MOMENTUM

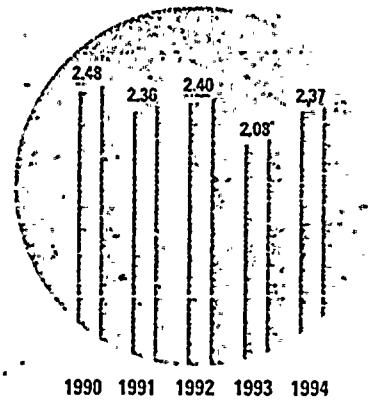
1994 ANNUAL REPORT

FINANCIAL HIGHLIGHTS

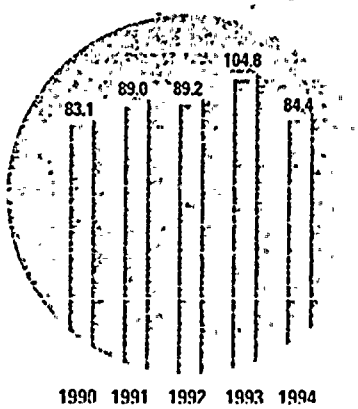
	1994	1993	% Change
At December 31			
Total Assets (Thousands)	$5,222,905	$5,287,958	(1)
Capitalization (Thousands)	$3,581,438	$3,511,826	2
Capital Structure (includes current maturities):			
Long-term Debt	46.7%	48.6%	(4)
Preferred Stock	7.3%	9.4%	(22)
Common Equity	46.0%	42.0%	10
Operating Results (Thousands)			
Total Operating Revenues	$1,898,855	$1,800,149	5
Operating Expenses	$1,576,171	$1,499,493	5
Net Income	$187,645	$166,028*	13
Earnings for Common Stock	$168,698	$145,390*	16
Retail Megawatt-hour Sales	13,148	13,088	–
Dekatherms of Natural Gas Delivered	58,624	58,046	1
Per Common Share			
Earnings	$2.37	$2.08*	14
Dividends	$2.00	$2.18	(8)
Book Value (year-end)	$23.28	$22.89	2
Market Value (year end)	$19.00	$30.75	(38)
Other Information			
Common Stock Price Range	$17¾–30½	$28¾–36½	
Return on Average Equity	10.3%	9.1%*	13
Market-to-Book Ratio (year end)	82%	134%	(39)
Average Common Shares Outstanding (Thousands)	71,254	69,990	2
Common Shareholders of Record (year end)	56,279	58,990	(5)

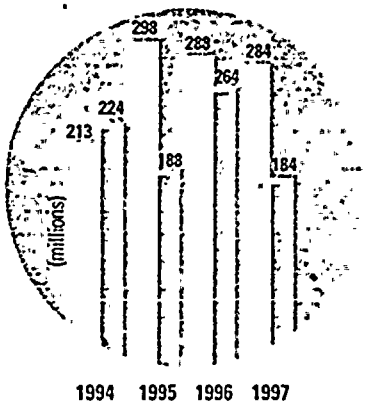
*Net income, earnings for common stock, earnings per common share and return on average equity for 1993 include the effects of restructuring expenses that decreased net income and earnings for common stock by $17 million, earnings per share by 25 cents and return on average equity by 1.1%.

Earnings (Dollars Per Share)



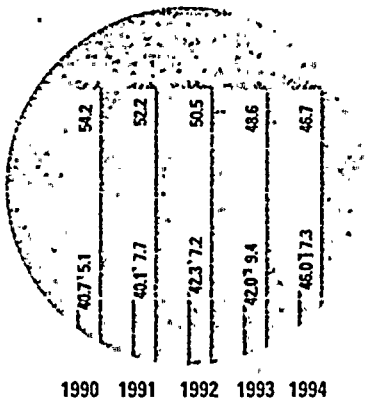
Dividend Payout Ratio (percent)





Comparison of Internal Cash Flow to Total Capital Expenditures

Internal Cash Flow
Capital Expenditures (regulated businesses only)



Capital Structure

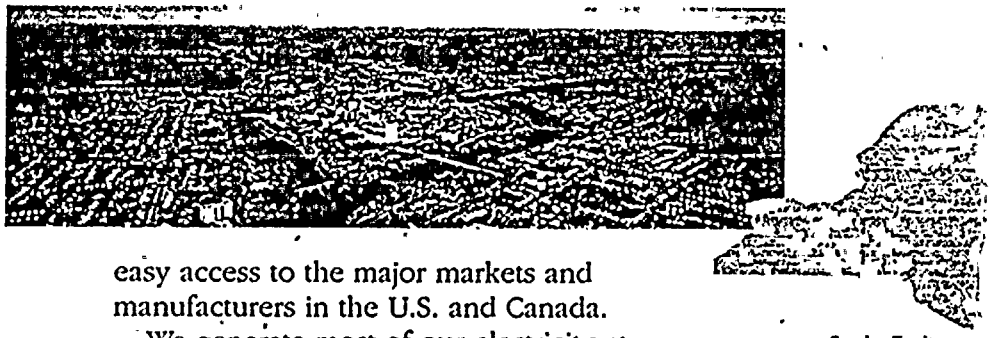
Long-term Debt
Preferred Stock
Common Stock Equity

CORPORATE PROFILE

New York State Electric & Gas Corporation (NYSEG) is an investor-owned electric and natural gas utility and diversified energy services company in upstate New York.

We provide electricity to 799,000 customers and natural gas to 231,000 customers throughout one-third of the state.

Communities within our service area offer high-tech businesses, first-rate universities, a skilled labor force and a superb transportation network that provides



Service Territory

Electricity
Natural Gas
Electric & Natural Gas

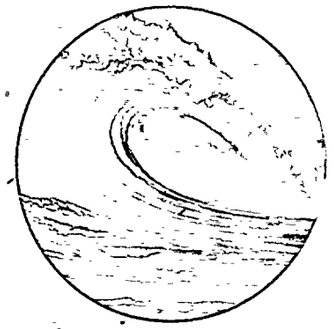
easy access to the major markets and manufacturers in the U.S. and Canada.

We generate most of our electricity at coal-fired plants that are collectively among the top 10 most efficient in the nation. Our Kintigh and Milliken generating stations operate the only two sulfur dioxide-reducing scrubbers in the state. We purchase our natural gas from pipeline companies, marketers and producers. Our residential natural gas prices are among the lowest in the state.

Our wholly-owned subsidiary, NGE Enterprises, Inc., owns XENERGY, Inc., an energy services and fuel management company serving clients across the U.S. and in Canada, Spain and France. NGE Enterprises also owns EnerSoft, a Houston company that has a strategic alliance with the New York Mercantile Exchange to develop a natural gas and pipeline capacity trading system.

Operating revenues in 1994 increased 5% over 1993 to $1.899 billion while earnings per share increased 2% from $2.33, excluding the effect of the 1993 restructuring charge, to $2.37.

MOMENTUM GAINING



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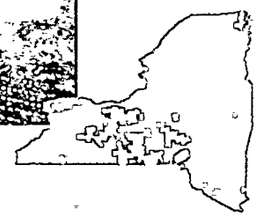

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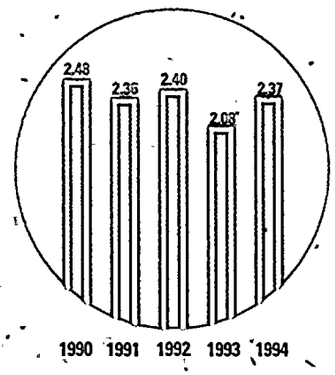
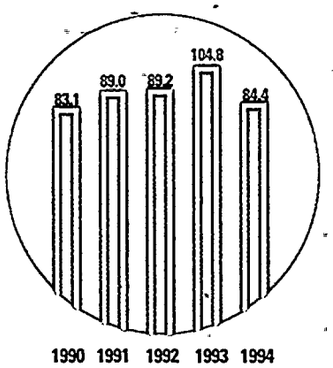


Dividend Payout Ratio (percent)



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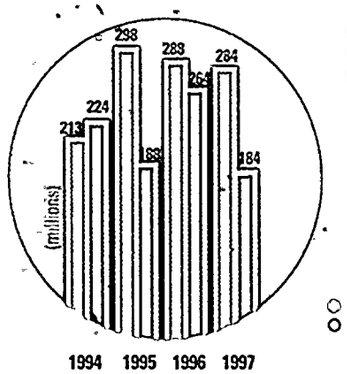
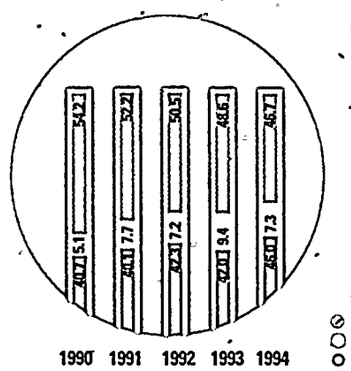


○ Internal Cash Flow
○ Capital Expenditures (regulated businesses only)

Capital Structure



⊘ Long-term Debt
○ Preferred Stock
○ Common Stock Equity

CONTENTS

THROUGH Tough Decisions

James A. Carrigg, chairman, president and chief executive officer

Dear Shareholder:

The powerful wave of change continues in the electric and natural gas industries.

This wave brings with it enormous challenges and exciting opportunities. We struggled at times in 1994. Our stock did poorly and customer service slipped. However, we acted decisively to meet these challenges and position your company for competition. During 1994 we:

- Completed a work force reduction begun in mid-1993 that totaled about 800 employees or 17%, including a 25% reduction in the number of officers.
- Planned cuts of more than $200 million in forecasted capital spending through 1996.
- Created a Customer Service Business Unit to restore our excellence in customer service and reduce costs, and moved responsibility for fuel procurement and wholesale sales to our generation department.
- Initiated a major natural gas storage project near Watkins Glen, New York.
- Acquired XENERGY, Inc., a successful energy services company serving clients across the U.S. and in Canada, Spain and France.
- Lowered our common stock dividend from $2.20 to $1.40 to give us the financial flexibility and strength we need to compete.

By year's end earnings were up, and customer service was back on track. We welcome competition and challenge. We are making tough decisions to ride the crest of the wave of change and improve shareholder value.

THE WAVE OF CHANGE

Competition in the energy industry is intensifying. By 1996 retail competition for large customers may be a reality in California. The transition for the electric industry in our state is less certain, but we believe that New York's high electric costs will ultimately result

in some industry restructuring. In December the Public Service Commission (PSC) issued an order that will intensify competition in the state's natural gas industry.

The financial markets also believe greater competition is inevitable. During 1994 utility stock prices fell 21% as measured by the Dow Jones Utility Average. While much of this decline resulted from rising interest rates, investors are also concerned about the uncertainties that competition brings. Rating agencies, for example, have changed the financial benchmarks they use in their ratings process to reflect greater business risks. As a result, more than one-quarter of the electric utility industry, including NYSEG, had its securities ratings downgraded in the past 18 months.

IN THE TROUGH OF THE WAVE

NYSEG's stock performance in 1994 was dismal. The market value of a common share fell 38%. We attribute most of this decline to rising interest rates and to our dividend reduction. In addition, late last summer the PSC staff recommended cutting Niagara Mohawk and Consolidated Edison revenues in 1995. New York utility shareholders lost more than $2 billion in common stock value as a result.

I am convinced that the dividend reduction, while difficult for shareholders now, will be beneficial in the future. Before the cut, we were paying out more than 90% of our earnings in dividends. That was simply too high. We now have additional cash to reduce debt and improve the company's financial flexibility and strength. The facts are clear. In 1994 the stocks of financially strong utilities outperformed those of weaker utilities. A stronger NYSEG will mean improved shareholder value in the future.

"By year's end earnings were up, and customer service was back on track."

Our long-term goal is to maintain our common stock dividend at 60 to 65% of earnings. Based on 1994 earnings of $2.37 per share, our $1.40 dividend is at the low end of this range. Future dividend levels will depend on earnings, among other things.

During 1994 customer service declined as a result of the start-up of our customer call center. But by December we had committed additional resources and had expanded hours of service by more than 80%. By early 1995 customer satisfaction had improved significantly.

Another disappointment in 1994 was a 12-cent-per-share production cost penalty, the maximum for 1993 under the current rate agreement. The penalty resulted primarily from lower sales and, therefore, a higher production cost per kilowatt-hour relative to that of other utilities. We believe a penalty for 1994 is unlikely, thanks to aggressive cost reduction and higher sales. Stringent cost controls also helped us improve earnings per share by 2% in 1994 despite the production cost penalty.

STRENGTHENING THE CORE BUSINESS

Because of the Energy Policy Act of 1992 and new technologies, many industry observers speculate that the traditional electric utility company may reorganize into separate generation, transmission and distribution companies. We cannot predict if this speculation will prove accurate.

But we do know that in times of uncertainty and instability we need to be as nimble as possible. To increase our flexibility, we just completed our most significant reorganization since 1990. The newly established Customer Service Business Unit is responsible for all aspects of customer service including our call center, transmission and distribution operations, electric marketing and sales, and all division operations. With this complete customer focus in one business unit, we will significantly improve customer service at reduced cost.

We also moved fuel procurement and wholesale electric sales to our generation department. With these new responsibilities, generation can now hone the marketing and financial skills necessary to compete if the electric industry restructures.

PROTECTING THE CORE BUSINESS

Our electric and natural gas businesses have several inherent strengths. We can produce wholesale electric power at a very competitive price. We also have a stable residential and commercial customer base, and only about 15% of our electric revenues come from industrial customers. So right now, only a small portion of our revenues is vulnerable to competitive options, such as self-generation or relocation out of our service territory.

Both businesses have developed flexible rate strategies to win long-term contracts with our larger customers for both existing and new load. To date 10 major industrial customers have signed contracts for electricity ranging from three to seven years. These contracts retain more than $33 million and add another $7 million in annual revenues.

"I am convinced that the dividend reduction, while difficult for shareholders now, will be beneficial in the future."

Each month our natural gas business develops more than 275 natural gas prices to compete with alternative fuels. Construction of the Seneca Lake Gas Storage Project will expand our supply alternatives and system capacity. This project will also allow us to lower the overall cost of natural gas by purchasing it for storage in the summer, when prices are low. We currently have some of the lowest residential natural gas prices in the state.

The competitive position of our natural gas business is testimony to the efforts of Russell Fleming, Jr., who was senior vice president of our Gas Business Unit (GBU) until his untimely death in August. While we will miss Russ's drive and vision, I am confident that the momentum he established will continue under the leadership of Michael German who comes to us from the American Gas Association, where he was senior vice president. In three years the GBU has increased its contribution to earnings to 22 cents per share in 1994, a 24-cent improvement. We anticipate the GBU will continue to grow.

CONTROLLING ELECTRIC PRICES

In the past three years our electric prices have risen 22% despite aggressive cost control. More than half of this rise was caused by increased taxes and mandated power purchases from non-utility generators (NUGs). These costs now account for more than one-third of our total electric price.

We estimate that our customers will overpay approximately $2 billion for electricity over the life of just two NUG contracts. We are convinced this mandated overpayment violates federal law under the 1978 Public Utility Regulatory Policies Act. In February 1995 we filed a petition asking the Federal Energy Regulatory Commission to lower the price our customers pay for electricity from these two NUGs. Throughout 1995 we will pursue this and every other available option to reduce the cost our customers pay for NUG power.

We continue to work hard for the elimination of the state gross receipts tax (GRT) that adds 4.25% to every energy bill and cost our customers $86 million in 1994. Although Governor George Pataki's immediate focus is on personal income tax reductions, we are urging him to eliminate the GRT.

We are also renegotiating the third year of our electric rate agreement to reduce the price increase due next August. We hope to mitigate that increase with a new multi-year agreement.

In 1994 our electric retail sales grew by about 0.5%. While modest, that's more growth than we achieved in the previous four years combined. Improving energy efficient sales is just as critical as lowering costs in helping us control our electric prices. Our electric marketing and sales group is on track with its ambitious two-year goal of increasing gross electric revenues by $40 million.

EXPANDING INTO RELATED BUSINESSES

"In three years the GBU has increased its contribution to earnings to 22 cents per share in 1994, a 24-cent improvement."

We are using our electric and natural gas expertise to diversify and grow. Our diversification plans focus on opportunities, specifically energy and environmental services, that relate to our core business.

In June 1994 we acquired XENERGY, an energy services and fuel management company that has been meeting our expectations and has excellent growth potential. During 1995 XENERGY will be looking to expand its services to include new software products, energy procurement and management products, and consulting to help utilities succeed in a rapidly changing environment.

Our other subsidiary, EnerSoft, is a start-up software company whose products will help customers purchase and manage their natural gas supply. EnerSoft has had delays in bringing its initial products to market. However, transactions on CH_4annel℠, the natural gas and pipeline capacity trading system being developed in a strategic alliance with the New York Mercantile Exchange, are expected to begin this spring.

Building on the expertise we have gained in our core business, we are also currently exploring pollution control opportunities with several strategic partners.

SUPPORTING STRATEGIES

For NYSEG to compete, we need to be financially strong and flexible. Since 1987 we have reduced debt from 62% to 47% of total capital and increased common equity from 33% to 46%. Through aggressive refinancings, we have also reduced interest costs by over $60 million a year. Our goal continues to be a 50% common equity ratio and an "A" bond rating.

Mergers and acquisitions can also improve the company's flexibility and strength. Columbia Gas of New York, acquired in 1991, was an excellent addition to our natural gas business. We will continue to look at other potential mergers or acquisitions that can improve our competitive position.

In November 1994 we reached an agreement with the International Brotherhood of Electrical Workers. This labor-management partnership includes a two-year extension of our existing labor agreement that would have expired in June 1995. Union and management also agreed to tackle key issues facing the company through joint task forces. This cooperative effort is critical since our work force is our key competitive advantage. This was a very difficult year for our employees because of the downsizing. I am profoundly grateful for their commitment, perseverance and high performance throughout 1994.

RIDING THE CREST

In addition to our longer-term strategic goals, our 1995 goals are to:

- Improve earnings per share by at least 5% over 1994.
- Achieve excellence in customer service and meet all customer service targets.
- Negotiate a positive modification to our existing three-year electric rate agreement.
- Develop greater rate flexibility to retain existing customers and attract new ones, and to properly price value-added services.
- Obtain PSC approval and begin construction of the $59 million Seneca Lake Gas Storage Project.
- Successfully introduce EnerSoft's CH_4annel℠ trading system in the spring of 1995.

I will update you on our progress throughout the year.

"We are using our electric and natural gas expertise to diversify and grow."

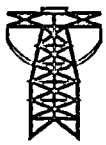
Despite increasing competition, technological advances will continue to increase the demand for electricity and natural gas. Those who position themselves correctly will be there to serve that demand. All of us at NYSEG are committed to making the tough decisions necessary for your company to prosper. We are gaining momentum. We will ride the crest of the wave of change and increase future shareholder value.

For the Board of Directors,

James A. Carrigg

James A. Carrigg
chairman, president and chief executive officer
February 15, 1995

February
Work force reduction: 384 employees take early retirement.



February
We announce flexible rate agreements with two large industrial customers that retain approximately $18 million in electric revenue annually.

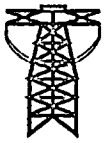
March
Work force reduction complete: last of 258 employees released.

April
Full retail competition for all customers proposed by 2002 in California.

May
Florida Power and Light cuts its dividend by 32%.

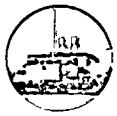
May
Anchor Glass Container of Elmira begins to receive New York Power Authority economic development power. NYSEG loses four megawatts (mw) of load.

June
Our wholly-owned subsidiary, NGE Enterprises, Inc., acquires XENERGY, Inc., a Burlington, Massachusetts energy services company serving clients across the U.S. and in Canada, Spain and France.

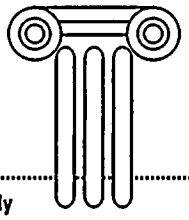


June
The PSC approves another NYSEG flexible rate that we can use to offer competitive pricing to companies looking to expand or relocate in our service territory.

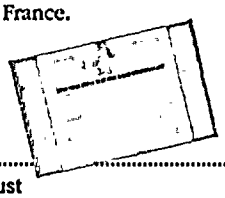
June
Due primarily to lower than expected sales in 1993, we incur a production cost penalty of $13 million or 12 cents per share.



June
Saranac Power Partners, L.P. begins commercial operation of its 240-mw generating plant in Plattsburgh. We are mandated to buy power from this NUG.

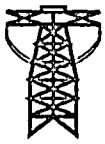


July
The PSC approves an electric price increase of 7.8% and a natural gas base rate increase of 1.9%.



August
We announce that the common stock dividend may need to be reduced to achieve financial flexibility. Our stock price declines from $25.50 to $20.875.

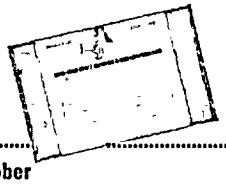
August
NYSEG files an innovative demand-side management plan that reduces spending to $10.5 million from a planned $42.8 million in 1995.



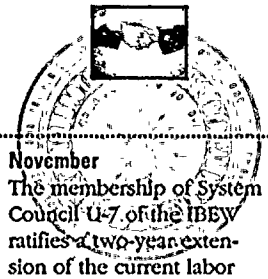
August
Another flexible rate agreement retains more than $4 million in electric revenue annually.

August/September
PSC staff recommends cutting Niagara Mohawk's and Con Ed's revenues in 1995. New York utilities' common stocks lose over $2 billion in market value as a result.

October
Coal tar soils from an out-of-state manufactured gas plant site are burned at Jennison Station.



October
NYSEG's Board of Directors reduces the common stock dividend 36%.



November
The membership of System Council U-7 of the IBEW ratifies a two-year extension of the current labor agreement.

December
Mike German, senior vice president of the American Gas Association, succeeds the late Russ Fleming as senior vice president-Gas Business Unit.

December
Jim Carrigg announces the creation of a Customer Service Business Unit.

January 1995
Our Gas Business Unit reports earnings of 22 cents per share, up from -2¢ per share in 1991.

January 1995
Milliken Generating Station starts up its new flue gas desulfurization system. Milliken, already one of the most efficient coal-fired plants in the nation, will now be among the cleanest.

Liquidity and Capital Resources

Competitive Conditions

Competition and deregulation are the foremost challenges currently facing the electric and natural gas industries and will increasingly present both opportunities and risks. There is the potential to gain new customers as well as the risk of losing existing customers. While the transition to a competitive marketplace in the electric industry is just beginning, the transition in the natural gas industry is further along: the production sector is now fully deregulated, and the interstate transmission and distribution sectors are in various stages of increasing competition.

In the electric industry, proceedings studying the possibility of introducing more competition and restructuring in some states, such as New York and California, may be paving the way for industry change nationwide. However, a number of complex issues (including transition costs and recovery of prudently incurred costs) must be addressed before restructuring can be accomplished. This makes it difficult to predict how soon market-driven competition will be established.

Contributing to increasing competition in the utility industry are legislation and regulatory policies such as the National Energy Policy Act of 1992 (Energy Policy Act) and Federal Energy Regulatory Commission (FERC) Order 636. The Energy Policy Act, enacted in October 1992, provides open access at the wholesale level to electric transmission services and is contributing to major changes in the electric industry. FERC Order 636, which took effect in November 1993, requires interstate natural gas pipeline companies to offer customers unbundled, or separate, services.

A major challenge to the company's electric business continues to be its ability to retain and expand its industrial base. The company's industrial customers, accounting for about 15% of total electric revenues, will increasingly have more supply alternatives available to them. Those alternatives currently include cogeneration, self-generation and fuel switching. Industrial customers can also decide to relocate.

The company has developed flexible rates that allow it to negotiate long-term contracts with both its electric and its natural gas customers.

There are other competitive pressures as well. More efficient technologies and more economical alternative fuels and renewable energy sources may increasingly challenge traditional energy sources. Another possibility is that municipalities would establish their own electric systems within the company's service territory.

The prospect of limited sales growth due to New York's sluggish economy is another challenge. Low growth potential for the company's core businesses makes it difficult to improve earnings and lower prices.

Faced with growing competition and more efficient technologies, utilities are increasingly focusing on the price of their products. The company's electric prices have been rising. The major contributors to these increases have been mandated purchases of power from non-utility generators (NUGs), rising taxes, demand-side management (DSM) programs, and compliance with environmental laws and regulations. DSM programs are initiatives designed to help customers use energy efficiently. Recent natural gas price increases have been caused by higher purchased gas costs, primarily due to transition costs resulting after FERC Order 636 and higher pipeline transportation costs.

The company has developed flexible rates that allow it to negotiate long-term contracts with both its electric and its natural gas customers. The contracts may cover existing load, new load, or both. To date, ten major electric industrial customers have signed contracts ranging from three to seven years. These contracts retain more than $33 million and add another $7 million in annual revenues, which together represent 2.5% of the company's total electric annual revenues. Also each month the company develops over 275 natural gas prices to compete with the alternative fuels available.

The Public Service Commission of the State of New York (PSC) has initiated a generic proceeding to study the broad subject of flexible, competitive rates. In July 1994 during Phase I of this proceeding, the PSC issued an opinion which approved flexible rate discounts for nonresidential electric customers having competitive alternatives. In approving the offering of discounts, the PSC adopted several guidelines that reaffirmed most of the company's flexible pricing programs.

In August 1994 the PSC instituted Phase II of the proceeding to address competitive opportunities available to electric customers and investigate the future regulation of electric service in light of competition. The overall objective is to identify regulatory and ratemaking practices that will assist the transition to a more competitive electric industry. Proposed principles to guide this transition were issued for comment by the PSC in December 1994.

This proceeding could affect the eligibility of electric utilities in New York State to apply Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). If the company could no longer meet the criteria of SFAS 71 for all or a part of its business, the company would have to expense certain previously deferred costs. Although the company believes it will continue to meet the criteria of SFAS 71 in the near future, it cannot predict what effect a competitive marketplace or future actions of the PSC will have on its ability to continue to do so.

In June 1994 the FERC issued a Notice of Proposed Rulemaking (NOPR) to address transition costs and invited representatives of the utility industry to comment on or suggest alternatives to the proposals. Transition costs are costs that utilities may incur (and that may become unrecoverable) as the industry moves from a heavily regulated environment to a less-regulated, competitive environment.

As one response to the competitive pressures faced by its natural gas business, the company plans to build a natural gas storage project near Seneca Lake, north of Watkins Glen, New York.

In December 1994 the company and a coalition of other New York State utilities filed joint comments addressing legal issues raised by the NOPR. The company also filed a separate document that addressed technical issues specific to the company. The coalition comments urge the FERC to set a national policy that will ensure recovery of transition costs so that competition will benefit all customers fairly. In a purely competitive environment, costs that utilities are required to bear (such as taxes, purchases of NUG power and DSM programs) would be difficult to recover because customers would have the opportunity to buy electricity from competitors who do not bear such costs, such as NUGs and municipal utilities. This could leave remaining customers bearing the full burden of those costs.

In 1994 the gas business operated its first full year under FERC Order 636 (see Note 11). Ultimately FERC Order 636 should prove beneficial to the company and its natural gas customers by providing greater opportunities to access natural gas supply, transportation and storage. Increased choices should result in lower natural gas costs in the intermediate and long term.

In December 1994 the PSC issued an order in its proceeding (instituted in late 1993) to investigate natural gas utility issues in view of FERC Order 636 and to determine to what extent New York State should adopt the federal policies. The PSC order also established a generic proceeding to investigate performance-based natural gas purchasing incentives and the availability and affordability of natural gas as the transition to a more competitive environment develops. While they found the majority of the PSC's findings favorable, the company and certain other parties to the proceeding have asked for a rehearing on certain points that they believe are inconsistent with the overall goal of encouraging competition. The company has already taken advantage of several new opportunities, including flexible customer rates, unbundling of services, and access to the secondary market for natural gas supplies and pipeline capacity.

As one response to the competitive pressures faced by its natural gas business, the company plans to build a natural gas storage project near Seneca Lake, north of Watkins Glen, New York. The project, which will cost $59 million and be regulated by the PSC, includes a storage facility and two separate pipelines to transport the natural gas. Its primary purpose is to ensure adequate supply to the company's core natural gas customers. The project will also increase supply flexibility, allow the company to retire propane plants and ultimately reduce pipeline demand charges. The company expects to receive PSC approval for the project and begin construction in 1995. The storage facility is scheduled to be in service for the 1996-1997 heating season.

During 1994 the company took a number of difficult steps to address the competitive challenges it faces. Foremost among them were the restructuring and workforce reduction completed in the first quarter of 1994 (see Note 6) and the decision to reduce the common stock dividend in the fourth quarter of 1994 (see Common Stock Dividend Policy).

Other steps the company has taken to address competitive pressures during 1994 include reducing capital expenditures and DSM program costs, placing two generating units on long-term cold standby, creating a customer service business unit and moving responsibility for fuel procurement and bulk power sales to the generation department.

On February 14, 1995, the company filed a petition with the FERC asking for relief from having to pay approximately $2 billion more than its avoided costs for power purchased over the life of the two NUG contracts mentioned below. The company believes that the overpayments under these two contracts violate the Public Utility Regulatory Policies Act of 1978.

The company is currently required to purchase 594 megawatts (mw) of NUG power. The company is required to make payments under these contracts only for the power it receives or when the company directs the NUG to reduce its output under the terms of the contract. Two contracts the company has with NUGs each provide more than 5% of current system capability. One contract provides for 177 mw or 5.4%, and the other provides for 240 mw or 7.3%. During 1994, 1993 and 1992 the company purchased approximately $214 million, $138 million and $71 million, respectively, of NUG power, including termination costs. The company estimates that NUG power purchases, excluding termination costs, over the next five years will be as follows:

1995	1996	1997	1998	1999
		(Millions)		
$274	$312	$322	$333	$344

Increases in the cost of NUG power purchases will contribute significantly to expected electric price increases in August 1995.

Diversification

Diversification will play an important role in the company's future. The company's primary objective is to enhance the competitiveness of its core electric and natural gas businesses. At the same time the company is actively evaluating opportunities for investment closely related to its core businesses that have the potential to augment future earnings. In April 1992 the PSC issued an order allowing the company to invest up to 5% of its consolidated capitalization (approximately $180 million at December 31, 1994) in one or more subsidiaries that may engage or invest in energy-related or environmental-services businesses and provide related services.

The company has been making investments in unregulated companies through its wholly owned subsidiary, NGE Enterprises, Inc. (NGE). NGE owns two unregulated businesses - EnerSoft Corporation (EnerSoft) and XENERGY, Inc. (XENERGY).

EnerSoft, a computer software company, was formed in May 1993 to produce and market software for natural gas utilities, marketers and pipeline operators. Through an alliance with the New York Mercantile Exchange, EnerSoft is developing CH_4annel[sm], a natural gas and pipeline capacity trading and information system for the North American market. While development of the system has taken longer than anticipated, CH_4annel[sm] is expected to be commercially available in the spring of 1995. Like most other start-up companies, EnerSoft has been incurring operating losses. The company expects that EnerSoft will continue to incur operating losses in the near term.

In June 1994 NGE acquired all of the outstanding stock of XENERGY, an energy services, information systems and energy-consulting company that specializes in energy management, conservation engineering and demand-side management. XENERGY currently provides a broad range of services to utilities throughout the United States, Canada, Spain and France. It also provides energy services, conservation engineering and DSM services to governmental agencies at both the state and federal levels, and to a large number of end users.

NGE is exploring environmental-services opportunities with both domestic and foreign strategic partners.

As of December 31, 1994 and 1993, the company had invested approximately $47 million and $3 million, respectively, in NGE to finance its diversified investments. For the years ended December 31, 1994 and 1993, NGE incurred net losses of $6.0 million and $1.4 million, respectively.

Common Stock Dividend Policy

In October 1994 the board of directors reduced the quarterly common stock dividend from 55 cents per share to 35 cents per share. This dividend reduction allows the company to achieve greater financial flexibility and strength and the company believes it will offer improved shareholder value over the long term. Financial flexibility will be essential in a competitive environment, and stronger utilities will command higher stock valuations.

The company can give no assurances as to future dividend levels. Dividends will depend on the company's earnings and financial requirements, developments in the utility industry and other factors. The company's long-term goal is a dividend payout ratio of 60% to 65% of earnings. The board of directors will continue to review the common stock dividend each quarter to ensure that it is consistent with the company's long-term interests.

Net Cash Provided by Operating Activities

Cash provided by operating activities in 1994 increased $38 million, up 9% from 1993. The increase was primarily due to a reduction in cash used for working capital items in 1994. Net cash from operating activities is derived by adjusting reported net income for charges or credits that have no cash effect (primarily depreciation, amortization and deferred income taxes) and changes in working capital items.

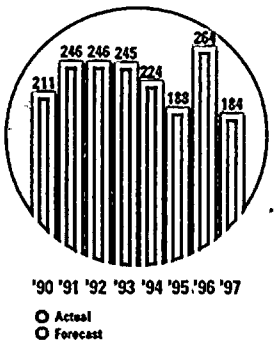
Net Cash Used in Investing Activities

In 1994, cash used in investing activities decreased $86 million, down 28% from 1993. The change was primarily due to a decrease in expenditures for utility plant construction.

The company's 1994 capital expenditures for its core electric and natural gas businesses totaled approximately $248 million. Most of the expenditures were for the extension of service, improvements at existing facilities, compliance with the Clean Air Act Amendments of 1990, and other environmental requirements. The company received $24 million from governmental and other sources in 1994 to partially offset expenditures for compliance with the Clean Air Act Amendments of 1990.

Capital expenditures projected for 1995-1997 have been limited and reflect planned cuts of more than $200 million. This represents one of the many actions the company is taking to address competition. Capital expenditures will be primarily for extension of service, necessary improve-

Capital Expenditures
(Millions of Dollars)



ments at existing facilities, the natural gas storage project, compliance with the Clean Air Act Amendments of 1990 and other environmental requirements (see Note 9). The company expects to finance these capital expenditures entirely with internally generated funds. The company forecasts that its current reserve margin, coupled with more efficient use of energy (see Conservation Programs) and purchases of power from NUGs, eliminates the need for additional generating capacity until after the year 2007.

The following table provides information on the company's estimated sources and uses of funds for 1995-1997. This forecast is subject to periodic review and revision. Actual capital expenditures may change to reflect the imposition of additional regulatory requirements and the company's continued focus on optimizing capital expenditures.

	1995	1996	1997	Total
		(Millions)		
Sources of funds				
Internal funds	$298	$288	$284	$870
Long-term financing	39	–	–	39
Total	$337	$288	$284	$909
Uses of funds				
Capital expenditures				
Cash	$185	$258	$180	$623
AFDC*	3	6	4	13
Total capital expenditures	188	264	184	636
Retirement of securities and sinking fund obligations	63	26	78	167
Repayment of short-term debt	55	20	33	108
Working capital, deferrals and other	31	(22)	(11)	(2)
Total	$337	$288	$284	$909

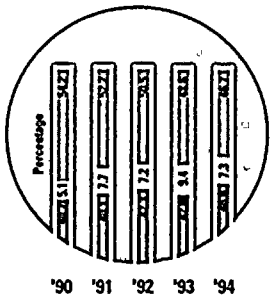
*Allowance for funds used during construction.

As shown in the preceding table, internal sources of funds represent 137% of capital expenditures for 1995-1997.

Net Cash Used in Financing Activities

Cash used in financing activities in 1994 increased $106 million, up 96% from 1993. This increase reflects a reduction of cash provided from the issuance of preferred stock and the use of cash provided by operating activities to reduce debt levels.

Capital Structure



The company believes that maintaining financial integrity and flexibility is critical to success in a competitive environment. The dividend reduction, along with recent cost reductions, will allow future cash flows to meet all of the company's operating and capital needs. The company plans to use its strong cash flow in excess of operating and capital needs primarily to reduce debt in preparation for competition. The company will also use its cash flow to invest in both regulated and unregulated businesses that relate to its core businesses and that have the potential to grow and yield value for the company's shareholders. Since 1987 the company has reduced its debt from 61.9% to 46.7% of total capital and has raised its common stock equity from 32.7% to 46%. Its goal is to achieve a 50% common equity ratio.

The common stock equity ratio improved in 1994 primarily as a result of retained earnings, the issuance of shares pursuant to the Dividend Reinvestment and Stock Purchase Plan (DRP), the repayment at maturity of $100 million of 8 3/8% bonds in August 1994 and the repayment of the $50 million revolving credit agreement note. The company received $22.7 million from the

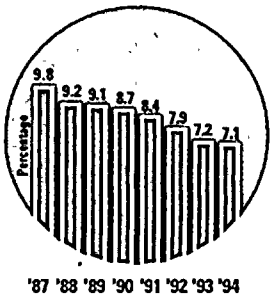
issuance of 0.9 million shares of common stock through the DRP. However, beginning in August 1994, the DRP began purchasing shares on the open market rather than the company issuing new shares. The company expects that the DRP will continue purchasing shares on the open market as long as the market price of the stock, which was below book value during the latter half of 1994, remains below book value. Issuing new shares below book value would decrease book value per share and lead to a decrease in future earnings per share.

The following table indicates the company's financing activities during 1994:

Month	Description	Interest Rate	Due	Amount
Issuances				(Thousands)
February (1)	Pollution control note	Various*	Feb. 1, 2029	$37,500
April (2)	Pollution control note	6.05%	Apr. 1, 2034	$100,000
June (3)	Pollution control note	Various*	June 1, 2029	$63,500
October (4)	Pollution control note	Various*	Oct. 1, 2029	$74,000
* Multi-mode note, maturity could be extended to 2034 under certain circumstances.				
Redemptions/ Maturities				
January	Preferred stock-Series A	Adj. Rate	n/a	$45,000
January	Preferred stock	8.80%	n/a	$25,000
February	Preferred stock	8.48%	n/a	$25,000
February	First mortgage bond	8 5/8%	Nov. 1, 2007	$23,000
August	First mortgage bond	8 3/8%	Aug. 15, 1994	$100,000
March	Pollution control note	2.75%	Mar. 1, 2015	$37,500
May	Pollution control note	12.0%	May 1, 2014	$60,000
July	Pollution control note	12.30%	July 1, 2014	$40,000
July	Pollution control note	2.60%	July 15, 2015	$63,500
December	Pollution control note	2.80%	Dec. 1, 2014	$74,000
May	Revolving credit agreement note	4.06%	July 31, 1997	$50,000

(1) Proceeds were used to refund, in March 1994, $37.5 million of one-year adjustable-rate pollution control revenue bonds, due 2015.
(2) Proceeds were used in connection with the redemption in May 1994 of $60 million of 12.0% pollution control bonds, due 2014, and the redemption in July 1994 of $40 million of 12.3% pollution control bonds, due 2014.
(3) Proceeds were used to refund, in July 1994, $63.5 million of one-year adjustable-rate pollution control revenue bonds, due 2015.
(4) Proceeds were used to refund, in December 1994, $74 million of one-year adjustable-rate pollution control revenue bonds, due 2014.

Embedded Cost of Long-Term Debt



The company reduced its embedded cost of long-term debt to 7.1% at the end of 1994 compared to 9.8% at the end of 1987. The company has refinanced more than $1.5 billion in long-term debt since the beginning of 1988 and reduced annual interest expense by more than $60 million. Unless interest rates fall further it will be difficult to significantly improve from the 7.1% level. All opportunities will continue to be pursued aggressively.

The company uses short-term unsecured notes, usually commercial paper, to finance certain refundings and for other corporate purposes. There was $151.9 million of commercial paper outstanding at December 31, 1994, at a weighted average interest rate of 5.8%.

The company also has a revolving credit agreement with certain banks that provides for borrowing up to $200 million to July 31, 1997. The company had an outstanding $50 million loan under this agreement at December 31, 1993, at an interest rate of 4.06%. This loan was repaid in May 1994.

During 1994 the company had its securities ratings downgraded by both Standard & Poor's and Moody's Investors Service. These downgrades reflect the rating agencies' use of more stringent

financial benchmarks in evaluating utilities, in order to reflect increasing competition and mounting business risks. More than one-quarter of the electric utility industry had its securities ratings downgraded in the past 18 months.

The company is committed to its goal of achieving an 'A' bond rating. The company plans to continue to strengthen its balance sheet by paying down debt with excess cash.

Regulatory Matters

In September 1993 the company reached a three-year electric and natural gas rate-settlement agreement with the PSC covering the period August 1, 1993 through July 31, 1996. Under the agreement, the allowed return on equity was 10.8% in year one, 11.4% in year two and 11.4% (subject to an indexing mechanism) in year three. Shareholders were allowed to keep 100% of any earnings above the allowed return in year one. Shareholders and customers are to share, on a 50%/50% basis, any earnings over the allowed return in years two and three. The calculation of earnings over the allowed return includes regulatory adjustments (such as the elimination of the impact of incentives and sharing mechanisms) and certain normalizing adjustments (such as spreading the 1993 restructuring charge over the term of the settlement agreement). For year one, the twelve months ended July 31, 1994, the company's earned return on equity, with adjustments, as discussed above, was 10.3%. The earned returns on electric equity and natural gas equity, with adjustments, were 10.1% and 12.7% respectively, for year one.

The agreement also includes a modified revenue decoupling mechanism (RDM) for electric sales. Rates are based on sales forecasts. Since actual sales may differ significantly from forecasted sales because of conservation efforts, unusual weather or changing economic conditions, revenues collected may be more or less than forecasted. Subject to the limits described below, the modified RDM lets the company adjust for most of the differences between forecasted and actual sales. For example, if revenues exceed the forecast for a given year, the excess is passed back to customers in a future year. If revenues are below the forecast, customers receive a surcharge in a future year. The company must share revenue excesses or shortfalls from sales to most large commercial and industrial customers on a 70%/30% (customer/shareholder) basis. In 1994 the company accrued $22.3 million under the modified RDM compared with $3.9 million in 1993. In 1993 the modified RDM covered only the period August through December.

The company is committed to its goal of achieving an 'A' bond rating. The company plans to continue to strengthen its balance sheet by paying down debt with excess cash.

Customer savings of $21 million in production and transmission operating costs are imputed over the three years of the agreement, at $7 million each year, whether or not such savings are realized.

The estimated total electric price increases anticipated by the agreement are $99.6 million, or 7.4%, in year one; $109.5 million, or 7.6% in year two; and $87.8 million, or 5.6% in year three. These include base rate increases plus estimated price increases for fuel, purchased power and other costs that are collected through the fuel adjustment clause (FAC). Actual costs collected through the FAC could vary from estimates, causing the total electric price increases to change.

The base rate increases for natural gas allowed by the agreement are $7.5 million, or 2.9%, in year one; $8.2 million, or 3.0%, in year two; and $7.2 million, or 2.5%, in year three. They do not include changes in natural gas costs, which will be collected through the gas adjustment clause. Natural gas costs can be expected to rise and fall with overall natural gas market conditions. Such fluctuations will affect the total natural gas price increases.

The agreement also provides for the stated base rate increases for electricity and natural gas to be adjusted up or down in the second and third years, as well as the year after the agreement period (year four). Base rates can be adjusted for several factors, such as electric sales, incentive mechanisms and other true-ups from the prior year. The electric base rate increases could be adjusted upward by up to 1.5% in years two and three and 1.6% in year four. The natural gas base rate

increases could be adjusted upward by up to 1.0% in year two and 1.2% in year three. The agreement does not specify a limit on the upward adjustment for natural gas base rates for year four. There is no limit to any downward adjustment of base rates for electric and natural gas.

In June 1994 the company finalized its filing of adjustments to the second-year electric and natural gas rates in accordance with the terms of the agreement. The company took voluntary action to lower the estimated total electric price increase to 7.8%. The electric price increase, which was primarily due to increases in mandated purchases of electricity from NUGs, increases in taxes and sales shortfalls related to mandated conservation programs and the weak economy in New York State, would have been substantially greater than 7.8% without the voluntary action. The filed natural gas base rate increase was 1.9%. On August 15, 1994, the PSC issued an Opinion and Order that approved the electric price increase of 7.8% and the 1.9% natural gas base rate increase effective August 1, 1994. In addition, the PSC directed the company and staff of the PSC to begin discussions on modifying the agreement to mitigate the projected third-year electric increase and bring rate predictability and stability to future years. Those discussions began in October 1994 and are continuing.

The agreement provides incentives (rewards or penalties) to the company for controlling production costs (PCI), improving customer service and implementing DSM programs. Those incentives could have increased the company's allowed return to 12.3% or decreased it to 9.95% in year one, increase it to 13.05% or decrease it to 10.4% in year two, and increase it to 13.25% or decrease it to 10.2% in year three. In June 1994 the company calculated and recorded a production-cost penalty for 1993 of $13.0 million, or 12 cents per share. This was the maximum permitted by the agreement.

The PCI is based on a comparison of the company with a 19-company peer group (which includes the company). The production measure compared is the relative change in production and certain other costs per megawatt-hour of retail sales occurring between the applicable calendar year and a base period (1989-1992). The company calculated the PCI penalty for 1993 using data reported in the peer group's FERC Form 1 Reports, which the company received in May 1994. The company's PCI penalty for 1993 was due primarily to a significantly lower increase in retail sales (after adjusting for the effect of sales lost due to DSM programs) for the company than for the peer group. It was also due to a greater increase in DSM program costs and purchased power costs for the company than for the peer group.

The company believes that a penalty for its PCI performance in 1994 is unlikely. This is primarily because of the company's recent cost-reduction efforts and improved sales compared to the sales increase of the peer group, which is projected to be less than the peer group's sales increase in 1993. This estimate includes the company's actual performance through December 31, 1994. However, it was necessary to make certain assumptions regarding the peer group's 1994 performance since the actual information needed for this calculation will not be available until the peer group's FERC Form 1 Reports become available in May 1995. As an example, retail sales units and certain production costs for the peer group were assumed to continue at the levels achieved through the first nine months of 1994. The maximum PCI allowed for 1994 by the agreement is a reward or penalty of $17.5 million, or 16 cents per share.

Conservation Programs

The company has implemented a number of DSM programs. As part of its three-year rate agreement (see Regulatory Matters), the rewards the company could earn for conducting efficient DSM programs were reduced from 15% to 5% of the net resource savings achieved by these programs. For 1995 the company expects to earn approximately $1 million in rewards as a result of DSM programs.

In 1994 customers saved approximately 64 million kilowatt-hours (kwh) on an annualized basis through DSM programs. These programs cost $14 million in 1994 and will cost approximately $11 million in 1995. The customer savings estimated for 1995 are 54 million kwh on an annualized basis. At both December 31, 1994 and 1993, the company had approximately $73 million of deferred DSM program costs on its consolidated balance sheets. The two-year (1993-1994) DSM plan, which received PSC approval, was modified to improve cost-effectiveness and reduce rate impacts. In August 1994 the company submitted its 1995 DSM plan to the PSC proposing DSM goals and budgets for the years 1995 through 2000. The company expects to change its DSM approach in 1995 to move toward promoting energy-efficient equipment in the mass market and phasing out rebates for individual customers.

Environmental Matters

The company continually assesses actions that may need to be taken to ensure compliance with changing environmental laws and regulations. Any additional compliance programs will increase the cost of electric and natural gas service by requiring changes in the company's operations and facilities. Historically, rate recovery has been authorized for the cost incurred to comply with environmental laws and regulations (See Note 9 and Note 10).

Results of Operations

	1994	1993	1992	1994 over 1993 Change	1993 over 1992 Change
	(Thousands, except per share amounts)				
Operating revenues	$1,898,855	$1,800,149	$1,691,689	5%	6%
Earnings available for common stock	$168,698	$145,390	$162,973	16%	(11%)
Average shares outstanding	71,254	69,990	67,972	2%	3%
Earnings per share	$2.37	$2.08	$2.40	14%	(13%)
Dividends per share	$2.00	$2.18	$2.14	(8%)	2%

Total operating revenues in 1994 increased $99 million, up 5% over 1993. In 1993, total operating revenues increased $108 million, up 6% from 1992. These results are discussed according to business segment beginning on page 17.

Earnings Per Share

In 1994 earnings per share increased 29 cents, up 14% over 1993, while in 1993 earnings per share decreased 32 cents, down 13% from 1992. Certain nonrecurring items lowered earnings per share for 1993 and 1992. Earnings in 1993 were reduced 25 cents per share by the corporate restructuring that reorganized the way the company delivers services to its electric and natural gas customers beginning in March 1994 (see Note 6). Earnings in 1992 were 24 cents per share lower than they otherwise would have been because of a six-month moratorium on electric rate increases that began in February 1992. Without these nonrecurring items, earnings per share were up 4 cents in 1994 compared to 1993, and were down 31 cents in 1993 compared to 1992.

The increase in 1994 earnings per share without the nonrecurring items was due to a combination of factors. Lower operation and maintenance expenses that resulted from cost controls and the workforce reduction helped 1994 earnings by 26 cents per share. Also, on a comparative basis, 1994 earnings rose because lower electric retail sales in 1993 before the effective date of

the company's modified RDM reduced 1993 earnings 9 cents per share. These increases in earnings per share were partially offset by the reduction in rewards earned from the company's DSM programs that lowered earnings by 13 cents per share; the 1993 production-cost penalty recorded in the second quarter of 1994 that reduced earnings by 12 cents per share; and losses incurred by the company's diversified operations that lowered earnings by 7 cents per share.

The decrease in 1993 earnings per share without the nonrecurring items was mainly due to lower electric retail sales before the effective date of the company's modified RDM, and to lower-than-anticipated natural gas sales. Both of these results were due to the sluggish economy in the company's service territory. Also, earnings per share decreased because of reductions in the company's allowed return on equity, from 11.7% effective through July 1992, to 11.2% effective through July 1993, and then to 10.8% beginning in August 1993.

Interest Expense

Interest expense (before the reduction for allowance for borrowed funds used during construction) decreased by $6 million, or 4% in 1994, and $10 million, or 6% in 1993. Interest on long-term debt decreased in 1994 and 1993 mainly due to the refinancing or refunding of certain high-coupon long-term debt. In 1993 interest expense also decreased due to lower interest rates on the company's variable rate debt.

Average Shares Outstanding

Average shares outstanding were 71 million in 1994, 70 million in 1993 and 68 million in 1992. The increases in average shares outstanding, 2% in 1994, and 3% in 1993, were both due to the issuance of shares of common stock through the DRP. A total of 0.9 million shares of common stock were issued through the DRP in 1994, and 1.2 million shares were issued in 1993. The number of shares issued in 1994 was lower than in 1993 because the DRP began purchasing shares on the open market as of August 1994 rather than the company issuing new shares. The company expects that the DRP will continue purchasing shares on the open market as long as the market price of the stock, which was below book value during the latter half of 1994, remains below book value. Issuing new shares below book value would decrease book value per share and lead to a decrease in future earnings per share.

Dividends per Share

Dividends decreased 8% in 1994 because the board of directors reduced the quarterly common stock dividend from 55 cents per share to 35 cents per share in October 1994 (see Common Stock Dividend Policy).

Operating Results for the Electric Business Segment

	1994	1993	1992	1994 over 1993 Change	1993 over 1992 Change
		(Thousands)			
Retail sales-kilowatt-hours (kwh)	**13,147,631**	13,088,175	13,294,466	–	(2%)
Operating revenues	**$1,600,075**	$1,527,362	$1,451,525	5%	5%
Operating expenses	**$1,306,871**	$1,250,000	$1,146,619	5%	9%
Operating income	**$293,204**	$277,362	$304,906	6%	(9%)

Electric retail sales for 1994 were up slightly compared to 1993 sales. In 1993, electric retail sales were down 2% from 1992 (despite a 1% increase in customers) due to the sluggish economy in the company's service territory.

Operating Revenues

Electric operating revenues increased by $73 million, or 5%, in 1994, and by $76 million, or 5%, in 1993. The more significant items contributing to these changes are as follows:

	1994	1993
	(Millions)	
Rate changes	$69	$53
RDM	18	4
Recovery of increases in NUG power through fuel adjustment clause (FAC)	16	28
Interchange profits	16	–
DSM incentives	(14)	–
DSM lost revenues	(15)	–
Production-cost penalty	(13)	–
Other	(4)	(9)
Total increase	$73	$76

Changes in electric rates effective in September 1993 and August 1994 were the principal reason for higher 1994 revenues. The rate changes were caused primarily by an increase in mandated purchases of NUG power and by higher federal taxes. The modified RDM contributed to revenues since actual electric sales in 1994 were below the levels forecasted in the company's rate agreement. Higher costs of NUG power, which are billed to customers in part through the FAC, also boosted 1994 revenues. Interchange profits helped revenues due to an increase in interchange sales volume over 1993. These increases were partially offset by a decrease in rewards earned from DSM programs, a decrease in DSM lost revenues recorded and the 1993 production-cost penalty recorded in the second quarter of 1994.

The $76 million, or 5%, increase in electric operating revenues in 1993 was primarily due to rate changes effective in August 1992 and September 1993, mainly the result of an increase in mandated purchases of NUG power and rising taxes. Higher costs of NUG power (billed to customers in part through the FAC) also contributed to the growth in revenues.

Operating Expenses

Electric operating expenses in 1994 increased $57 million, or 5%, over the 1993 level. The principal cause was an increase of $80 million in electricity purchased, primarily purchases from NUGs. Federal income taxes grew by $17 million, the result of higher pretax book income. Gross receipts taxes and school taxes added another $7 million to expenses. Depreciation expense rose $12 million compared to 1993. Those increases were partially offset by decreases of $15 million in operating expenses (mainly due to cost controls and the workforce reduction) and $14 million in fuel used in electric generation (due to reduced generation). Also, expenses were $21 million lower in 1994 because of the restructuring charge recorded in the fourth quarter of 1993.

In 1993 electric operating expenses were $103 million, or 9%, higher than in 1992. The major contributor to this increase was electricity purchased from NUGs, which rose by $67 million. Postretirement-benefit costs other than pensions increased $7 million. Corporate restructuring added another $21 million to electric operating expenses. These increases were partially offset by a $17 million decrease in fuel used in electric generation (the result of reduced generation and a lower price for coal) and by a $12 million decrease in federal income taxes (the result of lower pretax book income).

Operating Results for the Natural Gas Business Segment

	1994	1993	1992	1994 over 1993 Change	1993 over 1992 Change
		(Thousands)			
Deliveries – dekatherms (dth)	58,624	58,046	56,366	1%	3%
Operating revenues	$298,780	$272,787	$240,164	10%	14%
Operating expenses	$269,300	$249,493	$221,307	8%	13%
Operating income	$29,480	$23,294	$18,857	27%	24%

Natural gas deliveries rose by 1% in 1994 and by 3% in 1993. The increase in deliveries in 1994 and 1993 was due to the addition of new customers, including several large volume customers.

Operating Revenues

Natural gas operating revenues rose by $26 million, or 10%, in 1994, and by $33 million, or 14%, in 1993. The more significant items that contributed to these changes are as follows:

	1994	1993
	(Millions)	
Natural gas price increases	$16	$23
Rate changes	7	8
Other	3	2
Total increase	$26	$33

Higher costs of natural gas (billed to customers) were the primary reason for the rise in 1994 revenues. Rate changes effective in September 1993 and August 1994 also added to revenues. However, since the company has a weather normalization mechanism for natural gas, $0.9 million of revenues attributable to colder weather was returned to customers in 1994.

In 1993 the leading contributors to the increase in revenues were higher costs of natural gas and the rate changes that became effective in August 1992 and September 1993. Revenues of $1.0 million were returned to customers in 1993 through the weather normalization mechanism.

Operating Expenses

Natural gas operating expenses were up by $20 million, or 8%, in 1994, mainly because of an increase of $20 million in natural gas purchased that was mostly due to higher prices. Higher federal income taxes increased operating expenses by $4 million, due to higher pretax book income. Gross receipts taxes and school taxes added another $1 million to expenses. Depreciation expense rose $2 million compared to 1993. Those increases were partially offset by a decrease of $5 million because of the restructuring charge recorded in 1993 and a $1 million decrease in marketing expenses due to improved operations.

Operating expenses in 1993 increased $28 million, up 13% from their 1992 level. Natural gas purchased rose by $12 million, mainly because of higher natural gas prices. Federal income taxes increased $3 million due to higher pretax book income. Corporate restructuring added $5 million to natural gas operating expenses.

CONSOLIDATED BALANCE SHEETS

December 31	1994	1993
	(Thousands)	
Assets		
Utility Plant, at Original Cost (Note 1)		
Electric (Note 8)	$4,916,960	$4,777,368
Natural gas	414,929	381,389
Common	143,366	158,986
	5,475,255	5,317,743
Less accumulated depreciation	1,642,653	1,535,307
Net Utility Plant in Service	3,832,602	3,782,436
Construction work in progress	154,723	143,859
Total Utility Plant	3,987,325	3,926,295
Other Property and Investments, Net (Note 12)	103,920	73,537
Current Assets		
Cash and cash equivalents (Notes 1 and 13)	22,322	4,264
Special deposits (Note 13)	7,591	145,335
Accounts receivable, net (Note 1)	155,665	181,586
Fuel, at average cost	49,934	54,791
Materials and supplies, at average cost	47,843	48,910
Prepayments	30,441	30,092
Accumulated deferred federal income tax benefits, net (Notes 1 and 2)	11,457	–
Total Current Assets	325,253	464,978
Deferred Charges (Note 1)		
Unfunded future federal income taxes (Notes 1 and 2)	363,151	380,056
Unamortized debt expense	114,444	112,059
Demand-side management program costs	72,849	73,113
Other	255,963	257,920
Total Deferred Charges	806,407	823,148
Total Assets	$5,222,905	$5,287,958

The notes on pages 25 through 42 are an integral part of the financial statements.

CONSOLIDATED BALANCE SHEETS

December 31	1994	1993
	(Thousands)	
Capitalization and Liabilities		
Capitalization		
Common stock equity		
Common stock ($6.66 2/3 par value, 90,000,000 shares authorized and 71,502,827 and 70,595,985 shares issued and outstanding at December 31, 1994 and 1993, respectively)	$476,686	$470,640
Capital in excess of par value	841,624	824,943
Retained earnings	346,547	320,114
Total common stock equity	1,664,857	1,615,697
Preferred stock redeemable solely at the option of the company (Note 4)	140,500	140,500
Preferred stock subject to mandatory redemption requirements (Notes 4 and 13)	125,000	125,000
Long-term debt (Notes 3 and 13)	1,651,081	1,630,629
Total Capitalization	3,581,438	3,511,826
Current Liabilities		
Current portion of long-term debt (Note 3)	36,231	237,709
Current portion of preferred stock (Note 4)	–	95,000
Notes payable (Notes 5 and 13)	151,900	50,200
Accounts payable and accrued liabilities	107,356	111,481
Interest accrued (Note 13)	25,132	31,348
Accumulated deferred federal income taxes, net (Notes 1 and 2)	–	1,132
Other	94,961	89,443
Total Current Liabilities	415,580	616,313
Deferred Credits and Other Liabilities		
Accumulated deferred investment tax credit (Notes 1 and 2)	132,440	138,478
Excess deferred federal income taxes (Notes 1 and 2)	34,040	36,378
Other postretirement benefits	55,887	28,074
Liability for environmental restoration (Note 10)	33,600	26,800
Other	131,585	133,488
Total Deferred Credits and Other Liabilities	387,552	363,218
Accumulated Deferred Federal Income Taxes (Notes 1 and 2)		
Unfunded future federal income taxes	363,151	380,056
Other	475,184	416,545
Total Accumulated Deferred Federal Income Taxes	838,335	796,601
Commitments and Contingencies (Note 9)	–	–
Total Capitalization and Liabilities	$5,222,905	$5,287,958

The notes on pages 25 through 42 are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31	1994	1993	1992
		(Thousands, except per share amounts)	
Operating Revenues			
Electric	$1,600,075	$1,527,362	$1,451,525
Natural gas	298,780	272,787	240,164
Total Operating Revenues	1,898,855	1,800,149	1,691,689
Operating Expenses			
Fuel used in electric generation	231,648	245,283	262,531
Electricity purchased (Note 9)	242,352	161,967	95,026
Natural gas purchased	161,627	141,635	126,815
Other operating expenses	328,961	349,177	318,680
Restructuring expenses (Notes 6 and 7)	–	26,000	–
Maintenance	106,637	111,757	102,500
Depreciation and amortization (Note 1)	178,326	164,568	158,977
Federal income taxes (Notes 1 and 2)	115,891	94,144	102,456
Other taxes	210,729	204,962	200,941
Total Operating Expenses	1,576,171	1,499,493	1,367,926
Operating Income	322,684	300,656	323,763
Other Income and Deductions (Note 12)	1,053	6,471	12,036
Income Before Interest Charges	323,737	307,127	335,799
Interest Charges			
Interest on long-term debt	126,083	134,330	145,822
Other interest	13,642	11,120	9,566
Allowance for borrowed funds used during construction	(3,633)	(4,351)	(3,557)
Interest Charges, Net	136,092	141,099	151,831
Net Income	187,645	166,028	183,968
Preferred Stock Dividends	18,947	20,638	20,995
Earnings Available for Common Stock	$168,698	$145,390	$162,973
Earnings Per Share	$2.37	$2.08	$2.40
Average Shares Outstanding	71,254	69,990	67,972

The notes on pages 25 through 42 are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31	1994	1993	1992
		(Thousands)	
Operating Activities			
Net income	$187,645	$166,028	$183,968
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	178,326	164,568	158,977
Deferred fuel and purchased gas	(1,944)	(10,671)	(14,645)
Federal income taxes and investment tax credits deferred, net	13,670	50,761	52,039
Unbilled revenue amortization (Note 1)	(3,769)	(5,335)	(10,451)
Demand-side management program costs	264	(29,064)	(22,863)
Restructuring expenses	–	26,000	–
Changes in current operating assets and liabilities:			
Special deposits	42,744	2,438	(1,873)
Accounts receivable excluding accounts receivable sold	25,921	(23,703)	(38,345)
Accounts receivable sold (Note 1)	–	13,800	–
Prepayments	(349)	7,805	(878)
Inventory	5,924	16,013	(1,376)
Accounts payable and accrued liabilities	(4,125)	15,485	(4,851)
Interest accrued	(6,216)	(6,342)	(5,750)
Other, net	12,287	24,407	(7,685)
Net Cash Provided by Operating Activities	450,378	412,190	286,267
Investing Activities			
Utility plant capital expenditures, net of allowance for other funds used during construction	(246,536)	(265,109)	(243,373)
Proceeds received from governmental and other sources	23,915	22,808	322
Expenditures for other property and investments	(34,482)	(16,975)	–
Funds restricted for capital expenditures	41,113	(42,437)	–
Net Cash Used in Investing Activities	(215,990)	(301,713)	(243,051)
Financing Activities			
Issuance of pollution control notes and first mortgage bonds	275,000	217,362	247,668
Proceeds from revolving credit agreement note	–	50,000	–
Sale of common stock	23,386	38,334	162,965
Sale of preferred stock	–	97,762	–
Repayments of pollution control notes, first mortgage bonds and preferred stock, including premiums	(497,450)	(326,091)	(178,289)
Repayment of revolving credit agreement note	(50,000)	–	–
Changes in funds set aside for preferred stock and first mortgage bond repayments	95,000	(8,904)	(83,096)
Long-term notes, net	(2,290)	8,393	(1,593)
Notes payable, net	101,700	(13,900)	(39,800)
Dividends on common and preferred stock	(161,676)	(173,137)	(165,704)
Net Cash Used in Financing Activities	(216,330)	(110,181)	(57,849)
Net Increase (Decrease) in Cash and Cash Equivalents	18,058	296	(14,633)
Cash and Cash Equivalents, Beginning of Year	4,264	3,968	18,601
Cash and Cash Equivalents, End of Year (Notes 1 and 13)	$22,322	$4,264	$3,968

The notes on pages 25 through 42 are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(Thousands, except shares and per share amounts)

	Common Stock $6.66 2/3 Par Value Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Total
Balance, January 1, 1992	63,400,238	$422,668	$673,791	$308,688	$1,405,147
Net income				183,968	183,968
Cash dividends declared:					
Preferred stock (at serial rates)					
Redeemable - optional				(11,164)	(11,164)
- mandatory				(9,831)	(9,831)
Common stock ($2.14 per share)				(144,621)	(144,621)
Issuance of stock:					
Public offering	5,000,000	33,333	99,367		132,700
Dividend reinvestment and stock purchase plan	1,039,159	6,928	23,347		30,275
Balance, December 31, 1992	69,439,397	462,929	796,505	327,040	1,586,474
Net income				166,028	166,028
Cash dividends declared:					
Preferred stock (at serial rates)					
Redeemable - optional				(11,085)	(11,085)
- mandatory				(9,553)	(9,553)
Common stock ($2.18 per share)				(152,316)	(152,316)
Issuance of stock:					
Dividend reinvestment and stock purchase plan	1,156,588	7,711	28,438		36,149
Balance, December 31, 1993	70,595,985	470,640	824,943	320,114	1,615,697
Net income				187,645	187,645
Cash dividends declared:					
Preferred stock (at serial rates)					
Redeemable - optional				(8,419)	(8,419)
- mandatory				(10,528)	(10,528)
Common stock ($2.00 per share)				(142,265)	(142,265)
Issuance of stock:					
Dividend reinvestment and stock purchase plan	906,842	6,046	16,681		22,727
Balance, December 31, 1994	71,502,827	$476,686	$841,624	$346,547	$1,664,857

The notes on pages 25 through 42 are an integral part of the financial statements.

1 Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include the company's wholly-owned subsidiaries, Somerset Railroad Corporation (SRC) and NGE Enterprises, Inc. (NGE). All significant intercompany balances and transactions are eliminated in consolidation.

Utility plant

The cost of repairs and minor replacements is charged to the appropriate operating expense accounts. The cost of renewals and betterments, including indirect costs, is capitalized. The original cost of utility plant retired or otherwise disposed of and the cost of removal less salvage are charged to accumulated depreciation.

Depreciation and amortization

Depreciation expense is determined using straight-line rates, based on the average service lives of groups of depreciable property in service. Depreciation accruals were equivalent to 3.5%, 3.4% and 3.3%, of average depreciable property for 1994, 1993 and 1992 respectively. Depreciation expense includes the amortization of certain deferred charges authorized by the Public Service Commission of the State of New York (PSC).

Revenue

During 1994, 1993 and 1992 the company recognized on the income statement approximately $4 million, $5 million and $10 million, respectively, of electric and natural gas unbilled revenues that had been accrued on its balance sheet for energy provided but not yet billed to minimize the rate increases for these years in accordance with various PSC rate decisions. The July 1992 rate decision allowed the company to recognize on its income statement, beginning in August 1992, electric and natural gas unbilled revenues on a full accrual basis.

The company recognizes as revenue, incentives earned as the result of conducting efficient demand-side management (DSM) programs. The company is collecting those incentives in rates within approximately one year after they are recognized. During 1994, 1993 and 1992 incentives earned were $2 million, $16.4 million and $15.6 million, respectively. At December 31, 1994 and 1993, approximately $1.2 million and $14.3 million, respectively, of DSM incentives were accrued and included in accounts receivable.

Accounts receivable

The company has an agreement that expires in November 1996 to sell, with limited recourse, undivided percentage interests in certain of its accounts receivable from customers. The agreement allows the company to receive up to $152 million from the sale of such interests. At December 31, 1994 and 1993, accounts receivable on the consolidated balance sheets are shown net of $152 million of interests in accounts receivable sold. All fees associated with the program are included in other income and deductions on the consolidated statements of income and amounted to approximately $7.4 million, $5.7 million and $6.5 million in 1994, 1993 and 1992, respectively. Accounts receivable on the consolidated balance sheets is also shown net of an allowance for doubtful accounts of $7.2 million and $4 million at December 31, 1994 and 1993, respectively. Bad debt expense was $19.6 million, $15.3 million and $11.5 million in 1994, 1993 and 1992, respectively.

Income taxes

The company adopted Statement of Financial Accounting Standards No. 109 (SFAS 109), Accounting for Income Taxes, in January 1993. Since the company had been accounting for income taxes under Statement of Financial Accounting Standards No. 96, Accounting for Income Taxes, there was no effect on the consolidated statements of income as a result of adopting SFAS 109. However, SFAS 109 did require the company's deferred tax balances to be reclassified on its consolidated balance sheets.

The company files a consolidated federal income tax return with SRC and NGE. Deferred income taxes are provided on all temporary differences between financial statement basis and taxable income. Investment tax credits, which reduce federal income taxes currently payable,

are deferred and amortized over the estimated lives of the applicable property. The effect of the alternative minimum tax (AMT), which increases federal income taxes currently payable and generates a tax credit available for future use, is deferred and amortized at such times as the tax credit is used on the company's federal income tax return.

Deferred charges

The company defers certain incurred expenses when authorized by the PSC. Those expenses will be recovered from customers in the future.

Consolidated Statements of Cash Flows

The company considers all highly liquid investments with a maturity or put date of three months or less when acquired to be cash equivalents. These investments are included in cash and cash equivalents on the consolidated balance sheets.

Total income taxes paid were $69.2 million, $27.0 million and $37.6 million for the years ended December 31, 1994, 1993 and 1992, respectively.

Interest paid, net of amounts capitalized, was $132.0 million, $138.2 million and $149.3 million for the years ended December 31, 1994, 1993 and 1992, respectively.

Reclassifications

Certain amounts have been reclassified on the consolidated financial statements to conform with the 1994 presentation.

2 Income Taxes

Year ended December 31	1994	1993	1992
		(Thousands)	
Charged to operations			
Current	$88,623	$34,989	$37,237
Deferred, net			
Accelerated depreciation	51,736	49,580	41,492
Unbilled revenues	(3,913)	5,073	160
Revenue decoupling mechanism	6,870	–	–
AMT credit	(4,744)	(3,194)	2,123
Demand-side management	(9,048)	13,479	9,324
NUG termination agreement	(1,313)	6,208	8,500
Nine Mile No. 2 litigation proceeds	(520)	4,756	(2,047)
Restructuring expenses	–	(6,965)	–
Postretirement benefits	(5,079)	(3,492)	(593)
Transmission facility agreement	(2,719)	(7,778)	(1,172)
Miscellaneous	(3,970)	(4,154)	(4,598)
Investment tax credit (ITC)	(32)	5,642	12,030
	115,891	94,144	102,456
Included in other income			
Amortization of deferred ITC	(6,006)	(8,892)	(16,927)
Miscellaneous	(7,424)	498	3,747
Total	$102,461	$85,750	$89,276

The company's effective tax rate differed from the statutory rate of 35% in 1994 and 1993 and 34% in 1992 due to the following:

Year ended December 31	1994	1993	1992
		(Thousands)	
Tax expense at statutory rate	$101,537	$88,684	$92,903
Depreciation not normalized	18,552	16,984	16,697
ITC amortization	(6,006)	(8,892)	(16,927)
Revenue Reconciliation Act of 1993, net	(3,736)	(631)	–
Research & Development (R&D) credit	(1,352)	(5,139)	–
Cost of removal	(5,462)	(4,921)	(4,079)
Other, net	(1,072)	(335)	682
Total	$102,461	$85,750	$89,276

The company's deferred tax assets and liabilities consist of the following:

December 31	1994	1993
	(Thousands)	
Current Deferred Taxes		
Demand-side management	$(548)	$(9,897)
Unbilled revenue	4,449	(783)
Pension expense	3,748	5,600
Other	3,808	3,948
Total current deferred taxes	$11,457	$(1,132)
Noncurrent Deferred Taxes		
Depreciation	$(740,961)	$(698,939)
Loss on reacquired debt	(26,663)	(28,440)
Regulatory asset (SFAS 109)	(143,285)	(149,636)
Deferred ITC (net of SFAS 109)	(86,205)	(91,006)
Demand-side management	(25,785)	(25,484)
NUG contract settlement costs	(13,850)	(15,163)
AMT credit	16,716	19,953
Excess tax reserve	11,788	12,603
Nine Mile No. 2 disallowed plant	13,519	19,347
Contributions in aid of construction	20,050	20,913
Capitalized interest	10,280	8,690
Other	(4,168)	(7,255)
Total noncurrent deferred taxes	$(968,564)	$(934,417)
Total deferred taxes	$(957,107)	$(935,549)
Valuation allowance	(2,211)	(662)
Net deferred taxes	$(959,318)	$(936,211)

The Revenue Reconciliation Act of 1993 (RRA 1993), enacted on August 10, 1993, provided among other things, for an increase of 1% in the statutory corporate income tax rate and an extension of the R&D credit until June 30, 1995.

In September 1993 the company reached a three-year rate settlement agreement with the PSC which included a provision for the company to petition to defer the effect of RRA 1993 until it is reflected in rates. The changes related to RRA 1993 were reflected in rates beginning August 1, 1994.

The company has recorded unfunded future federal income taxes and a corresponding receivable from customers of approximately $363 million and $381 million as of December 31, 1994 and 1993, respectively, primarily representing the cumulative amount of federal income taxes on temporary depreciation differences, which were previously flowed through to customers. Those

amounts, including the tax effect of the future revenue requirements, are being amortized over the life of the related depreciable assets concurrent with their recovery in rates.

The company has approximately $16.7 million of AMT credits that do not expire.

3 Long-Term Debt

At December 31, 1994 and 1993, long-term debt was (Thousands):

First mortgage bonds

Series	Due	Amount 1994	Amount 1993
8 3/8%	Aug. 15, 1994	$ –	$100,000
5 5/8%	Jan. 1, 1997	25,000	25,000
6 1/4%	Sept. 1, 1997	25,000	25,000
6 1/2%	Sept. 1, 1998	30,000	30,000
7 5/8%	Nov. 1, 2001	50,000	50,000
6 3/4%	Oct. 15, 2002	150,000	150,000
7 1/4%	June 1, 2006	12,000	12,000
6 7/8%	Dec. 1, 2006	25,000	25,250
8 5/8%	Nov. 1, 2007	37,000	60,000
9 7/8%	Feb. 1, 2020	100,000	100,000
9 7/8%	May 1, 2020	100,000	100,000
9 7/8%	Nov. 1, 2020	100,000	100,000
8 7/8%	Nov. 1, 2021	150,000	150,000
8.30 %	Dec. 15, 2022	100,000	100,000
7.55 %	Apr. 1, 2023	50,000	50,000
7.45 %	July 15, 2023	100,000	100,000
Total first mortgage bonds		1,054,000	1,177,250

Pollution control notes

Interest Rate	Maturity Date	Interest Rate Adjustment Date	Letter of Credit Expiration Date	Amount 1994	Amount 1993
12%	May 1, 2014	–	–	–	60,000
12.30%	July 1, 2014	–	–	–	40,000
2.80%	Dec. 1, 2014	–	–	–	74,000
2.75%	Mar. 1, 2015	–	–	–	37,500
3.25% (1)	Mar. 15, 2015	Mar. 15, 1995	Mar. 31, 1996	60,000	60,000
2.60%	July 15, 2015	–	–	–	63,500
4.10% (1)	Oct. 15, 2015	Oct. 15, 1995	Oct. 31, 1996	30,000	30,000
4.60% (1)	Dec. 1, 2015	Dec. 1, 1995	Dec. 15, 1996	42,000	42,000
4.10% (1)	July 1, 2026	July 1, 1996	July 15, 1996	65,000	65,000
5.95%	Dec. 1, 2027	–	–	34,000	34,000
5.70%	Dec. 1, 2028	–	–	70,000	70,000
Var. % (2)	Feb. 1, 2029	Various	Feb. 23, 1996	37,500	–
Var. % (2)	June 1, 2029	Various	June 15, 1996	63,500	–
Var. % (2)	Oct. 1, 2029	Various	Oct. 25, 1996	74,000	–
6.05%	Apr. 1, 2034	–	–	100,000	–
Total pollution control notes				576,000	576,000
Revolving credit agreement note				–	50,000
Long-term notes due December 31, 1997				34,000	36,100
Various long-term notes				5,726	–
CNG Transmission Corp. notes due November 10, 1996 and July 11, 1997				6,080	8,862
Obligations under capital leases				21,423	30,902
Unamortized premium and discount on debt, net				(9,917)	(10,776)
				1,687,312	1,868,338
Less: debt due within one year – included in current liabilities				36,231	237,709
Total				$1,651,081	$1,630,629

At December 31, 1994, long-term debt and capital lease payments that will become due during the next five years are:

1995	1996	1997	1998	1999
		(Thousands)		
$36,231	$16,138	$86,850	$31,414	$1,274

The company's mortgage provides for a sinking and improvement fund. This provision requires the company to make annual cash deposits with the Trustee equivalent to 1% of the principal amount of all bonds delivered and authenticated by the Trustee prior to January 1 of that year (excluding any bonds issued on the basis of the retirement of bonds). The company satisfied this requirement in 1994 by depositing $23 million in cash that was used to redeem in February 1994 $23 million of 8⅝% Series first mortgage bonds, due 2007. The company satisfied this requirement in 1995 by depositing $23 million in cash that was used to redeem in February 1995 $23 million of 9⅞% Series first mortgage bonds, due February 2020.

Mandatory annual cash sinking fund requirements are $600,000 beginning June 1, 2001, for the 7¼% Series and $250,000 on December 1 in each year 1995 to 1996, for the 6⅞% Series. The amount increases to $500,000 and $750,000 on December 1, 1997 and December 1, 2002, respectively, for the 6⅞% Series.

The company's first mortgage bond indenture constitutes a direct first mortgage lien on substantially all utility plant.

(1) Adjustable rate pollution control notes were issued to secure like amounts of tax-exempt adjustable rate pollution control revenue bonds (Adjustable Rate Revenue Bonds) issued by a governmental authority. The Adjustable Rate Revenue Bonds bear interest at the rate indicated through the date preceding the interest rate adjustment date. The adjustable rate pollution control notes bear interest at the same rate as the Adjustable Rate Revenue Bonds. On the interest rate adjustment date and annually thereafter (every three years thereafter in the case of the Adjustable Rate Revenue Bonds due July 1, 2026), the interest rate will be adjusted, not to exceed a rate of 15%, or at the option of the company, subject to certain conditions, a fixed rate of interest, not to exceed 18%, may become effective. In the case of the Adjustable Rate Revenue Bonds due July 1, 2026, at the option of the company, subject to certain conditions, a fixed rate of interest may become effective prior to the interest rate adjustment date or each third year thereafter. Bond owners may elect, subject to certain conditions, to have their Adjustable Rate Revenue Bonds purchased by the Trustee.

(2) Multi-mode pollution control notes were issued to secure like amounts of tax-exempt multi-mode pollution control refunding revenue bonds (Multi-mode Revenue Bonds) issued by a governmental authority. These Multi-mode Revenue Bonds have a structure that enables the company to optimize the use of short-term rates by allowing for the interest rates to be based on a commercial paper rate, a daily rate, a weekly rate or an auction rate. The structure also provides flexibility to convert the interest rates to term rates or fixed rates, in the event that it is in the company's best interest to do so. The multi-mode pollution control notes bear interest at the same rates as the Multi-mode Revenue Bonds. Bond owners may elect, while the Multi-mode Revenue Bonds bear interest at a daily rate or a weekly rate, to have their Multi-mode Revenue Bonds purchased by the Registrar and Paying Agent. The maturity date of the Multi-mode Revenue Bonds due February 1, 2029, June 1, 2029, and October 1, 2029, can be extended, subject to certain conditions, to a date not later than February 1, 2034, June 1, 2034, and April 1, 2034, respectively. The weighted average interest rate for all three series (totaling $175 million principal amount) was 3.9%, excluding letter of credit fees, at December 31, 1994.

The company has irrevocable letters of credit that expire on the letter of credit expiration dates and that the company anticipates being able to extend if the interest rate on the related Adjustable Rate Revenue Bonds and Multi-mode Revenue Bonds is not converted to a fixed interest rate. Those letters of credit support certain payments required to be made on the Adjustable Rate Revenue Bonds and Multi-mode Revenue Bonds. If the company is unable to extend the letter of credit that is related to a particular series of Adjustable Rate Revenue Bonds, that series will have to be redeemed unless a fixed rate of interest becomes effective. Multi-mode Revenue Bonds are subject to mandatory purchase upon any change in the interest rate mode and in certain other circumstances. Payments made under the letters of credit in connection with purchases of Adjustable Rate Revenue Bonds and Multi-mode Revenue Bonds are repaid with the proceeds from the remarketing of such Bonds. To the extent the proceeds are not sufficient, the company is required to reimburse the bank that issued the letter of credit.

4 Preferred Stock

At December 31, 1994 and 1993, serial cumulative preferred stock was:

Series	Par Value Per Share	Redeemable Prior to	Redeemable Per Share	Shares Authorized and Outstanding (1)	Amount 1994	Amount 1993
					(Thousands)	
Redeemable solely at the option of the company:						
3.75%	$100		$104.00	150,000	$15,000	$15,000
4 1/2% (1949)	100		103.75	40,000	4,000	4,000
4.15%	100		101.00	40,000	4,000	4,000
4.40%	100		102.00	75,000	7,500	7,500
4.15% (1954)	100		102.00	50,000	5,000	5,000
6.48%	100		102.00	300,000	30,000	30,000
8.80%	100			–	–	25,000
8.48%	25			–	–	25,000
7.40% (2)	25	12/1/98	26.85	1,000,000	25,000	25,000
		Thereafter	25.00			
Adjustable Rate	25			–	–	45,000
Adjustable Rate (3)	25	12/1/98	27.50	2,000,000	50,000	50,000
		Thereafter	25.00			
					140,500	235,500
Less: preferred stock redemptions within one year – included in current liabilities					–	95,000
Total					$140,500	$140,500
Subject to mandatory redemption requirements:						
6.30% (4)	100	1/1/96	105.04	250,000	$25,000	$25,000
8.95% (5)	25	1/1/96	26.64	4,000,000	100,000	100,000
Total					$125,000	$125,000

At December 31, 1994, preferred stock redemptions and annual redeemable preferred stock sinking fund requirements for the next five years were:

1995	1996	1997	1998	1999
		(Thousands)		
$–	$–	$5,000	$5,000	$5,000

(1) At December 31, 1994, there were 1,550,000 shares of $100 par value preferred stock, 3,800,000 shares of $25 par value preferred stock and 1,000,000 shares of $100 par value preference stock authorized but unissued.

(2) The company is restricted in its ability to redeem this Series prior to December 1, 1998.

(3) The payment on the Adjustable Rate Serial Preferred Stock, Series B, for April 1, 1995, is at an annual rate of 6.54% and subsequent payments can vary from an annual rate of 4% to 10%, based on a formula included in the company's Certificate of Incorporation. The company is restricted in its ability to redeem this Series prior to December 1, 1998.

(4) On January 1 in each year 2004 through 2008, the company must redeem 12,500 shares at par, and on January 1, 2009, the company must redeem the balance of the shares at par. This Series is redeemable at the option of the company at $105.04 per share prior to January 1, 1996. The $105.04 price will be reduced annually by 63 cents for the years ending 1996 through 2002; thereafter, the redemption price is $100.00. The company is restricted in its ability to redeem this Series prior to January 1, 2004.

(5) On January 1 in each year 1997 through 2016, the company must redeem 200,000 shares at par. This Series is redeemable at the option of the company at $26.64 per share prior to January 1, 1996. The $26.64 price will be reduced annually by 15 cents for the years ending 1996 through 1999; by 14 cents for the year ending 2000; and by 15 cents for the years ending 2001 through 2005. The company is restricted in its ability to redeem this Series prior to January 1, 1996.

5 Bank Loans and Other Borrowings

The company has a revolving credit agreement with certain banks that provides for borrowing up to $200 million to July 31, 1997. At the option of the company, the interest rate on borrowings is related to the prime rate, the London Interbank Offered Rate (LIBOR) or the interest rate applicable to certain certificates of deposit. The agreement also provides for the payment of a commitment fee that can fluctuate from .15% to .375% depending upon the ratings of the company's first mortgage bonds. The commitment fee was .1875% at December 31, 1994 and 1993, and was .22% at December 31, 1992.

The company did not have any outstanding loans under the revolving credit agreement at December 31, 1994. At December 31, 1993, the company had an outstanding loan of $50 million under the revolving credit agreement at an interest rate of 4.06% under the LIBOR option. This loan was repaid in May 1994. The revolving credit agreement does not require compensating balances.

The company uses short-term unsecured notes, usually commercial paper, to finance certain refundings and for other corporate purposes. The weighted average interest rates on notes payable balances at December 31, 1994, 1993 and 1992 were 5.8%, 3.5% and 4.0%, respectively. At each year end, notes payable consisted of commercial paper with maturity dates of less than one year.

6 Restructuring

In the fourth quarter of 1993 the company recorded a $26 million restructuring charge. The corporate restructuring reorganized the way the company delivers services to its electric and natural gas customers beginning in March 1994. The restructuring reduced 1993 earnings available for common stock by approximately $17.2 million or 25 cents per share.

During the first quarter of 1994 the restructuring resulted in a workforce reduction totaling 642 persons throughout the organization, the elimination of customer walk-in services at 28

locations, and the closing of seven electric and natural gas operation facilities. The closing of additional electric and natural gas operation facilities will continue to be evaluated.

The workforce reduction of 642 employees, which was greater than the company's target of 600, was accomplished through a voluntary early retirement program (See Note 7) and an involuntary severance program. Of the 642 employees, 384 employees accepted the early retirement program and 258 employees were involuntarily severed. The company estimated the savings, excluding fringe benefits, related to the workforce reduction to be approximately $31.5 million, on an annual basis. As the workforce decreased, the company experienced savings in line with this estimate for 1994. The majority of these savings were used to minimize the company's electric and natural gas price increases in the second and third years of the rate settlement agreement.

7 Retirement Benefits

Pensions

The company has a noncontributory retirement annuity plan that covers substantially all employees. Benefits are based principally on the employee's length of service and compensation for the five highest paid consecutive years out of the last 10 years of service. It is the company's policy to fund pension costs accrued each year to the extent deductible for federal income tax purposes.

Effective January 1, 1993, the retirement benefit plans for hourly and salaried employees were combined into one plan. Combining the two plans did not affect benefit levels.

Net pension benefit for 1994, 1993 and 1992 included the following components:

	1994	1993	1992
		(Thousands)	
Service cost: Benefits earned during the year	$17,637	$17,688	$15,387
Interest cost on projected benefit obligation	43,328	40,710	35,253
Actual return on plan assets	(17,409)	(77,129)	(60,020)
Net amortization and deferral	(48,824)	12,989	7,844
Net pension (benefit)	$(5,268)	$(5,742)	$(1,536)

The funded status of the plan at December 31, 1994 and 1993 was:

	1994	1993
	(Thousands)	
Actuarial present value of accumulated benefit obligation:		
Vested	$410,732	$390,716
Nonvested	38,176	55,476
Total	448,908	446,192
Fair value of plan assets	$733,661	$753,292
Actuarial present value of projected benefit obligation	(597,398)	(608,216)
Plan assets in excess of projected benefit obligation	136,263	145,076
Unrecognized net transition asset	(66,374)	(73,612)
Unrecognized net gain	(92,851)	(83,709)
Unrecognized prior service cost	9,066	4,182
Net pension (liability)	$(13,896)	$(8,063)

Plan assets primarily consist of equity securities; U.S. agency, corporate and Treasury bonds; and cash equivalents.

The projected benefit obligation was measured using an assumed discount rate of 7.75% for 1994, 7% for 1993 and 7.75% for 1992, and a long-term rate of increase in future compensation levels of 5.5% for 1994, 5% for 1993 and 6% for 1992. The net pension benefit was measured using an expected long-term rate of return on plan assets of 8% in 1994 and 1993, and 7.5% in 1992.

Early retirement

As part of the corporate restructuring that was announced in the fourth quarter of 1993 (See Note 6), the company offered a voluntary early retirement program from December 1, 1993, through January 21, 1994, to employees who were 55 years and older and who had at least 10 years of service with the company. The program included two provisions: an unreduced pension benefit for those eligible employees who were under 60 years old, and a monthly supplemental payment to "bridge" employees to age 62 when they can begin collecting Social Security benefits. 384 employees accepted the early retirement opportunity. In 1993 the company recorded a $19.9 million expense for the early retirement program. This was included in the total $26 million restructuring charge.

Postretirement benefits other than pensions

The company has postretirement benefit plans, such as a comprehensive health insurance plan and a prescription drug plan, that provide certain benefits for retired employees and their dependents. Substantially all of the company's employees who retire under the company's pension plan may become eligible for those benefits at retirement. At December 31, 1994, 1993 and 1992, 2,331, 1,996 and 1,905 retirees and their dependents, respectively, were covered under these plans. The postretirement benefit plans are unfunded as of December 31, 1994.

In January 1993 the company adopted Statement of Financial Accounting Standards No. 106 (SFAS 106), Employers' Accounting for Postretirement Benefits Other Than Pensions, which requires the company to accrue a liability for estimated future postretirement benefits during an employee's working career rather than recognize an expense when benefits are paid. At the time of adoption, the actuarially determined accumulated postretirement benefit obligation (APBO) was $206.6 million. The company elected to recognize the APBO over 20 years.

In September 1993 the PSC issued a Statement of Policy concerning the accounting and ratemaking treatment for pensions and postretirement benefits other than pensions (PSC Policy). The PSC Policy was effective January 1993, adopted SFAS 106 for accounting and ratemaking purposes, and complies with generally accepted accounting principles.

The postretirement benefits cost other than pensions recognized on the income statement for the twelve months ended December 31, 1994, 1993 and 1992, was $14.5 million, $11.4 million and $5 million, respectively. The amounts for 1994 and 1993 represent the portion of SFAS 106 costs that the company has been allowed to collect from its customers. The amount for the twelve months ended December 31, 1992 represents the postretirement benefits cost as determined prior to the adoption of SFAS 106, when the cost was not recognized as an expense until the benefits were paid. The company has deferred $10.4 million and $10.1 million of SFAS 106 costs as of December 31, 1994 and 1993, respectively. The company expects to recover any deferred SFAS 106 amounts in accordance with the PSC Policy.

The PSC Policy allows various rate mechanisms, including the use of excess pension fund assets, such as Internal Revenue Service Code of 1986 Section 420 transfers, to temper the effect of SFAS 106 on rates. In 1994 and 1993 the company transferred $6.1 million and $5 million, respectively, of its excess pension plan assets to cover most of the cost of retirees' health care for those years. As a result of these transfers, the company recognized a decrease in its deferred SFAS 106 asset.

The estimated net postretirement benefits cost other than pensions for the 12 months ended December 31, 1994 and 1993, included the following components:

	1994	1993
	(Thousands)	
Service cost: Benefits accumulated during the year	$7,050	$6,888
Interest cost on accumulated postretirement benefit obligation	15,903	16,304
Amortization of transition obligation over 20 years	10,330	10,330
Amortization of loss	2	–
Deferral for future recovery	(18,757)	(22,095)
Net periodic postretirement benefits cost	$14,528	$11,427

The status of the plans for postretirement benefits other than pensions, as reflected in the company's consolidated balance sheets at December 31, 1994 and 1993, are as follows:

	1994	1993
	(Thousands)	
Accumulated postretirement benefit obligation (APBO):		
Retired employees	$112,311	$69,947
Fully eligible active plan participants	7,774	36,454
Other active plan employees	92,464	107,708
Total APBO	212,549	214,109
Less unrecognized transition obligation	185,937	196,268
Less unrecognized net gain	(28,382)	(10,233)
Accrued postretirement liability	$54,994	$28,074

An 11% annual rate of increase in the per capita costs of covered health care benefits was assumed for 1995, gradually decreasing to 5% by the year 2003. Increasing the assumed health care cost trend rates by 1% in each year would increase the APBO as of January 1, 1995, by $44.4 million and increase the aggregate of the service cost and interest cost components of the net postretirement benefits cost for 1994 by $5.0 million. A discount rate of 7.75% was used to determine the APBO.

8 Jointly-Owned Generating Stations

Nine Mile Point Unit 2

The company has an undivided 18% interest in the output and costs of the Nine Mile Point nuclear generating unit No. 2 (NMP2) which is operated by Niagara Mohawk Power Corporation (Niagara Mohawk). Ownership of NMP2 is shared with Niagara Mohawk 41%, Long Island Lighting Company 18%, Rochester Gas and Electric Corporation 14%, and Central Hudson Gas & Electric Corporation 9%. The company's share of the rated capability is 189,000 kilowatts. The company's net utility plant investment, excluding nuclear fuel, was approximately $638 million and $652 million, at December 31, 1994 and 1993, respectively. The accumulated provision for depreciation was approximately $120 million and $103 million, at December 31, 1994 and 1993, respectively. The company's share of operating expenses is included in the consolidated statements of income.

A low level radioactive waste management and contingency plan for NMP2 provides assurance that NMP2 is properly prepared to handle interim storage of low level radioactive waste until 1998.

Niagara Mohawk has contracted with the U.S. Department of Energy (DOE) for disposal of high level radioactive waste (spent fuel) from NMP2. The company is reimbursing Niagara Mohawk for its 18% share of the cost under the contract (currently approximately $1 per megawatt hour of net

generation). The DOE's schedule for start of operations of their high level radioactive waste repository has slipped from 2003 to no sooner than 2010. The company has been advised by Niagara Mohawk that the NMP2 Spent Fuel Storage Pool has a capacity for spent fuel that is adequate until 2014. If further DOE schedule slippage should occur, construction of pre-licensed dry storage facilities would extend the on-site storage capability for spent fuel at NMP2 beyond 2014.

Nuclear insurance

Niagara Mohawk maintains public liability and property insurance for NMP2. The company reimburses Niagara Mohawk for its 18% share of those costs.

The public liability limit for a nuclear incident is approximately $8.3 billion. Should losses stemming from a nuclear incident exceed the commercially available public liability insurance, each licensee of a nuclear facility would be liable for up to a maximum of $75.5 million per incident, payable at a rate not to exceed $10 million per year. The company's maximum liability for its 18% interest in NMP2 would be approximately $13.6 million per incident. The $75.5 million assessment is subject to periodic inflation indexing and a 5% surcharge should funds prove insufficient to pay claims associated with a nuclear incident. The Price-Anderson Act also requires indemnification for precautionary evacuations whether or not a nuclear incident actually occurs.

Niagara Mohawk maintains nuclear property insurance for NMP2 and is reimbursed by the company for its 18% interest. Niagara Mohawk has procured property insurance aggregating approximately $2.8 billion through the Nuclear Insurance Pools and the Nuclear Electric Insurance Limited (NEIL). In addition, the company has purchased NEIL insurance coverage for the extra expense incurred in purchasing replacement power during prolonged accidental outages. Under NEIL programs, should losses resulting from an incident at a member facility exceed the accumulated reserves of NEIL, each member, including the company, would be liable for its share of the deficiency. The company's maximum liability per incident under the property damage and replacement power coverages is approximately $2.5 million.

Nuclear plant decommissioning costs

In May 1993 the Nuclear Regulatory Commission (NRC) updated labor, energy and burial cost factors for determining the minimum funding requirement for nuclear decommissioning. As a result, the company's 18% share of the cost to decommission NMP2 is estimated to be $234 million in 2027, when decommissioning is expected to commence ($76 million in 1994 dollars). A preliminary estimate from Niagara Mohawk indicates that the cost to decommission NMP2 is greater than this amount. Niagara Mohawk has advised the company that in 1995 it expects to perform a detailed study to update the cost to decommission NMP2. The company plans to revise its estimate of the cost to decommission NMP2 after Niagara Mohawk completes its study.

The company's annual decommissioning allowance currently included in electric rates is approximately $1.6 million and is sufficient to recover the NRC's minimum funding requirement. These costs are charged to depreciation and amortization expense and are recovered over the expected life of the plant. The company believes that any increase in decommissioning costs will ultimately be recovered in rates.

The company has established a Qualified Fund under applicable provisions of the federal tax law. The fund also complies with the NRC regulations that require the use of an external trust fund to provide funds to decommission the contaminated portion of NMP2. The balance in this fund, including reinvested earnings, was approximately $7.4 million and $5.7 million at December 31, 1994 and 1993, respectively. These amounts are included on the consolidated balance sheets in other property and investments, net. The related liability for decommissioning is included in deferred credits and other liabilities - other. At December 31, 1994, the external trust fund investments were primarily debt securities, classified as available-for-sale, and their carrying value approximated fair value.

The Financial Accounting Standards Board is currently reviewing the accounting for obligations for decommissioning of nuclear power plants, including the balance sheet presentation of estimated decommissioning costs.

Homer City

The company has an undivided 50% interest in the output and costs of the Homer City Generating Station, which is comprised of three generating units. The station is owned with Pennsylvania Electric Company, which operates the facility. The company's share of the rated capability is 950,000 kilowatts and its net utility plant investment was approximately $265 million and $258 million at December 31, 1994 and 1993, respectively. The accumulated provision for depreciation was approximately $153 million and $159 million, at December 31, 1994 and 1993, respectively. The company's share of operating expenses is included in the consolidated statements of income.

9 Commitments and Contingencies

Capital expenditures

The company has substantial commitments in connection with its capital expenditure program and estimates that expenditures for 1995, 1996 and 1997 will approximate $188 million, $264 million and $184 million, respectively. The program is subject to periodic review and revision. Actual capital expenditures may change to reflect the imposition of additional regulatory requirements and the company's continued focus on optimizing capital expenditures. Capital expenditures will be primarily for extension of service, necessary improvements at existing facilities, the natural gas storage project, compliance with the Clean Air Act Amendments of 1990 (1990 Amendments) and other environmental requirements.

The 1990 Amendments will result in expenditures of approximately $174 million, on a present value basis, over a 25-year period, for all capital and operating and maintenance expenses related to the reduction of sulfur dioxide and nitrogen oxides at several of the company's coal-fired generating stations, of which $106.5 million had been incurred as of December 31, 1994. The cost to comply with the sulfur dioxide and nitrogen oxide limitations includes the construction of an innovative flue gas desulfurization (FGD) system and a nitrogen oxide reduction system that was recently completed at the company's Milliken Generating Station. The company estimates that approximately a 1% electric rate increase will be required for the cost of reducing sulfur dioxide and nitrogen oxide emissions in both Phase I (which began on January 1, 1995) and Phase II (begins January 1, 2000), as discussed below. In addition, the company anticipates that it will have to significantly reduce its nitrogen oxide emissions even further by the year 2003, which includes an interim reduction in the year 1999, as a result of proposed U.S. Environmental Protection Agency (EPA) regulations. The cost to comply with these proposed regulations cannot be estimated at this time, since the reduction will be based on additional research scheduled to be completed later in the decade. As a result of the 1990 Amendments, the company plans to reduce its annual sulfur dioxide emissions by an amount that will allow the company to meet the sulfur dioxide levels established for the company, which are approximately a 49% reduction from approximately 138,000 tons in 1989 to 71,000 tons by the year 2000.

The cost of controlling toxic emissions under the 1990 Amendments, if required, cannot be estimated at this time, since the type and level of reductions that may be required is dependent on a study currently being performed by the EPA, which is scheduled to be completed by the end of 1995. Regulations may be adopted at the state level that would limit toxic emissions even further, at an additional cost to the company. The company anticipates that the costs incurred to comply with the 1990 Amendments will be recoverable through rates based on previous rate recovery of required environmental costs.

The 1990 Amendments require the EPA to allocate annual emissions allowances to each of the company's coal-fired generating stations based on statutory emissions limits. An emissions allowance represents an authorization to emit, during or after a specified calendar year, one ton of sulfur dioxide. During Phase I, the company estimates that it will have allowances in excess of the affected coal-fired generating stations' actual emissions. The company's present strategy is to bank these allowances for use in later years. By using a banking strategy, it is estimated that Phase II allowance requirements will be met through the year 2005 by utilizing the allowances banked during Phase I, which includes the extension reserve allowances discussed below, together with the company's Phase II annual emissions allowances. This strategy could be modified should market or business conditions change. In addition to the annual emissions allowances allocated to the company by the EPA, the company has received a portion of the extension reserve allowances issued by the EPA to utilities electing to build scrubbers in Phase I, as a result of a pooling agreement that it entered into with other utilities who were also eligible to receive some of these extension reserve allowances.

As a result of existing and new solid waste disposal legislation and regulations in Pennsylvania, the company will incur approximately $28 million, on a present value basis, of additional costs over the next 30 years at the Homer City Generating Station. The majority of these costs will be incurred over the next 10 years to install new equipment, modify or replace existing equipment, and improve the design of a proposed expansion of disposal facilities. The company expects to recover these expenditures in rates, since the company has been allowed by the PSC to recover similar costs in rates, such as groundwater protection costs to meet permit conditions and regulatory requirements.

Long-term power purchase contracts

The company is currently required to purchase 594 megawatts (mw) of NUG power. The company is required to make payments under these contracts only for the power it receives or when the company directs the NUG to reduce its output under the terms of the contract. Two contracts the company has with NUGs each provide more than 5% of current system capability. One contract provides for 177 mw or 5.4%, and the other provides for 240 mw or 7.3%. During 1994, 1993 and 1992 the company purchased approximately $214 million, $138 million and $71 million, respectively, of NUG power, including termination costs. The company estimates that NUG power purchases, excluding termination costs, over the next five years will be as follows:

1995	1996	1997	1998	1999
		(Millions)		
$274	$312	$322	$333	$344

Increases in the cost of NUG power purchases will contribute significantly to expected electric price increases in August 1995.

Coal purchasing contracts

The company has long-term contracts with nonaffiliated mining companies for the purchase of coal for the jointly-owned Homer City Generating Station. The contracts, which expire between 1995 and the end of the expected service life of the generating station, require the purchase of either fixed or minimum amounts of the station's coal requirements. The contracts are based on fixed price plus escalation provisions. The company's share of the cost of coal purchased under these agreements is expected to aggregate $52 million, $53 million and $55 million for the years 1995, 1996 and 1997, respectively.

In addition, the company has a long-term contract for the purchase of coal for the Kintigh and Milliken Generating Stations. The contract, which expires in 2003, supplies the annual coal requirements of the Kintigh station. One-third of the tonnage price is renegotiated annually to reflect market conditions. The contract also supplies the requirements of the Milliken station for the years 1995-1997. The delivered cost of coal purchased under this agreement is expected to be $76 million, $78 million, and $81 million for the years 1995, 1996 and 1997, respectively.

10 Environmental Liability

The company continually assesses actions that may need to be taken to ensure compliance with changing environmental laws and regulations. Any additional compliance programs will increase the cost of electric and natural gas service by requiring changes in the company's operations and facilities. Historically, rate recovery has been authorized for the cost incurred to comply with environmental laws and regulations.

Due to existing and proposed legislation and regulations, and legal proceedings commenced by governmental bodies and others, the company may also incur costs from the past disposal of hazardous substances produced during the company's operations or those of its predecessors. The company has been notified by the EPA and the New York State Department of Environmental Conservation (NYSDEC), as appropriate, that it is among the potentially responsible parties (PRPs) who may be liable to pay for costs incurred to remediate certain hazardous substances at eight waste sites, not including the company's inactive gas manufacturing sites, which are discussed below. With respect to the eight sites, six sites are included in the New York State Registry of Inactive Hazardous Waste Sites (New York State Registry) and two of those sites are also included on the National Priorities list.

Any liability may be joint and several for certain of these sites. The company has recorded a liability related to four of these eight sites, which is reflected in the company's consolidated balance sheets at December 31, 1994, in the amount of $1.1 million. The ultimate cost to remediate these sites may be significantly more than this amount and will be dependent on such factors as the remedial action plan selected, the extent of site contamination, and the portion attributed to the company. The company has notified the EPA and the NYSDEC, as appropriate, that it believes it has no responsibility at three sites and has already incurred expenditures related to the remediation at the remaining site. A deferred asset has also been recorded in the amount of $2.1 million, of which $1.0 million relates to costs that have already been incurred. The company believes it will recover these costs, since the PSC has allowed other utilities to recover these types of remediation costs and has allowed the company to recover similar costs in rates, such as investigation and cleanup costs relating to inactive gas manufacturing sites. The estimated liability of $1.1 million was derived by multiplying the total estimated cost to clean up a particular site by the related company contribution factor. Estimates of the total cleanup costs were determined by using information related to a particular site, such as investigations performed to date at a site or from the data released by a regulatory agency. In addition, this estimate was based upon currently available facts, existing technology, and presently enacted laws and regulations. The contribution factor is calculated using either the company's percentage share of the total PRPs named, which assumes all PRPs will contribute equally, or the company's estimated percentage share of the total hazardous wastes disposed of at a particular site, or by using a 1% contribution factor for those sites at which it believes that it has contributed a minimal amount of hazardous wastes.

The company has notified its former and current insurance carriers that it seeks to recover from them certain of these cleanup costs. However, the company is unable to predict the amount of insurance recoveries, if any, that it may obtain.

A number of the company's inactive gas manufacturing sites have been listed in the New York State Registry. In late March 1994 the company entered into an Order on Consent with the NYSDEC requiring the company to investigate and, where necessary, remediate 33 of the company's 38 known inactive gas manufacturing sites. The schedule for investigating and remediating these 33 sites will be determined through further negotiations with the NYSDEC. The company has a program to investigate and initiate necessary remediation at its 38 known inactive gas manufacturing sites. Expenditures through the year 2009 are estimated at $32.5 million, including the impact of the Order on Consent. This estimate was determined by using the company's experience and knowledge related to these sites as a result of the investigation and remediation that the company has performed to date. It is based upon currently available facts, existing technology, and presently enacted laws and regulations. This liability to investigate and initiate remediation, as necessary, at the known inactive gas manufacturing sites, is reflected in the company's consolidated balance sheets at December 31, 1994 and 1993 in the amount of $32.5 million and $25 million, respectively. The company also has recorded a corresponding deferred asset, since it expects to recover such expenditures in rates, as the company has previously been allowed by the PSC to recover such costs in rates. The PSC has asked its staff to prepare a recommendation on a generic policy for these types of expenditures by the spring of 1995. The company has notified its former and current insurance carriers that it seeks to recover from them certain of these cleanup costs. However, the company is unable to predict the amount of insurance recoveries, if any, that it may obtain.

11 Federal Energy Regulatory Commission (FERC) Order 636

FERC Order 636 became effective in November 1993 and requires interstate natural gas pipeline companies to offer customers unbundled, or separate, services equivalent to their former sales service. With the unbundling of services, primary responsibility for reliable natural gas supply has shifted from interstate pipeline companies to local distribution companies, such as the company. FERC Order 636 has substantially restructured the interstate natural gas market.

As a result of the restructuring of services required by FERC Order 636, pipelines have incurred and will continue to incur transition costs. These include the costs of restructuring existing natural gas supply contracts, unrecovered costs that would otherwise have been billable to pipeline customers under previously existing rules and costs of assets needed to implement the order. FERC Order 636 allows pipelines to recover all prudently incurred costs from their customers.

The company's liability for transition costs is based on the pipelines' filings with the FERC to recover such costs. The company has reached a final resolution with one of its pipeline suppliers regarding transition costs and is currently negotiating with its other pipeline suppliers. Final resolution of the issue may not occur for several years. The company's estimated liability for transition costs was $21 million and $29 million at December 31, 1994 and 1993, respectively. The company has recorded a corresponding deferred asset, since it has been recovering transition costs from its customers through its gas adjustment clause and believes that such costs will continue to be recoverable from its customers.

12 Diversified Operations

In April 1992 the PSC issued an order allowing the company to invest up to 5% of its consolidated capitalization (approximately $180 million at December 31, 1994) in one or more subsidiaries that may engage or invest in energy-related or environmental-services businesses and provide related services.

The company has been making investments in unregulated companies through its wholly owned subsidiary, NGE Enterprises, Inc. (NGE). NGE owns two unregulated businesses - EnerSoft Corporation (EnerSoft) and XENERGY, Inc. (XENERGY).

EnerSoft, a computer software company, was formed in May 1993 to produce and market software for natural gas utilities, marketers and pipeline operators. Through an alliance with the New York Mercantile Exchange, EnerSoft is developing CH_4annel^{sm}, a natural gas and pipeline capacity trading and information system for the North American market. While development of the system has taken longer than anticipated, CH_4annel^{sm} is expected to be commercially available in the spring of 1995. Like most other start-up companies, EnerSoft has been incurring operating losses. The company expects that EnerSoft will continue to incur operating losses in the near term.

In June 1994 NGE acquired all of the outstanding stock of XENERGY, an energy services, information systems and energy-consulting company that specializes in energy management, conservation engineering and demand-side management. XENERGY currently provides a broad range of services to utilities throughout the United States, Canada, Spain and France. It also provides energy services, conservation engineering and DSM services to governmental agencies at both the state and federal levels, and to a large number of end users.

As of December 31, 1994 and 1993, the company had invested approximately $47 million and $3 million, respectively, in NGE to finance its diversified investments. The majority of this investment is included in other property and investments, net on the consolidated balance sheets. NGE's total liabilities and capitalization at December 31, 1994 and 1993 was approximately $52 million and $7 million, respectively. For the years ended December 31, 1994 and 1993, NGE incurred net losses of $6.0 million and $1.4 million, respectively, which are included in other income and deductions on the consolidated statements of income.

13 Fair Value of Financial Instruments

The estimated fair values of the company's financial instruments at December 31, 1994 and 1993, were as follows:

	Carrying Amount		Fair Value	
	1994	1993	1994	1993
	(Thousands)			
First mortgage bonds	$1,044,083	$1,166,779	$1,010,239	$1,274,883
Pollution control notes	$576,000	$575,695	$484,005	$581,928
Preferred stock subject to mandatory redemption requirements	$125,000	$125,000	$127,875	$134,000

The fair value of the company's first mortgage bonds, pollution control notes and preferred stock is estimated based on the quoted market prices for the same or similar issues of the same remaining maturities.

The carrying amount for the following items approximates estimated fair value because of the short maturity (within one year) of those instruments: cash and cash equivalents, notes payable, and interest accrued.

Special deposits include restricted funds that are set aside for preferred stock and long-term debt redemptions. Special deposits also include restricted funds that are used to finance a portion of the costs incurred in the construction of certain solid waste disposal and other related facilities. The carrying amount approximates fair value because the special deposits have been invested in securities with a short-term maturity (within one year).

The carrying amount of the revolving credit agreement note outstanding at December 31, 1993 approximated fair value because its pricing was based on short-term interest rates.

14 Industry Segment Information

Certain information pertaining to the electric and natural gas operations of the company follows:

	1994		1993		1992	
	Electric	Natural Gas	Electric	Natural Gas	Electric	Natural Gas
	(Thousands)					
Operating						
Revenues	$1,600,075	$298,780	$1,527,362	$272,787	$1,451,525	$240,164
Expenses	$1,306,871	$269,300	$1,250,000	$249,493	$1,146,619	$221,307
Income	$293,204	$29,480	$277,362	$23,294	$304,906	$18,857
Depreciation and amortization*	$167,484	$10,842	$155,231	$9,337	$150,549	$8,428
Capital expenditures	$183,910	$40,396	$208,576	$36,453	$210,185	$35,433
Identifiable assets**	$4,623,731	$486,075	$4,627,905	$458,596	$4,540,724	$377,424

*Included in operating expenses.

**Assets used in both electric and natural gas operations not included above were $113,099, $201,457 and $159,768 at December 31, 1994, 1993, and 1992, respectively. They consist primarily of cash and cash equivalents, special deposits and prepayments.

15 Quarterly Financial Information (Unaudited)

Quarter ended	March 31	June 30	Sept. 30	Dec. 31
		(Thousands, except per share amounts)		
1994				
Operating revenues	$565,167	$388,639 (1)	$432,451	$512,598
Operating income	$119,990	$47,784	$63,351	$91,559
Net income	$84,693	$12,395 (1)	$30,953	$59,604
Earnings available for common stock	$79,834	$7,745	$26,251	$54,868
Earnings per share	$1.13	$.11 (1)	$.37	$.77
Dividends per share	$.55	$.55	$.55	$.35
Average shares outstanding	70,801	71,214	71,490	71,503
Common stock price*				
High	$30.50	$27.88	$25.88	$19.75
Low	$26.50	$23.25	$18.38	$17.75
1993				
Operating revenues	$522,383	$388,601	$396,410	$492,755
Operating income	$109,893	$56,649	$66,108	$68,006
Net income	$74,039	$21,500	$32,541	$37,948 (2)
Earnings available for common stock	$68,838	$16,299	$27,340	$32,913
Earnings per share	$.99	$.23	$.39	$.47 (2)
Dividends per share	$.54	$.54	$.55	$.55
Average shares outstanding	69,561	69,836	70,119	70,431
Common stock price*				
High	$35.13	$36.50	$36.25	$35.50
Low	$31.63	$32.13	$34.63	$28.75

(1) Second quarter 1994 results include the company's change in estimate for the 1993 production cost penalty of $13 million or 12 cents per share.
(2) Fourth quarter 1993 results reflect the effects of restructuring expenses, which decreased net income and earnings for common stock by $17.2 million and decreased earnings per share by 24 cents.

* The company's common stock is listed on the New York Stock Exchange. The number of shareholders of record at December 31, 1994, was 56,279.

Dividend Limitations: After dividends on all outstanding preferred stock have been paid, or declared, and funds set apart for their payment, the common stock is entitled to cash dividends as may be declared by the board of directors out of retained earnings accumulated since December 31, 1946. Common stock dividends are limited if common stock equity (46% at December 31, 1994) falls below 25% of total capitalization, as defined in the company's Certificate of Incorporation. Dividends on common stock cannot be paid unless sinking fund requirements of the preferred stock are met. The company has not been restricted in the payment of dividends on common stock by these provisions. Retained earnings accumulated since December 31, 1946, were approximately $347 million and $320 million as of December 31, 1994 and 1993, respectively.

Report of Management

The company's management is responsible for the preparation, integrity and objectivity of the consolidated financial statements, notes and other information in this Annual Report. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles and include estimates that are based upon management's judgment and the best available information. Other financial information contained in this report was prepared on a basis consistent with that of the consolidated financial statements.

In recognition of its responsibility for the consolidated financial statements, management maintains a system of internal accounting controls designed to provide reasonable assurance as to the integrity and reliability of the financial statements, the protection of assets from unauthorized use or disposition, and the prevention and detection of fraudulent financial reporting. Management continually monitors its system of internal controls for compliance. The company maintains an internal audit department that independently assesses the effectiveness of the internal controls. In addition, the company's independent accountants, Coopers & Lybrand L.L.P., have considered the company's internal control structure to the extent they considered necessary in expressing an opinion on the consolidated financial statements. Management is responsive to the recommendations of its internal audit department and Coopers & Lybrand L.L.P. concerning internal controls, and corrective measures are taken when considered appropriate. Management believes that as of December 31, 1994, the company's system of internal controls provides reasonable assurance as to the integrity and reliability of the consolidated financial statements.

The board of directors oversees the company's financial reporting through its audit committee. This committee, which is comprised entirely of outside directors, meets regularly with management, the internal auditor, and Coopers & Lybrand L.L.P. to discuss auditing, internal control and financial reporting matters. To ensure their independence, both the internal auditor and independent accountants have free access to the audit committee, without management's presence.

James A. Carrigg
chairman, president and chief executive officer

Sherwood J. Rafferty
vice president and treasurer (chief financial officer)

Gary J. Turton
controller (chief accounting officer)

Report of Independent Accountants

Coopers & Lybrand
Coopers & Lybrand L.L.P.
a professional services firm

To the Stockholders and Board of Directors,
New York State Electric & Gas Corporation and Subsidiaries
Ithaca, New York

We have audited the accompanying consolidated balance sheets of New York State Electric & Gas Corporation and Subsidiaries as of December 31, 1994 and 1993, and the related consolidated statements of income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 1994. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of New York State Electric & Gas Corporation and Subsidiaries at December 31, 1994 and 1993, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1994, in conformity with generally accepted accounting principles.

As discussed in Note 7 to the consolidated financial statements, the Company and Subsidiaries changed its method of accounting for postretirement benefits other than pensions in 1993.

Coopers & Lybrand L.L.P.

New York, New York
January 27, 1995

SELECTED FINANCIAL DATA AND OPERATING STATISITICS

	1994	1993	1992	1991	1990	1989	1984
			(Thousands, except per share amounts)				
Operating Revenues							
Electric	$1,600,075	$1,527,362	$1,451,525	$1,367,936	$1,334,509	$1,266,668	$921,248
Natural gas	298,780	272,787	240,164	187,879	162,271	161,077	207,818
Total Operating Revenues	1,898,855	1,800,149	1,691,689	1,555,815	1,496,780	1,427,745	1,129,066
Operating Expenses							
Fuel used in electric generation	231,648	245,283	262,531	274,877	274,245	279,075	227,998
Electricity purchased	242,352	161,967	95,026	45,808	34,613	26,019	69,206
Natural gas purchased	161,627	141,635	126,815	99,528	88,589	101,598	146,040
Other operating expenses	328,961	349,177	318,680	279,364	268,829	238,804	141,056
Restructuring expenses	–	26,000	–	–	–	–	–
Maintenance	106,637	111,757	102,500	110,131	106,665	97,420	68,606
Depreciation and amortization	178,326	164,568	158,977	152,380	147,659	148,375	65,198
Federal income taxes	115,891	94,144	102,456	94,447	89,577	64,489	78,144
Other taxes	210,729	204,962	200,941	178,185	158,770	146,605	102,152
Total Operating Expenses	1,576,171	1,499,493	1,367,926	1,234,720	1,168,947	1,102,385	898,400
Operating Income	322,684	300,656	323,763	321,095	327,833	325,360	230,666
Other Income and Deductions	1,053	6,471	12,036	6,076	(1,508)	7,474	129,960
Income Before Interest Charges	323,737	307,127	335,799	327,171	326,325	332,834	360,626
Interest Charges							
Interest on long-term debt	126,083	134,330	145,822	151,649	158,209	164,573	164,435
Other interest	13,642	11,120	9,566	11,877	15,181	15,495	11,650
Allowance for borrowed funds used during construction	(3,633)	(4,351)	(3,557)	(4,998)	(5,078)	(5,013)	(26,835)
Interest Charges, Net	136,092	141,099	151,831	158,528	168,312	175,055	149,250
Net Income	187,645	166,028 (1)	183,968	168,643	158,013	157,779	211,376
Preferred Stock Dividends	18,947	20,638	20,995	20,330	12,662	12,975	27,370
Earnings Available for Common Stock	168,698	145,390 (1)	162,973	148,313	145,351	144,804	184,006
Common Stock Dividends	142,265	152,316	144,621	131,875	121,302	115,224	118,058
Retained Earnings Increase (Decrease)	$26,433	$(6,926)	$18,352	$16,438	$24,049	$29,580	$65,948
Average Number of Shares of Common Stock Outstanding	71,254	69,990	67,972	62,906	58,678	57,138	49,955
Earnings Per Share	$2.37	$2.08 (1)	$2.40	$2.36	$2.48	$2.53	$3.68
Dividends Paid Per Share	$2.00	$2.18	$2.14	$2.10	$2.06	$2.02	$2.38
Book Value Per Share of Common Stock (Year End)	$23.28	$22.89	$22.85	$22.16	$21.85	$21.29	$23.71
AFDC and Non-cash Return	$7,974	$8,003	$6,482	$7,541	$5,776	$6,387	$126,265
Capital Expenditures	$224,306	$245,029	$245,618	$245,883	$210,725	$192,022	$349,718
Total Assets	$5,222,905	$5,287,958	$5,077,916	$4,924,836	$4,737,431	$4,670,283	$3,733,146
Long-term Obligations, Capital Leases and Redeemable Preferred Stock	$1,776,081	$1,755,629	$1,883,927	$1,897,465	$1,766,457	$1,799,800	$1,663,784

(1) Reflects the effect of restructuring expenses, which decreased net income and earnings available for common stock by $17.2 million and decreased earnings per share by 25 cents.

	1994	1993	1992	1991	1990	1989	1984
Financial Statistics							
Return on average common stock equity – percent	10.3	10.1 (1)	10.6	10.7	11.4	11.5 (3)	15.9
Percentage of AFDC and non-cash return to total earnings	4.7	5.5	4.0	5.1	4.0	4.6	68.6
Mortgage bond interest – times earned	3.5	3.0	3.1	3.0	2.9	2.9	3.0
Interest charges and preferred dividends – times earned	2.1	1.9	1.9	1.8	1.8	1.8	1.9
Market value per share of common stock (year end)	$19.00	$30.75	$32.50	$29.00	$26.00	$28.88	$23.00
Dividend payout ratio (percent)	84.4	104.8	89.2	89.0	83.1	79.8	64.7
Price earnings ratio (year end)	8.0	14.8	13.5	12.3	10.5	11.4	6.3
Property, Plant and Equipment (includes construction work in progress)				(Thousands)			
Electric	$5,027,137	$4,887,125	$4,694,073	$4,537,356	$4,367,913	$4,217,920	$3,526,364
Natural gas	431,202	393,945	361,630	336,199	222,125	201,942	147,120
Common	171,639	180,532	205,345	189,135	175,703	155,340	60,775
Total	$5,629,978	$5,461,602	$5,261,048	$5,062,690	$4,765,741	$4,575,202	$3,734,259
Accumulated Depreciation	$1,642,653	$1,541,456	$1,427,793	$1,309,829	$1,174,651	$1,063,630	$617,687
Capitalization (includes current maturities)				(Thousands)			
Long-term debt	$1,687,312	$1,868,338	$1,891,036	$1,825,918	$1,815,686	$1,801,762	$1,691,367
Preferred stock	265,500	360,500	269,050	270,700	172,350	174,000	277,300
Common stock equity	1,664,857	1,615,697	1,586,474	1,405,147	1,364,344	1,225,184	1,234,561
Total Capitalization	$3,617,669	$3,844,535	$3,746,560	$3,501,765	$3,352,380	$3,200,946	$3,203,228
Capitalization Ratios (percent)							
Long-term debt	46.7	48.6	50.5	52.2	54.2	56.3	52.8
Preferred stock	7.3	9.4	7.2	7.7	5.1	5.4	8.7
Common stock equity	46.0	42.0	42.3	40.1	40.7	38.3	38.5
Number of Shareholders of Record							
Common stock	56,279	58,990	61,183	59,593	60,585	62,552	81,258
Preferred stock	1,329	3,632	3,829	3,943	4,068	4,238	6,380
Payroll (including pensions, etc.)				(Thousands)			
Charged to operations	$194,769	$197,023 (2)	$181,245	$163,421	$148,007	$140,415	$108,707
Charged to construction and other accounts	69,048	85,929	89,463	82,455	72,761	64,890	56,573
Total	$263,817	$282,952	$270,708	$245,876	$220,768	$205,305	$165,280
Number of employees (year end)	4,192	4,746	4,888	4,842	4,599	4,558	4,347

(1) The return on equity for 1993 excludes restructuring expenses.
(2) Payroll charged to operations for 1993 excludes restructuring expenses.
(3) The return on equity for 1989 excludes the Nine Mile Point nuclear generating unit No. 2 write-off adjustments.

	1994	1993	1992	1991	1990	1989	1984
Kilowatt-Hour (kwh) Sales (Millions)							
Residential	5,399	5,423	5,472	5,297	5,319	5,233	4,575
Commercial	3,315	3,298	3,283	3,285	3,235	3,181	2,611
Industrial	2,997	2,950	3,082	3,068	3,175	3,210	2,832
Other	1,437	1,417	1,457	1,457	1,468	1,431	1,269
Total Retail	13,148	13,088	13,294	13,107	13,197	13,055	11,287
Other electric utilities	6,827	6,233	6,003	5,066	4,750	4,461	3,158
Total	19,975	19,321	19,297	18,173	17,947	17,516	14,445
Operating Revenues (Thousands)							
Residential	$679,124	$635,155	$601,042	$553,056	$521,688	$510,941	$365,331
Commercial	366,854	333,674	314,272	293,197	267,598	261,606	190,891
Industrial	245,218	228,215	225,832	207,933	196,016	196,701	156,680
Other	153,888	138,320	133,819	124,575	116,352	114,364	86,400
Total Retail	1,445,084	1,335,364	1,274,965	1,178,761	1,101,654	1,083,612	799,302
Other electric utilities	141,902	147,175	143,414	131,412	145,104	134,108	107,209
Unbilled revenue recognition, net	–	2,257	(427)	35,333	42,995	–	–
Other operating revenues	13,089	42,566	33,573	22,430	44,756	48,948	14,737
Total Operating Revenues	$1,600,075	$1,527,362	$1,451,525	$1,367,936	$1,334,509	$1,266,668	$921,248
Operating Revenues Per kwh (Cents)							
Residential	12.58	11.71	10.98	10.44	9.81	9.76	7.99
Commercial	11.07	10.12	9.57	8.93	8.27	8.22	7.31
Industrial	8.18	7.74	7.33	6.78	6.17	6.13	5.53
Other	10.71	9.76	9.18	8.55	7.93	7.99	6.81
Total retail	10.99	10.20	9.59	8.99	8.35	8.30	7.08
Other electric utilities	2.08	2.36	2.39	2.59	3.05	3.01	3.39
Number of Customers (Year End)							
Residential	710,112	703,503	699,387	692,922	685,898	676,590	619,116
Commercial	75,575	73,727	72,463	71,463	70,802	69,230	62,089
Industrial	1,532	1,542	1,508	1,506	1,498	1,465	1,385
Other	11,366	11,091	11,073	10,907	10,825	10,694	10,221
Total	798,585	789,863	784,431	776,798	769,023	757,979	692,811
Annual Average Use (kwh) (1)							
Residential	7,615	7,708	7,843	7,672	7,796	7,786	7,426
Commercial	44,054	44,781	45,258	45,864	45,826	46,095	42,035
Industrial (thousands)	1,948	1,935	2,047	2,047	2,142	2,200	2,079
Annual Average Bill (1)							
Residential	$958	$903	$861	$801	$765	$760	$593
Commercial	4,877	4,531	4,333	4,093	3,791	3,791	3,073
Industrial	159,346	149,747	149,955	138,714	132,265	134,819	115,037

(1) Computed using the weighted average number of customers for the year.

NATURAL GAS SALES STATISTICS

	1994	1993	1992	1991	1990	1989	1984
Dekatherm (dth) Sales (Thousands) (1)							
Residential	24,662	25,080	24,913	18,115	14,809	15,331	14,120
Commercial	10,611	10,640	10,796	8,054	6,532	6,926	7,761
Industrial	2,180	1,820	1,689	1,788	2,023	2,167	9,817
Other	2,038	1,805	1,959	1,917	2,151	2,071	3,691
Total Retail	39,491	39,345	39,357	29,874	25,515	26,495	35,389
Transportation of customer-owned natural gas	19,133	18,701	17,009	12,530	8,157	8,853	–
Total	58,624	58,046	56,366	42,404	33,672	35,348	35,389
Operating Revenues (Thousands) (1)							
Residential	$185,073	$170,734	$152,325	$111,106	$94,531	$93,873	$92,288
Commercial	72,360	66,648	59,939	43,969	37,852	38,726	45,403
Industrial	11,542	9,602	8,092	8,640	10,267	10,437	49,087
Other	12,997	10,943	10,762	10,243	11,574	10,776	20,058
Total Retail	281,972	257,927	231,118	173,958	154,224	153,812	206,836
Transportation of customer-owned natural gas	12,791	12,091	11,639	9,571	7,169	6,721	–
Unbilled revenue recognition, net	3,768	2,686	(3,626)	3,770	853	–	–
Other natural gas revenue	249	83	1,033	580	25	544	982
Subtotal	16,808	14,860	9,046	13,921	8,047	7,265	982
Total Operating Revenues	$298,780	$272,787	$240,164	$187,879	$162,271	$161,077	$207,818
Operating Revenues per dth							
Residential	$7.50	$6.81	$6.11	$6.13	$6.38	$6.12	$6.54
Commercial	6.82	6.26	5.55	5.46	5.79	5.59	5.85
Industrial	5.29	5.28	4.79	4.83	5.08	4.82	5.00
Other	6.38	6.06	5.49	5.34	5.38	5.20	5.43
Total retail	7.14	6.56	5.87	5.82	6.04	5.83	5.87
Transportation	0.67	0.65	0.68	0.76	0.88	0.76	–
Number of Customers (Year End) (1)							
Residential with house heating	189,482	185,117	182,795	178,625	117,429	114,497	103,513
Residential without house heating	13,409	12,943	13,181	12,906	8,360	8,079	8,533
Commercial with space heating	24,130	23,327	23,165	23,023	16,843	16,626	15,936
Commercial without space heating	1,746	2,281	2,282	2,241	1,548	1,476	1,402
Industrial	383	394	390	386	334	343	403
Transportation of customer-owned natural gas	441	444	389	342	277	228	–
Other	1,709	1,693	1,657	1,557	1,246	1,154	1,141
Total	231,300	226,199	223,859	219,080	146,037	142,403	130,928
Annual Average Use (dth) (2)							
Residential	123	127	129	105	119	126	126
Commercial	410	416	428	345	358	386	451
Industrial	5,561	4,515	4,387	4,781	6,003	6,246	24,666
Annual Average Bill (2)							
Residential	$923	$864	$786	$641	$763	$774	$826
Commercial	2,796	2,605	2,377	1,882	2,076	2,158	2,639
Industrial	29,418	23,827	21,018	23,102	30,466	30,079	123,334
Cost of Natural Gas Purchased							
Amount (thousands)	$161,627	$141,635	$126,815	$99,528	$88,589	$101,598	$146,040
Per dth	$4.02	$3.56	$3.22	$3.30	$3.64	$3.57	$4.09
Natural Gas Operation and Maintenance Expenses (Thousands)							
Production	$161,768	$142,229	$126,984	$101,458	$88,901	$102,014	$146,401
Transmission and distribution	21,067	20,712	19,938	18,491	13,982	13,247	9,651
Customer accounting	11,848	10,959	9,233	8,046	5,765	4,990	4,043
Customer service	5,992	6,972	8,152	6,533	5,942	3,972	1,580
Administrative and general	17,694	24,263 (3)	18,040	15,735	6,464	8,571	9,383
Total	$218,369	$205,135	$182,347	$150,263	$121,054	$132,794	$171,058

(1) The increase in 1991 is primarily due to the acquisition of Columbia Gas of New York, Inc.
(2) Computed using the weighted average number of customers for the year.
(3) Includes restructuring expenses of $5 million.

	1994	1993	1992	1991	1990	1989	1984
System Capability (Megawatts)							
Coal	2,278	2,394	2,415	2,412	2,414	2,414	2,376
Nuclear	189	189	188	196	194	193	–
Hydro	69	67	70	70	68	66	60
Internal combustion	7	7	8	8	7	7	7
Total Generating Capability	2,543	2,657	2,681	2,686	2,683	2,680	2,443
Purchased – Power Authority	514	486	489	488	487	487	683
– NUG	594	362	347	110	–	–	–
– Other	–	–	–	–	53	9	–
Less: Firm sales	(367)	(311)	(8)	–	–	(115)	–
Total System Capability	3,284	3,194	3,509	3,284	3,223	3,061	3,126
System Capability (Percent)							
Coal	69	75	69	74	75	80	76
Nuclear	6	6	5	6	6	6	–
Hydro	2	2	2	2	2	2	2
Total Generating Capability	77	83	76	82	83	88	78
Purchased – Power Authority	16	15	14	15	15	16	22
– NUG	18	12	10	3	–	–	–
– Other	–	–	–	–	2	–	–
Less: Firm sales	(11)	(10)	–	–	–	(4)	–
Total System Capability	100	100	100	100	100	100	100
Production Statistics							
Annual load factor (percent)	70.2	66.7	67.0	68.9	69.4	64.7	67.3
Coal burned (thousands of net tons)	5,524	5,918	6,478	6,310	6,395	6,472	5,126
Coal heat value (Btu per lb.)	12,695	12,674	12,668	12,610	12,510	12,477	12,202
Btu per kwh generated (net)	9,897	9,997	9,902	9,898	9,936	9,931	10,562
Kilowatt-Hour (kwh) Production, Net (Millions)							
Generated:							
Coal	14,338	15,131	16,709	16,157	16,211	16,345	11,850
Nuclear	1,509	1,295	922	1,180	743	773	–
Hydro	321	309	301	258	356	292	246
Total Generated	16,168	16,735	17,932	17,595	17,310	17,410	12,096
Purchased – Power Authority	1,700	1,617	1,635	1,667	1,607	1,667	2,980
– NUG	3,601	2,472	1,260	473	124	34	20
– Other, net	14	78	(10)	(130)	223	68	630
Total	21,483	20,902	20,817	19,605	19,264	19,179	15,726
Production Expenses (Thousands)							
Generated	$339,546	$371,891	$375,209	$391,393	$391,977	$381,371	$287,299
Purchased – Power Authority	21,478	16,713	15,661	14,668	13,534	12,012	30,953
– NUG	214,010	137,791	71,260	30,028	7,700	1,905	1,119
– Other	6,864	7,463	8,105	1,112	13,379	12,102	37,134
Total	$581,898	$533,858	$470,235	$437,201	$426,590	$407,390	$356,505
Cost Per kwh (Mills)							
Generated	21.00	22.22	20.92	22.24	22.64	21.91	23.75
Purchased – Power Authority	12.63	10.34	9.58	8.80	8.42	7.21	10.39
– NUG	59.43	55.74	56.56	63.48	62.10	56.03	55.95
– Other	23.51	20.62	21.39	21.67	30.41	40.47	46.30
Operating expense (excluding production)	12.61	14.20	12.15	11.34	11.70	10.57	7.97
Total	39.70	39.74	34.74	33.64	33.84	31.81	30.64
Electric Operation and Maintenance Expenses (Thousands)							
Production	$581,898	$533,858	$470,235	$437,201	$426,590	$407,390	$356,505
Transmission	34,777	32,734	31,623	30,462	30,118	29,239	16,093
Distribution	64,337	69,322	64,428	62,763	58,876	54,420	42,494
Customer accounting	40,283	35,559	31,180	28,861	26,861	23,242	17,824
Customer service	25,546	34,749	31,390	24,345	27,625	23,426	6,149
Administrative and general	106,015	124,462 (1)	94,349	75,812	81,815	72,405	42,783
Total	$852,856	$830,684	$723,205	$659,444	$651,885	$610,122	$481,848

(1) Includes restructuring expenses of $21 million.

New York State Electric & Gas Corporation
Ithaca-Dryden Road
P.O. Box 3287
Ithaca, NY 14852-3287

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OFFICERS

Ages and years of service as of January 1, 1995, in parentheses

James A. Carrigg (61, 36)
chairman, president and chief executive officer

Patricia A. Orzell (52, 33)
assistant secretary

Teresa M. Turner (44,19)
executive assistant to the chairman, president and chief executive officer

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executive vice president

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senior vice president-Management Services Business Unit

Michael I. German (44, 0)
senior vice president-Gas Business Unit

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Sherwood J. Rafferty (47, 14)
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Robert T. Pochily (45, 23)
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Susan T. Schattschneider (41, 12)
assistant controller

INVESTOR INFORMATION

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Kirkwood Industrial Park
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(607) 729-2551

Ithaca Executive Offices
Ithaca-Dryden Road
P.O. Box 3287
Ithaca, NY 14852-3287
(607) 347-4131

General Counsel
Huber Lawrence & Abell
605 Third Avenue
New York, NY 10158

Independent Accountants
Coopers & Lybrand
1301 Avenue of the Americas
New York, NY 10019

To present certificates for transfer, write to:
Chemical Bank
Attention: Stock Transfer Administration
P.O. Box 24935
Church Street Station
New York, NY 10249
(Certified or registered mail is recommended.)

For stock transfer instructions, write to:
Chemical Bank
Attention: Legal Transfer
450 West 33rd Street
New York, NY 10001

Please contact NYSEG shareholder services with questions regarding:

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- our dividend reinvestment and stock purchase plan
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- a change of address
- report requests
- our annual meeting of stockholders

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P.O. Box 3200
Ithaca, NY 14852-3200

You may also obtain a free copy of Form 10-K, which is filed each year with the Securities and Exchange Commission, by contacting shareholder services at the telephone number or address above.

Trading Symbol
The trading symbol for our common stock which is listed on the New York Stock Exchange is NGE.

Securities Listed on the New York Stock Exchange:

- Common Stock
- 3.75% Preferred Stock
- Adjustable Rate Preferred Stock ($25 par value)
- 7.40% Preferred Stock ($25 par value)
- 7 5/8% First Mortgage Bonds
- 8 5/8% First Mortgage Bonds

Annual Meeting

Friday, May 12, 1995, at 11 a.m.
Ithaca Executive Offices
Ithaca-Dryden Road
Dryden, NY

Formal notices of the meeting, a proxy statement and form of proxy will be mailed to stockholders in early April.

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First year elected in parentheses

James A. Carrigg (1983)
chairman, president and chief executive officer of the corporation
Binghamton, NY

Alison P. Casarett (1979)
special assistant to the president
Cornell University
Ithaca, NY

Everett A. Gilmour (1980)
chairman of the board
The National Bank and Trust Company of Norwich and N.B.T. Bancorp, Inc.
Norwich, NY

Paul L. Gioia (1991)
partner
LeBoeuf, Lamb, Greene & MacRae (attorneys at law)
Albany, NY

John M. Keeler (1989)
managing partner
Hinman, Howard & Kattell (attorneys at law)
Binghamton, NY

Allen E. Kintigh (1987)
former president and chief operating officer of the corporation
Binghamton, NY

Ben E. Lynch (1987)
president
Winchester Optical Company
Elmira, NY

Alton G. Marshall (1971)
president
Alton G. Marshall Associates, Inc. (a real estate investment corporation)
New York, NY

David R. Newcomb (1979)
former president and chief executive officer
Buffalo Forge Company (manufacturer of heating, ventilation and air conditioning equipment)
Buffalo, NY

Robert A. Plane (1982)
president emeritus
Wells College
Aurora, NY

Charles W. Stuart (1971)
chairman and chief executive officer
C.W. Stuart & Co., Inc. (interstate trucking concern)
Newark, NY

Committees of the Board

Chairperson listed first

Audit:
Plane, Gioia, Keeler, Lynch

Corporate Diversification:
Gioia, Carrigg, Gilmour, Lynch

Executive:
Carrigg, Gilmour, Kintigh, Marshall, Newcomb, Stuart

Executive Compensation and Succession:
Gilmour, Casarett, Lynch, Marshall, Newcomb

Nominating:
Marshall, Casarett, Gilmour, Newcomb

Pension:
Keeler, Kintigh, Plane, Stuart

Public Affairs:
Casarett, Gioia, Keeler, Lynch

Mr. Carrigg is an ex officio member of the pension and public affairs committees.

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Kirkwood Industrial Park
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Binghamton, NY 13902-5224
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New York, NY 10001

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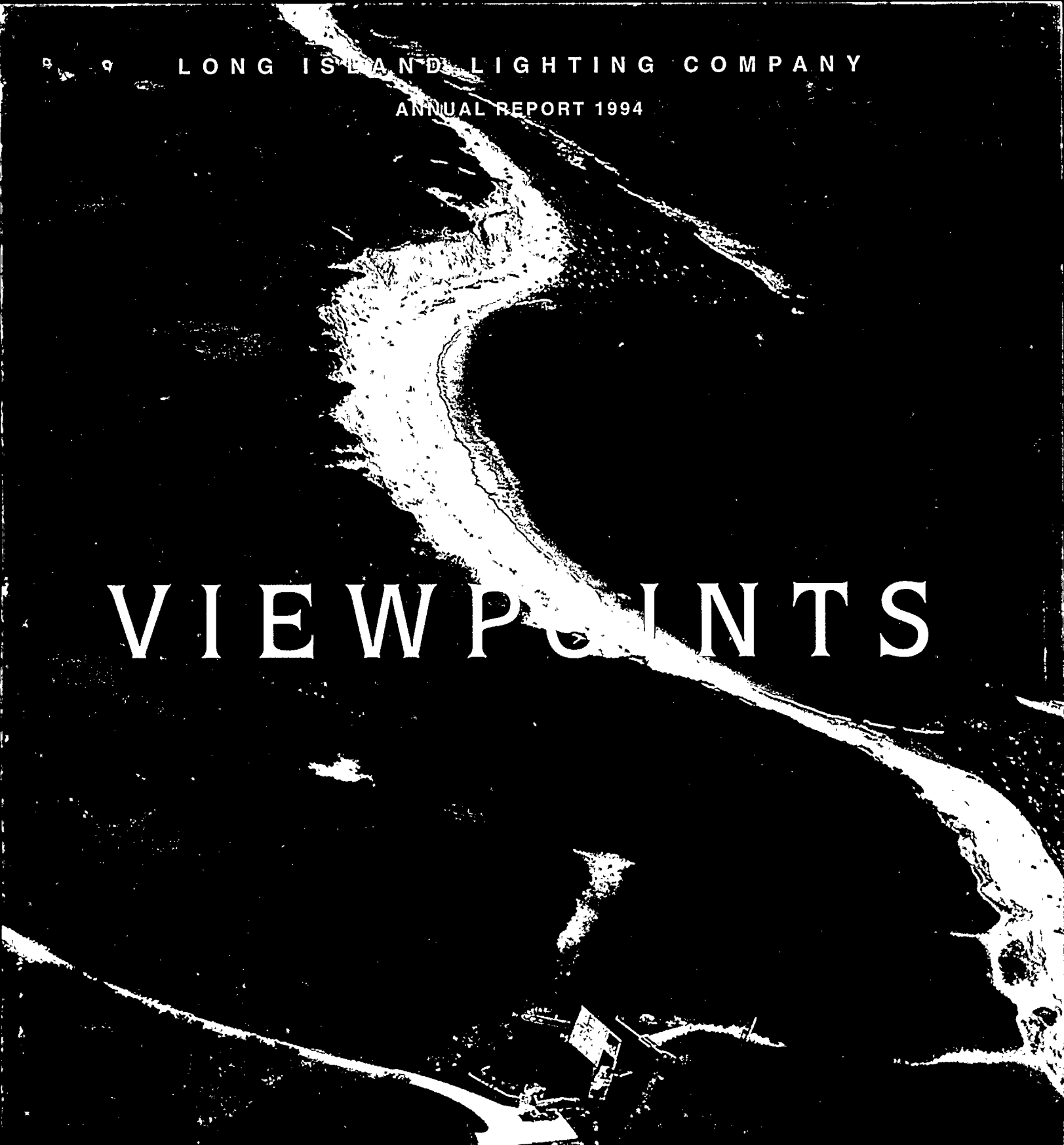
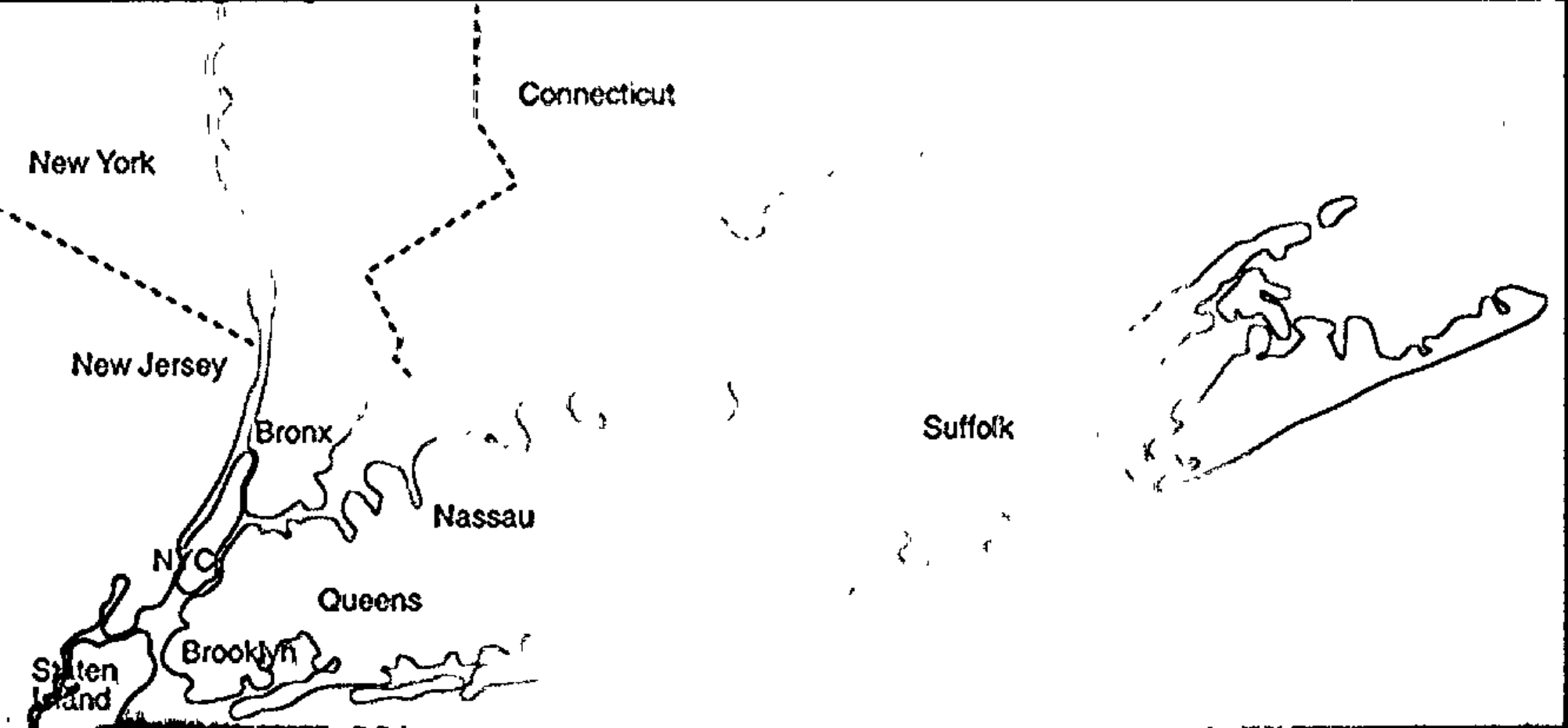
LONG ISLAND LIGHTING COMPANY

ANNUAL REPORT 1994



VIEWPOINTS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Bronx
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Queens
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Staten Island

CONTENTS

1994 HIGHLIGHTS

- Positive cash flow allowed the Company to meet all operating and construction requirements, as well as satisfy a portion of maturing debt.
- Earnings for common stock maintained at 1993 levels despite a higher number of shares outstanding and a lower allowed rate of return on common equity for the gas system.
- First common stock offering in ten years raised approximately $100 million.
- New record gas sendout of 585,227 dekatherms established in January.
- New record for customer energy use in a single month–1,975 gigawatt hours–established in July.
- Shoreham Nuclear Power Station decommissioning completed, pending final regulatory approval.

TO OUR SHAREOWNERS

1994

LILCO achieved a financial milestone in 1994, generating sufficient cash from operations to meet all of its operating and construction requirements, in addition to satisfying a portion of its maturing debt obligations with cash on hand. The Company earned $2.15 per common share in 1994 on revenues of $3,067,307,000, the same level of earnings as in 1993, despite a higher number of common shares outstanding and a lower allowed rate of return on common equity for the gas system. The Company also maintained the quarterly common stock dividend at 44.5 cents per share.

LILCO's improved financial position enabled the Company to file with the Public Service Commission (PSC) a three-year electric rate plan requesting a base rate freeze through November 30, 1996, and a 4.3 percent increase beginning December 1, 1996. Even with the rate freeze, LILCO is in a stronger financial position today than was anticipated in the Shoreham settlement, due largely to implementing cost-cutting measures, refinancing higher cost debt, and purchasing fuel at lower costs. By holding base rates at current levels, the Company can better prepare for a more competitive market and aid the economic recovery of Long Island. The PSC indicated that it will act on the Company's pending rate request in April 1995.

◇Competing Viewpoints

Discussions about introducing competition into the electric industry continued to dominate the industry, as policymakers nationwide confront the complex issues surrounding wholesale and retail wheeling. The financial markets reacted adversely to the discussions which, along with rising interest rates, caused the Dow Jones Utility Index to drop 20 percent.

In New York State, the PSC has been holding Competitive Opportunities Proceedings to evaluate the future structure of the electric industry. In Phase I of the proceedings, the PSC adopted

guidelines for flexible electric rates under which utilities can negotiate individual contracts with large commercial/industrial customers to dissuade them from leaving the system. In Phase II, the Commission has taken up the larger issue of wholesale and retail wheeling.

◇ On The Homefront

In October 1994, Governor Cuomo proposed a state takeover of LILCO as part of his re-election campaign. The $21.50 per share proposal promised to cut electric rates by 10 percent or more by substituting tax-exempt securities for the Company's stocks and bonds, and by eliminating federal income tax. Your Board of Directors had authorized management to commence discussions with the state to pursue their offer, but since Cuomo's defeat in the November election, the takeover plan has not been pursued by Governor Pataki's administration.

Energy costs continue to be a political issue on Long Island, with local public officials offering various plans to lower rates. Suffolk County has indicated that it will seek permission from the Federal Energy Regulatory Commission to municipalize the electric system in the county. Nassau County has filed a petition with the PSC to allow retail competition in its county. We will vigorously oppose both proposals because we believe neither would result in lower rates for all LILCO customers.

Proposals like these underscore the need for a structure that would allow for competition to be implemented in a manner that is fair to both residential and commercial ratepayers and to shareowners. To that end, we encourage all utility investors to make their viewpoints known through shareowner organizations or directly to elected officials.

◇ Working Our Strengths

To hold down rates and position the Company for a more competitive market, it has been necessary to vigorously cut costs. LILCO has saved $100 million in interest annually through aggressive refinancing of higher cost debt and preferred stock, and an additional $73 million in 1994 by combining off-system power purchases with burning natural gas in our power plants. In the last few years, we reduced our workforce by 600 employees through attrition and project an additional reduction of 250 employees by the end of 1995. And since 1989, we have saved more than $130 million by implementing cost containment programs, overtime reductions, managed health care and improvements in power plant reliability.

In addition to reducing costs, we are working hard to retain revenues. We established a major accounts organization focusing on our largest customers, especially those with options for alternative energy sources. We are working to expand the Island's economy, which had suffered a recession

following the defense cutbacks a few years ago. Through our efforts, 169 companies and 9,300 jobs have come to or expanded on Long Island. We also embarked on an innovative program with the state to retain and revitalize the region's manufacturing industry, involving 81 companies and more than 21,000 jobs.

In addition, LILCO's Research & Development Initiative continues to take the unique research and technology assets of the region and put them to work at LILCO. By partnering Long Island industries in creating new technologies for utility use, we are able to improve our service and strengthen the local economy.

In stimulating the region's economy, we are seeking to hold down rates by spreading our fixed costs over a larger customer base. Although the region has not fully recovered from the recession, we are confident that Long Island will rebound because of its proximity to New York City and international airports, its highly skilled workers, and its growing technology industries.

◇ Redefining Our Business

LILCO is implementing new strategies to respond to Long Island's energy needs. On the electric side of the business, we are exploring energy-efficient technologies that increase electric load while allowing customers to decrease overall energy costs. On the gas side, we have targeted expanded use of natural gas in homes and businesses that already have a gas service, allowing the Company to increase sales with minimal capital expenditure. Despite a significant decrease in fuel oil prices, we have continued to add customers to the gas system and see significant long-range opportunities there.

As always, our focus is providing unparalleled service to customers and excellent value to shareowners. Despite changes in the industry, our commitment to that goal will never change. On behalf of LILCO's Board of Directors and its employees, I would like to thank you for your confidence in our ability to keep that commitment.

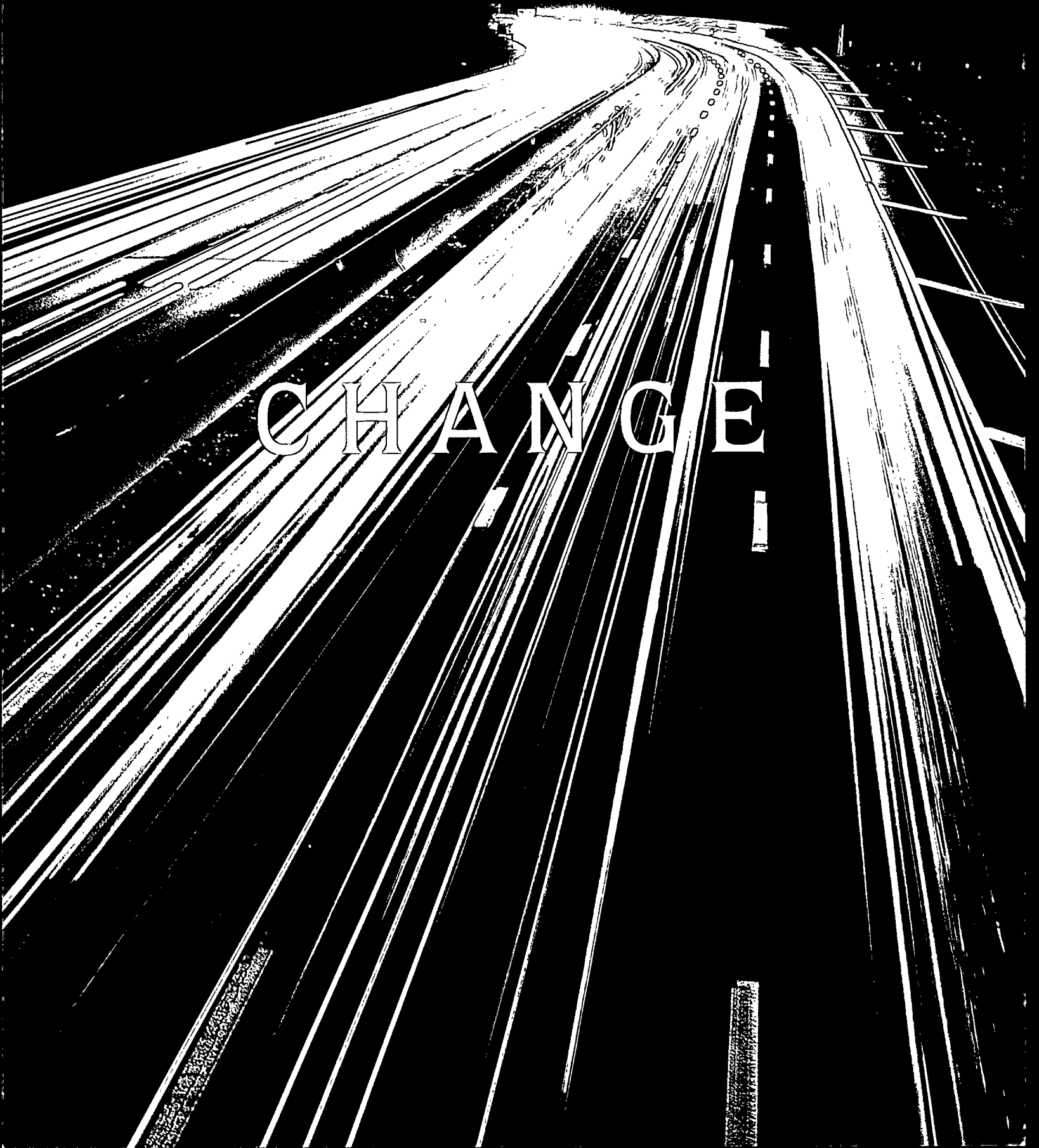
Sincerely,

William J. Catacosinos

Chairman, President and Chief Executive Officer

VIEWPOINTS

The utility industry is heading in a new direction towards a market in which the communities we serve are no longer defined by simple geography, but instead by unparalleled service. This, as always, is LILCO's goal. As we position our company to meet the challenges of this rapidly changing market, it is crucial that we take time to evaluate our strengths, and identify areas for improvement. Toward that end, we invited experts from various communities we serve to look at LILCO's performance in 1994 and provide insights into the progress we have made, as well as the steps yet to be taken.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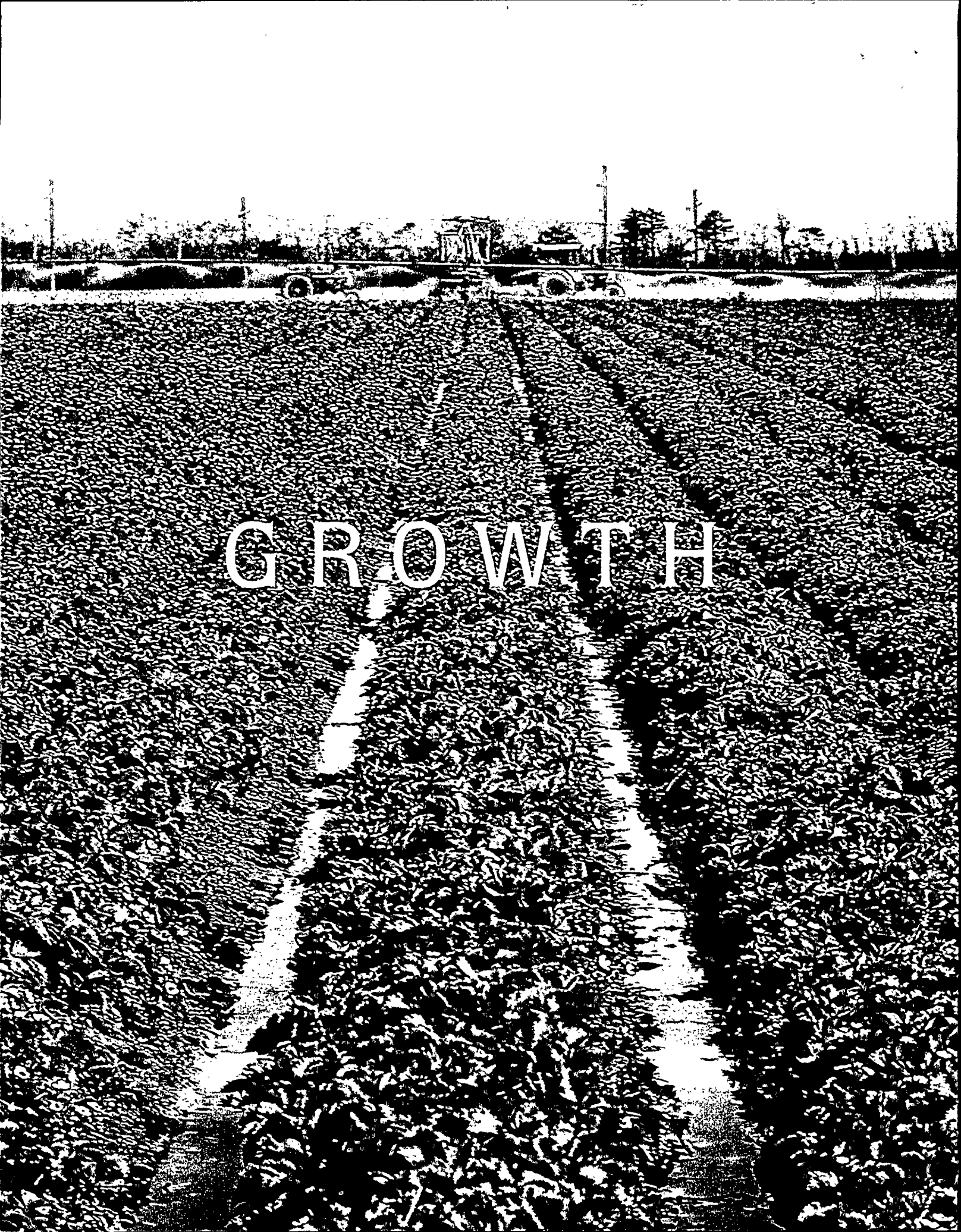
GROWTH

While new forms of competition are being debated, utilities have been purchasing low cost power through the power pool and two-party transactions. LILCO's system dispatchers continually compare LILCO's cost of generation against outside power to provide electric service at the lowest possible cost. The Company's dedication to cost-effectiveness also includes using the most economic mix of fuels and generating units within LILCO's system.

In 1994, combined savings from off-system power purchases and burning natural gas in our power plants totaled more than $73 million.

Dr. William W. Hogan
Professor of Public Policy and Management, Harvard University

EMERGING COMPETITION

"There's tremendous pressure in New York for electric competition to move ahead rapidly. The rhetoric suggests that we must have competition because electric prices are 'suddenly' much higher here than the national average. But when you look at the cost of electricity in real terms for industry in New York, the rhetoric is not based in fact. What actually is different is that now there is the opportunity to buy from other sources through retail competition. Customers want to buy elsewhere and avoid paying utility historical costs.

The trick is to design a system that allows for competition at the margin, but doesn't compromise the ability to collect costs that have been prudently incurred. That's not impossible. What is impossible is to design a system that produces dramatic reductions in rates quickly. It's the very nature of the electricity industry that a large portion of the costs are historical costs and nothing will reduce them. You can either have dramatic reductions in rates or honor the commitment to collect prudently incurred costs, but you cannot have both.

In a sense, LILCO is in a better position to handle competition than some other utilities. There are a limited number of transmission cables connecting Long Island to the Northeast power grid, through which competitive power would have to be delivered. Since much of the capacity on these cables is being utilized now, only so much outside power can be brought in for off-system sales. LILCO is also 'protected' in that the Company has fewer large customers than many other utilities, and these large customers are the ones that are most likely to have the ability to leave the system. And, unlike other utilities, LILCO has reached an agreement with the state on its sizeable regulatory asset. Other utilities have yet to complete this process.

To equitably implement competition, regulators need to separate the historical costs from the actual costs for generating electricity. When competitors come up against the real costs at the margin – in LILCO's case, 3.4 cents (kWh) – suddenly LILCO is looking pretty competitive."

Ernest S. Liu
Partner, Goldman Sachs

FINANCIAL HEALTH

"By far the biggest challenge facing utilities today is to adjust to competition while protecting their financial health. The underlying issue is that utilities have always been heavily regulated. Within that environment, they constructed electric systems, obtaining capital with regulatory assurances that they would be able to recover prudent costs. Today, there are less expensive technologies available to non-utility generators that, along with other factors, allow them to offer lower prices to consumers. Utilities are left with immense investments, undertaken to meet regulatory obligations, that are not yet fully amortized.

The stock market is worried about utilities being able to fully recover historical assets and still pay a stream of dividends to stockholders. It's a question of honoring commitments. And in LILCO's case, the question goes specifically to the Shoreham agreement. Investors are asking, with the recent change in administration and emphasis on promoting competition, does New York State intend to honor the future recovery of this asset?

The market is looking for assurances that the agreement between LILCO and the state is one which all future administrations will honor. Certainly LILCO has lived up to its part of the bargain. The Company has worked hard to improve its financial standing, using the improved cash flow we have seen in recent years to retire and refinance high cost debt. They have decreased their head count, improved their balance sheet by thickening their equity base, and maintained their dividend, which is essential to retaining credibility with the capital market.

The worst enemy of the investor is uncertainty. The financial community recognizes that LILCO has made much faster progress in improving its operations and cash flow, but people need to see some sign of good faith on the part of the state. I believe if we get that sign, LILCO stock will show some rebound and that, in turn, will enable the Company to continue to improve its balance sheet."

Despite external forces that impacted the valu of utility stocks nation wide, LILCO's financial health continued to improve in 1994. Earnings and common stock dividends were maintained at 1993 levels and, for the first time in ten years, the Company offered shares of common stock, raising approximately $100 million.

This offering, combined with satisfying a portion of maturing debt with cash on hand, allowed LILCO to reduce its debt ratio from 65 percent in 1993 to 62.5 percent by the end of 1994.

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layed a key role in the
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coalition of business,
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han $2 million in the
artnership effort, LILCO
as been instrumental
attracting, retaining or
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50 companies, and a
otal of 30,000 jobs on
ong Island.

Roslyn D. Goldmacher
Executive Director, Long Island Development Corporation

REGIONAL ADVANCES

"In the 1980s, the Long Island region was prosperous and the economy essentially drove itself. The changes of the 1990s demonstrate, however, the importance of aggressive economic development efforts even in a healthy economy.

LILCO has realized it needs to be a leader in this area. Nationwide, utilities have traditionally played the key role in economic development for their communities. The local utility has a unique link to every business and every consumer. It is tied to the community. If it is in anyone's interest to keep the region vibrant and healthy, it's in the utility's interest.

LILCO's involvement in regional economic development in the last few years has been very beneficial for the area's stability and growth. Long Island has many layers of government and with so many players in one pot, someone must take the lead to provide a cohesive, effective effort.

LILCO has created a formal method for coordinating economic development resources in the region through the New Long Island Partnership. It provides a single point-of-contact where businesses can go and say, 'I need help, how can you help me?' and the right resources are brought to the table. And LILCO has done this without creating additional financial burden on those resources. LILCO has effectively allowed the economic development agencies to extend their outreach without spending more money.

The 'hand-holding' LILCO provides has resulted in many companies making the decision to stay, or expand, or come to Long Island. It has made the process more user-friendly. In economic development, that's the whole idea.

LILCO's involvement in economic development efforts benefits ratepayers and stockholders, as well. Ultimately, if the economy thrives, so will the utility. Rates remain stable and dividends get paid. So it's not just a matter of a moral obligation to the community. Good business is good business. It's as simple as that."

Dr. Philip F. Palmedo
President, Long Island Research Institute

RESEARCH AND DEVELOPMENT

"The general public, even the corporate and investment worlds, have not yet come to appreciate the strength in high-tech research and development that exists on Long Island. Many regions of the country have strength in R&D, but few have the concentrated, diversified strengths we have here. The fact that Long Island has a major strength not in one narrow area but in many suggests that synergistic technological combinations will emerge here.

Unfortunately, Long Island has lacked a coordinated regional effort to capitalize on these strengths properly. When you think of the regions across the country that have excelled in technology-based economic development, they are not necessarily those with the best research, but those capable of translating that research into commercial activity.

Somebody has to have the imagination to envision the route to concrete commercial uses of innovative research; to move technology from creator to user. That's the basic philosophy of the Long Island Research Institute. We look at technologies and build bridges out to the potential users. That's also the philosophy behind LILCO's R&D Initiative, and I am a great supporter of their efforts because they are working to build bridges from their end.

The process of converting technologies from a research stage to practical application requires the ability to evaluate a technology for competition with others and an understanding of the appropriate business strategy to move that technology into industry. But the really critical component is understanding the user's point of view. When you have a company like LILCO, a major user participating in the process, that focuses and expedites the entire effort.

The region would greatly benefit if other industry sectors would emulate LILCO's Initiative and would energize applied research and development to address the important needs and opportunities in their specific fields."

LILCO's Research & Development Initiative is currently entering its fourth successful year. Created to provide LILCO with innovative technologies needed to compete in the consumer-driven service industry of the 90s, the Initiative has awarded more than $10.7 million to 45 Long Island technical institutions for 84 projects since 1991. Matching research talent with industrial resources has helped stimulate regional economic growth while helping us improve the ways we produce, deliver and conserve electricity and natural gas.

INNOVATION


COMMUNITY

LCO has an extensive ommunity outreach pro-ram, providing services a variety of "special ublics" including senior tizens, children, teach-s, and disadvantaged milies. LILCO employ-es are also heavily volved in Company-ide volunteer activities. 1994, employees articipated in "casual ays" for United Cere-al Palsy and to help unch "Project Warmth," ong Island's first fuel nd; raised more than 18,000 in the American eart Walk; contributed 855,000 to the United Vay Campaign, and elped provide Christ-as toys for 5,000 Long land children.

Msgr. Thomas J. Hartman
Executive Director, Telicare

SOCIAL INVOLVEMENT

"I grew up on Long Island in the generation following World War II, a very prosperous time for our region. Most families then were very traditional, with Dad going to work and Mom staying home to take care of the kids. Families had that luxury in those days. But today, we're in very different times. We're in different times in terms of government—with serious cutbacks in services; in terms of jobs—with the declining defense industry creating unemployment problems, and in terms of family—there's a lot of social and economic pressure that makes it difficult for people to function as a family.

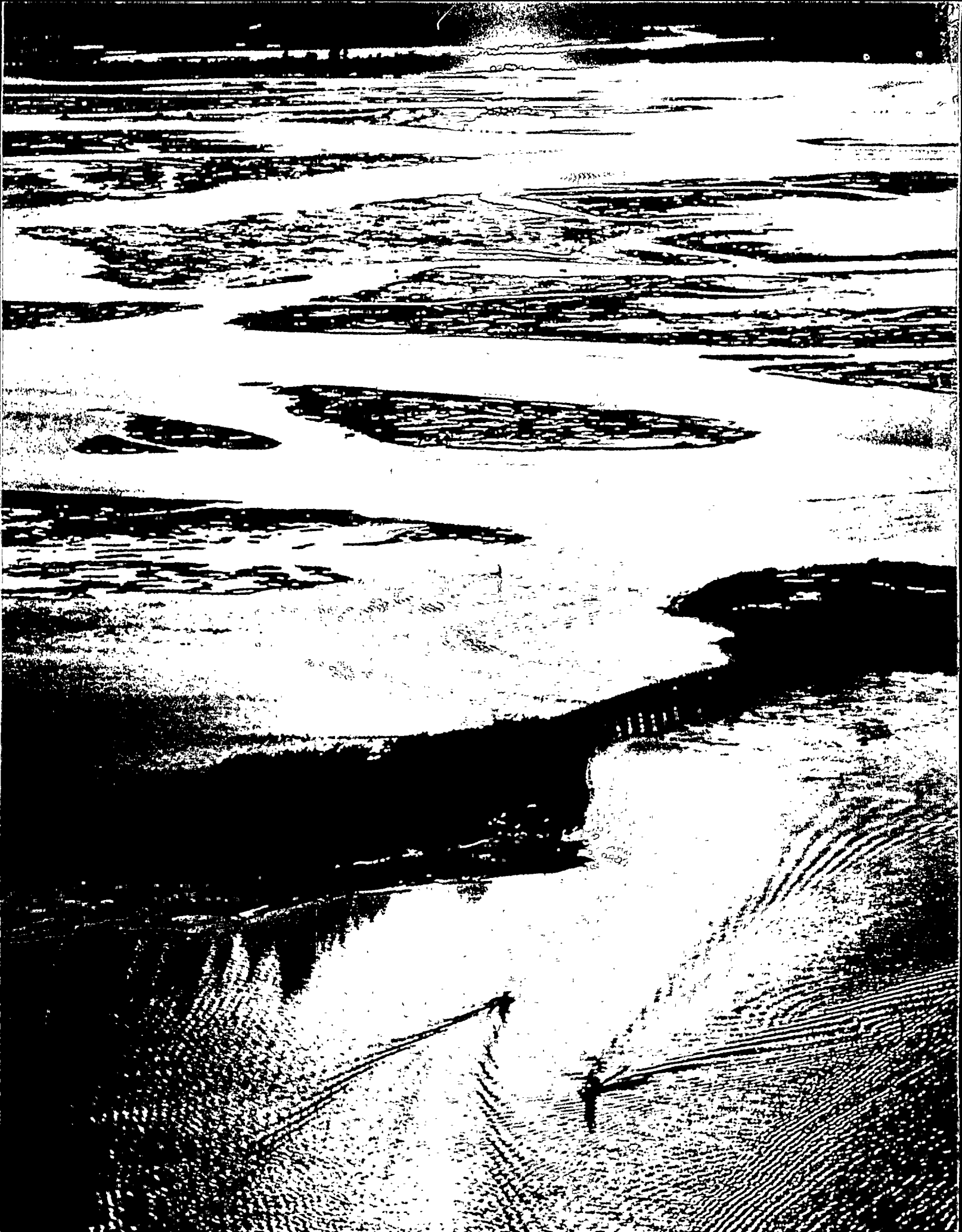
In the midst of these changes, there is a temptation to say that the problems are so great, nothing can be done. I don't agree. Problems are always solved one at a time. They're always solved looking into the eyes of individual people.

The challenge for a corporation like LILCO is to continue to care about the problems affecting the people of Long Island. Why? Because any corporation is really a composite of people. The individuals who come to work at LILCO are not only workers, they are part of the community. For the corporation to understand them, it must be part of the community, too.

If a company grows and makes its money on Long Island and does not give back to the community, its people become disenchanted. But if it engages its people in a dialogue, lets them know it cares about this Island, that can make all the difference.

When I went to LILCO a few years ago and asked if they could help Helen Keller Services for the Blind, they listened. They had respect for the cause, and the company got involved. If you have a child who is blind and you don't have the resources to take care of that child, what the people at LILCO are doing makes a big difference. They're not just providing a service and sending a bill—they are a neighbor.

The challenge to corporations is to be responsive. It isn't a question of whether to be involved, but how to be involved. We're all part of the human story. We need to be connected."



FINANCIAL CONTENTS

Overview

In 1994, the Company reached a milestone by generating sufficient cash from operations to meet all of its operating and construction requirements in addition to satisfying a portion of its maturing debt obligations with cash on hand. The positive cash flow resulted, in part, from the collection of deferred revenues associated with the Rate Moderation Component (RMC) and the Long Island Lighting Company Ratemaking and Performance Plan, and the Company's continued efforts to maximize operating efficiencies while reducing operating costs.

Since 1989, the Company has received six electric rate increases and has experienced lower than anticipated fuel costs, financing costs and production expenses, all of which have helped to improve cash flow, which in turn, has improved the Company's financial health. This improved financial health has enabled the Company to file with the Public Service Commission of the State of New York (PSC) on December 31, 1993, a three year electric rate plan (Electric Rate Plan) requesting that base electric rates be frozen through November 30, 1996, and that overall electric rates increase 4.3% beginning December 1, 1996. The Electric Rate Plan, as designed, will help to better position the Company to meet existing and anticipated competitive challenges in addition to assisting the economic recovery of Long Island.

Three Administrative Law Judges (ALJs) issued a recommended decision to the PSC with respect to the Company's Electric Rate Plan. The ALJs agreed with the Company's proposal to freeze base electric rates for the first year, and implied that base rates could remain frozen for the second year as well. The ALJs encouraged the Company and other intervening parties in the proceeding to negotiate a settlement regarding the third year of the Company's Electric Rate Plan. The Company, the PSC and other parties to this proceeding continue to negotiate toward a three year rate settlement. The Company believes that a three year rate settlement is in the best interest of shareowners and ratepayers.

Other significant achievements during 1994 included:

- The Company maintained the same level of earnings per common share in 1994 as in 1993, despite a lower allowed return on common equity for the gas business and the issuance of 6.1 million shares of common stock during 1994;

- The public offering of 5.1 million shares of the Company's common stock, for the first time in nearly ten years, raising approximately $100 million. This offering, combined with the satisfaction of a portion of maturing debt with cash on hand, has resulted in the reduction in the Company's debt ratio to 62.5% at December 31, 1994 from 65.0% at December 31, 1993;

- The continuation of the Company's quarterly common stock dividend rate at 44½ cents per share;

- The reduction of the Company's average coupon rate on its outstanding long-term debt to 7.9% as a result of the Company's refinancing activities. The refinancing of a significant amount of the Company's long-term debt and preferred stock, over the past several years, has resulted in annual cash savings of approximately $100 million;

- The reduction of the RMC balance from $610 million at December 31, 1993 to $463 million at December 31, 1994. This reduction resulted, in part, from current year revenues under the Rate Moderation Agreement exceeding revenues that were required in 1994 under conventional ratemaking;

- The completion, pending final regulatory approval, of the decommissioning of the Shoreham Nuclear Power Station, including the removal and transportation of Shoreham's fuel to another utility;

- The receipt of a gas rate increase effective December 1, 1994, which is the second of three gas rate increases under a three-year settlement between the Company and the PSC which provides for annual rate increases of 4.7%, 3.8% and 2.8% for the rate years beginning December 1, 1993, 1994 and 1995, respectively;

- The addition of over 8,500 new gas space heating customers, resulting from the continuation of the Company's gas expansion program;

- The establishment of a record maximum day gas sendout of 585,227 dekatherms on January 19, 1994.

In addition, in 1994, the Company received an invitation at the request of the former Governor of New York State, from the chief executives of the New York Power Authority and the Long Island Power Authority, for the Company to enter into negotiations with them in a proposal to convert the Company into a public power utility. The new Governor empaneled a task force to study the "takeover" proposal. While the task force did not make its recommendation public, published reports in local newspapers indicate that the task force recommended to reject the proposal.

Liquidity

At December 31, 1994, the Company's cash and cash equivalents amounted to approximately $185 million, compared to $249 million at December 31, 1993. The decrease in cash and cash equivalents reflects the Company's strategy of applying available cash balances toward the satisfaction of maturing debt.

The Company has available for its use a $300 million revolving line of credit through October 1, 1995, provided by its 1989 Revolving Credit Agreement (1989 RCA). At December 31, 1994, no amounts were outstanding under the 1989 RCA. This line of credit is secured by a first lien upon the Company's accounts receivable and fuel oil inventories. The 1989 RCA may be extended for one year periods upon the acceptance by the lending banks of a request by the Company. The Company's request must be delivered to the lending banks prior to April 1 of each year. In 1995, the Company intends to request such an extension. For a further discussion of the 1989 RCA, see Note 7 of Notes to Financial Statements.

Capitalization

The Company's capitalization, including current maturities of long-term debt and current redemption requirements of preferred stock, at December 31, 1994, was approximately $8.3 billion, compared to $8.4 billion at December 31, 1993. At December 31, 1994 and 1993, the Company's capitalization ratios were as follows:

	1994	*1993*
Long-term debt	**62.5%**	65.0%
Preferred stock	**8.6**	8.5
Common shareowners' equity	**28.9**	26.5
	100.0%	100.0%

The Company is committed to reducing its debt ratio. To achieve this goal, the Company intends to continue reducing debt with cash generated from operations and intends to issue common or preferred stock if market conditions prove favorable. With this commitment in mind, the Company issued 5.1 million shares of common stock in 1994, marking the first time in approximately ten years that the Company issued common equity, other than through its Automatic Dividend Reinvestment Plan, its Employee Stock Purchase Plan or through the conversion of Series I Preferred Stock.

In 1994, the Company applied the net proceeds from the sale of the 5.1 million shares of common stock and the issuance of $285 million of General and Refunding Bonds (G&R Bonds) toward the repayment, at maturity, of $400 million of debentures and the redemption of $30 million and $5 million of debentures that had been scheduled to mature in 1999 and 2019, respectively. Cash from operations provided the balance of funds needed to retire/redeem this debt and to retire $25 million of First Mortgage Bonds, which matured in June 1994. In addition, in November 1994 the Company used cash on hand to satisfy the payment of $175 million of maturing debentures.

The Company's need to access the financial markets to provide additional capital or to refinance its maturing debt has diminished compared to prior years. The Company intends to use cash generated from operations to satisfy the payment of $25 million of First Mortgage Bonds maturing on June 1, 1995. With respect to the repayment of $455 million and $286 million of debt maturing in 1996 and 1997, respectively, the Company intends to use cash generated from operations to the maximum extent practicable. The balance of funds necessary to satisfy maturing debt obligations in 1996 and 1997 will be obtained through the issuance of either debt or equity securities, or some combination thereof.

Despite improving financial indicia, the Company's securities, which are rated by Standard and Poor's Corporation (S&P), Moody's Investors Service (Moody's), Fitch Investors Service, L.P. (Fitch) and Duff and Phelps, Inc. (D&P), have been downgraded by certain rating agencies over the past eighteen months. In June 1994, Moody's lowered the credit ratings of the Company reflecting Moody's expectations that the Company's high tariff rates will intensify business risk in an increasingly competitive environment. Recently, S&P placed its ratings on the Company's securities on "Credit Watch with negative implications," Fitch changed its credit trends to "declining" and Moody's placed the Company's credit ratings under review for a possible downgrade reflecting their respective concerns about the regulatory environment in New York State.

At December 31, 1994, the ratings for each of the Company's principal securities were as follows:

	S&P	*Moody's*	*Fitch*	*D&P*
First Mortgage Bonds	**BBB–**	**Baa3**	**BBB**	**BBB**
G&R Bonds	**BBB–**	**Baa3**	**BBB**	**BBB**
Debentures	BB+	Ba1	**BBB–**	BB+
Preferred Stock	BB+	ba1	**BBB–**	BB
Minimum Investment Grade	**BBB–**	**Baa3**	**BBB–**	**BBB–**

Bold face indicates securities that meet or exceed minimum investment grade.

The Company's Authority Financing Notes (Notes), some of which are secured by letters of credit, are rated by certain of the rating agencies. The ratings on the Notes secured by letters of credit reflect the ratings of the institutions issuing the letters of credit, and not that of the Company.

Capital Requirements and Capital Provided

Capital requirements and capital provided for 1994 and 1993 were as follows:

	(In millions of dollars)	
	1994	*1993*
Capital Requirements		
Construction		
Electric	$ 135	$ 136
Gas	119	125
Common	23	41
Total Construction	277	302
Refundings and Dividends		
Long-term debt	635	960
Preferred stock	5	206
Common stock dividends	205	196
Preferred stock dividends	53	57
Redemption costs	2	15
Total Refundings and Dividends	900	1,434
Shoreham post settlement costs	167	207
Total Capital Requirements	**$ 1,344**	**$ 1,943**
Capital Provided		
Cash generated from operations	$ 836	$ 582
Long-term debt issued	331	1,090
Common stock issued	118	14
Preferred stock issued	—	202
Financing costs	(4)	(6)
Decrease in cash	63	61
Total Capital Provided	**$ 1,344**	**$ 1,943**

For further information, see the Statement of Cash Flows.

Given the Company's current electric load forecast and the availability of electricity provided by the Company's generating facilities and by purchases of power from others, the Company forecasts that it will not need any new generating facilities until beyond the year 2000. As a result, the Company does not forecast any need for external financing for the construction of generating facilities during this period. With respect to financing other capital additions to plant, the Company estimates that cash generated from operations will be sufficient to meet any such requirements in 1995.

For 1995, total capital requirements (excluding common stock dividends) are estimated at $431 million, of which maturing debt is $25 million, additions to plant are $277 million, preferred stock dividends are $53 million, preferred stock sinking funds are $5 million and Shoreham post settlement costs are $71 million, including $58 million for payments in lieu of taxes.

Rate Matters

Electric

In conjunction with the 1989 Settlement, the PSC agreed to the recognition of a regulatory asset known as the Financial Resource Asset (FRA). The FRA consists of two components, the Base Financial Component (BFC) and the Rate Moderation Component (RMC), discussed in Note 1 of Notes to Financial Statements. The Rate Moderation Agreement (RMA), one of the constituent documents of the 1989 Settlement, provides for the full recovery of the FRA.

The BFC was granted rate base treatment under the terms of the RMA and is included in the Company's revenue requirements through an amortization included in rates over forty years on a straight-line basis that began July 1, 1989. The RMC had provided the Company with a substantial amount of non-cash earnings since the effective date of the 1989 Settlement through December 31, 1992, as the revenues provided under the RMA were less than the revenues required under conventional ratemaking. During 1993, however, as the revenues provided under the RMA began to exceed the revenues that would have been provided under conventional ratemaking, the RMC balance began to decline.

Pursuant to the 1989 Settlement, the Company has received six electric rate increases as contemplated by the RMA. In November 1991, the PSC approved the Long Island Lighting Company Ratemaking and Performance Plan (LRPP) which provided annual electric rate increases of 4.15%, 4.1% and 4.0% effective December 1, 1991, 1992 and 1993, respectively. The LRPP provided for an allowed return on common equity from electric operations of 11.6% for each of the three rate years.

The LRPP was designed to be consistent with the RMA's long-term goals. One principal objective of the LRPP is to reassign risk so that the Company assumes the responsibility for risks within the control of management, whereas risks largely beyond the control of management would be assumed by the ratepayers.

One of the major components of the LRPP provides for a revenue reconciliation mechanism that eliminates the impact on earnings of experiencing electric sales that are above or below the LRPP forecast by providing a fixed annual net margin level (defined as sales revenues, net of fuel and gross receipts taxes) that the Company receives under the LRPP.

The LRPP allows the Company to earn for each rate year up to 60 additional basis points, or forfeit up to 38 basis points, of the allowed return on common equity as a result of the Company's performance within certain incentive and/or penalty programs. These programs consist of a customer service performance plan, a demand side management (DSM) program, a time-of-use program, a partial pass through fuel cost incentive plan, and effective December 1, 1993, an electric transmission and distribution reliability plan. Based upon the Company's performance within these programs, the Company earned a total of 50 and 49 basis points, or approximately $9.2 million, net of tax effects, for each of the rate years ended November 30, 1994, and 1993. For the rate year ended November 30, 1992, the Company earned approximately $4.3 million, net of tax effects, for its performance in these programs.

The LRPP contains a mechanism whereby earnings in excess of the allowed return on common equity of 11.6%, excluding the impacts of the various incentive and/or penalty programs, are shared equally between ratepayers and shareowners. The Company earned $8.9 million and $21.4 million, net of tax effects, for the rate years ended November 30, 1993 and 1992, respectively, in excess of its allowed return on common equity which was shared equally between ratepayers (by a reduction to the RMC) and shareowners. For the rate year ended November 30, 1994, the Company did not earn in excess of its allowed return on common equity.

In December 1993, the Company filed a three year Electric Rate Plan with the PSC for the period beginning December 1, 1994 that minimizes future electric rate increases while retaining consistency with the RMA's objective of the restoration of the Company's financial health. The Electric Rate Plan requests an allowed return on common equity of 11.0%, and provides for base rates to be frozen in years one and two and an overall rate increase of 4.3% in the third year. Although base electric rates would be frozen during the first two years of the Electric Rate Plan, annual rate increases of approximately 1% are expected to result from the operation of the Company's fuel cost adjustment (FCA) clause. The FCA captures, among other things, amounts to be recovered from or refunded to ratepayers in excess of $15 million, which result from the reconciliation of revenues, certain expenses and earned performance incentive components, under the LRPP, discussed in Note 3 of Notes to Financial Statements.

The Company's Electric Rate Plan reflects four underlying objectives: (i) to limit the balance of the RMC during the three year period to no more than its 1992 peak balance of $652 million; (ii) to recover the RMC within the time frame established in the 1989 Settlement; (iii) to minimize, beginning in the third year of the Electric Rate Plan, the final three rate increases contemplated in the 1989 Settlement that follow the two year rate freeze period; and (iv) to continue the Company's gradual return to financial health.

The Electric Rate Plan provides for, with some modifications, the continuation of the LRPP revenue and expense reconciliations and performance incentives. The Electric Rate Plan includes the annual reconciliation of certain expenses for property taxes, interest costs, DSM costs and the deferral and amortization of certain costs for enhanced reliability. The Company would be allowed to earn for each of the three rate years under the Electric Rate Plan up to 50 additional basis points, excluding incentives under the DSM program, or forfeit up to 47 basis points of the allowed return on common equity of 11.0% as a result of the Company's performance within certain performance programs. These programs consist of a customer service program, a partial pass through fuel cost incentive plan, a DSM program and an electric transmission and distribution reliability plan.

The Company's Electric Rate Plan provides for lower annual electric rate increases than originally anticipated under the 1989 Settlement. However, as a result of changes in certain assumptions upon which the RMA was based, their impact on the RMC and the Company's plans to reduce DSM, operations and maintenance and capital expenditures, the Company has determined that the overall objectives of the RMA can be met under the Electric Rate Plan. As a result of lower than originally anticipated inflation, interest costs, property taxes, fuel costs and return on common equity allowed by the PSC, the RMC, which originally had been anticipated to peak at $1.2 billion in 1994, peaked at $652 million in 1992. With the exception of a projected increase in 1995 and 1996, which is not now anticipated to cause the RMC to increase above its $652 million peak, the RMC is expected to decline until it is fully amortized.

Under the Electric Rate Plan, the recovery of the RMC would be extended, if necessary, for an additional period of not more than three years beyond the approximate ten year period envisioned in the RMA. The actual length of the RMC extension will depend upon the extent to which the assumptions underlying the Electric Rate Plan materialize. The Company's current projections indicate that the RMC will be recovered in eleven years.

The Staff of the PSC (Staff) and other intervening parties filed testimony in response to the Company's Electric Rate Plan. Staff concurs with the Company's proposal for an 11.0% return on common equity in each of the three years, and has reaffirmed its commitment to the principals of the RMA, including the full recovery of the RMC within the time frame established by the RMA. However, Staff has recommended an overall zero percent rate increase for the first two years, contrasted with the Company's proposal for a base rate freeze with FCA adjustments of approximately 1% in years one and two, as described above. Staff did not make a recommendation for the level of rate relief in the third year.

In September 1994, three ALJs of the PSC issued a recommended decision to the PSC with respect to the Company's Electric Rate Plan. The ALJs agreed with the Company's proposed 11.0% return on common equity and its proposal to freeze base electric rates for the first rate year. While no explicit recommendation was made concerning the second year, the recommended decision implied that base rates could remain frozen for the second rate year as well.

With respect to the third rate year beginning December 1, 1996, the ALJs determined that it was not appropriate for them to issue a recommendation since, in their opinion, the Company's revenue requirements for the third rate year could not be precisely determined at this time. Alternatively, the ALJs encouraged the Company and other parties in the proceeding to negotiate a settlement concerning any rate increase for the third rate year.

The PSC had been expected to issue a final order on the Company's Electric Rate Plan before November 29, 1994, the date that the statutory suspension period was scheduled to terminate. However, in order to accommodate further settlement negotiations in the proceeding, the Company has requested extensions through April 1995, which were granted by the PSC. The Company's offers to extend the suspension period were conditioned upon the continuation of the current LRPP rate mechanisms. Although the ultimate outcome of the Electric Rate Plan cannot be predicted, the Company expects that any PSC order will be consistent with the provisions of the RMA respecting the recovery of the FRA and other 1989 Settlement deferred charges.

Gas

In December 1993, the PSC approved a three year gas rate settlement, between the Company and the Staff of the PSC. The gas rate settlement provides that the Company receive, for each of the rate years beginning December 1, 1993, 1994 and 1995, annual gas rate increases of 4.7%, 3.8% and 2.8%, respectively. An allowed return on common equity of 10.1% was used in the determination of the revenue requirements for the gas rate settlement. The gas rate decision provides that earnings in excess of a 10.6% return on common equity in any of the three rate years covered by the settlement be shared equally between the Company's firm gas customers and its shareowners. For the rate year ended November 30, 1994, the Company earned $9.2 million, net of tax effects, in excess of the 10.6% return on common equity. The firm gas customers' portion of these excess earnings amounting to $4.6 million, net of tax effects, has been deferred until its final disposition is determined by the PSC.

Environment

During 1994, the Company spent approximately $6.4 million in order to comply with the 1990 amendments to the Federal Clean Air Act (Act). These expenditures were necessary to meet continuous emissions monitoring requirements and Phase I nitrogen oxide (NOx) reduction requirements under the Act.

The Company expects that it will have to expend approximately $1 million in 1995 to meet continuous emission monitoring requirements and to meet Phase I NOx reduction requirements. In order to generate 210 tons of NOx reduction credits already under contract for sale to a third party, the Company anticipates spending $2.5 million in 1995 and $1.9 million in 1996 for earlier than required NOx reduction systems. Subject to requirements that are expected to be promulgated in forthcoming regulations, the Company estimates that it may be required to spend an additional $80 million (net of NOx credit sales) by 2003 to meet Phase II and Phase III NOx reduction requirements. In an effort to minimize costs associated with anticipated NOx reduction requirements, the Company is engaged in a $7 million research and development project along with several co-funding organizations to demonstrate an innovative NOx reduction technology at its E.F. Barrett Power Station. The Company is committed to fund $3.6 million of the project costs. Through 1994, approximately $5 million has been expended by all of the co-funders. It is anticipated that the remaining $2 million will be spent in 1995. In addition, the Company estimates that it may be required to spend approximately $24 million by 1999 to meet potential requirements for the control of hazardous air pollutants from power plants. The Company believes that all of the above mentioned costs will be recoverable through rates.

The New York State Department of Environmental Conservation has indicated to New York State utilities that it may require all such utilities to investigate and, where necessary, remediate their former manufactured gas plant sites. The Company is the owner of six pieces of property on which the Company or certain of its predecessor companies produced manufactured gas. Although the exact amount of the Company's clean-up costs cannot yet be determined, based on the findings of investigations at two of these six sites, preliminary estimates indicate that it will cost approximately $35 million to clean-up all of these sites over the next five to ten years. Accordingly, the Company has recorded a $35 million liability and a corresponding regulatory asset to reflect its belief that the PSC will provide for the future recovery of these costs through rates as it has for other New York State utilities. The Company has notified its former and current insurance carriers that it seeks to recover from them certain of these clean-up costs. However, the Company is unable to predict the amount of insurance recovery, if any, that it may obtain.

The Company has been notified by the Environmental Protection Agency (EPA) that it is one of many potentially responsible parties (PRPs) that may be liable for the remediation of three contaminated licensed treatment, storage and disposal sites. At one site, located in Philadelphia, Pennsylvania, and operated by Metal Bank of America, the Company and nine other PRPs, all of which are public utilities, have completed a Remedial Investigation and Feasibility Study which is currently being reviewed by the EPA. The level of remediation required will be determined when the EPA issues its decision, currently expected in May 1995. The Company currently anticipates that the total cost to remediate this site will be between $14 million and $30 million. The Company has recorded a liability of $1.1 million representing its estimated share of the cost to remediate this site. The Company believes that any cost incurred to remediate this site will be recoverable through rates.

With respect to the other two sites, which are located in Kansas City, Kansas and Kansas City, Missouri, the Company is investigating allegations that it had previously stored or made agreements for the disposal of polychlorinated biphenyls (PCBs) or items containing PCBs at these sites. The Company is currently unable to determine its share of the cost to remediate these sites or the impact, if any, on the Company's financial position. The Company believes that any cost incurred to remediate these sites will be recoverable through rates.

NYPA and LIPA Proposal

At the request of the then Governor of the State of New York, on October 13, 1994 the chief executives of the New York Power Authority (NYPA) and the Long Island Power Authority (LIPA) invited the Company to enter into negotiations with them regarding a proposal to convert the Company into a public power utility. Under the proposal, the two state authorities contemplated a business combination in which holders of the Company's common stock would receive $21.50 in cash for each outstanding share of the Company's common stock. NYPA and LIPA indicated that the completion of this transaction would be subject to, among other things, the availability of tax-exempt financing sufficient to complete the transaction and the verification by NYPA and LIPA that the transaction would result in rate reductions in excess of 10%. The Company's Board of Directors has authorized the Company to enter into discussions with NYPA and LIPA to explore the proposal in greater detail, but no such discussions have been held.

The new Governor of the State of New York had empaneled a task force to study the takeover proposal. While the task force did not make its recommendation public, published reports in local newspapers indicate that the task force recommended to reject the proposal.

Competitive Environment

Significant changes are taking place in the business and regulatory environment in which electric utilities operate. In response, the Company, like utilities across the nation, is actively involved with federal and State agencies in evaluating what type of competition would best serve both customers and investors. The Company has also undertaken a review of its current operations, seeking to shape those operations to best meet the challenges of a competitive environment. As federal legislators and regulators continue pursuing a policy of evaluating competition in the electric utility industry, state regulators are addressing the many complex and politically sensitive issues which will affect the cost and reliability of service to customers in their jurisdictions. The focus on electric competition has also prompted municipalities, school districts and certain other customers to seek permission to buy energy elsewhere.

The Electric Industry — Federal Regulatory Issues

As a result of Congress' passage of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the National Energy Policy Act of 1992 (NEPA), the once monopolistic electric utility industry now faces competition.

PURPA's goal was to reduce the United States' dependence on foreign oil, encourage energy conservation and promote diversification of fuel supply. Accordingly, PURPA provided for the development of a new class of electric generators which rely on either cogeneration technology or alternate fuels. The utilities are obligated under PURPA to purchase the electric output of certain of these new generators, which are known as qualified facilities (QFs).

NEPA sought to increase economic efficiency in the creation and distribution of power by relaxing restrictions on the entry of new competitors to the wholesale electric power market (i.e., sales to an entity for resale to the ultimate consumer). NEPA does so by creating exempt wholesale generators that can sell power in wholesale markets without the regulatory constraints placed on generators such as the Company. NEPA also expanded the Federal Energy Regulatory Commission (FERC)'s authority to grant access to utility transmission systems to all parties who seek wholesale wheeling for wholesale competition. Significant issues associated with the removal of wholesale transmission system access restrictions have yet to be resolved and the potential impact on the Company's financial position cannot yet be determined.

FERC is in the process of setting policy which will largely determine how wholesale competition will be implemented. FERC has recently declared that utilities must provide wholesale wheeling to others that is comparable to the service utilities provide themselves. The policy will be tested and further defined in individual proceedings. In addition, FERC has issued policy statements concerning regional transmission groups, transmission information requirements and "good faith" requests for service and transmission pricing. FERC is also initiating proceedings to address issues relating to stranded assets and power pooling. Utilities, including the Company, and other interested parties are actively involved in these proceedings.

Major issues are arising as the industry and government contemplate the move toward a more market-driven environment. These issues include: the impact of competition on customers who are unable to or who have chosen not to avail themselves of competition options; the ability of utility investors to continue to receive a return of and a reasonable return on their investments; the effect on service quality and reliability; comparability of service; the parameters of regulatory jurisdiction; the relative efficiency of competitors; the effects of mergers and the recoverability of transition costs and of assets that may become impaired.

The Electric Industry — New York State Regulatory Issues
The PSC has instituted a number of cases which will determine the boundaries within which power providers can compete in New York.

In 1994, the PSC completed the first phase of a competitive opportunities proceeding, issuing guidelines that allow New York utilities, at their option, to negotiate discounted rates with customers who otherwise would purchase electricity elsewhere. Any net revenue lost through these negotiations will be shared between ratepayers and shareowners, with percentages to be determined in rate cases. With respect to the Company, the Commission has ruled that the Company's shareowners must bear 30% of any "discount" negotiated by the Company in order to retain customers. While this percentage is comparable to that required of other utilities, the Company believes the percentage should be significantly lower due to the Company's unique financial structure and, therefore, has appealed the PSC's decision.

The PSC has recently begun a second phase of this proceeding in which it will develop principles to guide the transition to a more competitive environment, explore how to improve the wholesale electric market and determine the role regulation will play. The issues to be reviewed include: wholesale competition with or without a spin-off of generation assets; retail competition; planning and reliability; customer impacts; financial and legal considerations; and affordability of electric service to all customers. The PSC will also address the critical issue of whether utilities will be required to write-off assets in order to offer more competitive prices.

In addition, the State Energy Planning Board has released the 1994 State Energy Plan (SEP) which calls for the development of a fully competitive wholesale generation market within five years. While continuing to caution that full retail competition may not be in the best interests of the State, the SEP threatens that retail competition should be considered sooner "in the absence of utility cooperation" in the development of a fully competitive wholesale market.

The Company's Service Territory
The changing utility regulatory environment has affected the Company in a number of ways. For example, PURPA's encouragement of the non-utility generator (NUG) industry has negatively impacted the Company. The Company estimates that in 1994, sales lost to NUGs totaled 237 gigawatt-hours (Gwh) representing a loss in revenues net of fuel (net revenues) of approximately $24 million, or approximately 1.1% of the Company's 1994 net revenues. Additionally, as mentioned above, the Company is required to purchase all the power offered by QFs. As of December 31, 1994, QFs were selling approximately 203 megawatts (MW) of power to the Company.

The Company estimates that, in 1994, purchases from QFs required by federal and State law cost the Company $53 million more than it would have cost had the Company generated this power. The Company has also contracted, beginning in early 1995, to purchase all excess power from the 40 MW Stony Brook project located at the State University of New York at Stony Brook, New York.

QFs have the choice of pricing sales to the Company at either (i) the PSC's published estimates of the Company's long run avoided costs (LRAC) or (ii) the Company's tariff rates, which are modified from time to time, reflecting the Company's actual avoided costs. Additionally, until repealed in 1992, New York State law set a minimum price of six cents per kilowatt-hour (kWh) for utility purchases of power from certain categories of QFs, considerably above the Company's avoided cost. The six cent minimum now only applies to contracts entered into before June 1992. The Company believes that the repeal of the six cent law, coupled with recent PSC updates which resulted in lower LRAC estimates, has significantly reduced the economic benefits to QFs seeking to sell power to the Company.

After the anticipated loss of the Stony Brook load, estimated to be approximately 190 Gwh annually, or a net revenue loss of approximately $13 million, the Company expects that electric load losses due to NUGs will stabilize. The Company believes that a number of factors, including customer load characteristics such as a lack of a significant industrial base and related large thermal load, will mitigate load loss and thereby make cogeneration economically unattractive.

The Company has also experienced a revenue loss as a result of its policy of voluntarily providing wheeling of NYPA power for economic development. The Company estimates that NYPA power has displaced approximately 400 Gwh of annual energy sales. The net revenue loss associated with this amount of sales is approximately $28 million or 1.4% of the Company's 1994 net revenues. Currently, the potential loss of additional load is limited by conditions in the Company's transmission agreements with NYPA.

Aside from NUGs, a number of customer groups are seeking to hasten consideration and implementation of full retail competition. For example, an energy consultant has petitioned the PSC, seeking alternate sources of power for Long Island school districts. The County of Nassau has also petitioned the PSC to authorize retail wheeling for all classes of electric customers in the county. In addition, several towns on Long Island are investigating municipalization. Municipalization, in which customers form a government-sponsored electric supply company, is one form of competition likely to increase as a result of NEPA. The Town of Southampton and several other towns in the Company's service territory are considering the formation of a municipally owned and operated electric authority to replace the services currently provided by the Company. Suffolk County has also approached FERC to determine whether it can qualify as a municipal power authority in order to purchase cheaper electricity from non-Company sources. The Company's geographic location and the limited electrical interconnections to Long Island serve to limit the accessibility of its transmission grid to potential competitors from off the system.

The matters discussed above involve substantial social, economic, legal, environmental and financial issues. The Company is opposed to any proposal that merely shifts costs from one group of ratepayers to another, that fails to enhance the provision of least-cost, efficiently-generated electricity or that fails to provide the Company's shareowners with an adequate return on and recovery of their investment. The Company is unable to predict what action, if any, the PSC or FERC may take regarding any of these matters, or the impact on the Company's financial condition if some or all of these matters are approved or implemented by the appropriate regulatory authority.

Conservation Services

In 1993, the Company filed a modified DSM plan with the PSC to support the objectives of the Company's Electric Rate Plan filed in December 1993. Under this modified plan, the Company proposed a substantially lower level of spending than that initially approved for 1994. The PSC did not approve the Company's proposed plan, but instead issued a ruling in July 1994, which dictated energy savings targets that were greater than those originally proposed by the Company. Specifically, the targets for the Company's DSM programs amounted to a 161.3 MW reduction in coincident peak demand and an annualized energy savings of 702.6 Gwh by December 31, 1994. The Company was successful in its DSM efforts.

In 1995, the Company intends to continue to carefully manage DSM expenditures and more fully transform DSM to a strategic marketing tool which can be used to position the Company for the future. In these efforts, the Company will act to further increase the emphasis on education and information programs and further decrease its emphasis on utility rebate payments. In addition, financing programs and other cost sharing arrangements will be stressed as a means to reduce DSM program costs. Finally, DSM programs will be redesigned to enhance the Company's competitive position through the offering of programs and services to the Company's customers which promote the efficient use of electricity, including energy-efficient load growth.

Results of Operations

Earnings

Summary results of earnings for the years 1994, 1993 and 1992 were as follows:

(In millions of dollars and shares except earnings per share)

	1994	*1993*	*1992*
Net income	$ 301.8	$ 296.6	$ 302.0
Preferred stock dividend requirements	53.0	56.1	64.0
Earnings for common stock	$ 248.8	$ 240.5	$ 238.0
Average common shares outstanding	115.9	112.1	111.4
Earnings per common share	$ 2.15	$ 2.15	$ 2.14

The Company achieved the same level of earnings per common share in 1994 as in 1993 despite an increase in the average number of common shares outstanding. This was primarily the result of the Company's cost containment program and the impact on earnings of positive cash flow from operations, which allowed the Company to use cash balances to satisfy maturing debt.

The electric business achieved a higher level of earnings in 1994 as compared to 1993, offset by a decrease in the gas business earnings. The decrease in gas business earnings in 1994 was the result of several factors including: (i) a lower allowed return on common equity; (ii) a write-off in 1994, of previously deferred storm costs and (iii) a provision in the Company's gas rate structure which became effective December 1, 1993, which requires earnings in excess of a 10.6% return on common equity be shared equally between the Company's firm gas customers and its shareowners.

The earnings in the electric business were lower in 1993 when compared to 1992 due primarily to the expensing of previously deferred storm costs, lower interest rates associated with short-term investments and certain regulatory adjustments recorded in accordance with the Company's electric rate structure. The lower level of earnings in the electric business was offset by a significant increase in earnings in the gas business, resulting from the continuation of the Company's gas expansion program.

Revenues

Total revenues, including revenues from recovery of fuel costs, were $3.1 billion, $2.9 billion and $2.6 billion for the years 1994, 1993 and 1992, respectively.

Electric Revenues

Revenues from the Company's electric operations for the years 1994, 1993 and 1992 were $2.5 billion, $2.4 billion and $2.2 billion, respectively.

In November 1991, the PSC approved the LRPP, which provided the Company with annual electric rate increases of 4.15%, 4.1% and 4.0% for the rate years beginning December 1, 1991, 1992 and 1993, respectively. These rate increases provided $69 million of additional revenues in 1994 as compared to 1993, and $75 million of additional revenues in 1993 as compared to 1992.

The LRPP contains several regulatory mechanisms that impact the level of revenues, but have no impact on earnings. The Company's current electric rate structure provides for a revenue reconciliation, which eliminates the impact on earnings of experiencing sales that are above or below the levels reflected in rates. As a result of lower than adjudicated electric sales, the Company recorded non-cash income, which is included in "Other Regulatory Amortization," of $50.9 million, $43.5 million and $78.5 million in 1994, 1993 and 1992, respectively.

Under the LRPP, base fuel costs collected in rates in excess of actual fuel costs are applied as a reduction to the RMC. The Company applied $83.9 million, $37.5 million and $22.9 million of amounts collected in excess of actual fuel costs as a reduction to the RMC for the rate years ended November 30, 1994, 1993 and 1992, respectively.

Under the LRPP, deferred balances associated with the reconciliation of revenue, expenses and performance incentives in excess of $15 million per annum are returned to or recovered from the ratepayers through the FCA. During the period August 1993 through July 1994, the Company collected, through the FCA, approximately $2.7 million per month for an aggregate of $30.2 million related to the deferred balances for the rate year ended November 30, 1992. Since August 1994, the PSC has allowed the Company to continue the collection of a like amount through the FCA which will continue through the end of the suspension period. These additional revenues, amounting to approximately $13.4 million through December 1994, were

recorded as a reduction to the RMC. The Company is awaiting PSC approval for the recovery of $48.1 million and $63.6 million for the 1993 and 1994 rate year deferrals. For a further discussion of the LRPP regulatory mechanisms, see Note 3 of Notes to Financial Statements.

Total electric sales volumes in millions of kWh were 16,382 in 1994, 16,128 in 1993 and 15,667 in 1992. The increase in sales in 1994 and 1993 was primarily the result of warmer than normal weather experienced in the summer months. The increases in sales were partially offset by sales lost to non-utility generators and power displaced by NYPA, discussed above under the heading "Competitive Environment." In 1994 and 1993, the composition of system sales was 45% residential and 52% commercial/industrial. In 1992, the composition was 44% residential and 53% commercial/industrial.

Gas Revenues

Revenues from the Company's gas operations for the years 1994, 1993 and 1992 were $586 million, $529 million and $427 million, respectively.

In December 1993, the PSC approved a three year gas rate settlement between the Company and the Staff of the PSC. The gas rate settlement provides the Company with annual gas rate increases of 4.7%, 3.8% and 2.8% for the rate years beginning December 1, 1993, 1994 and 1995, respectively. The Company had also received an annual gas rate increase of 7.1% effective December 1, 1992. These rate increases provided $25 million in additional revenues for 1994 as compared to 1993, and $35 million in additional revenues for 1993 as compared to 1992.

Total firm sales volumes in thousands of dekatherms (Mdth) were 58,889 in 1994, 59,183 in 1993 and 56,292 in 1992. In 1994, firm sales volumes decreased when compared to 1993 primarily due to warmer weather experienced during the 1994 heating season as compared to 1993, partially offset by the addition of approximately 8,500 new gas space heating customers resulting from the continuation of the Company's gas expansion program. The number of monthly average space heating customers was 273,633, 266,665 and 259,500 for the years 1994, 1993 and 1992, respectively. The Company has a weather normalization clause which mitigates the impact on revenues of experiencing weather that is warmer or colder than the "normal" value used for projecting sales. In 1993, firm sales volumes increased as a result of colder weather experienced during the 1993 heating season as compared to 1992 combined with additional gas space heating customers resulting from the Company's gas expansion program.

The Company began selling gas off-system in 1993. Off-system gas sales revenues were $26 million and $8 million on volumes of 7,232 Mdth and 2,894 Mdth, for the years ended December 31, 1994 and 1993, respectively. Any profits realized from off-system sales are allocated 85% to ratepayers and 15% to shareowners.

Recoveries of gas fuel expenses increased revenues by $33 million and $26 million in 1994 and 1993, respectively. In 1994, the increase in the recoveries of gas fuel expenses was primarily due to increased billed sales volumes and higher average gas prices, when compared to 1993. In 1993, the increase was primarily due to higher average gas prices, when compared to 1992.

Operating Expenses

Fuel and Purchased Power

Summary of fuel and purchased power expenses for the years 1994, 1993 and 1992 were as follows:

(In thousands of dollars)

	1994	*1993*	*1992*
Fuel for Electric Operations			
Oil	$ 145	$ 180	$ 190
Gas	101	93	79
Nuclear	15	13	11
Purchased power	308	293	280
Total	569	579	560
Gas fuel	279	249	182
Total	$ 848	$ 828	$ 742

Despite an increase in electric sales volumes during 1994 and rising fuel oil prices, fuel for electric operations decreased primarily as a result of the Company's efforts to reduce its dependency on oil as the primary fuel for electric generation. The Company, over the past several years, has refitted several generating facilities to enable them to burn either oil or natural gas, depending upon the relative cost of each commodity at any given time.

In addition to the increased use of natural gas, the Company has reduced oil consumption by using energy generated at Nine Mile Point Nuclear Power Station, Unit 2 (NMP2) and by purchasing power from other systems, cogenerators and independent power producers. The total barrels of oil consumed for electric operations was 7.5 million, 9.7 million and 10.7 million, for the years 1994, 1993 and 1992, respectively.

Cogenerators and independent power producers provided approximately 9% of the Company's system requirements in 1994, 1993 and 1992. The increase in purchased power expenses in 1994 is primarily attributable to purchases from the 136 MW facility in Holtsville, New York, owned by NYPA, constructed for the benefit of the Company.

Summary of electric fuel and purchased power mix for the years 1994, 1993 and 1992 were as follows:

	(Percent of system energy requirements)		
	1994	*1993*	*1992*
Oil	25%	33%	37%
Gas	23	19	19
Nuclear	9	7	6
Purchased power	43	41	38
Total	100%	100%	100%

Gas fuel expenses for gas operations increased by $30 million and $67 million in 1994 and 1993, respectively. The increase in 1994 is primarily attributable to the additional fuel costs associated with the Company's off-system gas sales, while the increase for 1993 was primarily due to significantly higher gas prices and increased volumes, as a result of colder than normal weather during the heating season.

Operations and Maintenance Expenses
Operations and maintenance (O&M) expenses, excluding fuel and purchased power, were $541 million, $522 million and $498 million, for the years 1994, 1993 and 1992, respectively. The increase in O&M for 1994 was primarily due to the recognition of previously deferred storm costs associated with gas operations, an increase in costs associated with the Company's gas expansion program, the recognition of certain costs which exceeded the Company's insurance recoveries, an increase in employee benefit costs and the effects of inflation. These higher O&M expenses were partially offset by the continuation of the Company's cost containment program. The increase in 1993 was principally due to the recognition of previously deferred storm costs associated with electric operations, the recording of higher accruals for uncollectible accounts and higher transmission and distribution costs for both the electric and gas businesses.

Rate Moderation Component and Related Carrying Charges
In 1994 and 1993, the Company recorded non-cash charges to income of approximately $198 million and $89 million, respectively, representing the amortization of the RMC. In 1992, the Company recorded non-cash income of approximately $30 million, representing the accretion of the RMC. The Company accrues a carrying charge on the unamortized balance of the RMC which amounted to $32 million, $40 million and $43 million for the years 1994, 1993 and 1992, respectively. For further discussion on the RMC, see Notes 1, 2 and 3 of Notes to Financial Statements.

Other Regulatory Amortization
In 1994, other regulatory amortization was a non-cash charge to income of $4.3 million, compared to a non-cash credit to income of $18.0 million in 1993. The change reflects an increase in the amortization of LRPP deferrals, higher amortization of Shoreham post settlement costs and a non-cash charge to income reflecting the operation of the interest deferral mechanism, as defined in the Company's electric rate structure. These items were partially offset by higher deferred net margin revenues, discussed above under "Revenues."

In 1993, other regulatory amortization was lower than 1992 as a result of lower net margin revenues and the amortization of the 1992 rate year LRPP deferrals which began in August 1993. Partially offsetting these items was the recognition of additional non-cash credits to income resulting from the operation of the interest deferral mechanism. For a discussion on the Company's rate mechanisms, see Note 3 of Notes to Financial Statements.

Operating Taxes
Operating taxes were $407 million, $386 million and $389 million, for the years 1994, 1993 and 1992, respectively. The increase in operating taxes of approximately $21 million in 1994 when compared to 1993 is primarily attributable to higher gross receipts taxes, resulting from increased revenues, higher property taxes, additional payroll taxes and higher dividend taxes.

Interest Expense

The reduction in interest expense in 1994 when compared to 1993 is primarily attributable to lower outstanding debt levels. The Company's strategy is to apply available cash balances toward the satisfaction of debt whenever practicable. During 1994, the Company used approximately $200 million of cash on hand and the proceeds from the issuance of 5.1 million shares of common stock to help lower debt by approximately $300 million. The lower interest expense also reflects the satisfaction of $175 million of maturing debt in November 1993, with cash on hand.

The increase in 1993 when compared to 1992 was attributable to higher debt levels and the conversion in June 1992 of $400 million of tax-exempt securities from a weekly variable interest rate to a higher thirty year fixed rate. Also contributing to the increase was the issuance in November 1992 of thirty year fixed rate debentures, the proceeds of which were used to eliminate variable rate bank debt. The conversion of the tax-exempt securities and refinancing of bank debt was done in order to take advantage of historically low long-term interest rates. Partially offsetting this increase in interest expense were savings realized from the effects of the Company's aggressive refinancing of higher-cost debt in 1993.

Accounting Pronouncements

Effective January 1, 1993, the Company adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions. Under a PSC order issued in response to SFAS No. 106, the Company defers as a regulatory asset the difference between postretirement benefits expense recorded for accounting purposes in accordance with SFAS No. 106 and postretirement expenses reflected in rates. The PSC order also requires that the ongoing annual postretirement benefit expense be phased into and fully recovered in rates within a five year period, with the accumulated postretirement benefit obligation being recovered in rates over a twenty year period. The adoption of SFAS No. 106 had no impact on net income for the years ended December 31, 1994 and 1993. For a further discussion of SFAS No. 106, see Notes 1 and 8 of Notes to Financial Statements.

Effective January 1, 1993, the Company adopted SFAS No. 109, Accounting for Income Taxes. SFAS No. 109 requires utilities to establish deferred tax assets and liabilities for, among other things, transactions that were not recognized under Accounting Principles Board Opinion No. 11, Accounting for Income Taxes. SFAS No. 109 provides that regulatory assets and liabilities may be established for these specific SFAS No. 109 created deferred tax assets and liabilities providing that the regulator provides for the future recovery or return of these amounts through rates. As a result of a PSC order issued in January 1993, providing for the recovery or return of such amounts, the Company has recorded regulatory tax assets and liabilities to offset the effect of accumulated deferred tax liabilities and assets created as a result of adopting SFAS No. 109. The adoption of SFAS No. 109 had no impact on net income for the years ended December 31, 1994 and 1993. For a further discussion of SFAS No. 109, see Notes 1 and 9 of Notes to Financial Statements.

Selected Financial Data

Additional information respecting revenues, expenses, electric and gas operating income and operations data and balance sheet information for the last five years is provided in Tables 1 through 11 of Selected Financial Data. Information with regard to the Company's business segments for the last three years is provided in Note 11 of Notes to Financial Statements.

Balance Sheet

Assets		(In thousands of dollars)
At December 31	*1994*	*1993*
Utility Plant		
Electric	$ 3,657,178	$ 3,544,569
Gas	994,742	860,899
Common	232,346	201,418
Construction work in progress	129,824	176,504
Nuclear fuel in process and in reactor	23,251	16,533
	5,037,341	4,799,923
Less — Accumulated depreciation and amortization	1,538,995	1,452,366
Total Net Utility Plant	3,498,346	3,347,557
Regulatory Assets		
Base financial component (less accumulated amortization of $555,340 and $454,369)	3,483,490	3,584,461
Rate moderation component	463,229	609,827
Shoreham post settlement costs	922,580	777,103
Shoreham nuclear fuel	73,371	75,497
Postretirement benefits other than pensions	412,727	402,921
Regulatory tax asset	1,831,689	1,848,998
Other	354,524	311,832
Total Regulatory Assets	7,541,610	7,610,639
Nonutility Property and Other Investments	24,043	23,029
Current Assets		
Cash and cash equivalents	185,451	248,532
Special deposits	27,614	23,439
Customer accounts receivable (less allowance for doubtful accounts of $23,365 and $23,889)	245,125	249,074
Other accounts receivable	14,030	12,199
Accrued unbilled revenues	164,379	170,042
Materials and supplies at average cost	74,777	68,882
Fuel oil at average cost	37,723	35,857
Gas in storage at average cost	68,447	75,182
Prepayments and other current assets	33,878	41,652
Total Current Assets	851,424	924,859
Deferred Charges		
Deferred federal income tax	951,766	1,094,088
Unamortized cost of issuing securities	313,207	350,239
Other	36,284	42,705
Total Deferred Charges	1,301,257	1,487,032
Total Assets	$ 13,216,680	$ 13,393,116

See Notes to Financial Statements.

Capitalization and Liabilities		(In thousands of dollars)
At December 31	*1994*	*1993*
Capitalization		
Long-term debt	$ 5,162,675	$ 4,887,733
Unamortized discount on debt	(17,278)	(17,393)
	5,145,397	4,870,340
Preferred stock — redemption required	644,350	649,150
Preferred stock — no redemption required	63,957	64,038
Total Preferred Stock	708,307	713,188
Common stock	592,083	561,662
Premium on capital stock	1,101,240	1,010,283
Capital stock expense	(52,175)	(50,427)
Retained earnings	752,480	711,432
Total Common Shareowners' Equity	2,393,628	2,232,950
Total Capitalization	8,247,332	7,816,478
Regulatory Liabilities		
Regulatory liability component	357,117	436,476
1989 Settlement credits	145,868	155,081
Regulatory tax liability	111,218	114,748
Other	143,611	138,612
Total Regulatory Liabilities	757,814	844,917
Current Liabilities		
Current maturities of long-term debt	25,000	600,000
Current redemption requirements of preferred stock	4,800	4,800
Accounts payable and accrued expenses	241,775	277,519
Accrued taxes (including federal income tax of $28,340 and $28,424)	58,133	52,656
Accrued interest	149,929	142,409
Dividends payable	57,367	54,542
Class Settlement	40,000	30,000
Customer deposits	28,474	27,046
Total Current Liabilities	605,478	1,188,972
Deferred Credits		
Deferred federal income tax	2,941,793	2,932,029
Class Settlement	147,437	164,942
Other	13,204	12,622
Total Deferred Credits	3,102,434	3,109,593
Operating Reserves		
Pensions and other postretirements benefits	453,016	424,442
Claims and damages	50,606	8,714
Total Operating Reserves	503,622	433,156
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 13,216,680	$ 13,393,116

See Notes to Financial Statements.

Statement of Income

	(In thousands of dollars except per share amounts)		
For year ended December 31	*1994*	*1993*	*1992*
Revenues			
Electric	$ 2,481,637	$ 2,352,109	$ 2,194,632
Gas	585,670	528,886	427,207
Total Revenues	3,067,307	2,880,995	2,621,839
Operating Expenses			
Operations — fuel and purchased power	847,986	827,591	741,784
Operations — other	406,014	387,808	372,209
Maintenance	134,640	133,852	125,736
Depreciation and amortization	130,664	122,471	119,137
Base financial component amortization	100,971	100,971	100,971
Rate moderation component amortization	197,656	88,667	(30,444)
Regulatory liability component amortization	(79,359)	(79,359)	(79,359)
1989 Settlement credits amortization	(9,214)	(9,214)	(9,214)
Other regulatory amortization	4,328	(18,044)	(22,072)
Operating taxes	406,895	385,847	388,988
Federal income tax — current	10,784	6,324	530
Federal income tax — deferred and other	170,997	178,530	172,468
Total Operating Expenses	2,322,362	2,125,444	1,880,734
Operating Income	744,945	755,551	741,105
Other Income and (Deductions)			
Allowance for other funds used during construction	2,716	2,473	4,725
Rate moderation component carrying charges	32,321	40,004	42,837
Other income and deductions, net	35,343	38,997	29,273
Class Settlement	(22,730)	(23,178)	(22,541)
Federal income tax — deferred and other	5,069	12,578	12,036
Total Other Income and (Deductions)	52,719	70,874	66,330
Income Before Interest Charges	797,664	826,425	807,435
Interest Charges and (Credits)			
Interest on long-term debt	437,751	466,538	450,621
Other interest	62,345	67,534	62,226
Allowance for borrowed funds used during construction	(4,284)	(4,210)	(7,386)
Total Interest Charges and (Credits)	495,812	529,862	505,461
Net Income	301,852	296,563	301,974
Preferred stock dividend requirements	53,020	56,108	63,954
Earnings for Common Stock	$ 248,832	$ 240,455	$ 238,020
Average Common Shares Outstanding (000)	115,880	112,057	111,439
Earnings per Common Share	$ 2.15	$ 2.15	$ 2.14
Dividends Declared per Common Share	$ 1.78	$ 1.76	$ 1.72

See Notes to Financial Statements.

Statement of Cash Flows

(In thousands of dollars)

For year ended December 31	*1994*	*1993*	*1992*
Operating Activities			
Net Income	$ 301,852	$ 296,563	$ 301,974
Adjustments to reconcile net income to net cash provided by operating activities			
Provision for doubtful accounts	19,542	18,555	16,329
Depreciation and amortization	130,664	122,471	119,137
Base financial component amortization	100,971	100,971	100,971
Rate moderation component amortization	197,656	88,667	(30,444)
Regulatory liability component amortization	(79,359)	(79,359)	(79,359)
1989 Settlement credits amortization	(9,214)	(9,214)	(9,214)
Other regulatory amortization	4,328	(18,044)	(22,072)
Rate moderation component carrying charges	(32,321)	(40,004)	(42,837)
Class Settlement	22,730	23,178	22,541
Amortization of cost of issuing and redeeming securities	46,237	52,063	41,204
Federal income tax — deferred and other	165,928	165,952	160,432
Allowance for other funds used during construction	(2,716)	(2,473)	(4,725)
Gas cost adjustment	11,709	(3,499)	(24,142)
Other	37,538	15,200	1,035
Changes in operating assets and liabilities			
Accounts receivable	(17,353)	(65,898)	(14,275)
Class Settlement	(30,235)	(25,302)	(19,039)
Accrued unbilled revenues	5,663	(26,870)	(6,607)
Materials and supplies, fuel oil and gas in storage	(1,026)	5,265	(10,933)
Prepayments and other current assets	7,774	(1,250)	(5,548)
Accounts payable and accrued expenses	(44,598)	(8,800)	62,513
Accrued taxes	5,477	(14,869)	7,351
Other	(5,498)	(11,290)	25,772
Net Cash Provided by Operating Activities	835,749	582,013	590,064
Investing Activities			
Construction and nuclear fuel expenditures	(276,954)	(302,220)	(268,179)
Shoreham post settlement costs	(167,367)	(207,114)	(227,658)
Other	(1,349)	(934)	(1,484)
Net Cash Used in Investing Activities	(445,670)	(510,268)	(497,321)
Financing Activities			
Proceeds from issuance of long-term debt	331,326	1,089,770	1,659,928
Proceeds from sale of common stock	118,108	14,323	5,670
Proceeds from sale of preferred stock	—	201,709	411,373
Redemption of long-term debt	(635,058)	(960,000)	(1,344,283)
Redemption of preferred stock	(4,800)	(205,600)	(389,428)
Common stock dividends paid	(205,086)	(195,794)	(190,477)
Preferred stock dividends paid	(52,927)	(56,727)	(69,923)
Cost of issuing and redeeming securities	(5,871)	(17,036)	(166,066)
Other	1,148	(3,343)	1,850
Net Cash Used in Financing Activities	(453,160)	(132,698)	(81,356)
Net (Decrease) Increase in Cash and Cash Equivalents	$ (63,081)	$ (60,953)	$ 11,387
Cash and cash equivalents at January 1	$ 248,532	$ 309,485	$ 298,098
Net (decrease) increase in cash and cash equivalents	(63,081)	(60,953)	11,387
Cash and Cash Equivalents at December 31	$ 185,451	$ 248,532	$ 309,485
Interest paid, before reduction for the allowance for borrowed funds used during construction	$ 446,340	$ 469,978	$ 424,842
Federal income tax — paid	$ 10,780	$ 6,000	$ 2,100
Federal income tax — refunded	$ —	$ 1,000	$ 1,566

See Notes to Financial Statements.

Statement of Retained Earnings

			(In thousands of dollars)
	1994	*1993*	*1992*
Balance at January 1	$ 711,432	$ 667,988	$ 620,373
Net income for the year	301,852	296,563	301,974
	1,013,284	964,551	922,347
Deductions			
Cash dividends declared on common stock	207,794	197,236	191,693
Cash dividends declared on preferred stock	53,046	55,861	62,387
Other adjustments	(36)	22	279
Balance at December 31	**$ 752,480**	$ 711,432	$ 667,988

See Notes to Financial Statements.

Statement of Capitalization

	Shares Outstanding		(In thousands of dollars)	
At December 31	*1994*	*1993*	*1994*	*1993*
Common Shareowners' Equity				
Common stock, $5.00 par value	118,416,606	112,332,490	$ 592,083	$ 561,662
Premium on capital stock			1,101,240	1,010,283
Capital stock expense			(52,175)	(50,427)
Retained earnings			752,480	711,432
Total Common Shareowners' Equity			2,393,628	2,232,950
Preferred Stock — Redemption Required				
Par value $100 per share				
7.40% Series L	182,000	192,500	18,200	19,250
8.50% Series R	75,000	112,500	7,500	11,250
7.66% Series CC	570,000	570,000	57,000	57,000
Less — Sinking fund requirement			4,800	4,800
			77,900	82,700
Par value $25 per share				
7.95% Series AA	14,520,000	14,520,000	363,000	363,000
$1.67 Series GG	880,000	880,000	22,000	22,000
$1.95 Series NN	1,554,000	1,554,000	38,850	38,850
7.05% Series QQ	3,464,000	3,464,000	86,600	86,600
6.875% Series UU	2,240,000	2,240,000	56,000	56,000
			566,450	566,450
Total Preferred Stock — Redemption Required			644,350	649,150
Preferred Stock — No Redemption Required				
Par value $100 per share				
5.00% Series B	100,000	100,000	10,000	10,000
4.25% Series D	70,000	70,000	7,000	7,000
4.35% Series E	200,000	200,000	20,000	20,000
4.35% Series F	50,000	50,000	5,000	5,000
5⅛% Series H	200,000	200,000	20,000	20,000
5¾% Series I – Convertible	19,569	20,375	1,957	2,038
Total Preferred Stock — No Redemption Required			63,957	64,038
Total Preferred Stock			$ 708,307	$ 713,188

See Notes to Financial Statements.

Statement of Capitalization (continued)

(In thousands of dollars)

At December 31	*Maturity*	*Interest Rate*	*Series*	*1994*	*1993*
First Mortgage Bonds (excludes Pledged Bonds)	June 1, 1994	4⅝%	N	$ —	$ 25,000
	June 1, 1995	4.55%	O	25,000	25,000
	March 1, 1996	5¼%	P	40,000	40,000
	April 1, 1997	5½%	Q	35,000	35,000
Total First Mortgage Bonds				100,000	125,000
General and Refunding Bonds	May 1, 1996	8¾%		415,000	415,000
	February 15, 1997	8¾%		250,000	250,000
	April 15, 1998	7⅝%		100,000	—
	May 15, 1999	7.85%		56,000	56,000
	April 15, 2004	8⅝%		185,000	—
	May 15, 2006	8.50%		75,000	75,000
	July 15, 2008	7.90%		80,000	80,000
	May 1, 2021	9¾%		415,000	415,000
	July 1, 2024	9⅝%		375,000	375,000
Total General and Refunding Bonds				1,951,000	1,666,000
Debentures	June 15, 1994	10.25%		—	400,000
	November 15, 1994	11.75%		—	175,000
	June 15, 1999	10.875%		—	30,545
	July 15, 1999	7.30%		397,000	397,000
	January 15, 2000	7.30%		36,000	36,000
	July 15, 2001	6.25%		145,000	145,000
	March 15, 2003	7.05%		150,000	150,000
	March 1, 2004	7.00%		59,000	59,000
	June 1, 2005	7.125%		200,000	200,000
	March 1, 2007	7.50%		142,000	142,000
	June 15, 2019	11.375%		—	4,513
	July 15, 2019	8.90%		420,000	420,000
	November 1, 2022	9.00%		451,000	451,000
	March 15, 2023	8.20%		270,000	270,000
Total Debentures				2,270,000	2,880,058
Authority Financing Notes					
Industrial Development Revenue Bonds	December 1, 2006	7.5%	1976A,B	2,000	2,000
Pollution Control Revenue Bonds	December 1, 2006	7.5%	1976A	28,375	28,375
	December 1, 2009	7.8%	1979B	19,100	19,100
	October 1, 2012	8¼%	1982	17,200	17,200
	March 1, 2016	3.0%	1985A,B	150,000	150,000
Electric Facilities Revenue Bonds	September 1, 2019	7.15%	1989A,B	100,000	100,000
	June 1, 2020	7.15%	1990A	100,000	100,000
	December 1, 2020	7.15%	1991A	100,000	100,000
	February 1, 2022	7.15%	1992A,B	100,000	100,000
	August 1, 2022	6.9%	1992C,D	100,000	100,000
	November 1, 2023	5.45%	1993A	50,000	50,000
	November 1, 2023	4.90%	1993B	50,000	50,000
	October 1, 2024	5.40%	1994A	50,000	—
Total Authority Financing Notes				866,675	816,675
Unamortized discount on debt				(17,278)	(17,393)
Total				5,170,397	5,470,340
Less current maturities				25,000	600,000
Total Long-Term Debt				5,145,397	4,870,340
Total Capitalization				$8,247,332	$7,816,478

See Notes to Financial Statements.

Note 1. Summary of Significant Accounting Policies

Regulation

The Company's accounting policies conform to generally accepted accounting principles as they apply to a regulated enterprise. Its accounting records are maintained in accordance with the Uniform Systems of Accounts prescribed by the Public Service Commission of the State of New York (PSC) and the Federal Energy Regulatory Commission (FERC).

Regulatory Assets and Liabilities

General

The Company's Balance Sheet reflects the rate actions of its regulators through the creation of regulatory assets and liabilities. Regulatory assets are generally created whenever it is probable that the regulators will permit the recovery through rates of a previously incurred cost that would otherwise be charged to expense. Regulatory liabilities are generally created whenever it is probable that the regulators will require a return through rates of revenues or gains that would otherwise be recorded to income.

Base Financial Component and Rate Moderation Component

Pursuant to the 1989 Settlement, the Company recorded a regulatory asset known as the Financial Resource Asset (FRA). The FRA is designed to provide the Company with sufficient cash flows to assure its financial recovery. The FRA has two components, the Base Financial Component (BFC) and the Rate Moderation Component (RMC).

The BFC represents the present value of the future net-after-tax cash flows which the Rate Moderation Agreement (RMA), one of the constituent documents of the 1989 Settlement, provided the Company for its financial recovery. The BFC was granted rate base treatment under the terms of the RMA and is included in the Company's revenue requirements through an amortization included in rates over forty years on a straight-line basis which began July 1, 1989.

The RMC reflects the difference between the Company's revenue requirements under conventional ratemaking and the revenues resulting from the implementation of the rate moderation plan provided for in the RMA. For a further discussion of the 1989 Settlement and FRA, see Note 2.

Shoreham Post Settlement Costs

The balance consists of Shoreham Nuclear Power Station (Shoreham) decommissioning costs, fuel disposal costs, payments in lieu of taxes, carrying charges and other costs. These costs are being capitalized and amortized, and recovered through rates over a forty year period on a straight-line remaining life basis which began July 1, 1989.

Shoreham Nuclear Fuel

The balance principally reflects the unamortized portion of Shoreham nuclear fuel which was reclassified from Nuclear Fuel in Process and in Reactor at the time of the 1989 Settlement. This amount is being amortized and recovered through rates over a forty year period on a straight-line remaining life basis which began July 1, 1989.

Postretirement Benefits Other Than Pensions

Under a PSC order issued in response to the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, the Company defers as a regulatory asset the difference between postretirement benefit expense recorded for accounting purposes in accordance with SFAS No. 106 and postretirement benefit expense reflected in rates. Pursuant to the PSC order, the ongoing annual postretirement benefit expense must be phased into and fully recovered in rates within a five year period, with the accumulated postretirement obligation being recovered in rates over a twenty year period. For a further discussion of SFAS No. 106, see Note 8.

Regulatory Tax Asset/Liability

SFAS No. 109, Accounting for Income Taxes, requires utilities to establish deferred tax assets and liabilities for, among other things, transactions that did not give rise to deferred tax assets and liabilities under Accounting Principles Board (APB) Opinion No. 11, Accounting for Income Taxes. SFAS No. 109 provides that regulatory assets and liabilities may be established for these specific SFAS No. 109 created deferred tax assets and liabilities providing that the regulator provides for the future recovery or return of these amounts through rates. As a result of a PSC order issued in January 1993, providing for the recovery or return of such amounts, the Company has recorded regulatory tax assets and liabilities to offset the effect of accumulated deferred tax liabilities and assets created as a result of adopting SFAS No. 109.

The tax effects of other differences between income for financial statement purposes and for federal income tax purposes are accounted for as current adjustments in federal income tax provisions.

Regulatory Liability Component

Pursuant to the 1989 Settlement, certain tax benefits attributable to the Shoreham abandonment are to be shared between ratepayers and shareowners. A regulatory liability of approximately $794 million was recorded in June 1989 to preserve an amount equivalent to the ratepayer tax benefits attributable to the Shoreham abandonment. This amount is being amortized over a ten year period on a straight-line basis which began July 1, 1989.

1989 Settlement Credits
The balance represents the unamortized portion of an adjustment of the book write-off to the negotiated 1989 Settlement amount. A portion of this amount is being amortized over a ten year period which began on July 1, 1989. The remaining portion is not currently being recognized for ratemaking purposes.

Utility Plant
Additions to and replacements of utility plant are capitalized at original cost, which includes material, labor, indirect costs associated with an addition or replacement and an allowance for the cost of funds used during construction. The cost of renewals and betterments relating to units of property is added to utility plant. The cost of property replaced, retired or otherwise disposed of is deducted from utility plant and, generally, together with dismantling costs less any salvage, is charged to accumulated depreciation. The cost of repairs and minor renewals is charged to maintenance expense. Mass properties (such as poles, wire and meters) are accounted for on an average unit cost basis by year of installation.

Allowance for Funds Used During Construction
The Uniform Systems of Accounts defines the allowance for funds used during construction (AFC) as the net cost of borrowed funds for construction purposes and a reasonable rate of return upon the utility's equity when so used. AFC is not an item of current cash income. AFC is computed monthly using a rate permitted by FERC on a portion of construction work in progress. The average annual AFC rate, without giving effect to compounding, was 9.18%, 9.73% and 9.98% for the years 1994, 1993 and 1992, respectively.

Depreciation
The provisions for depreciation result from the application of straight-line rates to the original cost, by groups, of depreciable properties in service. The rates are determined by age-life studies performed annually on depreciable properties. Depreciation for electric properties was equivalent to approximately 3.0% , 3.0% and 3.2% of respective average depreciable plant costs for the years 1994, 1993 and 1992. Depreciation for gas properties was equivalent to approximately 2.0%, 2.0% and 2.6% of respective average depreciable plant costs for the years 1994, 1993 and 1992.

Cash and Cash Equivalents
Cash equivalents are highly liquid investments with maturities of three months or less when purchased. The carrying amount approximates fair value because of the short maturity of these investments.

Fair Values of Financial Instruments
The fair values for the Company's long-term debt and redeemable preferred stock are based on quoted market prices, where available. The fair values for all other long-term debt and redeemable preferred stock are estimated using discounted cash flow analyses which are based upon the Company's current incremental borrowing rate for similar types of securities.

Capitalization — Premiums, Discounts and Expenses
Premiums or discounts and expenses related to the issuance of long-term debt are amortized over the life of each issue. Unamortized premiums or discounts and expenses related to issues of long-term debt that are refinanced are amortized and recovered through rates over the shorter life of either the redeemed issue or the new issue. Capital stock expense and redemption costs related to certain issues of preferred stock that have been refinanced as well as the cost of issuance of the preferred stock issued are recorded as deferred charges. These amounts are being amortized and recovered through rates over the shorter life of the redeemed issue or the new issue.

Revenues
The Company accrues electric and gas revenues for services rendered to customers but not billed at month-end. The Company's electric rate structure, discussed in Note 3, provides for a revenue reconciliation mechanism which eliminates the impact on earnings of experiencing electric sales that are above or below the levels reflected in rates. The Company's gas structure provides for a weather normalization clause, which reduces the impact on revenues of experiencing weather which is warmer or colder than the "normal" value used for projecting sales.

Fuel Cost Adjustments
The Company's electric and gas tariffs include fuel cost adjustment (FCA) clauses which provide for the disposition of the difference between actual fuel costs and the fuel costs allowed in the Company's base tariff rates (base fuel costs). The Company defers these differences to future periods in which they will be billed or credited to customers, except for base electric fuel costs in excess of actual electric fuel costs, which are currently credited to the RMC as incurred.

Federal Income Tax
Effective January 1, 1993, the Company adopted SFAS No. 109. As permitted under SFAS No. 109, the Company elected not to restate the financial statements of prior years.

The Company provides deferred federal income taxes with respect to certain items of income and expense that are reported in different years for financial statement purposes and for federal income tax purposes.

The Company defers the benefit of 60% of pre-1982 gas and pre-1983 electric and 100% of all other investment tax credits, with respect to regulated properties, when realized on its tax returns. Accumulated deferred investment tax credits are amortized ratably over the lives of the related properties.

For ratemaking purposes, the Company provides deferred federal income taxes with respect to certain differences between income before income taxes and taxable income in certain instances when approved by the PSC, as disclosed in Note 9. Also certain accumulated deferred federal income taxes are deducted from rate base and amortized or otherwise applied as a reduction (increase) in federal income tax expense in future years.

Reserves for Claims and Damages
Losses arising from claims against the Company, including workers' compensation claims, property damage, extraordinary storm costs and general liability claims, are partially self-insured. Reserves for these claims and damages are based on, among other things, experience, risk of loss and the ratemaking practices of the PSC. Extraordinary storm losses incurred by the Company are partially insured by certain commercial insurance carriers. These insurance carriers provide partial insurance coverage for individual storm losses to the Company's transmission and distribution system between $5 million and $50 million. Storm losses which are outside of the above-mentioned range are self-insured by the Company. The Company is currently assessing its storm insurance requirements, as current policies expire March 1, 1995.

Reclassifications
Certain prior year amounts have been reclassified in the financial statements to be consistent with the current year's presentation.

Note 2. The 1989 Settlement

On February 28, 1989, the Company and the State of New York entered into the 1989 Settlement resolving certain issues relating to the Company and providing, among other matters, for the financial recovery of the Company and for the transfer of Shoreham and its subsequent decommissioning. Upon the effectiveness of the 1989 Settlement, in June 1989, the Company simultaneously recorded on its Balance Sheet the retirement of its investment of approximately $4.2 billion principally in Shoreham and the establishment of the FRA.

The BFC, a component of the FRA, as initially established, represents the present value of the future net-after-tax cash flows which the RMA provided the Company for its financial recovery. The BFC was granted rate base treatment under the terms of the RMA and is included in the Company's revenue requirements through an amortization included in rates over forty years on a straight-line basis that began July 1, 1989. At December 31, 1994 and 1993, the unamortized balance of the BFC was approximately $3.5 billion and $3.6 billion, respectively.

The RMC, a component of the FRA, reflects the difference between the Company's revenue requirements under conventional ratemaking and the revenues resulting from the implementation of the rate moderation plan provided for in the RMA. Prior to December 31, 1992, the RMC had increased as the difference between revenues resulting from the implementation of the rate moderation plan provided for in the RMA and revenue requirements under conventional ratemaking, together with a carrying charge equal to the allowed rate of return on rate base, was deferred. The RMC had provided the Company with a substantial amount of non-cash earnings from the effective date of the 1989 Settlement through December 31, 1992. Subsequent to December 31, 1992, the RMC balance had been decreasing as revenues resulting from the operation of the rate moderation plan exceeded revenue requirements under conventional ratemaking. The RMC is currently adjusted, on a monthly basis, for the Company's share of certain Nine Mile Point Nuclear Power Station, Unit 2 (NMP2) operations and maintenance expenses, fuel credits resulting from the Company's electric fuel cost adjustment clause discussed in Note 1 and gross receipts tax adjustments related to the FRA. At December 31, 1994 and 1993, the RMC balance was $463 million and $610 million, respectively. For a further discussion of the impact on the amortization of the RMC under the Long Island Lighting Company Ratemaking and Performance Plan (LRPP) and the Company's Electric Rate Plan for the three year period beginning December 1, 1994, see Note 3.

On February 29, 1992, the Company transferred ownership of Shoreham to the Long Island Power Authority (LIPA), an agency of the State of New York. Pursuant to the 1989 Settlement, the Company has funded the decommissioning of Shoreham. Based on the latest available information, LIPA has reported that the cost of decommissioning Shoreham, which is essentially complete, totaled approximately $181 million, excluding the costs associated with the disposal of Shoreham's fuel which was also completed in 1994 and cost approximately $112 million. LIPA anticipates that the Nuclear Regulatory Commission (NRC) will terminate its license for Shoreham during 1995.

Note 3. Rate Matters

Electric

Long Island Lighting Company Ratemaking and Performance Plan

Pursuant to the 1989 Settlement, discussed in Note 2, the Company received electric rate increases as contemplated by the RMA for each of the three rate years in the period ended November 30, 1991. The RMA contemplates that the Company will apply to the PSC for targeted annual rate increases of 4.5% to 5.0% in each year for an eight year period beginning December 1, 1991. In November 1991, the PSC approved the LRPP which provided annual electric rate increases of 4.15%, 4.1% and 4.0%, respectively, for each of the three rate years in the period beginning December 1, 1991, with an allowed return on common equity from electric operations of 11.6% for each of the three rate years. After giving effect to the reductions required by the Class Settlement discussed in Note 4, the Company's annual electric rate increases were approximately 4.15%, 3.9% and 3.9%, with an allowed return on common equity from electric operations of 10.92%, 10.72% and 10.58%, for the rate years beginning December 1, 1991, 1992 and 1993, respectively.

The LRPP was designed to be consistent with the RMA's long term goals. One principal objective of the LRPP was to reassign risk so that the Company assumes the responsibility for risks within the control of management, whereas risks largely beyond the control of management would be assumed by the ratepayers. The LRPP reflects an update of the long range forecast of the Company's revenue requirements which was the basis of the RMA's initial three rate increases. The LRPP contains three major components — revenue reconciliation, expense attrition and reconciliation and performance incentives.

Revenue reconciliation is provided through a mechanism that eliminates the impact of experiencing electric sales that are above or below the LRPP forecast by providing a fixed annual net margin level (defined as sales revenues, net of fuel and gross receipts taxes) that the Company will receive under the LRPP. The differences between the actual electric net revenues and the annual net margin level are deferred on a monthly basis during the rate year.

The expense attrition and reconciliation component permits the Company to make adjustments for certain expenses recognizing that certain cost increases are unavoidable due to inflation and changes in the business. The LRPP includes the annual reconciliation of certain expenses for wage rates, property taxes, interest costs and demand side management (DSM) costs. The LRPP also provides for the deferral and amortization of certain costs for enhanced reliability and production operations and maintenance expenses and the application of an inflation index to other expenses for the rate years beginning December 1, 1992 and 1993.

Under the performance incentive component of the LRPP, the Company is allowed to earn for each rate year up to 60 additional basis points, or forfeit up to 38 basis points, of the allowed return on common equity as a result of its performance within certain incentive and/or penalty programs. These programs consist of a customer service program, a time of-use program, a partial pass through fuel cost incentive plan, a DSM program and, effective December 1, 1993, an electric transmission and distribution reliability plan. These incentives and/or penalties, except for incentives earned under the DSM program, are determined on a monthly basis during the rate year and deferred until final approval from the PSC. The incentives earned from the DSM program are collected in rates on a monthly basis through the FCA. Based upon the Company's performance within these programs, the Company earned a total of 50 and 49 basis points or approximately $9.2 million, net of tax effects, for each of the rate years ended November 30, 1994 and 1993. For the rate year ended November 30, 1992 the Company earned a total of 23 basis points or approximately $4.3 million, net of tax effects.

The deferred balances resulting from the net margin, property taxes, interest costs, wage rates, performance incentives and associated carrying charges, excluding DSM incentives, are netted at the end of each rate year. The LRPP established a band whereby the first $15 million of the total net deferrals are used to increase or decrease the RMC balance. The LRPP provides for the disposition of the total net deferrals in excess of the $15 million band. Upon approval by the PSC, the total net deferrals in excess of $15 million are refunded to or recovered from the ratepayers through the FCA over a twelve month period.

The Company recorded deferred balances of approximately $45.2 million, $63.1 million and $78.6 million of the total net deferrals for the rate years ended November 30, 1992, 1993 and 1994, respectively. The first $15 million of the total net deferrals has been recorded for the rate years ended November 30, 1992 and 1993 and upon approval by the PSC of the Company's reconciliation filing will be recorded for the rate year ended November 30, 1994 as an increase to the RMC with the remaining net deferrals of $30.2 million, $48.1 million and $63.6 million, respectively, recovered from the ratepayers through the FCA. As of July 31, 1994, the Company has fully collected the November 30, 1992 net deferrals through the FCA and is awaiting PSC approval for the collection of the 1993 and 1994 rate year net deferrals through the FCA. Effective August 1994, the PSC has allowed the Company to continue the collection of a like amount of the total net deferrals related to the rate

year ended November 30, 1992 through the FCA. These additional revenues amounting to approximately $13.4 million through December 1994 were recorded as a reduction to the RMC. The Company expects to collect the 1993 rate year net deferrals of $48.1 million by November 30, 1995 and the 1994 rate year net deferrals of $63.6 million over the twelve month period ending November 30, 1996.

The LRPP contains a mechanism whereby earnings in excess of the allowed return on common equity of 11.6%, excluding the impacts of the various incentive and/or penalty programs, are shared equally between ratepayers and shareowners. The Company earned $8.9 million and $21.4 million, net of tax effects, for the rate years ended November 30, 1993 and 1992, respectively, in excess of its allowed return on common equity. The amount in excess of the allowed return on common equity was shared equally between ratepayers (by a reduction to the RMC) and shareowners for the rate years ended November 30, 1993, and 1992. For the rate year ended November 30, 1994, the Company did not earn in excess of its allowed return on common equity.

To assist in the recovery of the RMC balance under the rates provided by the LRPP, the Company, in accordance with the LRPP, has credited the RMC with several deferred ratepayer benefits. In December 1994, the Company applied a total of approximately $5.1 million of net deferred ratepayer benefits to the RMC including DSM revenues overcollected in the 1994 rate year. In December 1993 and 1992, the Company reduced the RMC by approximately $10.1 million and $22.5 million representing various deferred ratepayer benefits including the ratepayers portion of the excess earnings for the rate years ended November 30, 1993 and 1992, respectively.

Electric Rate Plan

In December 1993, the Company filed a three year Electric Rate Plan with the PSC for the period beginning December 1, 1994 that minimizes future electric rate increases while retaining consistency with the RMA's objective of the restoration of the Company's financial health. The Electric Rate Plan requests an allowed return on common equity of 11.0% and provides for base rates to be frozen in years one and two and an overall rate increase of 4.3% in the third year. Although base electric rates would be frozen during the first two years of the Electric Rate Plan, annual rate increases of approximately 1% are expected to result from the operation of the Company's FCA. The FCA captures, among other things, amounts to be recovered from or refunded to ratepayers in excess of $15 million which result from the reconciliation of revenues, certain expenses and earned performance incentive components, discussed above.

The Company's Electric Rate Plan reflects four underlying objectives: (i) to limit the balance of RMC during the three year period to no more than its 1992 peak balance of $652 million; (ii) to recover the RMC within the time frame established in the 1989 Settlement; (iii) to minimize, beginning in the third year of the Electric Rate Plan, the final three rate increases contemplated in the 1989 Settlement that follow the two year rate freeze period; and (iv) to continue the Company's gradual return to financial health.

The Electric Rate Plan provides for, with some modifications, the continuation of the LRPP revenue and expense reconciliations and performance incentives. The Electric Rate Plan includes the annual reconciliation of certain expenses for property taxes, interest costs, DSM costs and the deferral and amortization of certain costs for enhanced reliability. The Company would be allowed to earn for the three rate years under the Electric Rate Plan up to 50 additional basis points, excluding incentives under the DSM program, or forfeit up to 47 basis points of the allowed return on common equity of 11.0% as a result of the Company's performance within certain performance programs. These programs consist of a customer service program, a partial pass through fuel cost incentive plan, a DSM program and an electric transmission and distribution reliability plan.

The Company's Electric Rate Plan provides for lower annual electric rate increases than originally anticipated under the 1989 Settlement. However, as a result of changes in certain assumptions upon which the RMA was based, their impact on the RMC and the Company's plans to reduce DSM, operations and maintenance and capital expenditures, the Company has determined that the overall objectives of the RMA can be met under the Electric Rate Plan. As a result of lower than originally anticipated inflation rates, interest costs, property taxes, fuel costs and return on common equity allowed by the PSC, the RMC, which originally had been anticipated to peak at $1.2 billion in 1994, peaked at $652 million in 1992. With the exception of a projected increase in 1995 and 1996, which is not now anticipated to cause the RMC to increase above its $652 million peak, the RMC is expected to decline until it is fully amortized.

Under the Electric Rate Plan, the recovery of the RMC would be extended, if necessary, for an additional period of not more than three years beyond the approximate ten year period envisioned in the RMA. The actual length of the RMC extension will depend on the extent to which the assumptions underlying the Electric Rate Plan materialize. The Company's current projections indicate that the RMC will be recovered in eleven years.

The staff of the PSC (Staff) and other intervening parties filed testimony in response to the Company's Electric Rate Plan. Staff concurs with the Company's proposal for an 11.0% return on common equity in each of the three years and has reaffirmed its commitment to the principles of the RMA, including the full recovery of the RMC within the time frame established by the RMA. However, Staff has recommended an overall zero percent rate increase for the first two years, contrasted with the Company's proposal for a base rate freeze with FCA adjustments of approximately 1% in years one and two, as described above. Staff did not make a recommendation for the level of rate relief in the third year.

In September 1994, three Administrative Law Judges (ALJs) of the PSC issued a recommended decision to the PSC with respect to the Company's Electric Rate Plan. The ALJs agreed with the Company's proposed 11.0% return on common equity and its proposal to freeze base electric rates for the first rate year. While no explicit recommendation was made concerning the second year, the recommended decision implies that base rates could remain frozen for the second rate year as well.

With respect to the third rate year beginning December 1, 1996, the ALJs determined that it was not appropriate for them to issue a recommendation since, in their opinion, the Company's revenue requirements for the third rate year cannot be precisely determined at this time. Alternatively, the ALJs encouraged the Company and other parties in this proceeding to negotiate a settlement concerning any rate increase for the third rate year.

The PSC had been expected to issue a final order on the Company's rate proposal before November 29, 1994, the date that the statutory suspension period was scheduled to terminate. However, in order to accommodate further settlement negotiations in the proceeding, the Company has requested extensions through April 1995, which were granted by the PSC. The Company's offers to extend the suspension period were conditioned upon the continuation of the current LRPP rate mechanisms. Although the ultimate outcome of the Electric Rate Plan cannot be predicted, the Company expects that any PSC order will be consistent with the provisions of the RMA respecting the recovery of the FRA and other 1989 Settlement deferred charges.

Gas

In December 1993, the PSC approved a three year gas rate settlement between the Company and the Staff of the PSC. The gas rate settlement provides that the Company receive, for each of the rate years beginning December 1, 1993, 1994 and 1995, annual gas rate increases of 4.7%, 3.8% and 2.8%, respectively. An allowed return on common equity of 10.1% was used in the determination of the revenue requirements for the gas rate settlement. The gas rate decision also provides that earnings in excess of a 10.6% return on common equity in any of the three rate years covered by the settlement be shared equally between the Company's firm gas customers and its shareowners. For the rate year ended November 30, 1994, the Company earned $9.2 million, net of tax effects, in excess of the 10.6% return on common equity. The firm gas customers' portion of these excess earnings amounting to $4.6 million, net of tax effects, has been deferred until its final disposition is determined by the PSC.

Note 4. The Class Settlement

The Class Settlement, which became effective on June 28, 1989, resolved a civil lawsuit against the Company brought under the federal Racketeer Influenced and Corrupt Organizations Act. The lawsuit which the Class Settlement resolved had alleged that the Company made inadequate disclosures before the PSC concerning the construction and completion of nuclear generating facilities. The Class Settlement provides the Company's electric ratepayers with reductions, aggregating $390 million, that are being reflected as adjustments to their monthly electric bills over a ten year period which began on June 1, 1990.

The reductions which begin in each of the remaining twelve month periods are as follows:

June 1995	$40 million
June 1996	50 million
June 1997	60 million
June 1998	60 million
June 1999	60 million

Upon its effectiveness, the Company recorded its liability for the Class Settlement on a present value basis at $170 million and simultaneously recorded a charge to income (net of tax effects of $57 million) of approximately $113 million. Each month the Company records the changes in the present value of its liability that results from the passage of time and from monthly reductions. The Company expects the Class Settlement liability will be fully satisfied by May 31, 2000.

In accordance with the Class Settlement, the Company, in 1990, established a $10 million fund to reimburse former electric ratepayers entitled to refunds under the Class Settlement. At December 31, 1994, approximately $4.5 million remains undistributed in the fund. Pursuant to the terms of the Class Settlement, the undistributed portion of the net fund balance will be used to reduce ratepayers' bills upon the Company's receipt of the funds from the trustee.

Note 5. Nine Mile Point Nuclear Power Station, Unit 2

The Company has an 18% undivided interest in NMP2 which is operated by Niagara Mohawk Power Corporation (NMPC) near Oswego, New York. Ownership of NMP2 is shared by five cotenants: the Company (18%), NMPC (41%), New York State Electric & Gas Corporation (18%), Rochester Gas and Electric Corporation (14%) and Central Hudson Gas & Electric Corporation (9%). At December 31, 1994, the Company's utility plant investment in NMP2 was $749 million, net of accumulated depreciation of $140 million, which is included in the Company's rate base. Output of NMP2 is shared in the same proportions as the cotenants' respective ownership interests. The operating expenses of NMP2 are also allocated to the cotenants in the same proportions as their respective ownership interests. The Company's share of these expenses is included in the appropriate operating expenses on its Statement of Income. The Company is required to provide its respective share of financing for any capital additions to NMP2. Nuclear fuel costs associated with NMP2 are being amortized on the basis of the quantity of heat produced for the generation of electricity.

NMPC has contracted with the United States Department of Energy for the disposal of nuclear fuel. The Company reimburses NMPC for its 18% share of the cost under the contract at a rate of $1.00 per megawatt hour of net generation less a factor to account for transmission line losses.

The Company's share of the decommissioning costs for NMP2 is estimated to be $82 million and $234 million, in 1994 dollars and 2027 dollars, respectively, based upon a 1989 study performed by NMPC which was updated in 1993 to reflect a change in the NRC minimum decommissioning funding requirement. NMPC has informed the Company that decommissioning costs for NMP2 will increase primarily as a result of the inclusion of nuclear fuel storage charges and costs for continuing care. NMPC will be performing an updated decommissioning study for NMP2 in 1995. The Company will update its estimate for decommissioning costs upon the NRC's approval of the 1995 study. NMPC expects to commence decommissioning in 2027, shortly after cessation of operations, using a method which removes or decontaminates NMP2 components promptly. The Company's share of estimated decommissioning costs are being provided for in electric rates and are being charged to operations as depreciation expense over the expected service life of NMP2. The amount of decommissioning costs recorded as depreciation expense was $1.6 million in 1994 and $1.7 million in both 1993 and 1992. The accumulated decommissioning costs collected in rates through December 31, 1994 amounted to $8.7 million. The Company has established an independent decommissioning trust fund for the decommissioning of the contaminated portion of the NMP2 plant, which is approximately 92% of total decommissioning costs. As of December 31, 1994, the Company has accumulated $8.3 million in this external trust fund. Net earnings on this fund are recorded as an increase to accumulated depreciation. This fund complies with regulations issued by the NRC governing the funding of nuclear plant decommissioning costs.

Note 6. Capital Stock

Common Stock

During 1994, the Company issued 6.1 million shares of common stock, including the public offering in June of 5.1 million shares at $20 per share. The Company has 150,000,000 shares of authorized common stock, of which 118,416,606 were issued and outstanding at December 31, 1994. The Company has reserved 1,747,570 shares for sale through its Employee Stock Purchase Plan, 5,009,762 shares were committed to the Automatic Dividend Reinvestment Plan and 114,126 shares were reserved for conversion of the Series I Convertible Preferred Stock at a rate of $17.15 per share. Common and preferred stock dividend limitations in the mortgage securing the Company's First Mortgage Bonds are not material. There are no dividend limitations contained in the Company's other debt instruments.

Preferred Stock

The Company has 7,000,000 authorized shares, cumulative preferred stock, par value $100 per share and 30,000,000 authorized shares, cumulative preferred stock, par value $25 per share. Dividends on preferred stock are paid in preference to dividends on common stock or any other stock ranking junior to preferred stock.

Preferred Stock Subject to Mandatory Redemption

The aggregate fair value of redeemable preferred stock with mandatory redemptions at December 31, 1994 and 1993 amounted to approximately $564 million and $659 million, respectively, compared to their carrying amounts of $649 million and $654 million, respectively.

The Company is required to redeem each year certain series of preferred stock through the operation of sinking fund provisions as follows:

Series	*Redemption Provision Beginning*	*Number of Shares*	*Redemption Price*
L	July 31, 1979	10,500	$100
R	December 15, 1982	37,500	100
NN	March 1, 1999	77,700	25
UU	October 15, 1999	112,000	25

In addition, the Company will have the non-cumulative option to double the number of shares to be redeemed pursuant to the sinking fund provisions in any year for the preferred stock series R, NN and UU. The aggregate par value of preferred stock required to be redeemed through sinking funds in 1995 and 1996 is $4.8 million, in 1997 and 1998 is $1.1 million and in 1999 is $5.8 million.

The Company is also required to redeem all shares of certain series of preferred stock which are not subject to sinking fund requirements. The scheduled mandatory redemption for these series are as follows: (i) Series GG on March 1, 1999; (ii) Series AA on June 1, 2000; (iii) Series QQ on May 1, 2001 ; and (iv) Series CC on August 1, 2002.

Preferred Stock Not Subject to Mandatory Redemption
The Company has the option to redeem certain series of its preferred stock. For the series subject to optional redemption at December 31, 1994, the call prices were as follows:

Preferred Stock	*Call Price*
5.00% Series B	$101
4.25% Series D	102
4.35% Series E	102
4.35% Series F	102
5⅛% Series H	102
5¾% Series I — Convertible	100

Preference Stock
At December 31, 1994, none of the authorized 7,500,000 shares of nonparticipating preference stock, par value $1 per share, which ranks junior to preferred stock, were outstanding.

Note 7. Long-Term Debt

Each of the Company's outstanding mortgages is a lien on substantially all of the Company's properties.

First Mortgage
All of the bonds issued under the First Mortgage, including those issued after June 1, 1975 and pledged with the Trustee of the General and Refunding Mortgage (G&R Trustee) as additional security for General & Refunding Bonds (G&R Bonds), are secured by the lien of the First Mortgage. First Mortgage Bonds pledged with the G&R Trustee do not represent outstanding indebtedness of the Company. Amounts of such pledged bonds outstanding were $1.3 billion and $1.0 billion at December 31, 1994 and 1993, respectively. The annual First Mortgage depreciation fund and sinking fund requirements for 1994, due not later than June 30, 1995, are estimated at $239 million and $21 million, respectively. The Company expects to meet these requirements with property additions and retired First Mortgage Bonds.

G&R Mortgage
The lien of the G&R Mortgage is subordinate to the lien of the First Mortgage. The annual G&R Mortgage sinking fund requirement for 1994, due not later than June 30, 1995, is estimated at $26 million. The Company expects to satisfy this requirement with retired G&R Bonds.

1989 Revolving Credit Agreement
The Company has available through October 1, 1995, $300 million under its 1989 Revolving Credit Agreement (1989 RCA). This line of credit is secured by a first lien upon the Company's accounts receivable and fuel oil inventories.

At December 31, 1994, no amounts were outstanding under the 1989 RCA. The Company has the option, when amounts are outstanding, to commit to one of three interest rates including: (i) the Adjusted Certificate of Deposit Rate which is a rate based on the certificate of deposit rates of certain of the lending banks, (ii) the Base Rate which is generally a rate based on Citibank, N.A.'s prime rate and (iii) the Eurodollar Rate which is a rate based on the London Interbank Offering Rate (LIBOR). The Company has agreed to pay a fee of one quarter of one percent per annum on the unused portion. The 1989 RCA may be extended for one year periods upon the acceptance by the lending banks of a request by the Company which must be delivered to the lending banks prior to April 1 of each year. It is the Company's intent to request an extension prior to April 1, 1995.

Authority Financing Notes
Authority Financing Notes are issued by the Company to the New York State Energy Research and Development Authority (NYSERDA) to secure certain tax-exempt Industrial Development Revenue Bonds, Pollution Control Revenue Bonds (PCRBs) and Electric Facilities Revenue Bonds (EFRBs) issued by NYSERDA. Certain of these bonds are subject to periodic tender at which time their interest rates may be subject to redetermination. Tender requirements of Authority Financing Notes at December 31, 1994 were as follows:

(In thousands of dollars)

Interest Rate	*Series*	*Principal*	
PCRBs			
8¼%	1982	$ 17,200	Tendered every three years, next tender October 1997
3.0%	1985A,B	150,000	Tendered annually on March 1
EFRBs			
5.45%	1993A	50,000	Tendered weekly
4.90%	1993B	50,000	Tendered weekly
5.40%	1994A	50,000	Tendered weekly

The 1994 and 1993 EFRBs and the 1985 PCRBs are supported by letters of credit pursuant to which the letter of credit banks have agreed to pay the principal, interest and premium, if applicable, in the aggregate, up to approximately $326 million in the event of default. The obligation of the Company to reimburse the letter of credit banks is unsecured. These letters of credit expire on October 26, 1997 for the 1994 EFRBs, November 17, 1996 for the 1993 EFRBs, and March 16, 1996 for the 1985 PCRBs, at each of which times the Company is required to obtain either an extension of the letters of credit or substitute credit backup. If neither can be obtained, the 1993 EFRBs, the 1994 EFRBs and the 1985 PCRBs must be redeemed unless the Company purchases them in lieu of redemption and subsequently remarkets them.

Fair Values of Long-Term Debt

The carrying amounts and fair values of the Company's long-term debt at December 31 were as follows:

(In thousands of dollars)

1994	*Fair Value*	*Carrying Amount*
First Mortgage Bonds	$ 95,688	$ 100,000
General and Refunding Bonds	1,844,289	1,951,000
Debentures	1,867,510	2,270,000
Authority Financing Notes	829,651	866,675
Total	$4,637,138	$5,187,675

1993	*Fair Value*	*Carrying Amount*
First Mortgage Bonds	$ 124,719	$ 125,000
General and Refunding Bonds	1,806,728	1,666,000
Debentures	2,944,499	2,880,058
Authority Financing Notes	851,800	816,675
Total	$5,727,746	$5,487,733

For a further discussion on the fair value of the securities listed above, see Note 1.

Maturity Schedule

Total long-term debt maturing in each of the next five years is $25 million (1995), $455 million (1996), $286 million (1997), $101 million (1998) and $454 million (1999).

Note 8. Retirement Benefit Plans

Pension Plans

The Company maintains a defined benefit pension plan which covers substantially all employees (Primary Plan), a supplemental plan which covers officers and certain key executives (Supplemental Plan) and a retirement plan which covers the Board of Directors (Directors' Plan). The Company also maintains 401(k) plans for its union and non-union employees. The Company does not contribute to these plans.

Primary Plan

The Company's funding policy is to contribute annually to the Primary Plan a minimum amount consistent with the requirements of the Employee Retirement Income Security Act of 1974 (ERISA) plus such additional amounts, if any, as the Company may determine to be appropriate from time to time.

For service before January 1, 1992, pension benefits are determined based on the greater of the accrued benefit as of December 31, 1991, or by applying a moving five year average of Plan compensation, not to exceed the January 1, 1992 salary, to certain percentages as defined in the Primary Plan, determined by years of service at December 31, 1991. For service after January 1, 1992, pension benefits are equal to 2% per year of Plan compensation through age 49 and 2 1/2% thereafter. Employees are vested in the Primary Plan after five years of service with the Company.

The Primary Plan's funded status and amounts recognized on the Balance Sheet at December 31, 1994 and 1993 were as follows:

(In thousands of dollars)

	1994	*1993*
Actuarial Present Value of Benefit Obligation		
Vested benefits	$ 467,962	$ 468,797
Nonvested benefits	50,385	49,815
Accumulated Benefit Obligation	$ 518,347	$ 518,612
Plan assets at fair value	$ 597,200	$ 598,600
Actuarial present value of projected benefit obligation	592,339	597,128
Projected benefit obligation less than plan assets	4,861	1,472
Unrecognized net obligation	84,577	91,397
Unrecognized net gain	(90,335)	(97,029)
Net Accrued Pension Cost	$ (897)	$ (4,160)

Periodic pension cost for 1994, 1993 and 1992 for the Primary Plan included the following components:

			(In thousands of dollars)
	1994	*1993*	*1992*
Service cost – benefits earned during the period	$16,465	$14,481	$13,661
Interest cost on projected benefit obligation and service cost	43,782	41,865	39,574
Actual return on plan assets	(12,431)	(54,010)	(47,156)
Net amortization and deferral	(31,633)	10,025	12,849
Net Periodic Pension Cost	$16,183	$12,361	$18,928

Assumptions used in accounting for the Primary Plan were as follows:

	1994	*1993*	*1992*
Discount rate	7.75%	7.25%	7.75%
Rate of future compensation increases	5.0%	5.0%	5.5%
Long-term rate of return on assets	7.5%	7.5%	7.5%

The Primary Plan assets at fair value include cash, cash equivalents, group annuity contracts, bonds and listed equity securities.

In 1993, the PSC issued an order which addressed the accounting and ratemaking treatment of pension costs in accordance with SFAS No. 87, Employers' Accounting for Pensions. Under the PSC order, the Company is required to recognize rate allowance deferred net gains or losses over a ten year period rather than using the corridor approach method. This change in the annual pension cost calculation reduced pension expense by $4.6 million in the year of adoption, 1993. The Company believes that this method of accounting for financial reporting purposes, results in a better matching of revenues and the Company's pension cost. The Company defers differences between pension rate allowance and pension expense under the PSC's order. In addition, the PSC requires the Company to measure the difference between the pension rate allowance and the annual pension contributions to the pension fund.

Supplemental Plan

The Supplemental Plan, the cost of which is borne by the Company's shareowners, provides supplemental death and retirement benefits for officers and other key executives without contribution from such employees. The Supplemental Plan is a non-qualified plan under the Internal Revenue Code. Death benefits are currently provided by insurance. The provision for plan benefits, which is unfunded, totaled approximately $2.3 million, $2.8 million and $.7 million which was recognized as expense in 1994, 1993 and 1992, respectively.

Directors' Plan

The Directors' Plan provides benefits to directors who are not officers of the Company. Directors who have served in that capacity for more than five years qualify as participants under the plan. The Directors' Plan is a non-qualified plan under the Internal Revenue Code. The provision for retirement benefits, which is unfunded, totaled approximately $148,000, $150,000 and $133,000 which was recognized as expense in 1994, 1993 and 1992, respectively.

Postretirement Benefits Other Than Pensions

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for retired employees. Substantially all of the Company's employees may become eligible for these benefits if they reach retirement age after working for the Company for a minimum of five years. These and similar benefits for active employees are provided by the Company or by insurance companies whose premiums are based on the benefits paid during the year. Effective January 1, 1993, the Company adopted the provisions of SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, which requires the Company to recognize the expected cost of providing postretirement benefits when employee services are rendered rather than when paid. As a result, the Company, in 1993, recorded an accumulated postretirement benefit obligation and a corresponding regulatory asset of approximately $376 million. Additionally, as a result of adopting SFAS No. 106, the Company's postretirement benefit cost for 1993 increased by approximately $28 million above the amount that would have been recorded under the pay-as-you-go method.

In 1993, the PSC issued an order which required that the effects of implementing SFAS No. 106 be phased into rates. The order requires the Company to defer as a regulatory asset the difference between postretirement benefit expense recorded for accounting purposes in accordance with SFAS No. 106 and the postretirement benefit expense reflected in rates. The ongoing annual postretirement benefit expense will be phased into and reflected in rates within a five year period with the accumulated postretirement obligation being recovered in rates over a twenty year period. In addition, the Company is required to recognize any deferred net gains or losses over a ten year period.

In 1994, the Company established Voluntary Employee's Beneficiary Association (VEBA) trusts for union and non-union employees for the funding of incremental costs collected in rates for postretirement benefits. In December 1994, the Company contributed $2.2 million for the incremental postretirement benefit cost collected in gas rates. In 1995, the Company will begin funding the incremental postretirement benefit cost for the electric business as these amounts are reflected in rates.

Accumulated postretirement benefit obligation other than pensions at December 31 was as follows:

	(In thousands of dollars)	
	1994	1993
Retirees	$ 159,590	$ 152,800
Fully eligible plan participants	57,788	63,800
Other active plan participants	133,030	137,200
Accumulated postretirement benefit obligation	$ 350,408	$ 353,800
Plan assets, cash	(2,200)	—
Accumulated postretirement benefit obligation in excess of plan assets	348,208	353,800
Unrecognized net gain	73,936	49,237
Accrued Postretirement Benefit Cost	$ 422,144	$ 403,037

Periodic postretirement benefit cost other than pensions for the years 1994, 1993 and 1992 was as follows:

	1994	1993	1992
Service cost – benefits earned during the period	$ 11,275	$ 12,980	$ —
Interest cost on projected benefit obligation and service cost	25,713	29,531	—
Amortization of net gain	(5,213)	—	—
Periodic Postretirement Benefit Cost	$ 31,775	$ 42,511	$ 13,400

Assumptions used to determine the postretirement benefit obligation were as follows:

	1994	1993
Discount rate	7.75%	7.25%
Rate of future compensation increases	5.0%	5.0%

The assumed health care cost trend rates used in measuring the accumulated postretirement benefit obligation at December 31, 1994 and 1993 were 9.0% and 9.5%, respectively, gradually declining to 6.0% in 2001 and thereafter. A one percentage point increase in the health care cost trend rate would increase the accumulated postretirement benefit obligation as of December 31, 1994 and 1993 by approximately $44 million and $46 million, respectively, and the sum of the service and interest costs in 1994 and 1993 by $6 million and $8 million, respectively.

Note 9. Federal Income Tax

At December 31, the significant components of the Company's deferred tax assets and liabilities calculated under the provisions of SFAS No. 109 were as follows:

	(In thousands of dollars)	
	1994	1993
Deferred Tax Assets		
Net operating loss carryforwards	$ 552,917	$ 707,400
Reserves not currently deductible	86,267	87,050
Tax depreciable basis in excess of book	48,557	59,147
Nondiscretionary excess credits	31,933	35,362
ITC carryforwards	142,329	142,329
Other	89,763	62,800
Total Deferred Tax Assets	$ 951,766	$ 1,094,088
Deferred Tax Liabilities		
1989 Settlement	$ 2,174,729	$ 2,180,413
Accelerated depreciation	608,302	597,827
Call premiums	56,324	63,735
Rate case deferrals	55,598	43,957
Other	46,840	46,097
Total Deferred Tax Liabilities	$ 2,941,793	$ 2,932,029
Net Deferred Tax Liability	$ 1,990,027	$ 1,837,941

Federal income tax expense in accordance with APB No. 11, for the year 1992 was as follows:

	(In thousands of dollars)
	1992
Federal Income Tax, per Statement of Income	
Current	$ 530
Deferred and other	
1989 Settlement	
Shoreham property	$ 3,806
Rate moderation component	10,351
Other 1989 Settlement items	8,622
Net operating loss carryforwards	(14,121)
Shoreham post settlement costs	60,125
Accelerated tax depreciation	35,951
Call premiums	35,441
Ratemaking and performance plan	17,680
Other items	2,577
Total Deferred and Other	$160,432
Total Federal Income Tax Expense	$160,962

The federal income tax amounts included in the Statement of Income differ from the amounts which result from applying the statutory federal income tax rate to income before income tax. The table below sets forth the reasons for such differences.

(In thousands of dollars)

	1994	*1993*	*1992*
Income before federal income tax	$ 478,564	$ 468,839	$ 462,936
Statutory federal income tax rate	35%	35%	34%
Statutory federal income tax	$ 167,497	$ 164,094	$ 157,398
Additions (Reductions) in Federal Income Tax			
1989 Settlement	4,213	4,256	4,003
AFC	(2,450)	(2,304)	(4,118)
Tax credits	(6,837)	(6,871)	(6,586)
Excess of book depreciation over tax depreciation	14,745	12,437	12,193
Interest capitalized	2,449	3,443	2,947
Other items	(2,905)	(2,779)	(4,875)
Total Federal Income Tax Expense	$ 176,712	$ 172,276	$ 160,962
Effective federal income tax rate	36.9%	36.7%	34.8%

The Company's net operating loss (NOL) carryforwards for federal income tax purposes is estimated to be approximately $1.6 billion at December 31, 1994. The NOL carryforwards will expire in the years 2004 through 2007. The amount of investment tax credit (ITC) carryforwards, net of the 35% reduction required by the Tax Reform Act of 1986, are approximately $142 million. The ITC carryforwards expire by the year 2005. For financial reporting purposes, a valuation allowance was not required to offset the deferred tax assets related to these carryforwards.

On January 8, 1990 and October 10, 1992, the Company received Revenue Agents' Reports disallowing certain deductions claimed by the Company on its tax returns for the audit cycle years 1984 through 1987 and 1988 through 1989, respectively. The Revenue Agents' Reports reflect proposed adjustments to the Company's federal income tax returns for 1984 through 1989 which, if sustained, would give rise to tax deficiencies totaling approximately $220 million. The Revenue Agents have proposed ITC adjustments which, if sustained, would reduce the Company's ITC carryforwards by approximately $96 million. The Company is protesting some of the adjustments and is seeking an administrative and, if necessary, a judicial review of the conclusions reached in the Revenue Agents' Reports. The Company cannot predict either the timing or the manner in which these matters will be resolved. If however, the ultimate disposition of any or all matters raised in the Revenue Agents' Reports are adverse to the Company, the Company expects that any deficiencies that may arise will be substantially offset by the net operating loss carrybacks associated with the 1989 Shoreham abandonment loss deduction of $1.8 billion and thus any impact would not have a material effect on the Company's financial condition or cash flows.

Note 10. Commitments and Contingencies

Commitments

The Company has entered into substantial commitments for gas supply, purchased power and transmission facilities. The costs associated with these commitments are recovered from ratepayers through provisions in the Company's rate schedules.

The Company expects that it will have to expend approximately $1 million in 1995 to meet continuous emission monitoring requirements and to meet Phase I nitrogen oxide (NOx) reduction requirements. Subject to requirements that are expected to be promulgated in forthcoming regulations, the Company estimates that it may be required to expend approximately $80 million (net of NOx credit sales) by 2003 to meet Phase II and Phase III NOx reduction requirements and approximately $24 million by 1999 to meet potential requirements for the control of hazardous air pollutants from power plants. The Company believes that all of the above costs will be recoverable through rates.

Contingencies

Environmental Matters

The Company is subject to federal, State and local laws and regulations dealing with air and water quality and other environmental matters. The Company continually monitors its activities in order to determine the impact of such activities on the environment and to ensure compliance with various environmental laws. Except as set forth below, no material proceedings have been commenced or, to the knowledge of the Company, are contemplated against the Company with respect to any matter relating to the protection of the environment.

The New York State Department of Environmental Conservation has indicated to New York State utilities that it may require all such utilities to investigate and, where necessary, remediate their former manufactured gas plant sites. The Company is the owner of six pieces of property on which the Company or certain of its predecessor companies produced manufactured gas. Although the exact amount of the Company's clean-up costs cannot yet be determined, based on the findings of investigations at two of these six sites, preliminary estimates indicate that it will cost approximately $35 million to clean up all of these sites over the next five to ten years. Accordingly, the Company has recorded a $35 million liability and has also recorded a $35 million regulatory asset to reflect its belief that the PSC will provide for the future recovery of these costs through rates as it has for other New York State utilities. The Company has notified its former and current insurance carriers that it seeks to recover from them certain of these clean-up costs. However, the Company is unable to predict the amount of insurance recovery, if any, that it may obtain.

The Company has been notified by the Environmental Protection Agency (EPA) that it is one of many potentially responsible parties (PRPs) that may be liable for the remediation of three contaminated licensed treatment, storage and disposal sites. At one site, located in Philadelphia, Pennsylvania, and operated by Metal Bank of America, the Company and nine other PRPs, all of which are public utilities, have completed a Remedial Investigation and Feasibility Study which is currently being reviewed by the EPA. The level of remediation required will be determined when the EPA issues its decision, currently expected in May 1995. The Company currently anticipates that the total cost to remediate this site will be between $14 million and $30 million. The Company has recorded a liability of $1.1 million representing its estimated share of the cost to remediate this site. The Company believes that any cost incurred to remediate this site will be recoverable through rates.

With respect to the other two sites, which are located in Kansas City, Kansas and Kansas City, Missouri, the Company is investigating allegations that it had previously stored or made agreements for disposal of polychlorinated biphenyls (PCBs) or items containing PCBs at these sites. The Company is currently unable to determine its share of the cost to remediate these two sites or the impact, if any, on the Company's financial position. The Company believes that any cost incurred to remediate these sites will be recoverable through rates.

As a result of its daily business activity, the Company is involved in various legal and administrative proceedings, including other environmental proceedings. The Company believes the resolution of these proceedings will not have a material adverse effect on the Company's financial position or results of operations.

Nuclear Plant Insurance

The NRC requires the owners of nuclear facilities to maintain certain types of insurance. For property damage at each nuclear generating site, the NRC requires a minimum of $1.06 billion of coverage. The NRC has provided the Company with a partial exemption from these requirements for Shoreham. With respect to third party liability and property damage, the NRC requires nuclear plant owners to carry $200 million in primary coverage. Pursuant to these requirements, the Company carries property insurance and third party bodily injury and property liability insurance for its 18% share in NMP2 and for Shoreham. The annual premiums for this coverage are not material.

The policies also include retroactive premiums under certain circumstances. For the property damage policies, the retroactive premium assessments, on a per occurrence basis, could be as much as $4.6 million. Once Shoreham is declared a non-nuclear site by the NRC this retroactive premium assessment may decrease significantly.

For the third party liability and property damage insurance, the retroactive premium is related to the NRC's requirement that nuclear facility owners, in addition to carrying $200 million in primary coverage, also participate in a Secondary Financial Protection Fund (fund). Under the Price Anderson Act, that assessment related to the fund could be up to $79.3 million per nuclear incident in any one year at any nuclear unit, but not in excess of $10 million in payments per year for each incident. The Price Anderson Act also limits liability for third-party bodily injury and third-party property damage arising out of a nuclear occurrence at each unit to $8.9 billion.

In 1994, the NRC granted the Company permission to withdraw from the fund because Shoreham had been defueled. The withdrawal was effective November 18, 1994. The withdrawal relieves the Company from any retroactive premium assessment relating to any nuclear incident as of November 18, 1994 or later. The Company remains liable for retroactive assessments for any nuclear incident occurring prior to November 18, 1994 during the time the Company participated in the Fund because of its Shoreham ownership. As a co-owner of NMP2, the Company remains liable for 18% of any retroactive premium assessment levied against the NMP2 owners.

Note 11. Segments of Business

The Company is engaged in the electric and natural gas utility businesses. The Company serves residential, commercial and industrial customers in Nassau and Suffolk Counties and the Rockaway Peninsula in Queens County, all on Long Island, New York. Identifiable assets by segment include net utility plant, regulatory assets, materials and supplies, accrued unbilled revenues, gas in storage, fuel and deferred charges. Assets utilized for overall Company operations consist primarily of cash and cash equivalents, accounts receivable and unamortized cost of issuing securities.

(In millions of dollars)

For year ended December 31	*1994*	*1993*	*1992*
Operating Revenues			
Electric	$ 2,481	$ 2,352	$ 2,195
Gas	586	529	427
Total	$ 3,067	$ 2,881	$ 2,622
Operating Expenses (excludes federal income tax)			
Electric	$ 1,640	$ 1,514	$ 1,355
Gas	500	427	353
Total	$ 2,140	$ 1,941	$ 1,708
Operating Income (before federal income tax)			
Electric	$ 842	$ 838	$ 840
Gas	85	102	74
Total operating income	927	940	914
AFC	(7)	(7)	(12)
Other income and deductions	(45)	(56)	(50)
Interest charges	500	534	513
Federal income tax	177	172	161
Net Income	$ 302	$ 297	$ 302
Depreciation and Amortization			
Electric	$ 112	$ 106	$ 104
Gas	19	16	15
Total	$ 131	$ 122	$ 119
Construction and Nuclear Fuel Expenditures*			
Electric	$ 155	$ 171	$ 164
Gas	125	134	109
Total	$ 280	$ 305	$ 273

**Includes non-cash allowance for other funds used during construction.*

At December 31	*1994*	*1993*	*1992*
Identifiable Assets			
Electric	$10,999	$11,194	$ 8,867
Gas	1,184	1,078	768
Total identifiable assets	12,183	12,272	9,635
Assets utilized for overall Company operations	1,034	1,121	1,129
Total Assets	$13,217	$13,393	$10,764

Note 12. Quarterly Financial Information

(Unaudited)

(In thousands of dollars except earnings per common share)

For quarter ended	*1994*	*1993*
Operating Revenues		
March 31	$ 872,143	$ 760,451
June 30	626,310	604,871
September 30	913,440	849,700
December 31	655,414	665,973
Operating Income		
March 31	$ 183,865	$ 192,391
June 30	139,478	167,599
September 30	276,965	263,984
December 31	144,637	131,577
Net Income		
March 31	$ 69,620	$ 67,861
June 30	24,787	56,806
September 30	168,872	144,549
December 31	38,573	27,347
Earnings for Common Stock		
March 31	$ 56,348	$ 53,286
June 30	11,516	42,451
September 30	155,620	131,022
December 31	25,348	13,696
Earnings per Common Share		
March 31	$ .50	$ .48
June 30	.10	.38
September 30	1.32	1.17
December 31	.21	.12

In the fourth quarter of 1993, the Company recorded income of approximately $6.5 million, net of tax effects, or $.06 per common share related to the settlement of certain litigation. In addition, in the fourth quarter of 1993, the Company recorded a charge to earnings of approximately $7.3 million, net of tax effects, or $.07 per common share principally related to previously deferred storm costs and the reconciliation of certain ratemaking mechanisms recorded in connection with the conclusion of the Company's rate year.

REPORT OF ERNST & YOUNG LLP, INDEPENDENT AUDITORS

To the Shareowners and Board of Directors of Long Island Lighting Company

We have audited the accompanying balance sheet of Long Island Lighting Company and the related statement of capitalization as of December 31, 1994 and 1993 and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1994. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Long Island Lighting Company at December 31, 1994 and 1993, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1994, in conformity with generally accepted accounting principles.

Ernst & Young LLP

Melville, New York
February 3, 1995

SELECTED FINANCIAL DATA

Table 1 — *(In thousands of dollars except per share amounts)*

Summary of Operations	1994	1993	1992	1991	1990
Revenues	$ 3,067,307	$ 2,880,995	$ 2,621,839	$ 2,547,729	$ 2,456,902
Operating expenses	2,322,362	2,125,444	1,880,734	1,762,449	1,654,272
Operating income	744,945	755,551	741,105	785,280	802,630
Other income and (deductions)	52,719	70,874	66,330	40,482	20,638
Income before interest charges and cumulative effect of accounting change	797,664	826,425	807,435	825,762	823,268
Interest charges and (credits)	495,812	529,862	505,461	520,224	503,631
Income before cumulative effect of accounting change	301,852	296,563	301,974	305,538	319,637
Cumulative effect of accounting change for unbilled gas revenues (net of tax)	—	—	—	—	11,680
Net income	301,852	296,563	301,974	305,538	331,317
Preferred stock dividend requirements	53,020	56,108	63,954	66,394	68,161
Earnings for Common Stock	$ 248,832	$ 240,455	$ 238,020	$ 239,144	$ 263,156
Average common shares outstanding (000)	115,880	112,057	111,439	111,348	111,290
Earnings per common share					
Before cumulative effect of accounting change	$ 2.15	$ 2.15	$ 2.14	$ 2.15	$ 2.26
Cumulative effect of accounting change	—	—	—	—	0.10
Earnings per Common Share	$ 2.15	$ 2.15	$ 2.14	$ 2.15	$ 2.36
Common stock dividends declared per share	$ 1.78	$ 1.76	$ 1.72	$ 1.60	$ 1.25
Common stock dividends paid per share	$ 1.78	$ 1.75	$ 1.71	$ 1.55	$ 1.125
Book value per common share at December 31	$ 20.21	$ 19.88	$ 19.58	$ 19.13	$ 18.57
Common shares outstanding at December 31 (000)	118,417	112,332	111,600	111,365	111,324
Common shareowners of record at December 31	96,491	94,877	86,111	90,435	82,903

Table 2

Capitalization Ratios*					
Long-term debt	62.5%	65.0%	64.7%	63.9%	62.2%
Preferred stock	8.6	8.5	8.8	8.8	9.4
Common equity	28.9	26.5	26.5	27.3	28.4
Total	100.0%	100.0%	100.0%	100.0%	100.0%

**Includes current maturities of long-term debt and current redemption requirements of preferred stock.*

Table 3 — *(In thousands of dollars)*

Operations and Maintenance Expense Details					
Payroll and employee benefits	$ 436,611	$ 438,079	$ 413,817	$ 398,000	$ 357,689
Less — Charged to construction and other	103,974	116,988	124,076	123,838	97,650
Payroll and employee benefits charged to operations	332,637	321,091	289,741	274,162	260,039
Fuel and Purchased Power					
Fuel — electric operations	261,154	287,349	282,138	354,859	447,481
Fuel — gas operations	267,629	253,511	206,344	172,992	185,474
Purchased power costs	307,584	292,136	280,914	197,154	168,749
Fuel cost adjustments deferred	11,619	(5,405)	(27,612)	43,697	(14,705)
Total fuel and purchased power	847,986	827,591	741,784	768,702	786,999
All other	208,017	200,569	208,204	248,597	215,770
Total Operations and Maintenance Expense	$ 1,388,640	$ 1,349,251	$ 1,239,729	$ 1,291,461	$ 1,262,808
Full-time employees at December 31	5,947	6,215	6,438	6,538	6,545

Table 4 *(In thousands of dollars)*

Electric Operating Income	1994	1993	1992	1991	1990
Revenues					
Residential	$1,202,124	$1,145,891	$1,045,799	$1,047,490	$ 997,868
Commercial and industrial	1,196,422	1,132,487	1,076,302	1,070,098	1,017,387
Other system revenues	52,477	49,790	49,395	47,838	46,673
Total system revenues	2,451,023	2,328,168	2,171,496	2,165,426	2,061,928
Sales to other utilities	14,895	12,872	9,997	23,040	24,140
Other revenues	15,719	11,069	13,139	8,102	9,592
Total Revenues	2,481,637	2,352,109	2,194,632	2,196,568	2,095,660
Operating Expenses					
Operations — fuel and purchased power	568,738	579,032	559,583	593,656	611,122
Operations — other	310,438	306,116	294,909	296,798	271,608
Maintenance	107,573	111,765	105,341	127,446	118,545
Depreciation and amortization	111,996	106,149	104,034	104,172	98,022
Base financial component amortization	100,971	100,971	100,971	100,971	100,971
Rate moderation component amortization	197,656	88,667	(30,444)	(228,572)	(297,214)
Regulatory liability component amortization	(79,359)	(79,359)	(79,359)	(79,359)	(79,359)
1989 Settlement credits amortization	(9,214)	(9,214)	(9,214)	(9,214)	(9,214)
Other regulatory amortization	(4,883)	(17,082)	(21,984)	10,375	14,427
Operating taxes	336,263	326,407	331,122	338,429	322,197
Federal income tax — current	10,784	6,324	530	515	3,138
Federal income tax — deferred and other	156,646	158,941	158,908	173,259	169,274
Total Operating Expenses	1,807,609	1,678,717	1,514,397	1,428,476	1,323,517
Electric Operating Income	$ 674,028	$ 673,392	$ 680,235	$ 768,092	$ 772,143

Table 5 *(In thousands of dollars)*

Gas Operating Income					
Revenues					
Residential — space heating	$ 326,474	$ 310,109	$ 243,950	$ 190,976	$ 198,734
Residential — other	42,263	39,515	33,035	29,383	30,854
Commercial and industrial — space heating	126,092	106,140	90,363	70,938	68,441
Commercial and industrial — other	35,275	33,181	29,094	25,515	26,501
Total firm revenues	530,104	488,945	396,442	316,812	324,530
Interruptible revenues	26,804	24,028	19,658	21,686	30,515
Total system revenues	556,908	512,973	416,100	338,498	355,045
Other revenues	28,762	15,913	11,107	12,663	6,197
Total Revenues	585,670	528,886	427,207	351,161	361,242
Operating Expenses					
Operations — fuel	279,248	248,559	182,201	175,046	175,877
Operations — other	95,576	81,692	77,300	78,469	68,910
Maintenance	27,067	22,087	20,395	20,046	16,746
Depreciation and amortization	18,668	16,322	15,103	14,783	12,862
Regulatory amortization	9,211	(962)	(88)	—	—
Operating taxes	70,632	59,440	57,866	49,951	48,120
Federal income tax — current	—	—	—	—	500
Federal income tax — deferred and other	14,351	19,589	13,560	(4,322)	7,740
Total Operating Expenses	514,753	446,727	366,337	333,973	330,755
Gas Operating Income	$ 70,917	$ 82,159	$ 60,870	$ 17,188	$ 30,487

Table 6

Electric Sales and Customers	1994	1993	1992	1991	1990
Sales — millions of kWh					
Residential	7,159	7,118	6,788	7,022	7,022
Commercial and industrial	8,394	8,257	8,181	8,322	8,359
Other	457	449	471	469	472
System sales	16,010	15,824	15,440	15,813	15,853
Sales to other utilities	372	304	227	598	532
Total Sales	16,382	16,128	15,667	16,411	16,385
Customers — monthly average					
Residential	908,490	905,997	902,885	898,974	895,294
Commercial and industrial	102,490	102,254	101,838	101,740	101,562
Other	4,583	4,553	4,593	4,540	4,504
Total Customers — monthly average	1,015,563	1,012,804	1,009,316	1,005,254	1,001,360
Customers — at December 31	1,016,739	1,011,965	1,009,028	1,005,363	1,001,441
Residential					
kWh per customer	7,880	7,856	7,518	7,811	7,843
Revenue per kWh	16.79¢	16.10¢	15.41¢	14.92¢	14.21¢
Commercial and Industrial					
kWh per customer	81,901	80,750	80,333	81,797	82,304
Revenue per kWh	14.25¢	13.72¢	13.16¢	12.86¢	12.17¢
System					
kWh per customer	15,765	15,624	15,297	15,731	15,832
Revenue per kWh	15.31¢	14.71¢	14.06¢	13.69¢	13.01¢

Table 7

Gas Sales and Customers					
Sales — thousands of dth					
Residential — space heating	35,693	37,191	35,089	29,687	29,810
Residential — other	3,151	3,297	3,203	3,195	3,448
Commercial and industrial — space heating	15,679	14,366	13,662	11,636	11,271
Commercial and industrial — other	4,366	4,329	4,338	4,171	4,352
Total firm sales	58,889	59,183	56,292	48,689	48,881
Interruptible sales	6,914	5,920	5,090	4,538	6,347
Off-system sales	7,232	2,894	—	—	—
Total Sales	73,035	67,997	61,382	53,227	55,228
Customers — monthly average					
Residential — space heating	239,857	233,882	227,834	220,562	211,400
Residential — other	163,608	166,974	169,189	171,581	176,000
Commercial and industrial — space heating	33,776	32,783	31,666	30,453	29,072
Commercial and industrial — other	10,448	10,631	10,777	11,003	11,310
Total firm customers	447,689	444,270	439,466	433,599	427,782
Interruptible customers	576	542	531	472	410
Total Customers — monthly average	448,265	444,812	439,997	434,071	428,192
Customers — at December 31	449,906	446,384	442,117	436,853	430,571
Residential					
dth per customer	96.3	101.0	96.4	83.9	85.8
Revenue per dth	$ 9.49	$ 8.64	$ 7.23	$ 6.70	$ 6.90
Commercial and Industrial					
dth per customer	453.3	430.6	424.1	381.3	386.9
Revenue per dth	$ 8.05	$ 7.45	$ 6.64	$ 6.10	$ 6.08
System					
dth per customer	146.8	146.4	139.5	122.6	128.9
Revenue per dth	$ 8.46	$ 7.88	$ 6.78	$ 6.36	$ 6.43

Table 8

Electric Operations	1994	1993	1992	1991	1990
Energy — millions of kWh					
Net generation	10,034	10,514	10,592	13,570	13,981
Power purchased	7,640	7,023	6,438	4,236	3,521
Total Energy Available	17,674	17,537	17,030	17,806	17,502
System sales	16,010	15,824	15,440	15,813	15,853
Company use and unaccounted for	1,292	1,409	1,363	1,395	1,117
Total system energy requirements	17,302	17,233	16,803	17,208	16,970
Sales to other utilities	372	304	227	598	532
Total Energy Available	17,674	17,537	17,030	17,806	17,502
Peak Demand — MW					
Station coincident demand	3,253	2,931	2,975	3,085	3,260
Power purchased — net	629	1,036	636	819	426
System Peak Demand	3,882	3,967	3,611	3,904	3,686
System Capability — MW					
Company stations	4,063	4,063	4,091	4,078	4,077
Nine Mile Point 2 (18% share)	189	188	188	194	194
Firm purchases — net	616	548	432	423	408
Total Capability	4,868	4,799	4,711	4,695	4,679
Fuel Consumed for Electric Operations					
Oil — thousands of barrels	7,518	9,740	10,656	15,314	16,401
Gas — thousands of dth	44,308	36,269	34,475	32,924	36,477
Nuclear — thousands of MW days	183	181	124	154	108
Total — billions of Btu	91,669	98,025	102,126	129,937	139,874
Dollars per million Btu	$ 2.69	$ 2.79	$ 2.62	$ 2.61	$ 3.07
Cents per kWh of net generation	2.88¢	2.97¢	2.76¢	2.73¢	3.24¢
Heat rate — Btu per net kWh	10,740	10,628	10,558	10,484	10,564
Fuel Mix (Percentage of system requirements)					
Oil	25%	33%	37%	50%	56%
Gas	23	19	19	18	20
Purchased power	43	41	38	25	20
Nuclear fuel	9	7	6	7	4
Total	100%	100%	100%	100%	100%

Table 9

Gas Operations					
Energy — thousands of dth					
Natural gas	75,360	69,970	64,911	55,579	55,407
Manufactured gas and change in storage	191	(68)	48	60	(15)
Total Company Requirements	75,551	69,902	64,959	55,639	55,392
System sales	65,803	65,103	61,382	53,227	55,228
Off-system sales	7,232	2,894	—	—	—
Company use and unaccounted for	2,516	1,905	3,577	2,412	164
Total Company Requirements	75,551	69,902	64,959	55,639	55,392
Maximum Day Sendout — dth	585,227	485,896	448,726	435,050	406,177
System Capability — dth per day					
Natural gas	579,897	561,584	561,584	507,344	507,344
LNG manufactured or LP gas	125,700	120,700	120,700	128,200	128,200
Total Capability	705,597	682,284	682,284	635,544	635,544
Calendar Degree Days (30 year average 4,797)	4,839	4,899	5,066	4,378	4,139

Table 10 *(In thousands of dollars)*

Balance Sheet	1994	1993	1992	1991	1990
Assets					
Net utility plant	$ 3,498,346	$ 3,347,557	$ 3,161,148	$ 3,002,733	$ 2,888,079
Regulatory assets					
Base financial component	3,483,490	3,584,461	3,685,432	3,786,403	3,887,373
Rate moderation component	463,229	609,827	651,657	602,053	411,443
Shoreham post settlement costs	922,580	777,103	586,045	378,386	225,818
Shoreham nuclear fuel	73,371	75,497	77,629	79,760	92,069
Postretirement benefits other than pensions	412,727	402,921	—	—	—
Regulatory tax asset	1,831,689	1,848,998	—	—	—
Other	354,524	311,832	220,380	104,484	106,654
Total Regulatory Assets	7,541,610	7,610,639	5,221,143	4,951,086	4,723,357
Nonutility property and other investments	24,043	23,029	20,730	9,788	6,381
Current assets	851,424	924,859	916,914	884,017	726,060
Deferred charges	1,301,257	1,487,032	1,444,524	1,290,871	1,173,361
Total Assets	$13,216,680	$13,393,116	$10,764,459	$10,138,495	$ 9,517,238
Capitalization and Liabilities					
Long-term debt	$ 5,162,675	$ 4,887,733	$ 4,755,733	$ 5,001,016	$ 4,556,016
Unamortized discount on debt	(17,278)	(17,393)	(14,731)	(14,850)	(23,125)
	5,145,397	4,870,340	4,741,002	4,986,166	4,532,891
Preferred stock — redemption required	644,350	649,150	557,900	524,912	527,550
Preferred stock — no redemption required	63,957	64,038	154,276	154,371	154,674
Total Preferred Stock	708,307	713,188	712,176	679,283	682,224
Common stock	592,083	561,662	558,002	556,825	556,620
Premium on capital stock	1,101,240	1,010,283	998,089	993,509	992,885
Capital stock expense	(52,175)	(50,427)	(39,304)	(40,216)	(42,676)
Retained earnings	752,480	711,432	667,988	620,373	560,405
Total Common Shareowners' Equity	2,393,628	2,232,950	2,184,775	2,130,491	2,067,234
Total Capitalization	8,247,332	7,816,478	7,637,953	7,795,940	7,282,349
Regulatory Liabilities					
Regulatory liability component	357,117	436,476	515,835	595,194	674,554
1989 Settlement credits	145,868	155,081	164,294	173,507	182,720
Regulatory tax liability	111,218	114,748	—	—	—
Other	143,611	138,612	100,470	72,277	102,655
Total Regulatory Liabilities	757,814	844,917	780,599	840,978	959,929
Current liabilities	605,478	1,188,972	1,181,297	492,895	449,830
Deferred credits	3,102,434	3,109,593	1,147,310	1,001,375	816,790
Operating reserves	503,622	433,156	17,300	7,307	8,340
Total Capitalization and Liabilities	$13,216,680	$13,393,116	$10,764,459	$10,138,495	$ 9,517,238

Table 11 *(In thousands of dollars)*

Construction Expenditures*					
Electric	$ 136,041	$ 137,583	$ 141,752	$ 129,643	$ 141,028
Gas	120,019	124,859	104,028	89,950	78,766
Common	23,610	42,251	27,124	17,958	12,671
Total Construction Expenditures	$ 279,670	$ 304,693	$ 272,904	$ 237,551	$ 232,465

**Includes non-cash allowance for other funds used during construction.*

Executive Offices
175 East Old Country Road
Hicksville, New York 11801
516-755-6650

Common Stock Listed
New York Stock Exchange
Pacific Stock Exchange

Ticker Symbol: LIL

Transfer Agent and Registrar
Common Stock and Preferred Stock
The Bank of New York
Shareholder Services Department
Church Street Station
P.O. Box 11277
New York, NY 10286-1612
1-800-524-4458

Shareowners' Agent for Automatic
Dividend Reinvestment Plan
The Bank of New York
Dividend Reinvestment Department
Church Street Station
P.O. Box 11277
New York, NY 10286-1612
1-800-524-4458

Dividend Reinvestment
Common stock shareowners who wish to acquire additional shares free of brokerage commissions or service charges are invited to join the Company's Automatic Dividend Reinvestment Plan. Under the plan, shareowners authorize the Company's transfer agent to purchase shares of the Company's common stock with their cash dividends. Shareowners may also participate in the plan by making optional cash payments, even if they decide not to reinvest their dividends. For further information, contact our transfer agent.

Dividend Direct Deposit
Shareowners can elect to have their quarterly cash dividends electronically deposited into their personal bank accounts. Deposits are made on the date the dividend is payable. If you would like to take advantage of this service, contact our transfer agent.

Annual Meeting
The Annual Meeting of Shareowners will be held on Wednesday, May 24, 1995 at 3:00 p.m. In connection with this meeting, proxies will be solicited by the Company.

Common Stock Prices and Dividends
The common stock of the Company is traded on the New York Stock Exchange and the Pacific Stock Exchange. Certain of the Company's preferred stock series are traded on the New York Stock Exchange. The quoted market prices and the dividends declared for the Company's common stock for the years 1994 and 1993 were as follows:

Quarter	*1994*			*1993*		
	High	*Low*	*Dividend*	*High*	*Low*	*Dividend*
First	$24¼	$21½	$.445	$28¾	$24⅞	$.435
Second	22⅞	17½	.445	28¼	24¾	.435
Third	19⅜	15	.445	29⅝	27	.445
Fourth	18⅛	15¼	.445	27¾	23¼	.445

Form 10-K Annual Report
The Company will furnish, without charge, a copy of the Company's Annual Report, Form 10-K, as filed with the Securities and Exchange Commission, upon written request to:

Investor Relations
Long Island Lighting Company
175 East Old Country Road
Hicksville, New York 11801

Our Investor Relations Department is available from 8:00 a.m. to 5:00 p.m., Monday through Friday to answer any questions you may have about your LILCO stock. If you have a question, please call us at 516-545-4914.

Duplicate Mailings
Shareowners with more than one account generally receive duplicate mailings of annual and other reports. To eliminate additional mailings, write to our transfer agent. Enclose labels or label information, where possible. Separate dividend checks and proxy material will continue to be sent for each account of record.

LILCO uses recycled paper to help conserve our natural resources.

DIRECTORS

William J. Catacosinos
Chairman of the Board,
President and
Chief Executive Officer
Long Island Lighting Company

A. James Barnes
Dean
School of Public and
Environmental Affairs
Indiana University

George Bugliarello
Chancellor
Polytechnic University

Renso L. Caporali
Former Chairman of the Board
and Chief Executive Officer
Grumman Corporation

Peter O. Crisp
President
Venrock, Inc.
Venture Capital Investments

Vicki L. Fuller
Senior Vice President
Emerging Markets
and High Yield
Alliance Capital Management
Corporation

Katherine D. Ortega
Former Treasurer
of the United States

Basil A. Paterson
Partner
Meyer, Suozzi, English
& Klein, PC
Law

Richard L. Schmalensee
Director
Center for Energy and
Environmental Policy Research
Massachusetts Institute
of Technology

George J. Sideris
Retired Senior Vice President
Finance
Long Island Lighting Company

John H. Talmage
Partner
H.R. Talmage & Son
Agriculture

Phyllis S. Vineyard
Representative to
Non-Governmental
Organization of
the United Nations

OFFICERS

William J. Catacosinos
Chairman of the Board,
President and
Chief Executive Officer

James T. Flynn
Executive Vice President
and Chief Operating Officer

Arthur C. Marquardt
Senior Vice President
Gas Business Unit

Anthony Nozzolillo
Senior Vice President Finance
and Chief Financial Officer

Edward J. Youngling
Senior Vice President
Electric Business Unit

Robert X. Kelleher
Vice President
Human Resources

John D. Leonard, Jr.
Vice President
Engineering and
Construction

Adam M. Madsen
Vice President
Corporate and
Strategic Planning

Kathleen A. Marion
Vice President
Corporate Services
and Corporate Secretary

Brian R. McCaffrey
Vice President
Administration

Joseph W. McDonnell
Vice President
External Affairs

Richard Reichler
Vice President
Tax and Benefits Planning
and Deputy General Counsel

William G. Schiffmacher
Vice President
Customer Relations

Robert B. Steger
Vice President
Electric Operations

William E. Steiger, Jr.
Vice President
Fossil Production

Leonard P. Novello
General Counsel

Theodore A. Babcock
Treasurer

Joseph E. Fontana
Controller

Herbert M. Leiman
Assistant General Counsel
and Assistant Corporate
Secretary