachusetts Division of Energy Resources and the Office of the Attorney General.

Customer Transition Charge

In September 1995, the DPU issued a ruling largely approving four rate tariffs, including a Customer Transition Charge (CTC), that were filed by Cambridge Electric on March 15, 1995. The CTC will protect remaining customers from paying stranded costs that were incurred in the event that Cambridge Electric's largest customers discontinue full service. These costs include long-term power contracts entered into to meet projected energy requirements, investments in substations, underground and overhead lines and current and future decommissioning costs associated with nuclear plants. This ruling is believed to be the first retail stranded cost charge approved nationally and follows the aforementioned DPU restructuring order which endorsed, in principle, the recovery of stranded investment costs.

Through the CTC, Cambridge Electric will initially recover 75% of net stranded investment costs as calculated in its proposal. Cambridge Electric's other rates include a Supplemental Service Rate, a Standby Service Rate and a Maintenance Service Rate each of which were approved with only minor changes. Management is encouraged by the DPU's position on recovery of stranded investment costs and expects to address recovery of the remaining 25% in its restructuring filing.

The Massachusetts Institute of Technology (MIT), one of Cambridge Electric's largest customers, appealed the DPU's decision to the Massachusetts Supreme Judicial Court (the SJC). A decision from the SJC is pending. In addition, on February 29, 1996, the Federal Energy Regulatory Commission (FERC) denied a petition filed in January 1996 by MIT, seeking relief from paying the CTC. The FERC ruled that the CTC does not discriminate against MIT as a qualifying facility and that stranded costs are to be resolved at the state level. Management believes that the FERC's action will be an important factor that the SJC will consider in the appeal process.

Condensed Statements *of* Income

Commonwealth Energy System and Subsidiary Companies

For the Years Ended December 31,	1995	1994	1993
	(Dollars in Thousands, Except Per Share Amounts)		
OPERATING REVENUES			
Electric	**$607,047**	$639,801	$624,020
Gas	**306,953**	323,568	302,644
Steam and other	**17,355**	15,867	14,035
	931,355	979,236	940,699
OPERATING EXPENSES			
Fuel and electricity purchased for resale	**332,615**	359,832	348,836
Cost of gas sold	**158,835**	177,150	156,709
Other operation and maintenance	**238,777**	244,024	247,627
Depreciation and amortization	**54,087**	50,056	48,244
Taxes	**50,431**	54,708	51,947
	834,745	885,770	853,363
Operating Income	**96,610**	93,466	87,336
OTHER INCOME (EXPENSE)	**(606)**	(1,024)	2,449
Income Before Interest Charges	**96,004**	92,442	89,785
INTEREST CHARGES			
Long-term debt	**38,581**	39,442	37,416
Other interest charges	**6,884**	4,475	6,730
Allowance for borrowed funds used during construction	**(857)**	(443)	(195)
	44,608	43,474	43,951
NET INCOME	**51,396**	48,968	45,834
Dividends on preferred shares	**1,110**	1,170	1,230
EARNINGS APPLICABLE *to* COMMON SHARES	**$ 50,286**	$ 47,798	$ 44,604
AVERAGE NUMBER *of* COMMON SHARES OUTSTANDING	**10,655,918**	10,413,781	10,215,614
EARNINGS PER COMMON SHARE	**$4.72**	$4.59	$4.37

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

Condensed Balance Sheets

Commonwealth Energy System and Subsidiary Companies

December 31,	1995	1994
	(Dollars in Thousands)	
ASSETS		
PROPERTY, PLANT and EQUIPMENT, at original cost	**$1,515,624**	$1,444,464
Less—Accumulated depreciation and amortization	**497,627**	461,310
	1,017,997	983,154
Construction work in progress and nuclear fuel in process	**10,276**	15,974
	1,028,273	999,128
LEASED PROPERTY, net	**14,931**	15,729
EQUITY IN CORPORATE JOINT VENTURES	**13,214**	13,648
CURRENT ASSETS		
Cash	**4,319**	7,722
Accounts receivable, net	**105,377**	92,157
Unbilled revenues	**31,642**	33,161
Other current assets	**41,381**	48,250
	182,719	181,290
DEFERRED CHARGES	**150,964**	134,921
	$1,390,101	$1,344,716
CAPITALIZATION and LIABILITIES		
CAPITALIZATION		
Common share investment	**$ 390,785**	$ 362,997
Redeemable preferred shares, less current sinking fund requirements	**13,840**	14,660
Long-term debt, less current sinking fund requirements and maturing debt	**377,181**	418,307
	781,806	795,964
CAPITAL LEASE OBLIGATIONS	**13,291**	14,098
CURRENT LIABILITIES		
Interim financing—		
Notes payable to banks	**55,600**	44,850
Maturing long-term debt	**33,230**	25,000
Accounts payable	**134,908**	117,953
Accrued taxes	**31,587**	17,947
Other current liabilities	**44,510**	45,297
	299,835	251,047
DEFERRED CREDITS		
Accumulated deferred income taxes	**170,182**	160,944
Unamortized investment tax credits and other	**124,987**	122,663
	295,169	283,607
COMMITMENTS and CONTINGENCIES		
	$1,390,101	$1,344,716

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

Condensed Statements *of* Cash Flows

Commonwealth Energy System and Subsidiary Companies

For the Years Ended December 31,	**1995**	1994	1993
		(Dollars in Thousands)	
OPERATING ACTIVITIES			
Net income	**$ 51,396**	$ 48,968	$ 45,834
Effects of noncash items—			
Depreciation and amortization	**50,799**	53,727	53,088
Deferred income taxes and investment tax credits, net	**2,781**	13,376	15,559
Earnings from corporate joint ventures	**(1,633)**	(1,750)	(1,642)
Dividends from corporate joint ventures	**2,067**	1,651	1,981
Change in working capital, exclusive of cash	**24,976**	52,693	8,303
Power contract buy-out	**(25,500)**	—	—
Fuel charge stabilization deferral	**(3,447)**	(15,964)	—
Deferred postretirement benefit and pension costs	**(4,479)**	(8,536)	(10,175)
Transition costs, net	**11,390**	(2,585)	(8,805)
All other operating items	**16,321**	(15,017)	(17,451)
Net cash provided by operating activities	**124,671**	126,563	86,692
INVESTING ACTIVITIES			
Additions to property, plant and equipment (exclusive of AFUDC)	**(80,643)**	(57,833)	(54,385)
Allowance for borrowed funds used during construction	**(857)**	(443)	(195)
Net cash used for investing activities	**(81,500)**	(58,276)	(54,580)
FINANCING ACTIVITIES			
Sale of common shares	**9,534**	9,434	7,118
Payment of dividends	**(33,142)**	(32,475)	(31,101)
Proceeds from (payment of) short-term borrowings, net	**10,750**	(27,125)	(93,625)
Long-term debt issues	**—**	—	134,000
Long-term debt issues refunded	**(25,000)**	(10,000)	(37,600)
Sinking funds payments	**(8,716)**	(6,406)	(6,419)
Net cash used for financing activities	**(46,574)**	(66,572)	(27,627)
Net increase (decrease) in cash	**(3,403)**	1,715	4,485
Cash at beginning of period	**7,722**	6,007	1,522
Cash at end of period	**$ 4,319**	$ 7,722	$ 6,007
SUPPLEMENTAL DISCLOSURES *of* CASH FLOW INFORMATION			
Cash paid during the period for:			
Interest (net of capitalized amounts)	**$ 42,051**	$ 41,022	$ 39,685
Income taxes	**$ 12,918**	$ 17,563	$ 13,528

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

Notes *to* Condensed Financial Statements

Commonwealth Energy System and Subsidiary Companies

1) GENERAL INFORMATION

Commonwealth Energy System (the System) is an exempt public utility holding company with investments in four operating public utility companies located in central, eastern and southeastern Massachusetts. The System is the parent company and, together with its subsidiaries, is collectively referred to as "the system."

The detailed Consolidated Balance Sheets, Statements of Income, Statements of Cash Flows, Statements of Capitalization, Statements of Changes in Common Shareholders' Investment, Statements of Changes in Redeemable Preferred Shares, Notes to Consolidated Financial Statements and Management's Discussion and Analysis of Financial Condition and Results of Operations are included in the Proxy Statement.

2) SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Accounting

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Certain prior year amounts are reclassified from time to time to conform with the presentation used in the current year's financial statements.

(b) Regulatory Assets and Liabilities

The system's operating utility companies are regulated as to rates, accounting and other matters by various authorities, including the Federal Energy Regulatory Commission (FERC) and the Massachusetts Department of Public Utilities (DPU).

Based on the current regulatory framework, the system accounts for the economic effects of regulation in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." Regulated subsidiaries of the System have established various regulatory assets in cases where the DPU and/or the FERC have permitted or are expected to permit recovery of specific costs over time. Similarly, the regulatory liabilities established by the system are required to be refunded to customers over time. In March 1995, the Financial Accounting Standards Board issued SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of." SFAS No. 121 imposes stricter criteria for regulatory assets by requiring that such assets be probable of future recovery at each balance sheet date. Management does not expect that the effects of SFAS No. 121, which the system adopted on January 1, 1996, will have a material impact on its financial position or results of operations. However, this conclusion may change in the future as changes are made in the current regulatory framework pursuant to an electric utility restructuring order issued by the DPU in August 1995. The principal regulatory assets included in deferred charges at December 31, 1995 and 1994 were as follows:

	1995	1994
	(Dollars in Thousands)	
Postretirement b[illegible]cluding pensions	**$ 24,608**	$ 20,129
Power contract buy-out	**23,838**	—
Fuel charge stabilization	**22,063**	16,638
Deferred income taxes	**14,106**	5,537
FERC Order 636 transition costs	**11,711**	19,201
Yankee Atomic unrecovered plant and decommissioning costs	**10,135**	18,368
Seabrook related costs	**9,511**	12,648
Other	**13,464**	19,216
	$129,436	$111,737

The regulatory liabilities, reflected in the accompanying balance sheets and related to deferred income taxes, were $14 million and $17.3 million at December 31, 1995 and 1994, respectively.

As of December 31, 1995, $96.2 million of the system's regulatory assets and all of its regulatory liabilities are reflected in rates charged to customers over a weighted average period of approximately 10 years. In addition, the fuel charge stabilization deferral is expected to be recovered over a six-year period beginning in April 1998, pursuant to a yet to be determined recovery schedule and subject to final DPU approval. System companies intend to request and expect to receive approval for recovery of their remaining regulatory assets in future rate proceedings.

3) COMMITMENTS *and* CONTINGENCIES

(a) Power Contracts

Cambridge Electric Light Company (Cambridge) and Commonwealth Electric Company (Commonwealth Electric) have long-term contracts for the purchase of electricity from various sources. Generally, these contracts are for fixed periods and require payment of a demand charge for the capacity entitlement and an energy charge to cover the cost of fuel. Pertinent information with respect to life-of-the-unit contracts for power from operating nuclear units in which the system has an equity ownership (Yankee Nuclear Units) is as follows:

Notes *to* Condensed Financial Statements

Commonwealth Energy System and Subsidiary Companies

	Connecticut Yankee	Maine Yankee	Vermont Yankee
	(Dollars in Thousands)		
Equity Ownership (%)	4.50	4.00	2.50
Plant Entitlement (%)	4.50	3.59	2.25
Plant Capability (MW)	560.0	870.0	496.0
System Entitlement (MW)	25.2	31.2	11.2
Contract Expiration Date	2007	2008	2012
1993 Actual Cost ($)	10,016	7,050	4,076
1994 Actual Cost ($)	8,902	6,250	3,660
1995 Actual Cost ($)	**9,498**	**7,376**	**4,003**
Decommissioning cost estimate (100%) ($)	385,523	361,212	347,383
System's decommissioning cost ($)	17,349	12,968	7,816
Market value of assets (100%) ($)	180,388	142,116	141,300
System's market value of assets ($)	8,117	5,102	3,179

Cambridge pays its share of the decommissioning expense to each of the operators of these nuclear facilities as a cost of electricity purchased for resale.

The system also has long-term contracts to purchase capacity from other generating facilities. Information relative to these contracts is as follows:

Type of Unit	Range of Contract Expiration Dates	Entitlement %	MW	1995 Cost	1994 Cost	1993 Cost
					(Dollars in Thousands)	
Cogenerating	2008-2018	*	205.3	**$121,636**	$137,304	$104,599
Nuclear	2012	11	73.2	**40,376**	41,475	40,578
Waste-to-energy	2015	100	67.0	**37,526**	38,107	34,189
Hydro	2014-2023	100	23.6	**9,933**	7,521	8,904
Total			369.1	**$209,471**	$224,407	$188,270

* Includes contracts to purchase power from various cogenerating units with capacity entitlements ranging from 11.1% to 100%.

Costs pursuant to these contracts are included in fuel and electricity purchased for resale in the accompanying statements of income and are recoverable in revenues.

The estimated aggregate obligations for capacity under the life-of-the-unit contracts from the operating Yankee Nuclear Units and the other long-term purchased power contracts in effect for the five years subsequent to 1995 is as follows:

	Equity Owned Nuclear Units	Long-Term Purchased Power	Total
		(Dollars in Thousands)	
1996	$21,195	$211,037	$232,232
1997	21,130	216,527	237,657
1998	23,596	225,337	248,933
1999	23,153	236,470	259,623
2000	23,813	239,709	263,522

(b) Yankee Atomic Nuclear Power Plant

In 1992, Yankee Atomic Electric Company (Yankee Atomic) permanently discontinued power operation and began the decommissioning of the Yankee Nuclear Power Station (the plant). At December 31, 1995, Cambridge and Commonwealth Electric's respective 2% and 2.5% investment in Yankee Atomic was approximately $1.1 million. The companies' estimated decommissioning costs include their unrecovered share of all costs associated with the shutdown of the plant, recovery of their plant investment, and decommissioning and closing the plant. The most recent cost estimate to permanently shut down the plant is approximately $225.2 million at December 31, 1995. The companies' share of this liability is $10.1 million and is reflected in the accompanying balance sheets as a liability and corresponding regulatory asset. The market value of the companies' share of assets in the plant's decommissioning trust at December 31, 1995 is approximately $5.7 million.

(c) Seabrook Nuclear Power Plant

The system's 3.52% interest in the Seabrook nuclear power plant is owned by Canal Electric Company (Canal), a wholesale electric generating subsidiary, to provide for a portion of the capacity and energy needs of affiliates Cambridge and Commonwealth Electric. Canal is recovering 100% of its Seabrook 1 investment through a power contract with Cambridge and Commonwealth Electric pursuant to FERC and DPU approval.

Pertinent information with respect to Canal's joint-ownership interest in Seabrook 1 and information relating to operating expenses which are included in the accompanying financial statements are as follows:

	1995	1994
	(Dollars in Thousands)	
Utility plant-in-service	**$232,547**	$232,374
Nuclear fuel	**20,138**	18,500
Accumulated depreciation and amortization	**(50,230)**	(41,654)
Construction work in progress	**946**	651
	$203,401	$209,871

Plant capacity (MW)	1,150
Canal's share:	
Percent interest	3.52%
Entitlement (MW)	40.5
In-service date	1990
Operating license expiration date	2026

	1995	1994	1993
	(Dollars in Thousands)		
Operating expenses:			
Fuel	**$ 2,353**	$ 1,939	$ 3,853
Other operation	**4,292**	4,340	4,580
Maintenance	**1,376**	1,688	893
Depreciation	**6,542**	6,531	6,522
Amortization	**1,319**	1,320	1,319
	$15,882	$15,818	$17,167

Canal and the other joint owners have established a decommissioning trust to cover decommissioning costs. The estimated

Notes *to* Condensed Financial Statements

Commonwealth Energy System and Subsidiary Companies

cost to decommission the plant is $431.6 million in current dollars. Canal's share of this liability (approximately $15.2 million), less its share of the market value of the assets held in a decommissioning trust (approximately $1.5 million), is approximately $13.7 million at December 31, 1995.

(d) Environmental Matters

The system is subject to laws and regulations administered by federal, state and local authorities relating to the quality of the environment. These laws and regulations affect, among other things, the siting and operation of electric generating and transmission facilities and can require the installation of expensive air and water pollution control equipment. These regulations have had an impact on the System's operations in the past and will continue to have an impact on future operations, capital costs and construction schedules of major facilities.

(e) FERC Order No. 636

As a result of implementing FERC Order No. 636 (Order 636), each interstate pipeline company is allowed to collect certain transition costs from its customers that resulted from the pipelines' need to buy out gas supply contracts entered into prior to the issuance of Order 636. Commonwealth Gas Company (Commonwealth Gas) has been billed a total of approximately $23.8 million from Tennessee Gas Pipeline Company, Algonquin Gas Transmission Company and Texas Eastern Transmission Company through December 31, 1995.

Commonwealth Gas' pipeline suppliers have made certain filings with the FERC for the collection of their respective transition costs. Commonwealth Gas' current best estimate of the total remaining transition costs from its suppliers is approximately $11.7 million. This balance has been recorded as a liability with a corresponding regulatory asset. The ultimate level of costs is dependent upon future events, including the market price of natural gas and final settlements between the FERC and the pipeline suppliers.

In May 1995, the DPU allowed Commonwealth Gas to accelerate recovery of its FERC Order No. 636 transition costs that were incurred to date. These costs had been deferred and accumulated as a regulatory asset and were being recovered through the cost of gas adjustment (CGA) over a four-year period that began in November 1993. The costs are now being recovered through the CGA over a one-year period that began May 1, 1995. The accelerated recovery period was permitted by the DPU due to the minimal impact on customers' bills. Any further transition costs are expected to be recovered by Commonwealth Gas through the CGA as incurred.

(f) Other Commitments

Other major commitments include construction expenditures, maturing debt issues and sinking fund payments as summarized below:

	1996	1997	1998	1999	2000
	(Dollars in Thousands)				
Construction expenditures	$69,272	$60,208	$59,660	$51,744	$52,146
Maturing debt issues	33,230	14,260	19,000	20,000	—
Sinking fund requirements	9,103	8,473	8,473	8,473	6,973

Report *of* Independent Public Accountants

To the Board of Trustees of
Commonwealth Energy System:

We have audited, in accordance with generally accepted auditing standards, the consolidated balance sheets and consolidated statements of capitalization of COMMONWEALTH ENERGY SYSTEM (a Massachusetts Trust) and subsidiary companies as of December 31, 1995 and 1994, and the related consolidated statements of income, cash flows, changes in common shareholders' investment and changes in redeemable preferred shares for each of the three years in the period ended December 31, 1995, appearing in Exhibit A to the proxy statement for the 1996 annual meeting of shareholders of the System (not presented herein).

In our opinion, the information set forth in the accompanying condensed consolidated balance sheets as of December 31, 1995 and 1994, and the related condensed statements of consolidated income and cash flows for each of the three years in the period ended December 31, 1995, is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

Boston, Massachusetts
February 16, 1996

Arthur Andersen LLP

Comparative Statistical Data

Commonwealth Energy System and Subsidiary Companies

	1995	1994	1993	1992	1991
			(Dollars in Thousands)		
OPERATIONS					
Revenues	**$931,355**	$979,236	$940,699	$906,450	$873,434
Operating Expenses					
Operations	**691,813**	744,484	712,598	690,991	665,255
Maintenance	**38,414**	36,522	40,574	39,836	44,312
Depreciation and amortization	**54,087**	50,056	48,244	50,861	44,660
Taxes	**50,431**	54,708	51,947	44,837	39,751
	834,745	885,770	853,363	826,525	793,978
Operating income	**96,610**	93,466	87,336	79,925	79,456
Add—Other income (expense)	**(606)**	(1,024)	2,449	1,410	(13,419)
Less—Interest charges	**44,608**	43,474	43,951	41,438	46,565
Net income	**51,396**	48,968	45,834	39,897	19,472
Preferred dividends	**1,110**	1,170	1,230	1,291	1,352
Earnings applicable to common shares	**$ 50,286**	$ 47,798	$ 44,604	$ 38,606	$ 18,120
Sources of Consolidated Net Income—					
Electric	**$ 34,739**	$ 36,473	$ 30,301	$ 28,415	$ 32,874
Gas	**16,229**	13,568	16,299	14,855	3,120
Steam and other	**428**	(1,073)	(766)	(3,373)	(16,522)
Total	**$ 51,396**	$ 48,968	$ 45,834	$ 39,897	$ 19,472
FINANCIAL					
Property, plant and equipment (including construction work in progress, net and nuclear fuel in process)	**$1,525,900**	$1,460,438	$1,409,997	$1,384,634	$1,335,795
Accumulated depreciation and amortization	**497,627**	461,310	425,483	406,069	372,987
CAPITALIZATION					
Long-term debt (1)	**$ 410,411**	$ 443,307	$ 458,893	$ 368,092	$ 409,582
Preferred shares	**13,840**	14,660	15,480	16,300	17,120
Common equity	**390,785**	362,997	337,070	315,219	300,859
Total	**$ 815,036**	$ 820,964	$ 811,443	$ 699,611	$ 727,561

(1) Includes maturing long-term debt.

Comparative Statistical Data

Commonwealth Energy System and Subsidiary Companies

	1995	1994	1993	1992	1991
STATISTICS and RATIOS					
Unit Sales -					
MWH — Residential	**1,752,430**	1,770,095	1,744,181	1,726,139	1,694,445
Commercial	**2,450,390**	2,406,077	2,378,073	2,305,720	2,272,146
Industrial	**421,224**	421,821	411,527	414,777	419,940
Other	**23,796**	23,216	22,243	23,236	20,565
Total Retail	**4,647,840**	4,621,209	4,556,024	4,469,872	4,407,096
Wholesale	**1,973,543**	3,803,786	3,689,129	3,898,924	4,027,714
Total	**6,621,383**	8,424,995	8,245,153	8,368,796	8,434,810
BBTU— Residential	**21,336**	21,515	22,252	22,392	19,851
Commercial	**10,710**	10,728	10,931	10,913	9,575
Industrial	**4,445**	4,401	4,205	4,717	5,388
Other	**1,967**	1,895	1,831	1,788	1,581
Total Firm	**38,458**	38,539	39,219	39,810	36,395
Off-system	**4,043**	6,401	—	—	—
Quasi-firm	**1,906**	487	—	—	—
Interruptible	**1,215**	1,927	1,896	2,464	2,937
Total	**45,622**	47,354	41,115	42,274	39,332
Capitalization Ratios -					
Long-term debt	**50.4 %**	54.0%	56.6%	52.6%	56.3%
Preferred shares	**1.7**	1.8	1.9	2.3	2.3
Common equity	**47.9**	44.2	41.5	45.1	41.4
Total	**100.0 %**	100.0%	100.0%	100.0%	100.0%
Return on average common equity	**13.3 %**	13.7%	13.7%	12.5%	6.0%
Common share dividend payout	**63.6 %**	64.9%	66.8%	76.2%	160.4%
Average price/earnings ratio	**8.7**	8.8	10.4	10.2	19.2
Common Share Data -					
Earnings per share (1)	**$ 4.72**	$ 4.59	$ 4.37	$ 3.83	$ 1.82
Dividends paid	**3.00**	2.98	2.92	2.92	2.92
Annual dividend rate at end of year	**3.00**	3.00	2.92	2.92	2.92
Book value	**36.30**	34.49	32.74	31.08	30.06
Closing price range -					
High	**47⅛**	45½	50¼	43	39¾
Low	**35⅝**	35⅜	40½	34⅞	30

(1) Based on the average number of shares outstanding.

Trustees *and* Officers

Commonwealth Energy System and Subsidiary Companies

(3) Sheldon A. Buckler
Chairman of the Board of Trustees of the System. Formerly Vice Chairman of the Board, Polaroid Corp., Cambridge, Massachusetts

(1) Peter H. Cressy
(5) *Chancellor, University of Massachusetts—Dartmouth, North Dartmouth, Massachusetts*

(2) Henry Dormitzer
(4) *Formerly Executive Vice President, Wyman-Gordon Company, Worcester, Massachusetts*

(1) Betty L. Francis
(3) *Executive Vice President and Chief Financial Officer, Banc-Boston Mortgage Corporation, Jacksonville, Florida*

(3) Franklin M. Hundley
(4) *Member and a Managing Director, Rich, May, Bilodeau & Flaherty, P.C., Boston, Massachusetts (Attorneys)*

(1) William J. O'Brien
(4) *President, William J. O'Brien, Inc., Southborough, Massachusetts*

William G. Poist
President and Chief Executive Officer of the System and Chairman, Chief Executive Officer and a Director of its subsidiary companies

(2) Michael C. Ruettgers
(5) *President, Chief Executive Officer and a Director, EMC Corporation, Hopkinton, Massachusetts*

(2) Gerald L. Wilson
(5) *Vannevar Bush Professor of Engineering, Massachusetts Institute of Technology, Cambridge, Massachusetts*

CORPORATE DIVISION

William G. Poist
Chairman and Chief Executive Officer

OFFICE *of the* CEO

Leonard R. Devanna
Vice President—Systems, Planning and Development

James D. Rappoli
Financial Vice President and Treasurer

Michael P. Sullivan
Vice President, Secretary and General Counsel

ELECTRIC DIVISION

Russell D. Wright
President and Chief Operating Officer

James J. Keane
Vice President—Power Supply and Transmission

Deborah A. McLaughlin
Vice President—Customer Service

John R. Williams
Vice President—Operations

COM/ENERGY SERVICES COMPANY

John A. Whalen
Vice President and General Manager

James M. Brown
Vice President—Chief Information Officer

GAS DIVISION

Kenneth M. Margossian
President and Chief Operating Officer

Stephen H. Bryant
Vice President—Marketing and Customer Relations

Samy H. Ibrahim
Vice President—Gas Supply

Richard D. Johnston
Vice President—Operations

(1) Member of Audit Committee (2) Member of Executive Compensation Committee
(3) Member of Nominating Committee (4) Member of Benefit Review Committee (5) Member of Strategic Planning Committee

Shareholder Information

Commonwealth Energy System and Subsidiary Companies

ANNUAL MEETING

All shareholders are invited to attend the next Annual Meeting which will be held on May 2, 1996 at the System's corporate headquarters at One Main Street in Kendall Square, Cambridge, Massachusetts. A formal notice of the meeting together with a proxy statement, a form of proxy and financial information is enclosed for use by shareholders entitled to vote at the meeting.

CLOSING MARKET PRICE *of* COMMON SHARES *and* DIVIDENDS PAID

1995	High	Low	Dividends
1st Quarter	$41⅞	$35⅝	$.75
2nd Quarter	41½	37¼	.75
3rd Quarter	43⅜	35⅛	.75
4th Quarter	47⅛	41	.75

1994	High	Low	Dividends
1st Quarter	$45½	$42⅛	$.73
2nd Quarter	43¾	39½	.75
3rd Quarter	40¾	37½	.75
4th Quarter	38¾	35⅜	.75

The System's Common Shares are listed on the Boston, New York and Pacific stock exchanges:

Ticker Symbol "**CES**"
Daily Newspaper Quotation "**ComES**"

TRANSFER AGENTS *and* REGISTRARS

Shareholder communications regarding transfer of Common Shares or lost certificates should be directed to:

Common Shares -
Transfer Agent and Registrar:
The First National Bank of Boston
P.O. Box 644
Boston, MA 02102-0644

Preferred Shares -
Transfer Agent:
Commonwealth Energy System
P. O. Box 9150
Cambridge, MA 02142-9150

Registrar:
State Street Bank and Trust Company

DIVIDEND PAYMENTS

Dividends are paid by the System subject to declaration by the Board of Trustees. Common dividends are paid on the first day of February, May, August and November. Preferred dividends are paid on the first day of January, April, July and October.

SHAREHOLDER SERVICES

The System has a dividend reinvestment plan which provides holders of Common Shares with an economical and convenient method for purchasing additional Common Shares of the System without paying brokerage fees or service charges.

The System also offers direct deposit to Common Shareholders so that dividends can be received faster. Dividends can be electronically credited to a checking, savings, credit union or thrift account.

A seasonal mailing address for your shareholder account(s) is also available for the period of time requested. This can help avoid lost interest on delayed deposits caused by forwarded mail.

For more information about these services or any other inquiries, please contact a Shareholder Services representative at the appropriate toll-free number listed below:

1-800-336-3773 *(within Massachusetts)*
1-800-447-1183 *(outside Massachusetts)*

FORMS 10-K *and* 10-Q

The System's annual report on Form 10-K and quarterly reports on Form 10-Q as filed with the Securities and Exchange Commission are available without charge upon request to:

Michael P. Sullivan
Vice President, Secretary and General Counsel
Commonwealth Energy System
P.O. Box 9150
Cambridge, MA 02142-9150

Many of the information requirements of Form 10-K are satisfied by the 1996 Proxy Statement.

BOND DATA

Trustees under indentures of trust are:
Citibank, N.A. -
Canal Electric Company Series B, E and F Bonds
State Street Bank and Trust Company -
Other Subsidiary Companies' Long-term Debt

NEW HAMPSHIRE ELECTRIC COOPERATIVE, INC.

FINANCIAL STATEMENTS

December 31, 1995 and 1994

With Independent Auditors' Report

BERRY, DUNN, McNEIL & PARKER
CERTIFIED PUBLIC ACCOUNTANTS
MANAGEMENT CONSULTANTS

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Members
New Hampshire Electric Cooperative, Inc.

We have audited the accompanying balance sheets of New Hampshire Electric Cooperative, Inc. (the Cooperative) as of December 31, 1995 and 1994, and the related statements of operations and accumulated deficit and cash flows for the years then ended. These financial statements are the responsibility of the Cooperative'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 and the standards for financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audits 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, such financial statements present fairly, in all material respects, the financial position of New Hampshire Electric Cooperative, Inc., as of December 31, 1995 and 1994, and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

As described in Note 1 to the financial statements, on March 20, 1992, the Bankruptcy Court entered an order confirming the Second Amended Plan of Reorganization, as modified, which became effective on December 1, 1993. Under the Plan of Reorganization, the Cooperative is required to comply with certain conditions as more fully described in Note 1.

Berry, Dunn, McNeil & Parker

Portland, Maine
March 20, 1996

NEW HAMPSHIRE ELECTRIC COOPERATIVE, INC.

Balance Sheets

December 31, 1995 and 1994

ASSETS

	1995 (000s)	1994 (000s)
Utility plant		
Nuclear production	$105,855	$105,905
Transmission	4,329	4,343
Distribution	129,451	123,818
General and other	12,930	11,952
Construction work in progress	6,865	2,189
Total utility plant	259,430	248,207
Less accumulated depreciation and amortization	59,548	52,956
Net utility plant	199,882	195,251
Investment in associated organizations, at cost	2,242	1,965
Current assets		
Cash and cash equivalents	888	264
Restricted cash	38	57
Temporary investments and special deposits	541	3,304
Receivables from members		
Energy sales, net of allowance for doubtful accounts $367 and $439 in 1995 and 1994, respectively	7,448	5,845
Other	689	332
Receivable, Public Service Company of New Hampshire	3,101	3,024
Materials and supplies	2,571	2,978
Prepayments and other current assets	983	1,146
Total current assets	16,259	16,950
Deferred debits and other assets	46,320	38,736
	$264,703	$252,902

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

LIABILITIES AND EQUITIES

	1995 (000s)	1994 (000s)
Equities		
Patronage capital	$ 13,308	$ 13,308
Accumulated deficit	(19,837)	(21,514)
Total deficit	(6,529)	(8,206)
Current liabilities		
Line of credit	-	3,000
Accounts payable	13,990	10,735
Accrued liabilities	3,642	2,223
Customer deposits	268	300
Current portion of long-term obligations	4,700	2,961
Total current liabilities	22,600	19,219
Long-term liabilities		
Long-term obligations	246,005	241,446
Other long-term liabilities	350	350
Total long-term liabilities	246,355	241,796
Deferred credits	2,277	93
	$264,703	$252,902

NEW HAMPSHIRE ELECTRIC COOPERATIVE, INC.

Statements of Operations and Accumulated Deficit

Years Ended December 31, 1995 and 1994

	1995 (000s)	1994 (000s)
Operating revenues	$ 96,487	$ 94,851
Operating expenses	83,131	78,432
Operating margin before interest and other deductions	13,356	16,419
Interest and other deductions	18,081	18,791
Net operating margins (deficits)	(4,725)	(2,372)
Nonoperating margins (deficits)		
Interest	3,431	3,199
Other	(327)	(546)
Total nonoperating margins	3,104	2,653
Net margins, before extraordinary item	(1,621)	281
Extraordinary item		
Gain on refinancing of long-term debt	3,298	-
Net margin, after extraordinary item	1,677	281
Accumulated deficit, beginning of year	(21,514)	(21,795)
Accumulated deficit, end of year	$(19,837)	$(21,514)

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

NEW HAMPSHIRE ELECTRIC COOPERATIVE, INC.

Statements of Cash Flows

Years Ended December 31, 1995 and 1994

	1995 (000s)	1994 (000s)
Cash flows from operating activities		
Net margins	**$ 1,677**	$ 281
Adjustments to reconcile net margins to net cash provided by operating activities		
Depreciation and amortization	**9,032**	8,402
Gain on sale of fixed assets	**-**	(34)
Interest added to principal	**4,055**	4,764
Patronage capital dividends	**(42)**	(62)
Deferred credits	**633**	(371)
Deferred debits	**(4,860)**	(7,302)
Gain on refinancing of long-term debt	**(3,298)**	-
Decrease (increase) in		
Member and other accounts receivable	**(2,037)**	(2,477)
Materials and supplies	**407**	178
Prepayments and other current assets	**163**	201
Increase (decrease) in		
Accounts payable	**3,255**	1,283
Accrued liabilities	**1,419**	1,227
Customer deposits	**(32)**	(100)
Net cash provided by operating activities	**10,372**	5,990
Cash flows from investing activities		
Proceeds from sale of assets	**-**	39
Construction and acquisition of plant	**(12,847)**	(7,432)
Plant removal costs	**(186)**	(216)
Materials salvaged from retirements	**142**	184
Investments in capital term certificates	**(235)**	-
Net cash used by investing activities	**(13,126)**	(7,425)

(Continued next page)

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

NEW HAMPSHIRE ELECTRIC COOPERATIVE, INC.

Statements of Cash Flows (Concluded)

Years Ended December 31, 1995 and 1994

	1995 (000s)	1994 (000s)
Cash flows from financing activities		
Net proceeds (payments) on credit line	$ (3,000)	$ 3,000
Principal payments of long-term obligations	(6,639)	(2,589)
Proceeds from long-term debt	11,735	-
Other payments on long-term debt	(1,500)	-
Net cash provided by financing activities	596	411
Net decrease in cash and cash equivalents	(2,158)	(1,024)
Cash and cash equivalents, beginning of year	3,625	4,649
Cash and cash equivalents, end of year	$ 1,467	$ 3,625
Supplemental disclosures of cash flow information		
Cash paid during the year for interest	$12,943	$13,640

The Cooperative refinanced $187,464,000 of long-term debt in a noncash transaction during 1995.

The Cooperative deferred interest expense of $4,500,000 in 1995 and $5,178,000 in 1994, and interest income of $3,743,000 in 1995 and $5,054,000 in 1994 in noncash transactions.

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

1. Reorganization Proceedings and Basis of Presentation

On May 6, 1991, New Hampshire Electric Cooperative, Inc. (NHEC or the Cooperative) filed a petition for relief under Chapter 11 of the Federal Bankruptcy Code in the United States Bankruptcy Court for the District of New Hampshire (the Bankruptcy Court). Under Chapter 11, most actions to recover claims against NHEC in existence prior to the filing of the petition for relief under the Federal Bankruptcy Code were stayed while NHEC continued business operations, under the direction of the Bankruptcy Court, as a debtor in possession.

On January 13, 1992, a Second Amended Plan of Reorganization (the Plan) jointly proposed by NHEC with the State of New Hampshire and Public Service Company of New Hampshire (PSNH) was submitted to the Bankruptcy Court. On March 20, 1992, the Bankruptcy Court confirmed the Second Amended Plan of Reorganization, as modified (the Plan). The Plan provided for NHEC to remain a member-owned electric cooperative and to retain all of its assets, including its 2.17391% undivided ownership interest in the Seabrook Nuclear Plant (Seabrook). Under the terms of the Plan, NHEC's indebtedness to the Rural Utilities Service (RUS) and the National Rural Utilities Cooperative Finance Corporation (CFC) was restructured and other creditors of NHEC were paid in full.

The Plan provided for NHEC to emerge from bankruptcy with forecast revenues sufficient both to meet its obligations for debt service and to provide continuing electric service to all of its members. Forecast revenues were based on load growth studies and certain retail rate assumptions. Retail rates are regulated by the New Hampshire Public Utilities Commission (NHPUC) and, although certain assumptions have been made in the Plan, NHEC is limited to those rates, approved in accordance with rate setting principles as implemented by the NHPUC.

In addition to the restructuring of RUS and CFC debt, the Plan provided for the full resolution and settlement of disputes between NHEC and PSNH, a subsidiary of Northeast Utilities (NU). NHEC will continue to purchase most of its wholesale power requirements from PSNH under a long-term contract through November 6, 2006, and will sell its Seabrook power to PSNH under a Sellback Contract through June 30, 2000.

On December 1, 1993, subsequent to satisfaction of all Plan conditions, the Plan became effective and the comprehensive settlement and discharge of all litigation and claims encompassed by the Plan became final.

2. Significant Accounting Policies

Organization and Purpose

NHEC is a rural electric cooperative utility established under the laws of the state of New Hampshire. The Cooperative is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the NHPUC for rates and other matters. Financing assistance has been provided by the RUS and, therefore, NHEC is subject to certain rules and regulations promulgated for rural electric borrowers by RUS. NHEC is a distribution cooperative, providing electric power to members in certain areas of New Hampshire, and has a 2.17391% ownership in the Seabrook nuclear facility. NHEC is presently serving over 66,000 members, spread over nine of New Hampshire's ten counties.

Use of Estimates

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

Regulatory Accounting

The Cooperative follows the accounting prescribed by the FERC Chart of Accounts and the NHPUC and Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulations." This accounting recognizes the economic effects of rate regulation by recording costs and a return on investment as such amounts are recovered through rates authorized by regulatory authorities. The Cooperative annually reviews the continued applicability of SFAS No. 71 based on the current regulatory and competitive environment.

Utility Plant and Depreciation

Utility plant and construction work in progress is stated at cost which includes an allowance for funds used during construction.

2. Significant Accounting Policies (Continued)

Utility Plant and Depreciation (Concluded)

The provision for depreciation and amortization is computed on a straight-line method at rates based upon the estimated service lives of the assets. Depreciation and amortization expense was approximately $8,303,000 in 1995 and $8,054,000 in 1994. Major depreciable assets are estimated to have the following services lives:

	Years
Nuclear plant	36
Transmission plant	29
Distribution plant	36
General plant	6 to 33

Maintenance and repairs of utility plant are charged to operations as incurred. Replacements and betterments are capitalized. At the time units of utility plant are retired, the cost of the property retired and costs of removal, less salvage, are charged to the allowance for depreciation.

Allowance for Funds Used During Construction

Allowance for funds used during construction represents the cost of related borrowed funds used for construction of utility plant. The allowance is capitalized as a component of the cost of utility plant. The Cooperative capitalized $259,000 and $60,000 of interest in 1995 and 1994, respectively.

Operating Revenues

Operating revenues are based on rates, authorized by the NHPUC, which are applied to members' consumption of electricity. NHEC bills its members on a cycle basis throughout the month. NHEC records revenues as it bills its customers. The Cooperative extends credit to its electric customers after appropriate review, based on guidelines set by the NHPUC.

Purchased Power Costs

NHEC rates reflect estimates of the cost of purchased power. Retail members are billed at a levelized power cost adjustment charge rate based on projected data for the cost of power from wholesale suppliers. To the extent that cost estimates differ from actual charges incurred, the differences are deferred and refunded or charged to members through periodic rate adjustments.

2. Significant Accounting Policies (Continued)

Materials and Supplies

Inventories of materials and supplies are stated at average cost.

Demand Side Management Costs

NHEC rates reflect estimates of the cost of the Cooperative's demand side management (DSM) program. Retail members are billed at a levelized DSM rate based on projected expenditures for the project. To the extent that cost estimates differ from actual charges incurred, the differences are deferred and refunded or charged to members through periodic rate adjustments.

Income Tax Status

NHEC is exempt from United States income taxes pursuant to §501(c)(12) of the Internal Revenue Code, which requires that at least 85% of a cooperative's net income be collected from its members.

Patronage Capital

The bylaws of the Cooperative provide that operating revenues from the furnishing of electric energy in excess of operating costs and expenses shall be allocated as patronage capital. All other amounts received in excess of other expenses shall be used to offset any losses incurred during the current or any prior fiscal year and, to the extent not needed for that purpose, allocated to its patrons on the basis of their patronage, and any amount so allocated shall be included as part of the capital credited to the accounts of patrons.

NHEC may refund patronage capital with the consent of RUS and CFC.

In the event of the dissolution or liquidation of NHEC, after all outstanding indebtedness has been paid, outstanding capital credits shall be retired without priority on a pro rata basis.

Cash and Cash Equivalents

NHEC considers all highly liquid debt instruments with an original maturity of three months or less to be cash equivalents.

2. Significant Accounting Policies (Concluded)

Cash and Cash Equivalents (Concluded)

The Cooperative maintains its cash in bank deposit accounts which may exceed federally insured limits. The Cooperative has not experienced losses in such accounts, and management does not believe that it is exposed to any significant risk on cash and cash equivalents.

Postretirement Benefit Plan

The Cooperative sponsors a defined benefit postretirement medical and life insurance plan through National Rural Electric Cooperative Association (NRECA) that covers substantially all of its employees. The Cooperative adopted FASB Statement No. 106 (FAS 106), "Employers' Accounting for Postretirement Benefits Other than Pension" for the year ended December 31, 1995. Management has chosen to account for the obligations under the statement in accordance with accounting treatment set forth by the NHPUC and RUS, which allows recognition of the Accumulated Postretirement Benefits Obligation (APBO) transition obligation in expense over twenty years. The Cooperative is currently involved in rate making proceedings regarding the method of recovering FAS 106 costs.

Reclassifications

Certain reclassifications have been made to 1994 balances so that they are consistent with 1995 presentation.

3. Utility Plant - Nuclear

The NHPUC, by an order dated May 3, 1991, established that NHEC's "initial plant investment" in the Seabrook nuclear facility for "wholesale" rate setting purposes shall be $126 million as of the in-service date of July 1, 1990.

The Plan provides for the sale of all of the capacity and related output of NHEC's 2.17391% share of the Seabrook nuclear facility to PSNH through June 30, 2000. The terms of the sale are specified in a Unit Contract (the Sellback) between NHEC and PSNH which became effective on December 1, 1993. The Sellback also provided that the valuation of the plant will be further reduced on the effective date. As of the effective date, the value of the plant was adjusted to approximately $99 million.

3. Utility Plant - Nuclear (Continued)

Upon termination of the Sellback in June 2000, the capacity and output from NHEC's share of the Seabrook nuclear facility will be available for NHEC to use or sell. Because current electric rates to power consumers other than PSNH exclude Seabrook costs, NHEC will be required to obtain regulatory approval for any new retail rates which contain costs related to Seabrook.

In 1984, construction of Seabrook Unit 2 ceased and in November 1986 the Joint Owners in Seabrook (the Joint Owners) voted to abandon the unfinished plant and reflected in the other long-term liabilities is $350,000 provided for NHEC's share of the net costs of dismantling. Unit 2 has yet to be dismantled.

Decommissioning costs are accrued over the service life of the Seabrook Plant. Decommissioning expenses totaled approximately $182,000 and $163,000 in 1995 and 1994, respectively. The license for the plant is scheduled to expire in 2026. The Cooperative's share of the estimated decommissioning cost is approximately $39 million. These costs are currently being recovered by NHEC through the Sellback Contract with PSNH. The Cooperative contributes its share of the costs of decommissioning to an external trust fund. The Cooperative's share of the decommissioning trust fund balance and the accumulated provision for decommissioning were $670,000 and $507,000 at December 31, 1995 and 1994, respectively. The Cooperative is scheduled to make payments ranging from $100,000 to $463,000 per year, through the year 2026, to the Seabrook Decommissioning Fund. These contributions will equal approximately $8,700,000 which, with fund earnings, are scheduled to be sufficient to cover estimated decommissioning costs. These amounts are subject to review and revision semiannually.

The Cooperative reflects its proportionate share of financial activities related to the operations of Seabrook in its financial statements when the activities are reported to the Cooperative on Seabrook owner reports. In addition to the financial activities reported to the Cooperative on the owner reports, NHEC records other balances and transactions related to the Cooperative's investment in Seabrook. PSNH purchases all of NHEC's Seabrook power capacity as disclosed with long-term power supply and sales agreements. Further, the Cooperative's initial investment in Seabrook was financed using long-term notes payable which are included in long-term obligations.

NHEC accounts for its investment in Seabrook utility plant based on amounts set forth in a NHPUC order. Seabrook owner reports do not reflect estimates of depreciation on utility plant or amortization of Nuclear fuel and, therefore, the Cooperative uses approved rates for the depreciation and amortization of these assets.

3. Utility Plant - Nuclear (Continued)

The Cooperative's proportionate share of expenses on the Seabrook owner reports were approximately $3,207,000 and $3,392,000 for the years ended December 31,1995 and 1994, respectively. Other expenses, excluding interest, related to the Cooperative's Seabrook activities were approximately $4,753,000 and $4,272,000 for the years ended 1995 and 1994, respectively, including depreciation and amortization of $3,658,000 for 1995 and $3,402,000 for 1994.

The Cooperative's assets and liabilities, excluding debt, related to its Seabrook investment, including amounts from the Seabrook owner reports, at December 31, 1995 and 1994, are as follows:

	1995 (000s)	1994 (000s)
Nuclear plant	**$105,855**	$105,905
Transmission plant	**1,494**	1,491
Distribution plant	**152**	152
General plant	**1,470**	1,460
Construction work-in-progress	**245**	176
Accumulated depreciation and amortization	**(15,233)**	(12,487)
Net utility plant in service	**93,983**	96,697
Other current and accrued assets	**4,162**	4,139
Deferred debits and other assets	**39,369**	35,396
Total assets	**$137,514**	$136,232
Current and accrued liabilities	**$ 981**	$ 653
Long-term obligations	**470**	478
Deferred credits	**55**	93
Total liabilities and credits	**$ 1,506**	$ 1,224

3. Utility Plant - Nuclear (Concluded)

Nuclear Liability Insurance

The Price-Anderson Act (the Act), a federal statute amended in 1988 to extend to the year 2002, limits the public liability of a licensee on a nuclear plant for a nuclear incident to approximately $9 billion.

Seabrook provides the Joint Owners with a primary layer of insurance in the amount of $200 million maintained with private insurance companies. Secondary coverage of up to $8.72 billion is provided by a retrospective assessment of up to $79.2 million per incident levied on each of the licensed operating nuclear units in the United States, subject to a $10 million maximum assessment per unit in any year. Additionally, if the sum of all public utility claims and legal costs arising from any nuclear accident exceeds the maximum amount of financial protection, each licensee can be assessed an additional 5% (up to $3.8 million) of the maximum retrospective assessment. There is no limit on the number of incidents for which a licensee could be assessed these sums.

The Joint Owners are insured, through policies purchased from the Nuclear Electric Insurance Limited (NEIL), for the cost of repair, replacement, decontamination or decommissioning of the plant resulting from insured occurrences. The Joint Owners are subject to maximum potential assessments against Seabrook, with respect to losses arising during current policy years, of approximately $15.1 million for excess property damage, decontamination and decommissioning. All companies insured with NEIL are subject to retroactive assessments if losses exceed the financial resources available to NEIL. However, over the years, the insurance has accumulated surpluses and assets which make the probability of retroactive premium assessments unlikely.

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 participating reactors insured under this coverage are subject to retroactive assessments of $3 million per reactor. These policies expire January 1, 1997.

4. **Investment in Associated Organization**

Investments in associated organizations, carried at cost, at December 31, 1995 and 1994, consist of the following:

	1995 (000s)	1994 (000s)
Capital term certificates - CFC	$2,136	$1,901
Patronage capital credits - CFC	105	63
Other	1	1
Total	$2,242	$1,965

5. **Deferred Debits and Other Assets**

Deferred debits and other assets at December 31, 1995 and 1994, were as follows:

	1995 (000s)	1994 (000s)
Deferred debits		
Deferred regulatory asset - Woodstock substation	$ 357	$ 387
Deferred power costs	2,548	1,952
Seabrook prefunding	472	593
Seabrook - other	312	392
Demand side management	-	235
Unamortized debt expense	1,375	-
Deferred interest	859	414
Deferred postretirement benefits	1,508	-
Other assets		
PSNH deferred sellback receivable	36,940	33,197
Nuclear fuel - Seabrook	1,645	1,214
Nonoperating property	91	100
Other	213	252
Total	$46,320	$38,736

6. Long-Term Obligations

As of December 31, 1995 and 1994, long-term obligations were as follow

	1995 (000s)	1994 (000s)
2.0% note payable to RUS, payable in monthly installments, including interest, through December 2012	$ 10,808	$ 11,288
5.0% note payable to RUS, payable in monthly installments, including interest, through December 2012	26,321	55,593
6.45% - 9.75% notes payable to CFC, payable in monthly installments, including interest, through December 2012	7,806	8,106
6.2% - 7.7% notes payable to CFC, payable in quarterly installments, including interest, through December 2022	132,207	-
6.96% - 7.2% notes payable to CFC, payable in quarterly installments, including interest, through December 2012	13,694	-
7.1% note payable to CFC, payable in quarterly installments, including interest, through December 2005	10,000	-
Variable rate note payable to CFC, payable in quarterly installments including interest (6.2% at December 31, 1995), through December 2022	5,848	-
Variable rate notes payable to CFC, payable in quarterly installments, interest only (6.2% at December 31, 1995), through July 2000. Principal will be paid at the maturity date.	25,715	-
Variable rate notes payable to CFC, payable in quarterly installments including interest (6.2% at December 31, 1995), through December 2028	11,728	-
PSNH Note	6,376	5,930
Other long-term obligations	202	277
Notes refinanced during 1995	-	163,213
Total obligations	250,705	244,407
Less current portion	(4,700)	(2,961)
Total long-term obligations	$246,005	$241,446

6. Long-Term Obligations (Continued)

As provided in the Plan, accrued interest on certain notes is added to principal balances. Accrued interest of $4,500,000 and $5,178,000 was added to principal during 1995 and 1994, respectively.

The mortgage agreements provide that all outstanding obligations to RUS and CFC are collateralized by substantially all assets and the rents, income, revenues, proceeds and benefits derived, received or had for any and all such assets.

The Cooperative must also comply with certain covenants which include restrictions on the Cooperative's ability to borrow additional monies, enter into specified transactions or to pay dividends or distribute capital without first seeking the mortgagees' approval. Additional covenants address insurance coverage, the sale of assets and other nonfinancial matters.

CFC has made a commitment to the Cooperative for a $10 million line of credit through December 31, 2023. There was no balance outstanding on the line of credit at December 31, 1995, and $3 million was outstanding at December 31, 1994. CFC also made a commitment to the Cooperative for the 1993/1994 work plan loan of approximately $12.2 million to finance future plant additions. Borrowings under this commitment were $11.7 million at December 31, 1995, and there was no outstanding balance at December 31, 1994.

During 1995, NHEC signed an agreement with CFC for a new work plan loan for approximately $19.7 million that will be used for plant additions in 1995 and 1996. No amounts were drawn down on this loan during 1995. The interest rate will be determined based on the CFC market rates at the time of each advance. The loan will be paid over a 35-year period from the date of each advance.

CFC Mortgage notes are subject to repricing periodically to reflect current market interest rates.

The PSNH note began accruing interest at the rate of 7.5% per annum starting on December 1, 1993. As approved by the NHPUC, the interest cost will be deferred until January 2002 through October 2006 during the time the note is repaid. Interest of approximately $445,000 and $414,000 were deferred in 1995 and 1994, respectively. Interest and principal will be payable as follows:

a. Annually through 2003, payments will be deemed made on the note in the amount of one cent for every kilowatt hour delivered by PSNH to NHEC under the amended wholesale power contract in excess of forecasted deliveries (deliveries credit). No deliveries credits were realized in 1995 or 1994.

6. Long-Term Obligations (Continued)

b. Any balance of interest and principal remaining unpaid on January 1, 2002, shall mature on October 31, 2006, and shall be payable by NHEC over the balance of the term of the note in equal monthly installments, adjusted for any payments in (a) above paid in 2002 and 2003, in an amount sufficient to pay such balance, and interest thereon on October 31, 2006.

On August 30, 1995, NHEC signed a loan agreement with CFC for the purpose of refinancing the Cooperative's long-term notes payable with RUS. The Restated Mortgage, dated January 1, 1993, was supplemented and amended to include the terms and conditions of the new financed notes. CFC has agreed and set forth a total commitment of $262,408,444. Included in the agreement with CFC and RUS was the cancellation of a $41.6 million contingent note that arose from the previously restructured debt, resulting in the payment of $1.5 million to RUS which is reflected as a deferred debit as approved by the NHPUC. The payment is being amortized over sixty months which began August 30, 1995. Amortization of $125,000 was taken in 1995 and is reflected in other nonoperating margins in the statement of operations.

The financing agreement requires the Cooperative to purchase long-term capital term certificates (LCTC) in an amount not to exceed three percent of the total principal amount borrowed from CFC. CFC calculates the amount of LCTC that are required to be purchased at the time of each loan advance. The Cooperative chose the option of purchasing the LCTC using future CFC patronage capital retirements. The amount of LCTC that NHEC is committed to purchase at December 31, 1995, is approximately $2,190,000.

CFC initially advanced funds totaling $187,464,000 on August 30, 1995, at CFC's long-term variable rate. The loan agreement allowed NHEC the option to secure fixed interest rates on specific advance amounts subsequent to the closing based on the CFC weekly published rate. Within the appropriate period NHEC elected to convert from the long-term variable rate to long-term fixed rate notes with various maturities and interest rates.

The refinancing transaction that occurred in 1995 resulted in a discount of approximately $3,298,000 which was reflected as an extraordinary item; gain on the retirement of debt.

Under the terms of the agreement, NHEC will refinance its remaining obligations with RUS by January 31, 1997. NHEC will receive an additional discount on the refinancing of the 2% and the 5% long-term debt notes payable. On January 30, 1996, CFC advanced NHEC $24,698,000 to prepay the 5% note payable with RUS, realizing a discount of approximately $1.4 million. The remaining 2% long-term obligation with RUS is scheduled to be refinanced in January 1997, at which time the discount will be determined subject to current interest rates.

6. Long-Term Obligations (Concluded)

Principal payments to be made on long-term obligations are as follows:

	(000s)
1996	$4,700
1997	4,721
1998	5,153
1999	5,528
2000	31,646

The above principal payments on long-term debt reflect the refinancing that will occur in 1996 and 1997 based on the agreement with CFC.

The principal payments for the year 2000 reflect the pay off of certain variable rate notes payable to CFC. This pay off will be funded by payments from PSNH, commencing in July 1997, in accordance with the Seabrook Sellback Contract.

7. Patronage Equities

At December 31, 1995 and 1994, patronage capital consisted of:

	1995 (000s)	1994 (000s)
Assigned	**$13,308**	$10,072
Unassigned	-	3,236
	$13,308	$13,308

8. Long-Term Power Supply and Sale Agreements

The Cooperative has traditionally been a distribution cooperative purchasing power at wholesale to distribute to its retail customers. In 1981, in connection with its acquisition of the 2.17391% interest in the Seabrook nuclear facility, NHEC updated a partial requirements service arrangement with PSNH and entered into a Sellback Contract (Sellback) which, for a period of ten years, required PSNH to buy, at NHEC's cost, any part of NHEC's Seabrook capacity and energy determined to be in excess of NHEC's needs.

8. Long-Term Power Supply and Sale Agreements (Concluded)

Pursuant to contracts agreed to under the Plan, PSNH provides NHEC wholesale power at the so-called "Muni Rate" (the wholesale power rates established pursuant to the settlement among PSNH and certain municipal electric utilities approved by the FERC) through November 1, 2006, and continuing thereafter unless five years notice of termination has been provided by either party. NHEC has an exclusive option to extend the contract term until November 1, 2011, upon notice to PSNH by November 1, 2001.

PSNH purchases power resulting from NHEC's Seabrook interest pursuant to a modified Sellback. The Sellback terms call for PSNH to purchase the entire amount of NHEC's Seabrook capacity and energy and to pay all NHEC's Seabrook and associated transmission costs, without regard to Seabrook's operating status, for the ten-year period which began on July 1, 1990. Revenue from the Sellback agreement, reflected in operating revenues, amounted to approximately \$16,538,000 and \$17,587,000 in 1995 and 1994, respectively. Accounts receivable currently due from PSNH under the contract are approximately \$3,101,000 and \$3,024,000 at December 31, 1995 and 1994, respectively. For purposes of the rates paid to the Cooperative by PSNH under the agreement, NHEC's initial cost of Seabrook was established at \$126 million by order of the NHPUC. The initial cost was further reduced on December 1, 1993 (effective date) by \$17 million pursuant to the modified Sellback. The terms of payment also provide for phase-in of Sellback rates through a graduated deferral of costs in the first five years commencing July 1, 1990, recovered with interest during the last three years. The Cooperative deferred approximately \$3,743,000 and \$5,054,000 in costs during 1995 and 1994, respectively, for a cumulative deferred balance of approximately \$36,940,000 at December 31, 1995, and \$33,197,000 at December 31, 1994. Interest on the deferred balance is accrued at the weighted average rate of Seabrook designated notes payable.

As part of the settlement between the Cooperative and PSNH, the Cooperative compensated PSNH for its pre-bankruptcy claim resulting from the excess of NHEC's unpaid bills from PSNH over PSNH's unpaid charges from NHEC under the Sellback (recomputed in accordance with the phase-in term discussed above). This compensation is in the form of a promissory note issued to PSNH on December 1, 1993, in the principal amount of \$5.5 million (see Note 6).

In addition, capacity and energy are purchased on a wholesale customer basis under contracts from four other suppliers.

9. Deferred Credits

Deferred credits at December 31, 1995 and 1994, were as follows:

	1995 (000s)	1994 (000s)
Demand side management over recovery	$ 671	$ -
Seabrook	55	93
Postretirement benefits	1,551	-
	$2,277	$93

10. Pension and 401(k) Savings Plan

Substantially all of the employees of the Cooperative participate in the National Rural Electric Cooperative Association (NRECA) Retirement and Security Program, a multi employer, defined benefit pension plan. The Cooperative funds accrued pension costs on an annual basis. From July 1, 1987, through October 1994, a moratorium on payments for normal and past service cost contributions had been imposed because the Pension Plan had reached funding limitations. The moratorium was lifted in November 1994. The Cooperative made one annual past service cost payment and four monthly future service cost payments in 1995 and one annual past service cost payment and two monthly future service cost payments in 1994. Pension costs totalled $560,500 and $383,900 for 1995 and 1994, respectively. The moratorium was reinstated in April of 1995 and is scheduled to be lifted in April of 1996 for an undetermined period.

The Cooperative has established a tax qualified 401(k) savings plan for the benefit of its employees and their beneficiaries. The Cooperative's contribution ranges from 1.6% - 2.0% of annual base pay; bonuses and overtime are excluded. The Cooperative's contribution totalled $129,600 and $119,200 for 1995 and 1994, respectively.

11. Employee Severance Agreements

The Reorganization Plan provided for the severance of several senior management personnel. Severance agreements were entered into with these individuals and the Cooperative made all payments required under the agreements, totaling approximately $114,000, in 1994.

12. Postretirement Benefit Plan

The Cooperative sponsors a defined benefit postretirement medical and life insurance plan for which it adopted FAS 106 for the year ended December 31, 1995. Expenses for 1995 include only amounts paid for retirees as is allowed in approved rate tariffs. The remaining obligation for past service costs, as well as service and interest costs for 1995, have been accrued. A deferred asset of $1,508,000 has been recorded for accrued unrecovered costs, the recovery of which is contingent upon the outcome of the rate making proceedings. Management expects to begin recovery of costs in 1996.

The plan is contributory, with contributions set as a percent of benefit costs plus deductibles and coinsurance. Current costs of retired employees were paid from operations.

The following sets forth the plan's funded status reconciled with amounts reported in the Cooperative's balance sheet at December 31, 1995:

	(000's)
Accumulated Postretirement Benefit Obligation (APBO):	
Retirees and dependents	$ (231)
Fully eligible active plan participants	(21)
Other active plan participants	(1,299)
	(1,551)
Plan assets at fair value	-
APBO in excess of plan assets	(1,551)
Unrecognized net gain from past experience different from that assumed and from changes in assumptions	-
Prior service costs not yet recognized in net periodic Postretirement benefit costs	-
Unrecognized transition obligation	-
Accrued postretirement benefit cost	$(1,551)

12. Postretirement Benefit Plan (Concluded)

Net periodic postretirement benefit cost for 1995 included the following companies:

	(000's)
Service costs	$ 79
Interest costs	111
Amortization of transition obligation over 20 years	71
Net periodic postretirement benefit cost	261
Amount deferred for rate making	200
Current expenses for retirees	$ 61

A 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 1995 and 9.5% for 1996. The rate was assumed to decrease gradually to 5.5% per year by 2004 and remain at that level, thereafter. The health care cost trend rate assumption has a significant effect on the amounts reported. To illustrate, increasing the assumed health care cost trend rates by 1% in each year would increase the APBO as of December 31, 1995, by $152,900 and the aggregate of the service and interest cost components of the net periodic postretirement benefit cost for the year by $20,500. The weighted-average of the assumed discount rate used in determining the APBO was 8%.

13. Fair Value of Financial Instruments

The Cooperative's financial instruments consist of cash, short-term trade receivables and payables, investments in nontraded stocks, lines of credit, and long-term debt. The carrying value of all instruments, except long-term debt, approximate their fair value. Based on the borrowing rates currently available to the Cooperative for loans with similar terms and average maturities, the fair value of long-term debt is approximately $261,300,000 as of December 31, 1995. These estimates are not necessarily indicative of the amounts that the Cooperative could realize in the current market and different methodologies may have a material effect on the estimated fair value amounts.

14. Subsequent Event - Pilot Program

In 1996, the New Hampshire legislature passed a bill to create a pilot program (the Pilot) to test the impact of allowing electric customers to choose the source of their electric supply. The NHPUC is responsible for oversight of this Pilot, and has set May 28, 1996, as the implementation date. The Pilot, which is expected to last up to two years, opens to competition the generation component of electric service and keeps the delivery of electricity with the existing franchised utilities. The Pilot is limited to 3% of NHEC's load which is approximately 2,350 of NHEC's 66,000 members.

Pursuant to the NHPUC's Pilot guidelines, NHEC has filed supplementary tariffs for the distribution of electric service and recovery of implementation costs for the Pilot. These tariffs and charges are subject to NHPUC approval which is anticipated prior to May 28, 1996.

NHEC supports the program and views competition as a benefit to its members. Since the cost of power is a significant component of NHEC's members electric bill and access to competitive power is anticipated to reduce members' bills, it is expected that NHEC's revenues will be reduced. However, if members purchase power directly from suppliers, NHEC's cost of purchase power should also drop. NHEC does not expect any significant financial impact as a result of members switching power suppliers.

15. Commitments and Contingencies

The Cooperative is involved in various legal proceedings incidental to the conduct of its normal business operations. In the opinion of management, these proceedings will not have a material adverse impact on the financial condition of the Cooperative.

FINANCIAL STATEMENTS AND
REPORT OF INDEPENDENT
CERTIFIED PUBLIC ACCOUNTANTS
TAUNTON MUNICIPAL LIGHTING PLANT
December 31, 1995 and 1994

CONTENTS

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Grant Thornton
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Report of Independent Certified Public Accountants

Municipal Light Commission
of the City of Taunton
Taunton, Massachusetts

We have audited the accompanying balance sheets of the Taunton Municipal Lighting Plant (a department of the City of Taunton) as of December 31, 1995 and 1994, and the related statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Plant'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 our audits provide a reasonable basis for our opinion.

As discussed in note H to the financial statements, certain disclosures required by the Governmental Accounting Standards Board relating to pensions have been omitted.

In our opinion, except for the omission of certain pension plan disclosures required by the Governmental Accounting Standards Board, the financial statements referred to in the first paragraph above present fairly, in all material respects, the financial position of the Taunton Municipal Lighting Plant as of December 31, 1995 and 1994, and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

As discussed in note A of notes to the financial statements, the Plant changed its method of accounting for vacation pay during 1994.

Grant Thornton LLP

Boston, Massachusetts
March 1, 1996

Taunton Municipal Lighting Plant

BALANCE SHEETS

December 31,

ASSETS

	1995	1994
UTILITY PLANT - AT COST		
Plant in service	$102,837,518	$91,447,840
Less accumulated depreciation (note A4)	59,865,179	56,046,338
Net utility plant in service	42,972,339	35,401,502
Investment in Seabrook (notes A9 and C)	3,054,850	3,189,676
Construction work in progress (note I)	2,447,515	6,431,926
Total utility plant	48,474,704	45,023,104
DEPRECIATION FUND (including certificates of deposit of $4,490,000 and $3,320,000 in 1995 and 1994, respectively) (notes A4 and B)	11,454,062	12,547,801
SICK LEAVE TRUST FUND (note A7)	3,165,943	2,750,723
OTHER ASSETS		
Investment in Hydro Quebec Project (note G)	311,472	311,472
Lightwaves (note D)	190,024	286,124
Other deferred debits (note J)	157,029	530,432
CURRENT ASSETS		
Cash (note B)	2,234,908	3,644,671
Customer deposits (note B)	388,175	346,761
Accounts receivable, less allowance for doubtful accounts of $666,721 and $703,154, respectively	4,003,474	3,273,919
Due from TMLP Retirement Trust (notes A5 and H)	523,851	451,320
Materials and supplies inventory (note A6)	1,581,601	1,848,482
Prepaid expenses	239,923	261,433
Total current assets	8,971,932	9,826,586
	$ 72,725,166	$71,276,242

RETAINED EARNINGS AND LIABILITIES

	1995	1994
RETAINED EARNINGS		
Appropriated retained earnings		
Loans repayment	$ 17,677,000	$16,837,000
Construction repayment	32,434	32,434
	17,709,434	16,869,434
Unappropriated retained earnings	28,763,980	26,777,454
Unrealized gain (loss) on securities held for sale	61,173	(140,498)
Total retained earnings	46,534,587	43,506,390
LONG-TERM DEBT (note E)	14,563,509	15,476,862
CURRENT LIABILITIES		
Accounts payable	2,506,746	2,430,151
Customer credits (note A8)	3,099,239	4,301,356
Customer deposits	419,973	364,414
Current maturities of long-term debt (note E)	910,000	840,000
Accrued liabilities		
Sick leave (note A7)	3,393,911	3,087,851
Vacation (note A11)	609,647	550,819
Interest	527,782	554,907
Payroll	157,100	153,335
Other	2,672	10,157
Total current liabilities	11,627,070	12,292,990
COMMITMENTS AND CONTINGENCIES (notes C, G, H, I and K)		
	$ 72,725,166	$71,276,242

The accompanying notes are an integral part of these statements.

Taunton Municipal Lighting Plant

STATEMENTS OF EARNINGS

Year ended December 31,

	1995	1994
Operating revenues (note A3)		
Sales of electricity		
Commercial and industrial	$22,478,329	$20,149,485
Residential	15,171,111	14,061,642
Sales for resale (note G)	3,026,888	2,750,653
Municipal	1,806,061	1,695,950
	42,482,389	38,657,730
Other operating revenues	287,218	224,284
Total operating revenues	42,769,607	38,882,014
Operating expenses		
Power production	23,423,761	20,359,073
Transmission and distribution	2,872,586	2,726,964
Customer accounting	1,372,857	1,374,869
Administrative and general (notes A7 and H)	4,837,896	4,700,143
Depreciation and amortization (note A4)	4,026,978	3,876,795
Nuclear expense	225,388	212,887
Total operating expenses	36,759,466	33,250,731
Earnings from operations	6,010,141	5,631,283
Other expense (income)		
Interest expense	1,256,410	1,317,094
Interest income	(267,390)	(276,044)
Other income (note G)	(165,405)	(112,763)
Total other expense	823,615	928,287
Earnings before provision for payment in lieu of taxes	5,186,526	4,702,996
Provision for payment in lieu of taxes (note F)	2,360,000	2,360,000
NET EARNINGS	$ 2,826,526	$ 2,342,996

The accompanying notes are an integral part of these statements.

Taunton Municipal Lighting Plant

STATEMENTS OF RETAINED EARNINGS

Years ended December 31, 1995 and 1994

	Appropriated Retained Earnings		
	Loan Repayment	Construction Repayment	Unappropriated Retained Earnings
Balance at January 1, 1994	$16,062,000	$32,434	$25,209,458
Transfer for bond repayment	775,000		(775,000)
Net earnings	—	—	2,342,996
Balance at December 31, 1994	16,837,000	32,434	26,777,454
Transfer for bond repayment	840,000		(840,000)
Net earnings	—	—	2,826,526
Balance at December 31, 1995	$17,677,000	$32,434	$28,763,980

The accompanying notes are an integral part of these statements.

Taunton Municipal Lighting Plant

STATEMENTS OF CASH FLOWS

Year ended December 31,

	1995	1994
Increase (Decrease) in Cash and Cash Equivalents		
Cash flows from operating activities:		
Net earnings	$ 2,826,526	$ 2,342,996
Adjustments to reconcile net earnings to net cash and cash equivalents provided by operating activities:		
Depreciation and amortization	4,026,978	3,876,795
Amortization of bond premium	(3,353)	(3,354)
Equity in losses of Seabrook investment	(20,418)	(18,579)
Change in assets and liabilities:		
(Increase) in customer deposit funds	(41,414)	(44,636)
(Increase) decrease in accounts receivable	(729,555)	78,093
Increase in due from retirement trust	(72,531)	(63,484)
Decrease in inventory	266,881	86,199
(Increase) decrease in prepaid expenses	21,510	(148,815)
Decrease (increase) in Lightwaves	96,100	(23,261)
Decrease in deferred debits	373,403	373,392
Increase in accounts payable	76,595	531,919
(Decrease) increase in customer credits	(1,202,117)	2,087,590
Increase in customer deposits	55,559	55,761
Increase in accrued sick leave and vacation	364,888	239,156
(Decrease) in other accrued liabilities	(30,845)	(31,541)
Net cash provided by operating activities	6,008,207	9,338,231
Cash flows from investing activities:		
Net additions to utility plant	(7,458,160)	(5,776,631)
Proceeds from maturing certificates of deposits - depreciation fund	-	2,500,000
Increase in Sick Leave Trust Fund	(213,549)	(269,816)
Net cash used in investing activities	(7,671,709)	(3,546,447)
Cash flows from financing activities:		
Payment of long-term debt	(840,000)	(775,000)
Net (decrease) increase in cash and cash equivalents	(2,503,502)	5,016,784
Cash and cash equivalents at beginning of year	12,872,472	7,855,688
Cash and cash equivalents at end of year	$10,368,970	$12,872,472

Taunton Municipal Lighting Plant

STATEMENTS OF CASH FLOWS - CONTINUED

Year ended December 31,

	1995	1994
Cash and cash equivalents at end of year is reflected on the balance sheets as follows:		
Depreciation funds	$ 8,134,062	$ 9,227,801
Cash	2,234,908	3,644,671
	$10,368,970	$12,872,472

Supplemental Disclosure of Cash Flow Information:

	1995	1994
Cash paid during the year for interest	$ 1,286,889	$ 1,341,958

The accompanying notes are an integral part of these statements.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A summary of Taunton Municipal Lighting Plant's (the "Plant") significant accounting policies consistently applied in the preparation of the accompanying financial statements follows.

1. Nature of Business

   Taunton Municipal Light Plant (TMLP) is a regulated municipal electric utility located in Taunton, Massachusetts. TMLP operates as an enterprise fund of the City of Taunton, Massachusetts, and produces, purchases and distributes electricity to approximately 35,000 customers in the City of Taunton and the surrounding areas.

2. Use of Estimates

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

3. Rates

   The Plant is under the charge and control of the Municipal Light Plant Commissioners in accordance with Chapter 164, Section 55 of the General Laws of the Commonwealth of Massachusetts. Electric power is both produced and purchased and is distributed to customers within their service area. The rates charged by the Plant to its customers are filed with the Massachusetts Department of Public Utilities (MDPU) and are subject to Chapter 164, Section 58 of the General Laws, which provides that prices shall be fixed to yield not more than 8% per annum on the cost of the plant after repayment of operating expenses, interest on outstanding debt and depreciation. The Plant's resulting net earnings amounted to 3.9% of utility plant in both 1995 and 1994.

4. Depreciation

   Pursuant to the Department of Public Utilities regulations, depreciation is calculated as a percentage of depreciable property at January 1. Depreciation is computed at 4% of the cost of depreciable property.

   Depreciation fund cash is used in accordance with state laws for replacements and additions to the utility plant in service.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

5. Pension Plan

Substantially all employees of the Plant are covered by a contributory pension plan administered by the City of Taunton in conformity with State Retirement Board requirements (see note H).

6. Inventory

Materials and supplies inventory is carried at cost, principally on the average cost method.

7. Sick Leave Trust Fund

The Plant established a Sick Leave Trust Fund ("Trust") in 1982 for the financing of future sick leave payments. It is the Plant's intention that the Trust be funded to the extent of the Plant's sick leave liability and that future sick leave expense will be paid by the Trust once full funding is achieved. The assets of the Trust are shown in the financial statements to provide a more meaningful presentation, as the assets of the Trust are for the sole benefit of the Plant.

Effective December 31, 1995, the Plant adopted Statement of Financial Accounting Standards ("SFAS") No. 115, "Accounting for Certain Investments in Debt and Equity Securities". Under SFAS No. 115, debt securities that the Company has the positive intent and ability to hold to maturity are classified as held to maturity and reported at amortized cost; debt and equity securities that are bought and held principally for the purpose of selling in the near term are classified as trading and reported at fair value, with unrealized gains and losses included in earnings; and debt and equity securities not classified as either held to maturity or trading are classified as available for sale and reported at fair value, with unrealized gains and losses excluded from earnings and reported as a separate component of retained earnings. Gains and losses on the sale of securities are recognized at the time of sale on a specific identification basis. The effect of the adoption of SFAS No. 115 on 1995 and 1994, was not significant.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

In addition to money market funds and accrued income, the estimated market values of securities included in the Sick Leave Trust Fund at December 31, were as follows:

	Cost	Unrealized Gains	Unrealized Losses	Estimated Market Value
		(In Thousands)		
Securities available for sale at December 31, 1995				
US Treasury obligations (maturing May 1997 through August 2023)	$1,893	$63		$1,956
US Government agency obligations (maturing August 1997 through September 1998)	218	1	$ 5	214
Other corporate obligations (maturing May 1996 through March 2000)	488	7	9	486
Foreign bonds and other	157	3	—	160
Total securities available for sale	$2,756	$74	$14	$2,816
Securities available for sale at December 31, 1994				
US Treasury obligations	$ 943	$1	$ 58	$ 886
US Government agency obligations	885	2	35	852
Other corporate obligations	603	2	38	567
Foreign bonds and other	244	-	15	229
Total securities available for sale	$2,675	$5	$146	$2,534

Net investment income for the Trust of approximately $219,000 and $147,000 in 1995 and 1994, respectively, is reflected in the statements of earnings as an offset to compensated absence expense, as these funds are restricted and can only be used for the payment of sick leave benefits. The net expense for sick leave was approximately $241,000 and $283,000 for the years ended December 31, 1995 and 1994, respectively.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

8. Customer Credits

The Plant's rates include a Purchased Power Cost Adjustment (PPCA) which allows an adjustment of rates charged to customers in order to recover all changes in power costs from stipulated base costs. The PPCA provides for a quarterly reconciliation of total power costs billed with the actual cost of power incurred. Any excess or deficiency in amounts collected as compared to costs incurred is deferred and either credited or billed to customers over subsequent periods.

9. Investment in Seabrook

The Plant's Investment in Seabrook represents a 0.10034% joint ownership share. The Plant records annually depreciation computed at 4% of the initial investment in Seabrook. The Plant's percentage share of new plant additions are capitalized and their share of operating and maintenance expenses, and decommissioning expenses (see note C) are charged against earnings.

10. Cash Equivalents

For purposes of the Statement of Cash Flows, the Plant considers certificates of deposit with maturities of three months or less to be cash equivalents.

11. Vacation

In 1994, the Plant adopted Governmental Accounting Standards Board Statement No. 16 (GASB No. 16), "Accounting for Compensated Absences". The effect of the adoption was not material to operations in 1994.

12. Reclassifications

Certain amounts in the financial statements for the year ended December 31, 1994, have been reclassified to conform to the current year presentation.

NOTE B - CASH AND CERTIFICATES OF DEPOSIT

The Plant's cash is deposited with the City of Taunton Treasurer who commingles it with other City funds. The City invests the cash and credits the Plant each year with interest earned on the cash deposits.

Cash and certificates of deposit deposited with the City of Taunton consists of the following at December 31,

	1995	1994
Interest bearing pooled funds including restricted customer deposits of $388,175 and $346,761, respectively	$ 9,587,145	$12,309,233
Certificates of deposit with rates of 4.95% - 5.25% maturing at various dates during 1995		910,000
Certificates of deposit with rates of 5.08% - 5.69% maturing at various dates during 1996	4,490,000	3,320,000
	$14,077,145	$16,539,233

Cash and certificates of deposit at December 31, is reflected as follows:

	1995	1994
Depreciation fund	$ 7,399,833	$ 8,696,950
Depreciation fund - Unit 9 principal and interest	4,054,229	3,850,851
Cash	2,234,908	3,644,671
Customer deposit principal and interest fund	388,175	346,761
	$14,077,145	$16,539,233

NOTE C - INVESTMENT IN SEABROOK

The Plant is a 0.10034% joint owner of the Seabrook New Hampshire Unit 1.

The joint owners of Seabrook have established a Decommissioning Fund that is currently held by a Trustee. The Plant's share of the estimated decommissioning liability is approximately $415,000 as of January 1, 1995 (the most current valuation date). The Plant is currently contributing, based on a present value formula, $550 per month over 36 years.

NOTE D - LIGHTWAVES

The Plant has initiated an energy saving program for commercial and industrial customers known as Lightwaves. The program entitles the customer to a free energy audit and installation of energy efficient equipment. Customers are required to pay a monthly fee for a 60 month period. The fee is based upon the administrative costs related to the program. The related administrative costs are being deferred and amortized over the 60 month billing period. As of December 31, 1994, the Plant has deferred these costs which will be billed to customers. During 1995, the Plant changed its method for accounting for the administrative cost by expensing current administrative cost relating to the lightwaves program and continuing to amortize cost previously deferred. This change did not have a material effect on the financial statements.

NOTE E - LONG-TERM DEBT

Long-term debt is comprised of the following bonds:

	1995	1994
Electric loan, Act of 1969		
Interest rate - various rates from 7.5% to 8%, interest payable February 1 and August 1, due serially to February 1, 2006	$15,440,000	$16,280,000
Unamortized premium	33,509	36,862
	15,473,509	16,316,862
Less current maturities	910,000	840,000
Total long-term debt	$14,563,509	$15,476,862

Aggregate maturities of long-term debt at December 31, 1995, are as follows:

1996	$ 910,000
1997	985,000
1998	1,065,000
1999	1,150,000
2000	1,250,000
Thereafter	10,080,000
	$15,440,000

The fair market value of the debt approximates its book value.

NOTE F - CONTRIBUTION IN LIEU OF TAXES

The Plant contributed $2,360,000 in 1995 and 1994 to the City of Taunton in lieu of taxes. All contributions to the City are voted by the Municipal Light Commission.

NOTE G - COMMITMENTS AND CONTINGENCIES

Interconnection Agreement

The City of Taunton, acting by vote of its Municipal Lighting Plant Commission, entered into an agreement with Montaup Electric Company ("Montaup"), dated July 31, 1970, as amended, concerning interconnection of electrical operations, purchase and sale of kilowatt capacity, and construction by Taunton of a generating unit of approximately 110 megawatt capability. Under the current interconnection agreement, the City agrees to exchange with Montaup Electric Company fifteen (15) megawatts of Unit No. 9 capacity for ten (10) megawatts of capacity from the Canal No. 2 generating unit, 50% of which is owned by Montaup. The Plant credited to sales for resale $377,383 and $317,755 of capacity and energy charges billed to Montaup Electric Company in 1995 and 1994, respectively, for its share of power under the interconnection agreement.

Hydro-Quebec Agreement

In 1988, the Plant entered into an agreement with the Massachusetts Municipal Wholesale Electric Company and other New England Utilities to support the operation of a transmission line to permit the interchange of electricity between such utilities and Hydro-Quebec Electric Corporation (HydroQuebec). In connection with the agreement, the Plant advanced approximately $800,000 toward development of the project of which approximately $450,000 was returned after the project had obtained financing. In 1991, the Hydro Quebec project was completed. Upon completion of this project, each participant received stock in the New England Hydro Transmission Electric Company and The New England Hydro Transmission Corporation proportional to their advances. The investment is being accounted for on the cost basis. The stock received is not readily marketable, but gives the holder rights to purchase power at a percentage of the fossil fuel rate.

During the years ended December 31, 1995 and 1994, the Plant received dividends from the above noted Companies in the amounts of $53,638 and $55,055, respectively.

NOTE G - COMMITMENTS AND CONTINGENCIES - Continued

Litigation and Other Matters

The Plant is involved in various legal matters incident to its business, none of which is believed by management to be significant to the financial condition of the Plant (see note I).

The Plant is also involved in several proceedings relating to environmental matters. Although it is difficult to estimate the liability, if any, of the Plant related to those environmental matters, the Plant believes that those matters will not have a material adverse effect upon its financial condition.

NOTE H - PENSION PLANS

The Plant contributes to the City of Taunton Retirement System ("System"), a public employee retirement system that acts as the investment and administrative agent for the City. All full-time employees participate in the System.

Instituted in 1937, the System is a member of the Massachusetts Contributory System and is governed by Massachusetts General Laws Chapter 32. Membership in the System is mandatory upon the commencement of employment for all permanent, full-time employees.

The System provides for retirement allowance benefits up to a maximum of 80% of a member's highest three-year average annual rate of regular compensation. Benefit payments are based upon a member's age, length of creditable service, level of compensation and group classification.

Members of the System become vested after 10 years of creditable service. A retirement allowance may be received upon reaching age 65 or upon attaining twenty years of service. The System also provides for early retirement at age 55 if the participant (1) has a record of 10 years of creditable service, (2) was on the City's payroll on January 1, 1978, (3) voluntarily left City employment on or after that date, and (4) left accumulated annuity deductions in the fund. Active members contribute either 5%, 7% or 8% of their regular compensation depending on the date upon which their membership began. The System also provides death and disability benefits.

NOTE H - PENSION PLANS - Continued

The System does not make a separate measurement of assets and the pension benefit obligation for the Plant. The pension benefit obligation is a standardized disclosure measure of the present value of pension benefits, adjusted for the effects of projected salary increases and step-rate benefits, estimated to be payable in the future as a result of employee service to date. The measure is intended to help users assess the funding status of the System on a going-concern basis, assess progress made in accumulating sufficient assets to pay benefits when due, and make comparisons among employers. The measure is the actuarial present value of credited projected benefits and is independent of the funding method used to determine contributions to the System. As of July 1, 1995 (the most current valuation date), the Plant's unfunded actuarial accrued liability is approximately $14,699,000.

The Plant has established a separate Employees Retirement Trust Fund (Trust Fund) for the financing of future pension payments. The Trust Fund had net assets (at cost) of approximately $12,934,000 and $12,806,000 at December 31, 1995 and 1994, respectively. The market value of the net assets at December 31, 1995 and 1994 was approximately $13,549,000 and $12,373,000, respectively. These funds are invested in money market funds, fixed income securities including government and corporate bonds and other equity securities. The Plant has made no contributions to the Trust Fund in either 1995 or 1994.

The Plant receives from the Trust Fund, over the next thirty-two years, an amount equal to eighty-five percent of the annual amortization of the unfunded pension liability. The remaining fifteen percent of the unfunded pension liability will be contributed from current year operations.

The following represents the components of the Plant's recorded pension expense:

	December 31,	
	1995	1994
Contributions to the System	$1,547,652	$1,364,761
Contributions from the Trust Fund	(975,163)	(839,146)
Recorded pension expense	$ 572,489	$ 525,615

Prior to 1993, the System's funding policy for the participating entities was not actuarially determined. The participating entities were required to contribute each fiscal year an amount approximating the pension benefits (less certain interest credits) expected to be paid during the year ("pay-as-you-go" method). Effective for fiscal year ends 1993 and beyond, the System has removed the "pay-as-you-go" method and will amortize the unfunded pension benefit obligation over thirty-two years. This change has been approved by Public Employees Retirement Association.

NOTE H - PENSION PLANS - Continued

Accounting standards require certain related disclosures be made including the components of pension costs and the funded status of the System The effect of omitting such disclosure on the accompanying financial statements has not been determined for the year ended December 31, 1995.

NOTE I - COAL FIRE ELECTRIC GENERATING FACILITY

On January 31, 1991, the Plant entered into contracts with Silver City Energy Limited Partnership (the "Developer"), a Delaware limited partnership. The contracts pertain to the leasing of a 25 acre parcel, owed by the Plant, adjacent to the Plant's Cleary-Flood Station and the subsequent building of a coal fired electric generating facility (coal plant) by the Developer.

The ground lease extends for a period of forty years. Rental payments to the Plant are $50,000 per year until the earlier of May 15, 1997, or the commencement date of operations, and $1,100,000 per year for the remaining lease term.

The Plant has agreed to purchase 20% of the power generated once the coal plant is in operation, which is approximately 30 megawatts. The agreement is for twenty years.

The Plant has secured a mortgage on the buildings and facilities to be constructed to secure payment of the aggregate differential. The aggregate differential represents funds to be paid to the Plant in the event that the project is not completed. Payment is based on a dollar value per kilowatt which increases over the duration of the construction period.

If operations do not commence by September 15, 1996, the Plant may terminate all contracts with the Developer. In the event of termination of the contracts, the Plant may be entitled to reimbursement by the Developer of up to 50% of certain costs incurred by the Plant.

As of December 31, 1995, the Plant has capitalized approximately $1,617,000 of legal and administrative costs which are included in construction work in progress. These costs will be amortized over the contract period once operations have commenced.

With respect to the proposed plant construction, the Plant is involved in certain legal matters relating to zoning. In the opinion of management, the resolution of these matters will not effect the ultimate completion of this project. Due to the uncertainties in the permitting process, however, it is at least reasonably possible that management's estimate of the outcome would change during the next year.

NOTE J - DEFERRED MAINTENANCE

A unit of the Plant underwent a maintenance overhaul, of which the related costs are being amortized over a five-year period. The unamortized balance at December 31, 1995 and 1994 is $157,029 and $530,432, respectively.

NOTE K - POST EMPLOYMENT BENEFITS

In addition to the pension benefits described in note H, the Plant provides post employment health care benefits to retirees that meet certain requirements. Retirees of the Plant under age 65 are eligible for the same health benefits as active employees, while retirees over the age of 65 are eligible for MEDEX. The costs of the benefits provided to retirees are borne 75% by the Plant, and 25% by the retirees. Retiree's survivors must bear the full cost of the benefits.

The Plant is charged their prorata portion of the "pay-as-you-go" cost of benefits based on an allocation by the City done annually. For 1995 and 1994, the costs allocated to the Plant were approximately $334,000 and $331,000, respectively.

SUPPLEMENTAL INFORMATION

Report of Independent Certified Public Accountants
on Supplemental Information

Taunton Municipal Lighting Plant

Our audit was conducted for the purpose of forming an opinion on the basic financial statements taken as a whole of Taunton Municipal Lighting Plant for the year ended December 31, 1995, which are presented in the preceding section of this report. The supplemental information presented hereinafter is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated, in all material respects, in relation to the basic financial statements taken as a whole.

Grant Thornton LLP

Boston, Massachusetts
March 1, 1996

Taunton Municipal Lighting Plant

OPERATING EXPENSES

For the year ended December 31,

	1995	1994
POWER PRODUCTION		
Operation		
Supervision and engineering	$ 668,878	$ 649,953
Fuel	3,149,467	2,594,936
Labor and expenses	1,868,474	1,850,835
	5,686,819	5,095,724
Maintenance		
Supervision and engineering	264,310	337,342
Structures	135,389	210,138
Boiler plant	804,485	826,422
Electric plant	968,278	497,693
Miscellaneous	321,262	219,876
	2,493,724	2,091,471
Purchased power	15,243,218	13,171,878
Total power production	23,423,761	20,359,073
TRANSMISSION AND DISTRIBUTION		
Operation		
Supervision and engineering	162,262	159,522
Labor	18,904	20,445
Supplies and expenses	8,002	10,269
Meter expenses	180,971	167,969
Customer installation	19,165	17,896
Transmission by others	216,010	172,927
Overhead lines	113,819	114,406
Miscellaneous	243,602	246,906
	962,735	910,340
Maintenance		
Supervision and engineering	313,039	341,599
Lines - electric	1,321,924	1,156,615
Street lighting and signal systems	132,137	147,579
Meters	9,915	9,117
Structures and equipment	1,238	11,786
Line transformers	69,279	51,205
Station equipment	53,449	88,307
Miscellaneous	8,870	10,416
	1,909,851	1,816,624
Total transmission and distribution	2,872,586	2,726,964
Forward	26,296,347	23,086,037

Taunton Municipal Lighting Plant

OPERATING EXPENSES - CONTINUED

Year ended December 31,

	1995	1994
Brought forward	$26,296,347	$23,086,037
CUSTOMER ACCOUNTING		
Meter reading labor and expenses	227,147	208,332
Accounting and collecting expenses	939,487	878,325
Uncollectible accounts	188,400	282,234
Advertising expense	17,823	5,978
Total customer accounting	1,372,857	1,374,869
ADMINISTRATIVE AND GENERAL		
Operation		
Administrative and general salaries	725,995	809,065
Office supplies and expenses	211,145	209,479
Outside services employed	190,561	175,767
Property insurance	149,223	125,092
Injuries and damages	445,819	465,372
Employee pensions and benefits	2,009,964	2,072,702
Miscellaneous general expenses	481,221	306,524
Transportation expenses	274,101	238,964
Regulatory commission expense	193,452	116,290
	4,681,481	4,519,255
Maintenance		
General plant	156,415	180,888
Total administrative and general	4,837,896	4,700,143
DEPRECIATION AND AMORTIZATION	4,026,978	3,876,795
NUCLEAR EXPENSE	225,388	212,887
	$36,759,466	$33,250,731

Taunton Municipal Lighting Plant
Utility Plant
For Period Ending December 31, 1995

Acct No	Title of Account	Balance 01/01/95	Additions	Retirements	Balance 12/31/95	Accumulated Depreciation 12/31/95	Depreciated Valve 12/31/95
Station Production Plant							
310	Land and Land Rights	749,366	-	-	749,366	-	749,366
311	Structures & Improvements	7,399,174	1,966,694	-	9,365,867	5,985,292	3,380,575
312	Boiler Plant Equipment	19,143,622	4,500,433	-	23,644,055	14,347,172	9,296,883
314	Turbo Generator Units	18,229,690	713,763	-	18,943,453	11,865,149	7,078,303
315	Acessory Electric Group	2,666,871	30,643	-	2,697,513	2,689,489	8,024
316	Misc Power Plant Equip	679,263	126,467	-	805,731	677,934	127,797
	Total Steam Production Plant	48,867,986	7,338,000	-	56,205,985	35,565,036	20,640,949
Other Production Plant							
342	Fuel Holders & Accessories	542,044	78,797	-	620,841	383,276	237,565
344	Generators	83,407	-	-	83,407	62,693	20,714
345	Accessory Electric Group	407,598	-	-	407,598	302,859	104,739
	Total Other Production Plant	1,033,049	78,797	-	1,111,846	748,828	363,017
Transmission Plant							
350	Land & Land Rights	216,242	-	-	216,242	-	216,242
351	Clearing Land Right of Way	35,022	-	-	35,022	-	35,022
352	Structures & Improvements	133,392	-	-	133,392	90,000	43,392
353	Station Equipment	2,395,854	8,644	-	2,404,498	1,604,250	800,248
354	Towers & Fixtures	908,333	97	-	908,430	66[illegible]46	240,284
355	Poles & Fixtures	2,139,909	1,539	-	2,141,448	788,741	1,352,707
356	Overhead Conductor Device	1,227,329	-	-	1,227,329	494,752	732,578
357	Underground Conduit Elec	3,104	-	-	3,104	2,235	869
358	Underground Conductor Elec	6,170	7	-	6,177	4,037	2,140
	Total Transmission Plant	7,065,355	10,286	-	7,075,642	3,652,161	3,423,481

Acct No.	Title of Account	Balance 01/01/95	Additions	Retirements	Balance 12/31/95	Depreciation 12/31/95	Depreciated Valve 12/31/95
	Distribution Plant						
360	Land & Land Rights	159,489	1,622	-	161,111	-	161,111
361	Structures & Improvements	667,485	215	-	667,700	276,165	391,535
362	Station Equipment	2,795,243	319,137	-	3,114,380	2,456,802	657,578
363	Storage Battery Equip	1,442	166	-	1,608	217	1,391
364	Poles Towers & Fixtures	4,040,324	319,960	-	4,360,284	3,065,485	1,294,799
365	Overhead Conduit & Device	5,646,977	701,670	-	6,348,648	2,562,589	3,786,059
366	Underground Conduit	2,602,650	114,513	-	2,717,163	1,940,229	776,934
367	Underground Conductor & Device	2,384,886	69,877	-	2,454,763	1,770,520	684,243
368	Line Transformers	4,133,175	510,698	-	4,643,873	1,919,713	2,724,160
369	Services	724,435	119,589	-	844,024	306,290	537,734
370	Meters	1,709,507	58,038	-	1,767,545	1,396,001	371,544
372	E C S Program	3,282,550	395,630	-	3,678,180	1,299,720	2,378,460
373	St. Light & Signal Systems	1,526,650	30,928	-	1,557,578	869,422	688,156
	Total Distribution Plant	29,674,813	2,642,044	-	32,316,857	17,863,153	14,453,704
	General Plant						
389	Land & Land Rights	40,972	-	-	40,972	-	40,972
390	Structures & Improvements	2,002,552	607,279	-	2,609,831	675,756	1,934,074
391	Office Furniture & Equipment	799,271	513,526	-	1,312,797	340,820	971,977
392	Transporation Equipment	1,466,820	145,475	66,239	1,546,056	782,859	763,197
393	Store Equipment	170,100	26,281	-	196,381	17,357	179,024
394	Tool Shop Garage Equip	32,325	2,498	-	34,823	21,310	13,513
395	Laboratory Equipment	15,204	203	-	15,407	16,325	(918)
396	Power Operated Equipment	28,568	1,027	-	29,595	29,465	130
397	Communication Equipment	201,274	77,156	-	278,430	95,943	182,487
398	Misc. Equipment	113,709	-	-	113,709	56,165	57,544
	Total General Plant	4,870,795	1,373,445	66,239	6,178,000	2,036,000	4,142,000
	Less Contributions in aid of construction	(64,158)	13,346		(50,812)		(50,812)
	Total Utility Plant in Service	91,447,840	11,455,917	66,239	102,837,518	59,865,179	42,972,339
107	Construction W.I.P.	6,4[illegible]1,926	7,515,572	11,499,983	2,447,515	-	2,447,515
		97,879,766	18,971,489	11,566,222	105,285,033	59,865,179	45,419,854