Long Island Lighting Company
1991 Annual Report

A Partnership
With
Long Island

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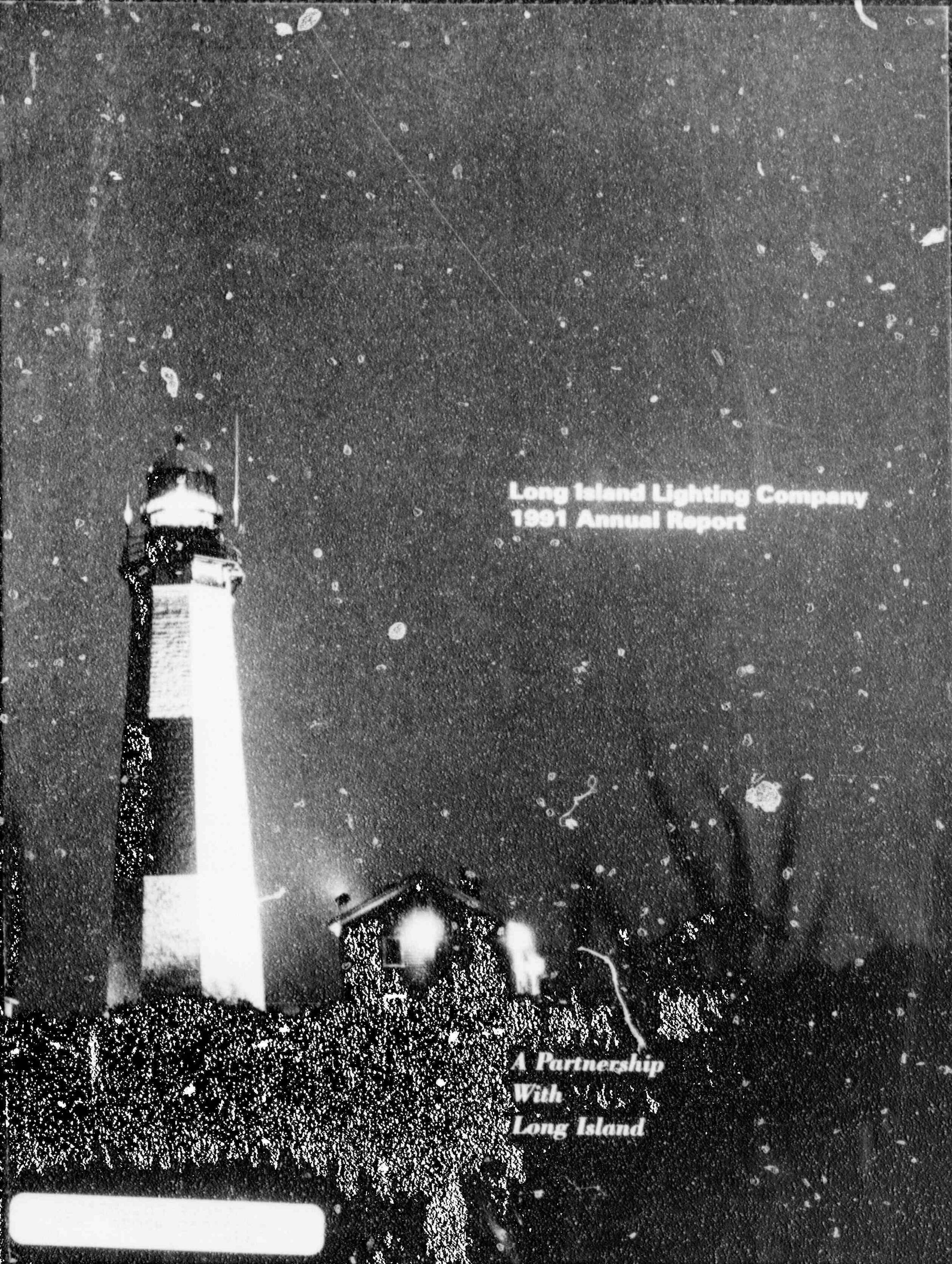
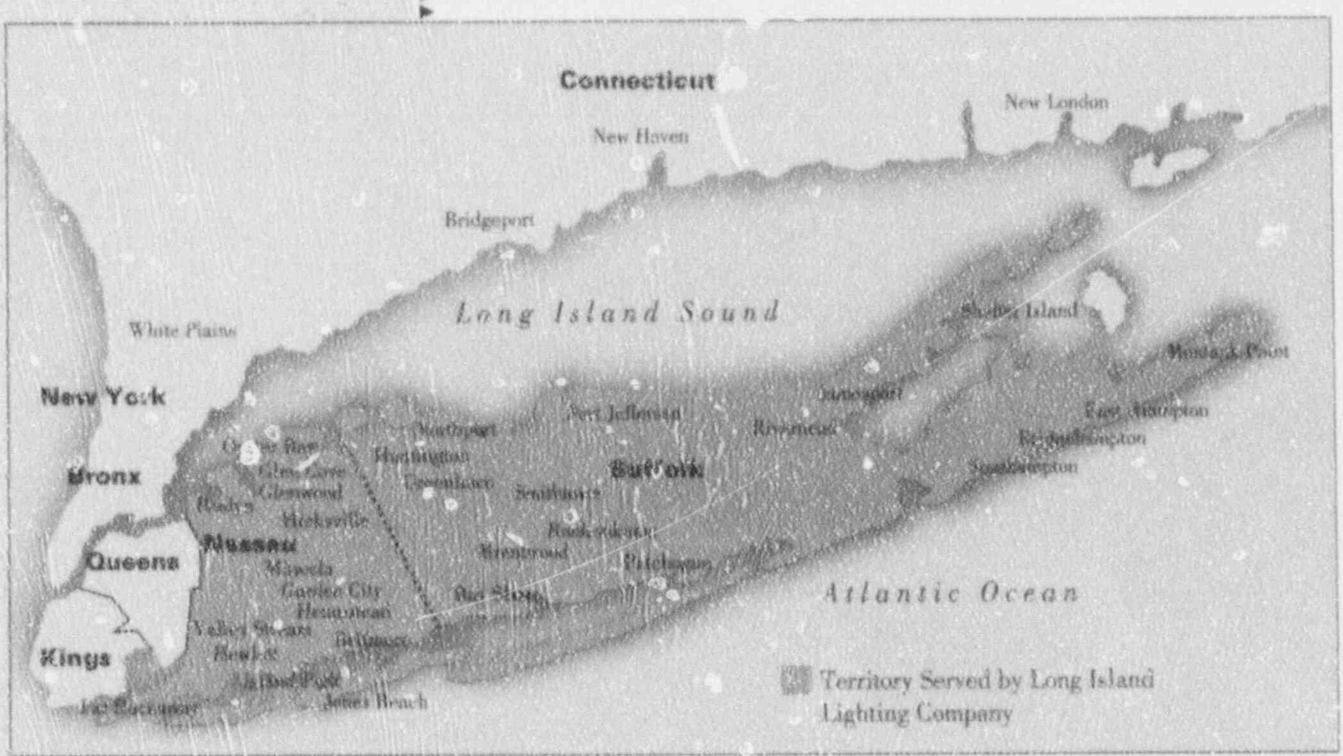


A Partnership With Long Island

The Long Island Lighting Company's 6,600 employees provide electric and gas service to 1 million customers in Nassau and Suffolk Counties and the Rockaway Peninsula in Queens County.

LILCO's service territory covers 1,230 square miles with a population of approximately 2.7 million people.



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On the cover: Commissioned by President George Washington in 1795, the Montauk Lighthouse is one of Long Island's most recognizable landmarks.

Photo right: Long Island's Suffolk County boasts a thriving agricultural industry with 35,000 acres of farmland producing $115 million in products each year.

To Our Shareowners,

LILCO's financial health continued to improve in 1991. Earnings for the year were $239 million or $2.15 per common share, and we increased our quarterly common stock dividend by 13 percent to 42.5 cents per share, effective October 1, 1991.

The PSC granted the Company electric rate increases of approximately four percent for each of the next three years, a sign that the Commission is fulfilling its obligation under the 1989 Shoreham settlement. The PSC also authorized a one-year gas rate increase of 4.1 percent. As a result, the Company's first mortgage and general and refunding bonds were once again upgraded by investment-rating agencies, allowing us to borrow money at lower interest rates.

We entered 1991 with the country perched at the brink of the Persian Gulf War, engendering an escalated concern over our nation's dependence on foreign oil. LILCO responded to that concern with aggressive sales of natural gas and a comprehensive conservation campaign.

Natural Gas Business Over the past two years, we installed gas heat in more than 20,000 homes and businesses on Long Island as we successfully market our product and expand our pipelines into new neighborhoods. On Long Island, 3 out of every 4 homes heat with oil which presents us with an opportunity to convert many homes to natural gas heat.

With the completion of the Iroquois pipeline which is now transporting gas from Canada to Long Island and a proposed new pipeline from New Jersey to Long Island scheduled to be completed in 1994, we will have sufficient gas supplies to take advantage of the demand for natural gas. We are poised to expand the gas business throughout the 90s.

Conservation Business The New York Public Service Commission (PSC) has provided utilities with financial incentives to promote energy conservation. LILCO has implemented one of the most comprehensive conservation programs in the country. Our many conservation programs provide our customers with opportunities to control their energy costs and preserve the environment. Along with our gas business, we view conservation as a growth business unit within the Company.

Electric Business As Long Island lifestyles become more and more dependent on electric appliances, customers are increasingly looking to us to provide their homes and businesses with an uninterrupted flow of electricity. We have responded with a comprehensive reliability program — trimming more trees away from power lines and installing more sophisticated equipment — which is having good results, despite the many storms that affect the Company's more than 50,000 miles of overhead lines.

Last summer, the Company received high marks from government officials and our customers for the quick response in restoring power following the damage caused by Hurricane Bob. The hurricane's 90-mile an hour winds uprooted trees, snapped utility poles and tore down power lines, wreaking havoc with the electric system. Our employees did a superb job in getting power back to our customers.

Creating Partnerships LILCO has taken a leadership position in helping to attract new businesses and more jobs to the community. As a member of the Long Island Partnership, LILCO is taking the lead in developing an economic development program to attract new businesses to the island. In addition, LILCO received PSC approval of a new rate design which offers attractive electric rates to companies relocating or expanding on Long Island.

In February 1991, we introduced the Long Island Energy Research and Development Initiative, a partnership between LILCO and Long Island's academic and research institutions designed to encourage energy research. The initiative allows the Company to take advantage of the research talents on Long Island to improve its operations.

Service First As 1991 drew to a close, we witnessed the end of the cold war with the extraordinary break-up of the Soviet Union. At LILCO, we also sought a new organizational structure, which would empower our employees to assume responsibility for the profitability of the Company and provide better service to our customers.

We selected an organizational structure to complement our very successful Service First program, which aims at providing our customers with unparalleled service. We are making great strides in becoming a premier service organization as our employees display genuine care in serving our customers.

On behalf of LILCO's Board of Directors and Officers, I extend my sincere thanks for your support in 1991. We are maki[illegible]at strides in our quest to provide unparalleled s[illegible]e; yet there is still much to accomplish. With the hard work and commitment to excellence that has been demonstrated by LILCO employees, we will continue on the steady track towards service excellence.

Sincerely,

W. J. Catacosinos

William J. Catacosinos
Chairman and Chief Executive Officer

William J. Catacosinos
Chairman and Chief Executive Officer

"Economic development projects benefit the community by broadening the tax base and increasing jobs in the region."
— *LILCO President Anthony Earley*

A Partnership With Long Island

Creating Partnerships

LILCO has set out to become a customer-driven organization, providing unparalleled service to our customers. We have improved service to customers by responding courteously to customer inquiries, reducing electric service interruptions, responding quickly to electric and gas service requests, and meeting commitment dates on new service installations.

In 1991, we extended our service goal a step further by taking a leadership role in the Long Island community. In February 1991, LILCO created the Long Island Energy Research and Development Initiative. The Initiative supports research on energy-related issues, using Long Island's considerable technological talent to improve methods of producing and distributing electricity, natural gas and conservation services.

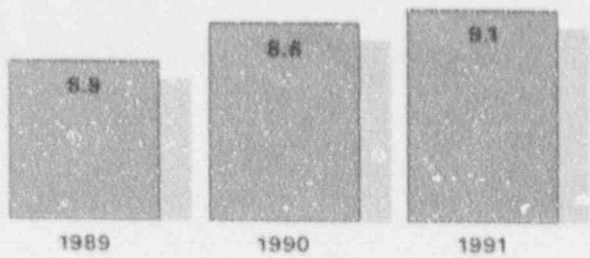
In May, we introduced an economic development program designed to attract new businesses to Long Island and to encourage businesses already on the Island to expand. The program urges environmentally sensitive growth by combining electric rate incentives with energy-efficiency requirements.

Explains LILCO President Anthony Earley, "Economic development projects benefit the community by broadening the tax base, increasing jobs in the region, and holding down the electric rates."

Photo right: Long Island's rapidly growing McArthur Airport handles both commuter and jet service daily.

Average Time Between Customer Interruptions

in months



A Partnership With Long Island

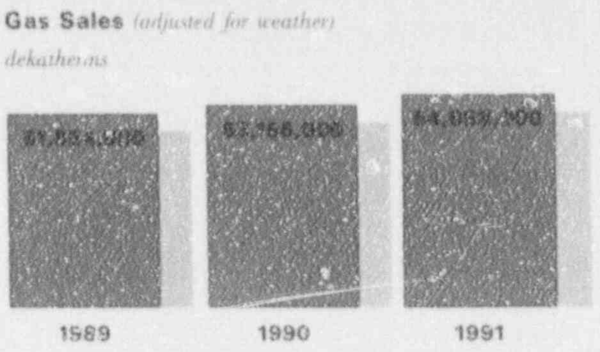
Electric Operations

LILCO significantly improved its electric reliability in 1991, a key element in customer satisfaction. The Company reduced the frequency of electric outages by extensively trimming trees and upgrading equipment throughout the electric distribution system. We also enhanced reliability with new transmission lines; one across Shelter Island provides a continuous loop of electric power between the North and South forks, and another provides a second link with the State's electric grid by connecting Nassau and Westchester Counties.

The Company is improving response to the day-to-day service requests of our customers as we begin to install computers in our service trucks, allowing us to dispatch job information directly to our field workers. We are also developing a new computerized system for scheduling service appointments, which lets us accurately schedule electric service calls so that our customers know exactly what time a LILCO representative will arrive at their home.

As part of the Company's multi-year capital improvement plan, major equipment overhauls and upgrades were conducted at LILCO's Northport, E.F. Barrett and Glenwood generating facilities. The result of these power plant improvements was a Company-wide system availability of 87.1 percent for the year, a LILCO record.

Photo left: EAB Plaza in Uniondale is one of the Island's most well-known office complexes.



A Partnership With Long Island

Gas Operations

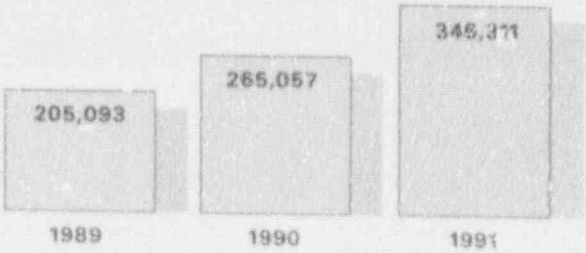
Skyrocketing oil prices due to the Middle East crisis caused many Long Islanders to convert to natural gas heat in late 1990. But even after the war, when oil prices fell and fierce competition from a coalition of Long Island oil heat companies increased, we installed more than 10,000 new gas heat customers, a good sign for future gas expansion.

LILCO's marketing efforts concentrated on natural gas as a price-stable, clean-burning fuel — the smarter fuel choice for our customers, both economically and environmentally. By combining its superior product with its superb service organization, LILCO offers customers an attractive alternative to oil heat. In 1991, LILCO developed a new Full-Service Gas Conversion program to make the conversion process hassle-free for customers. By handling all the necessary details, from arranging financing to supplying a contractor, we offer customers a "one-stop shopping" approach. Initiated as a pilot program in September, the program has received enthusiastic response from our customers, and LILCO expects to expand the program Island-wide in 1992.

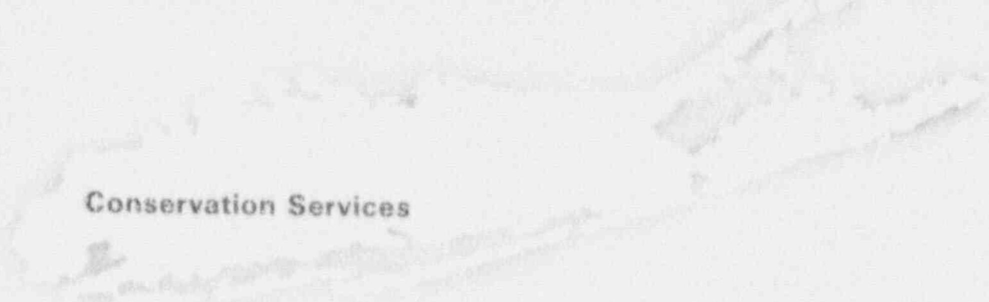
The Company's aggressive approach to natural gas sales also included an expanded Gas Main Extension program, bringing more than 140,000 feet of new gas mains into communities that previously did not have access to natural gas supplies.

Photo right: Entenmann's Bakery lowered operating costs by converting their ovens to natural gas.

Conservation Customer Contacts



A Partnership With Long Island



Conservation Services

Successful energy conservation programs provide options for our customers to help them lower their energy bills, while helping LILCO meet the community's energy needs. More than 20 percent of our customers took advantage of the Company's energy conservation programs in 1991, saving an estimated 209 megawatts, or enough power to supply more than 100,000 homes.

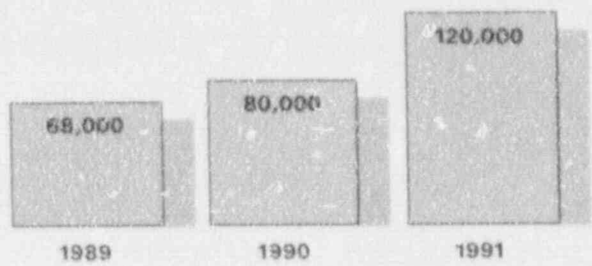
Last year, LILCO's new lighting rebate program offered customers the opportunity to purchase screw-in fluorescent bulbs directly from LILCO and receive a $6 rebate on every bulb ordered. Long Islanders purchased more than 60,000 bulbs from LILCO in 1991.

The Company also introduced an energy-efficient refrigerator rebate program, offered in conjunction with local retail appliance dealers and the New York State Energy Office. The program, implemented in July, gave customers up to $120 in rebates for purchasing energy-efficient refrigerators. By the end of the year, more than 3,700 customers had received rebates.

Conservation options for commercial and industrial customers were expanded as well, with rebates available for additional technologies and customized energy-efficient systems. Programs were designed to help businesses, new construction projects, and not-for-profit organizations make their facilities as energy-efficient as possible. The Company also created specialized workshops for Long Island's school administrators, helping them choose energy conservation measures to lower operating costs and ease tight school budgets.

Photo left: Energy specialist Karen Busweiler advises customer Ruby Vitelli about efficient insulation.

Golden Link Memberships



Customer Outreach

An important part of providing unparalleled service to our customers is creating and supporting community outreach programs. LILCO has put in place special programs for seniors, educators, youth and low-income customers.

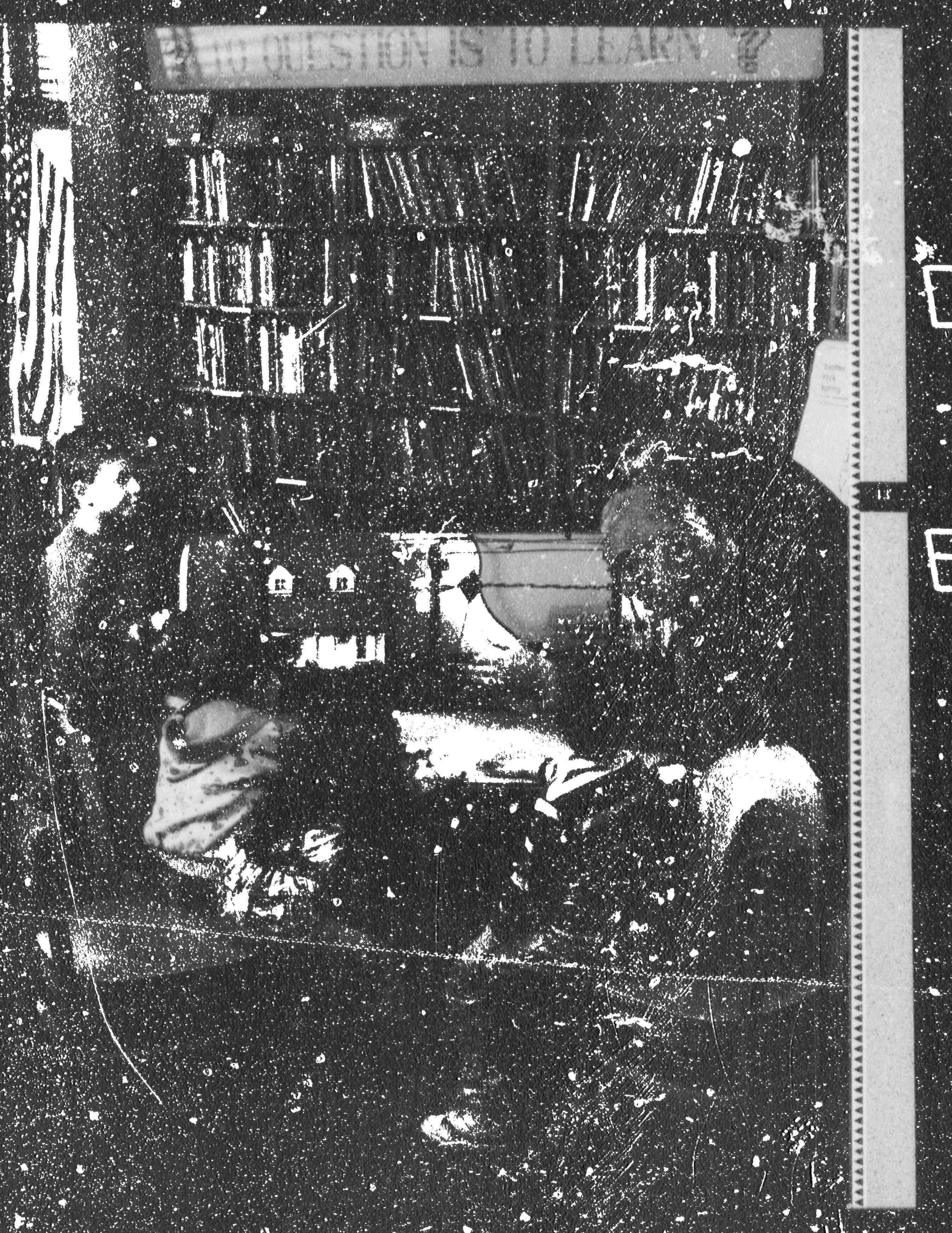
For senior citizens, the Company offers Golden Link, a program designed to provide seniors with information on energy issues, community resources, and health news. In 1991, Golden Link membership increased by 50 percent to 120,000 members.

To assist Long Island educators, LILCO spearheaded a special project to develop environmental curricular materials specific to Long Island. With the State University at Stony Brook and 26 local secondary school teachers, the Company produced materials on topics such as energy conservation, recycling and solid waste management for Long Island schools.

For Long Island's youth, the Company initiated many programs, including the LILCO Scout Academy, where more than 600 scouts learned about energy, safety and environmental issues. Participation in the Scout Academy assists these youngsters in attaining an energy merit badge.

The national recession has troubled many Long Island families, and LILCO has responded to customers in financial crisis by providing trained social workers to help families receive support services. In addition, our successful "Energy Packager" weatherization program provides energy conservation assistance to low-income families to help them reduce their energy bills.

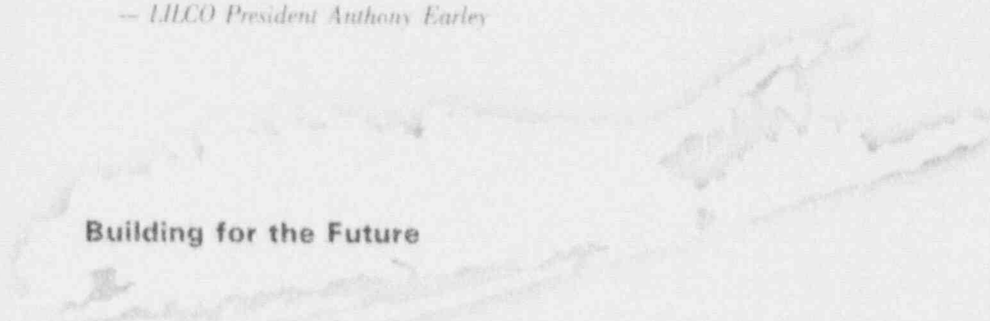
Photo right: Youngsters at Santapogue Elementary get a lesson in electric safety from LILCO retiree, Enrico Scena.



QUESTION IS TO LEARN

"We are working toward a model that will help us better serve our customers."
— *LILCO President Anthony Earley*

A Partnership With Long Island



Building for the Future

In 1992, LILCO will continue to create and implement new programs to bring the Company closer to achieving its goal of unparalleled customer service. The Company will begin to implement a major Company reorganization plan, designed to further our goal of becoming a service-driven organization.

In the reorganization, the Company will consolidate activities into three distinct business units — Electric, Gas and Conservation — with support services assigned specifically to each unit. The reorganization will also decentralize the gas and electric businesses into geographic regions to bring decision-making closer to the customer. A "one-stop shopping" feature will be established for customers conducting business with LILCO, enabling them to complete all transactions through a single point of contact. Implementation of the reorganization will be done in phases and is expected to take up to three years to complete.

LILCO employees played an integral role in the reorganization process. Representatives from various areas of the Company initially studied the new organizational structure and meetings were held to solicit feedback from all management employees.

"We are working towards a model that will improve information flow, facilitate decision-making, more clearly define accountability, and integrate many company functions into the business units themselves," said LILCO President Anthony Earley. "It is a major undertaking that will help us better serve our customers."

Photo left: Beautiful beaches on Long Island provide recreation — and a chance to build castles — to millions.

Financial Review

Overview

The year 1991 was another year of continued improvement in the Company's financial health. This improvement is evidenced, in part, by the elevation by certain rating agencies in 1991 of the Company's First Mortgage Bonds and General and Refunding Bonds (G&R Bonds) from minimum investment grade to one notch above and the elevation of the Company's unsecured debt by one notch to minimum investment grade. In addition, one rating agency upgraded the Company's preferred stock to minimum investment grade. This is the second time in the past two years that the investment ratings of the Company's securities have been upgraded.

Other significant events in 1991 included:

- Approval, by the New York State Public Service Commission (PSC), of a three-year rate plan granting the Company annual electric rate increases of 4.15%, 4.1% and 4.0%, respectively, beginning December 1, 1991.
- An increase in gas rates of 4.1% effective December 1, 1991.
- An increase in the Company's common stock quarterly dividend from 37½ cents per quarter to 42½ cents per quarter.

  Earnings for common stock for 1991 were $2.15 per common share compared to $2.26 per common share for 1990.
- Refinancing of approximately $1.2 billion of high-cost securities which significantly lowered the Company's cost of debt and preferred stock.
- Issuance of $100 million of low-cost tax-exempt securities resulting in substantial savings for the Company's ratepayers because these securities carry significantly lower interest rates than taxable bonds.
- Completion of the Iroquois Gas Transmission System, increasing the reliability of the Company's gas supply and enabling it to provide natural gas to an additional 40,000 homes.
- The addition of more than 10,000 new gas heating installations, 34% of which were residential conversions.
- Receipt of a possession-only license from the Nuclear Regulatory Commission (NRC) which will pave the way for the transfer of the Shoreham Nuclear Power Station (Shoreham) to an agency of the State of New York.

The financial viability of the Company had been jeopardized in the recent past by the controversy concerning Shoreham and the federal Racketeer Influenced and Corrupt Organizations Act (RICO Act) litigation. The 1989 Settlement was designed to eliminate the controversy over Shoreham by providing for the transfer of Shoreham to an agency of the State, reciting the intention to return the Company to investment grade financial condition, authorizing fixed rate increases of 5.4% and 5.0% in 1989 and 5.0% in 1990, and targeting annual rate increases of 4.5% to 5.0% in each year thereafter through 1998 based upon assumptions as originally set forth in the 1989 Settlement. The Company's financial recovery began in 1989 following the 1989 Settlement and a class action settlement (Class Settlement) entered into between the Company and its ratepayers to resolve the RICO Act litigation. During 1990, the financial recovery of the Company continued as evidenced by the Company increasing the common stock quarterly dividend from 25 cents per quarter to 37½ cents per quarter. The Company also utilized $100 million of tax-exempt securities in 1990.

Liquidity and Capital Resources

Cash and Revolving Credit

At December 31, 1991, the Company's cash and cash equivalents amounted to approximately $298 million compared to $103 million at December 31, 1990.

In addition, the Company has an estimated $114 million available under a revolving line of credit through October 1, 1992, provided by its 1989 Revolving Credit Agreement (1989 RCA). For additional information respecting the 1989 RCA, see Note 7 of Notes to Financial Statements.

Rate Matters

In response to the Company's rate filing in December 1990, the PSC approved the Long Island Lighting Company Ratemaking and Performance Plan (LRPP) which provides for annual electric rate increases, before giving effect to the Class Settlement discussed in Note 4 of Notes to Financial Statements, of 4.15%, 4.1% and 4.0% effective December 1, 1991, 1992 and 1993, respectively. The LRPP is designed to be consistent with the long-term goals of the 1989 Settlement. One principle objective of the LRPP is to reassign risk so that the Company assumes the responsibility for risks within the control of management. Risks largely beyond the control of management are assumed by the ratepayers.

The LRPP provides for an 11.6% return on common equity for the three years commencing December 1, 1991. Under the LRPP, the Company is allowed to earn up to 60 additional basis points or forfeit up to 38 basis points of the return on common equity as a result of its performance within certain incentive and/or penalty programs. These programs consist of a customer service performance plan, a demand side management program, a fuel-cost adjustment (FCA) incentive plan and a time-of-use program. The LRPP contains a mechanism whereby earnings in excess of the allowed rate of return on common equity, excluding the impacts of the various incentive/penalty programs, will be shared equally between ratepayers and shareowners.

In conjunction with the 1989 Settlement, the PSC authorized the Company, in 1989, to record on its books a Financial Resource Asset (FRA). The FRA consists of two components, the Base Financial Component (BFC) and the Rate Moderation Component (RMC). The Rate Moderation Agreement (RMA), one of the constituent documents of the 1989 Settlement, provides that the Company amortize the BFC over a forty-year period, through rates, beginning July 1, 1989, and permits a full return on the unamortized balance. The BFC, as initially established, represents the present value of the future net-after-tax cash flows provided to the Company for its financial recovery. 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 in the RMA. The RMC is initially deferred but is designed to be fully recovered over a ten-year period with a full return on the unamortized balance. The RMA is designed to hold electric rate increases to the levels provided for in the 1989 Settlement, subject to adjustments provided therein.

The rate structure under the 1989 Settlement, as reflected in the LRPP, is intended to provide the Company with adequate and timely rate relief which, when coupled with access to the capital markets, will enable the Company to meet its operating and capital requirements.

In November 1991, the PSC issued a rate order granting a gas rate increase of 4.1% which became effective on December 1, 1991. The gas rate increase reflects costs related to expected levels of capital expenditures, operations and maintenance expenses and the Company's gas expansion program. The gas rate order contains a weather normalization clause which moderates the impact of variations in temperature on gas revenues.

On December 31, 1991, the Company filed a request with the PSC to increase its gas rates effective December 1, 1992, by 5.8% or $30 million in additional revenues. Although the Company calculated that an increase of 9.8%, or $51 million, is warranted, the Company proposes to collect only 5.8% in the rate year and defer the balance of the request for recovery in later years. This filing reflects the Company's latest projections of capital expenditures, operations and maintenance expenses and continued expansion of its gas business.

For a further discussion of the 1989 Settlement and Rate Matters, see Notes 2 and 3 of Notes to Financial Statements.

Financing Program

During the period 1992 to 1995, the Company estimates that it will be required to seek external financing of approximately $1.8 billion. Although a portion of this financing will be used to meet its operating and capital requirements, most will be used to refund maturing debt. In addition, the Company intends, when market conditions permit, to refinance higher-cost debt and preferred stock.

The Company refinanced approximately $1.2 billion of higher-cost debt and preferred stock in 1991 as follows:

- The Company issued $250 million of 8¾% G&R Bonds in February, the proceeds of which were used in March to redeem, at the applicable regular redemption price, $225 million of G&R Bonds, 13¼% Series Due 1995.
- The Company issued a total of $830 million of 8¾% and 9¾% G&R Bonds in May, the proceeds of which were used in June to redeem, at their applicable regular redemption prices, $525 million aggregate amount of higher-cost G&R Bonds. The balance of the net proceeds were used to reimburse the Company's treasury for previously incurred capital expenditures and to provide working capital.
- The Company also issued $65 million of Preferred Stock, $2.35, Series Z, in May, the proceeds of which were used in June to redeem, at its applicable optional redemption price, $50 million par value of Preferred Stock, $3.31, Series T.
- The Company issued $375 million of 9⅝% G&R Bonds in August, the proceeds of which were used to redeem, at its applicable regular redemption price, $350 million Debentures, 11.50% Series Due 2014.

In addition, the Company utilized $100 million of tax-exempt securities in January 1991 to reimburse the Company's treasury for previously incurred capital expenditures.

Consistent with the Company's aggressive refinancing strategy to further reduce interest cost to the Company's ratepayers, the Company utilized $100 million of tax-exempt securities in February 1992 to reimburse the Company's treasury for previously incurred capital expenditures. In addition, the Company intends, if market conditions permit, during 1992, to refund higher-cost debt and preferred stock.

The Company will also seek permission to utilize the proceeds from the sale of an additional $100 million of tax-exempt securities which would be sold later in 1992. The proceeds would be applied to reimburse the Company's treasury for previously incurred capital expenditures.

The 1989 Settlement committed New York State to support an allocation to the Company of at least $500 million of New York State private activity bond volume cap (at a minimum of $100 million per year) to permit the sale of tax-exempt securities for the Company's benefit. After the issuance of $100 million of tax-exempt securities in February 1992, the Company has at least $200 million of this volume cap remaining.

Capital Requirements and Capital Provided

Capital requirements and capital provided for 1991 and 1990 were as follows:

Capital Requirements *(In millions of dollars)*	1991	1990
Construction		
Electric	$ 137	$ 138
Gas	90	79
Common	18	13
Total Construction	235	230
Refundings and Dividends		
Long-Term Debt	1,129	82
Preferred Stock	71	14
Preferred Stock Dividends	66	68
Common Stock Dividends	173	125
Total Refundings and Dividends	1,439	289
Subtotal	1,674	519
Shoreham Post Settlement Costs	158	153
Total Capital Requirements	$ 1,832	$ 672

Capital Provided *(In millions of dollars)*	1991	1990
(Increase) Decrease in Cash	$ (195)	$ 237
Long-Term Debt	1,532	112
Preferred Stock	63	—
Financing Costs	(88)	2
Internal Cash Generation from Operations	520	321
Total Capital Provided	$ 1,832	$ 672

For further information, see the Statement of Cash Flows.

For 1992, total capital requirements (excluding common stock dividends) are estimated at $608 million, of which construction requirements are estimated to be $316 million, mandatory refundings are $10 million, preferred stock sinking fund requirements are $11 million, preferred stock dividends are $64 million, and Shoreham post-settlement costs are estimated at approximately $207 million.

Investment Rating

The Company's securities are rated by Moody's Investors Service, Inc. (Moody's), Standard and Poor's Corporation (S&P), Fitch Investors Service, Inc. (Fitch) and Duff and Phelps (D&P).

The 1989 Settlement was intended to improve the Company's credit ratings. In 1989, the rating agencies significantly upgraded their ratings on each of the Company's principal securities. In 1990, the four major independent rating agencies upgraded the Company's First Mortgage Bonds and G&R Bonds to minimum investment grade. In 1991, the Company's Debentures were similarly upgraded to minimum investment grade by two of these agencies which also upgraded the Company's First Mortgage Bonds and G&R Bonds one level.

The chart below indicates the ratings for each of the Company's principal securities at December 31, 1991, and the minimum investment grade ratings used by each agency.

	Moody's	S&P	Fitch	D&P
First Mortgage Bonds	Baa2	BBB–	BBB–	BBB
G&R Bonds	Baa2	BBB–	BBB–	BBB
Debentures	Baa3	BB+	BB+	BBB–
Preferred Stock	baa3	BB+	BB	BB+
Minimum Investment Grade	**Baa3**	**BBB–**	**BBB–**	**BBB–**

Capitalization

The Company's capitalization (defined as the total of long-term debt, preferred stock and common shareowners' equity) at December 31, 1991, was approximately $7.8 billion, as compared to $7.3 billion at December 31, 1990. This increase in capitalization of approximately $492 million reflects an increase in long-term debt associated with the Company's financing activities in 1991 and an increase in common shareowners' equity comprising 1991 net income of approximately $306 million offset by $245 million of common and preferred stock dividends.

At December 31, 1990, capitalization increased by approximately $134 million from the December 31, 1989, balance of $7.2 billion. This increase in capitalization primarily reflects an increase in common shareowners' equity comprising 1990 net income of $331 million offset by $207 million of common and preferred stock dividends.

At December 31, 1991, 1990 and 1989, the components of the Company's capitalization ratios were as follows:

Capitalization Ratios	1991	1990	1989
Long-Term Debt	63.9%	62.3%	63.1%
Preferred Stock	8.8	9.5	9.9
Common Shareowners' Equity	27.3	28.2	27.0
	100.0%	100.0%	100.0%

Other Items

Tax Matters

The Internal Revenue Service has confirmed the Company's entitlement to the Shoreham abandonment loss deduction which the Company claimed on its 1989 federal income tax return. Principally, as a result of this deduction, the Company, at December 31, 1991, had a net operating loss (NOL) carryforward of approximately $2.2 billion. Accordingly, for 1991, the Company's payments for federal income taxes were minimal. The Company estimates that the balance of the NOL carryforward will be fully utilized to reduce federal income tax payments within the 15-year statutory carryforward period.

Electric Competition, Conservation and Supply

The Company is presently experiencing competition from cogeneration and small independent power production projects. These projects supply electric energy to existing or new industrial and commercial customers and excess electricity is sold to the Company pursuant to the purchase requirements of the Public Utility Regulatory Policy Act of 1978 (PURPA). The Company is unable to predict whether the volume of electric customers gaining access to non-Company sources will be significant in the future.

During 1991, the Company sponsored various PSC approved energy efficient and peak load reduction programs. The Company estimates these programs reduced annual electric usage by approximately 309,000 megawatt hours and reduced peak electricity demand by approximately 210 megawatts in 1991. Due to the success of these programs, the Company collected, through rates, approximately $5 million of revenue incentives during 1991.

The Company's current electric load forecasts indicate that, with continued implementation of its aggressive conservation and load management programs and with electricity provided by independent power producers anticipated to come on line, the Company's existing generating facilities and contracts for purchased power are adequate to meet the energy demands on Long Island to the end of the century.

Gas Competition

In 1987, the Federal Energy Regulatory Commission (FERC) issued an order allowing gas pipeline companies and producers access to certain of the Company's customers for the purpose of supplying competing gas service. As of December 31, 1991, approximately 100 of the Company's former large gas customers were purchasing gas directly from gas pipeline companies and producers and arranging for its transportation through the Company's gas mains. The Company receives a fee for this transportation service which accounted for approximately 3% of total gas revenues for 1991.

Clean Air Act

In late 1990, significant amendments to the federal Clean Air Act were adopted. A number of electric utilities anticipate substantial increases in operating costs and capital expenditures as a result of the amendments. The Company does not expect to incur any costs to satisfy these recent amendments with respect to the reduction of sulfur dioxide emissions, since the Company already uses fuel with acceptable levels of sulfur. However, the Company expects that it will incur costs for additional continuous emission monitoring (CEM) requirements and for future nitrogen oxide reduction requirements that may be imposed under federal or state regulations. The Company estimates that the cost of installing CEM and nitrogen oxide control equipment, which the Company will seek to recover through rates, will be approximately $15 million and $100 million, respectively.

Business Units

In 1992, the Company will continue to enhance its organizational structure through a corporate reorganization designed to consolidate activities into three separate and distinct business units — Electric Operations, Gas Operations and Conservation Services.

Results of Operations

Earnings

For 1991, earnings for common stock were approximately $239 million, or $2.15 per common share. Earnings for common stock for 1990 were approximately $251 million, or $2.26 per common share, excluding the effect in 1990 of the accounting change for unbilled gas revenues discussed below. The decrease of approximately $12 million, or 11 cents per share, compared with 1990 was primarily attributable to increases in non-fuel operation and maintenance expenses, operating taxes and depreciation expense, partially offset by higher electric revenues.

Earnings for common stock reflected the positive effects of the 1989 Settlement for the entire year. Earnings for common stock in 1990 also reflected a change in the Company's method of recognizing gas revenues. Effective January 1, 1990, the Company's revenues include estimated consumption of gas delivered to customers, but not yet billed at month-end, resulting in the full accrual of all unbilled gas revenues. The cumulative effect of this accounting change increased 1990 earnings by nearly $12 million, net of tax effects, or 10 cents per common share. Excluding this item, earnings for common stock in 1990 would have been approximately $251 million, or $2.26 per common share. This would have been an increase of 34 cents per share over 1989, excluding the 1989 non-cash charges to net income attributable to the 1989 Settlement, the Class Settlement and the Nine Mile Point Nuclear Power Station, Unit 2 (NMP2) disallowance.

In 1989, the Company incurred a loss for common stock of approximately $175 million, or $1.57 per common share that resulted from recording non-cash charges to net income attributable to the 1989 Settlement and the Class Settlement.

Under the 1989 Settlement, the Company recorded on its books the establishment of the FRA and the write-off of its investment in Shoreham (and other related assets). The net loss resulting from the write-off and the reduction of net income resulting from the cessation of the allowance for funds used during construction (AFC) accruing on Shoreham, which mitigated such write-off, totaled approximately $269 million, net of tax effects, or $2.41 per common share. Upon the effectiveness of the Class Settlement, the Company recorded a charge to income of approximately $113 million, net of tax effects, or $1.02 per common share, which represented the present value at June 30, 1989 of the total amount of the Class Settlement.

Also, the Company, the other cotenants of NMP2, the PSC and other interested parties reached an agreement in January 1990 with respect to the construction of NMP2 and its operation through January 19, 1990. Under the terms of the agreement, the Company's share of disallowed costs aggregated approximately $7 million, net of tax effects, or 6 cents per common share, and was charged to income in 1989 in accordance with the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 90, Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs.

Excluding these three items, earnings for common stock in 1989 would have been approximately $213 million, or $1.92 per common share.

Earnings (loss) per common share for 1991, 1990 and 1989 are shown below. The presentation reflects per share data on the basis of excluding and including the items described above.

	1991	1990	1989
Earnings, excluding the following items	$ 2.15	$ 2.26	$ 1.92
• Unbilled Gas Revenues	—	.10	—
• 1989 Settlement	—	—	(2.41)
• Class Settlement	—	—	(1.02)
• NMP2 Disallowance	—	—	(.06)
Earnings (Loss) Per Common Share	$ 2.15	$ 2.36	$ (1.57)

Revenues

Total revenues in 1991, including revenues from recovery of fuel costs, were $2.5 billion, which represents an increase of $102 million, or 4.2%, over 1990 revenues. Total revenues for the Company's electric and gas operations for 1991, 1990 and 1989 are shown below:

(In millions of dollars)	1991	1990	1989
Revenues			
Electric	$ 2,198	$ 2,086	$ 1,983
Gas	351	361	365
Total Revenues	$ 2,549	$ 2,447	$ 2,348

Electric Revenues: In 1991, electric revenues increased $112 million, or 5.4%, over 1990. Revenues in 1990 had increased $102 million, or 5.2%, over 1989. The increase in electric revenues resulted primarily from several factors in the amounts shown in the following table:

(In millions of dollars)	91/90	90/89
Customer Consumption	$ 13	$ (70)
Customer Additions	8	12
Fuel Cost Adjustments	10	77
Rate Increases	81	83
Total	$ 112	$ 102

Average customer consumption decreased by 38 kilowatt-hours (kWh), or approximately 0.2%, in 1991, primarily as the result of the expansion of the Company's aggressive conservation programs, and the continued sluggishness of the region's economy. However, despite the slight decline in average overall consumption, changes in the customer mix resulted in higher revenues. Weather was not a significant factor in 1991. In 1990, average consumption decreased compared to 1989 for many of the same reasons plus a decline in sales to other utilities and the loss of potential sales resulting from independent power producers and cogeneration ventures, most notably the Grumman Cogeneration project.

The average number of electric customers served in 1991 was approximately 1,005,000, up about 4,000, or 0.4%, over 1990. The increase in 1990, compared to 1989, was about 6,000, or 0.6%.

Revenues from fuel cost adjustments were higher in 1991 primarily due to increased recoveries of conservation expenses. Revenues from fuel cost adjustments were higher in 1990 than in 1989 primarily due to increased oil prices. The average cost of oil burned in the Company's steam generating plants in 1991 was $17.38 per barrel, compared with $20.49 per barrel in 1990. The average cost of oil burned in 1989 was $17.83 per barrel.

On December 1, 1991, the Company was granted an electric rate increase of 4.15% and had been granted increases of 5.0% on December 1, 1990, 5.0% on December 1, 1989 and 5.4% on February 18, 1989. These rate increases provided incremental revenues of $81 million in 1991 and $83 million in 1990.

Gas Revenues: In 1991, gas revenues decreased by $10 million, or 2.8%, compared to 1990. Revenues in 1990 had decreased $3 million, or 0.8%, compared to 1989. The decreases in gas revenues resulted primarily from several factors, in the amounts shown in the following table:

(In millions of dollars)	91/90	90/89
Customer Consumption	$ (2)	$ (9)
Customer Additions	5	4
Fuel Cost Adjustments	(15)	(2)
Rate Increases	2	4
Total	$ (10)	$ (3)

The decrease in average customer consumption in 1991 was 6 dekatherms (dth), or 4.9%, and was largely attributable to warmer winter weather. Also, many of the Company's large interruptible customers are now purchasing much of their gas from other suppliers. While this results in lower sales and revenues, there is no effect on net income since profits from interruptible sales are passed back to firm customers through fuel cost adjustment credits and are not retained by the Company.

On average, the total number of gas space heating customers served in 1991 was up about 10,500, or 4.4%, over 1990, including about 4,000 existing customers who converted their heating systems to gas during the year.

Revenues from fuel cost adjustments were lower in 1991 primarily due to lower sales. The average cost of gas sold in 1991 was $3.29 per dth, compared with $3.19 per dth in 1990. The increase in average gas prices in 1991 was more than offset by the decrease in sales volume. The average cost of gas sold in 1989 was $3.31 per dth.

Effective December 1, 1991, the Company was granted a gas rate increase of 4.1%, which provided additional revenues of $0.5 million in 1991.

In January 1990, the Company was granted a gas rate increase of approximately 1.3%. This rate increase provided the Company with incremental revenues of $4 million in 1990 and another $1.3 million in 1991. The Company did not receive any gas rate increases in 1989.

Operating and Maintenance Expenses

Operating and maintenance (O&M) expenses, excluding fuels and purchased power, were $523 million in 1991, an increase of $47 million, or 9.9%, over 1990. In 1990, these O&M expenses increased $49 million, or 11.4%, over 1989.

The increase in 1991 was primarily attributable to higher expenses for employee wages and benefits, electric production, gas distribution and higher provisions for doubtful accounts reflecting the continuing weakness in the region's economy. The Company continues to pursue aggressive collection practices and has further enhanced its procedures that were implemented in 1990.

The increase in 1990 was principally due to higher research and development expenditures, the implementation and expansion of aggressive energy conservation programs and the costs of maintaining electric production plant, reflecting the Company's commitment to enhanced customer service and service reliability. Higher costs for employee wages, health insurance and higher provisions for doubtful accounts also contributed to the increase.

Other Items

For a discussion of the accounting treatment of the 1989 Settlement and the Class Settlement, see Notes 2, 3 and 4 of Notes to Financial Statements.

In 1991, federal income taxes were approximately $182 million. In 1990, federal income taxes were $183 million, excluding the tax effect of the accounting change for unbilled gas revenues. In 1989, the Company recorded a federal income tax benefit of $1.0 billion, principally resulting from the Shoreham abandonment loss deduction.

Operating taxes, predominantly property taxes, were $388 million in 1991, compared to $370 million in 1990 and $364 million in 1989.

Depreciation expense increased by $12 million in 1991 and by $9 million in 1990 primarily attributable to additional plant in service. Interest expense increased by $16 million in 1991 and by $24 million in 1990 principally due to increased debt levels, partially offset by reductions in interest rates.

In 1991, the Company recorded non-cash charges to income of approximately $25 million, or $17 million, net of tax effects, for the ongoing carrying costs of its obligation under the Class Settlement. In 1990, these ongoing charges amounted to approximately $23 million, or $15 million, net of tax effects.

The Company ceased accruing AFC on its investment in Shoreham, effective January 1, 1989. AFC has not been a significant component of the Company's earnings since then. However, other non-cash income has been substantial, generated principally by the accretion of the RMC of the FRA. In 1991, the accretion of the RMC amounted to approximately $229 million, or $151 million, net of tax effects. In 1990 and 1989, these amounts were $297 million, or $196 million, net of tax effects, and $131 million, or $87 million, net of tax effects, respectively. RMC carrying charges of $40 million, $16 million and $1 million for the years ended December 31, 1991, 1990 and 1989, respectively, are included in other income on the Statement of Income. For a further discussion of the FRA, see Notes 1 and 2 of Notes to Financial Statements.

The Company was required to reduce the RMC for earnings in excess of the sum of the 70 basis point incentive cap and the allowed electric rate of return of 12.77% for the rate year ended November 30, 1991. Accordingly, the Company reduced the RMC by approximately $15.3 million.

The Company is required to adopt SFAS No. 96, Accounting for Income Taxes, no later than January 1, 1993. The impact of SFAS No. 96 on the Statement of Income is not expected to be material. However, the Company estimates that had it adopted SFAS No. 96 at December 31, 1991, the Company would have recorded an accumulated deferred tax liability and an offsetting regulatory asset of approximately $1.5 billion. See Note 1 of Notes to Financial Statements.

In December 1990, the FASB issued SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions. SFAS No. 106 will require the Company to change its method of accounting for such benefits from a pay-as-you-go basis to an accrual basis by requiring the accrual of the expected cost of providing postretirement benefits over the period employee service is rendered. The Company believes that it will be permitted to record a regulatory asset resulting from the adoption of this statement. This regulatory asset would be recovered through rates at the time these expenses are funded. This accounting treatment is subject to the approval of the PSC. The Company must adopt SFAS No. 106 by January 1, 1993, and does not expect to do so prior to that date. The Company estimates that had it adopted SFAS No. 106 at December 31, 1991, it would have recorded an accumulated postretirement benefit obligation and a regulatory asset of approximately $350 million. See Note 8 of Notes to Financial Statements.

Selected Financial Data

Additional information respecting revenues, expenses, electric and gas operating income and operations data, capital expenditures 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.

Report of Ernst & Young 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 as of December 31, 1991 and 1990 and the related statements of income, shareowners' equity and cash flows for each of the three years in the period ended December 31, 1991. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Long Island Lighting Company at December 31, 1991 and 1990, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1991 in conformity with generally accepted accounting principles.

Ernst & Young

Melville, New York
February 6, 1992

Financial Statements

Statement of Income

For year ended December 31 *(In thousands of dollars except per share amounts)*

	1991	1990	1989
Revenues			
Electric	$ 2,197,689	$ 2,085,605	$ 1,983,288
Gas	35[illegible],161	361,242	364,326
Total Revenues	2,548,850	2,446,847	2,347,614
Expenses			
Operations — fuel and purchased power	768,702	786,999	772,452
Operations — other	375,267	340,518	297,518
Maintenance	147,492	135,291	129,788
Depreciation, depletion and amortization	124,820	112,784	103,430
Base financial component amortization	100,971	100,971	50,485
Regulatory liability component amortization	(86,3[illegible])	(86,101)	(43,038)
Rate moderation component	(228,572)	(297,214)	(131,167)
Regulatory liability component	—	—	793,592
Jamesport amortization	—	—	104,160
Operating taxes	388,380	370,317	364,391
Federal income tax — current	515	3,638	14,612
Federal income tax (credit) — deferred and other	168,937	177,014	(729,032)
Total Expenses	1,760,152	1,644,217	1,727,191
Operating Income	788,698	802,630	620,423
Other Income and (Deductions)			
Allowance for other funds used during construction, net of financial stability adjustment revenues	2,202	2,940	(54,918)
Rate moderation component carrying charges	40,456	15,683	682
Other income and deductions, net	32,074	27,218	32,948
1989 Settlement	—	—	(303,947)
Class Settlement	(25,467)	(22,574)	(186,000)
Federal income tax credit (charge) — deferred and other	(12,201)	(2,629)	322,991
Total Other Income and (Deductions)	37,064	20,653	(188,244)
Income Before Interest Charges and Cumulative Effect of Accounting Change	825,762	823,268	432,179
Interest Charges and (Credits)			
Interest on long-term debt	472,9[illegible]	467,700	453,267
Other interest	50,84[illegible]	40,559	31,366
Allowance for borrowed funds used during construction, net of financial stability adjustment revenues	(3,592)	(4,628)	43,349
Total Interest Charges and (Credits)	520,224	503,631	527,982
Income (Loss) Before Cumulative Effect of Accounting Change	305,538	319,637	(95,803)
Cumulative Effect of Accounting Change for Unbilled Gas Revenues (net of applicable taxes of $6,017)	—	11,680	—
Net Income (Loss)	305,538	331,317	(95,803)
Preferred stock dividend requirements	66,394	68,161	79,232
Earnings (Loss) for Common Stock	$ 239,144	$ 263,156	$ (175,035)
Average Common Shares Outstanding (000)	111,348	111,290	111,215
Earnings (Loss) per Common Share			
Before cumulative effect of accounting change	$ 2.15	$ 2.26	$ (1.57)
Cumulative effect of accounting change	—	.10	—
Earnings (Loss) per Common Share	$ 2.15	$ 2.36	$ (1.57)
Dividends Declared per Common Share	$ 1.60	$ 1.25	$ .50
Pro Forma Earnings — with Accounting Change Applied Retroactively			
Earnings (loss) for common stock		$ 251,476	$ (173,251)
Earnings (loss) per common share		$ 2.26	$ (1.56)

See Notes to Financial Statements.

Balance Sheet

Assets At December 31 *(In thousands of dollars)*	1991	1990
Utility Plant		
Electric	$ 3,323,008	$ 3,213,032
Gas	666,904	565,272
Common	157,495	141,700
Construction work in progress	157,511	183,337
Nuclear fuel in process and in reactor	29,818	47,481
	4,334,736	4,150,822
Less — Accumulated depreciation, depletion and amortization	1,332,003	1,262,743
Total Net Utility Plant	3,002,733	2,888,079
Regulatory Asset		
Base financial component (less accumulated amortization of $252,427 and $151,456)	3,786,403	3,887,373
Nonutility Property and Other Investments	9,788	6,381
Current Assets		
Cash and cash equivalents	298,098	102,936
Special deposits	23,207	21,492
Customer accounts receivable (less allowance for doubtful accounts of $26,935 and $18,684)	210,525	216,732
Other accounts receivable	6,515	9,694
Accrued revenue	136,565	138,917
Materials and supplies at average cost	86,863	92,138
Fuel oil at average cost	44,002	68,866
Gas in storage at average cost	43,388	41,466
Prepayments and other current assets	34,854	33,819
Total Current Assets	884,017	726,060
Deferred Charges		
Rate moderation component	602,053	411,443
Shoreham post settlement costs	378,386	225,818
Shoreham nuclear fuel	79,760	62,069
Unamortized storm damage costs	28,435	34,754
Unamortized cost of issuing securities	227,713	132,875
Accumulated deferred income taxes	439,235	359,768
Other	104,778	78,064
Total Deferred Charges	1,860,360	1,334,791
Total Assets	$ 9,543,301	$ 8,842,684

See Notes to Financial Statements.

Capitalization and Liabilities

At December 31 *(In thousands of Dollars)*	1991	1990
Capitalization		
Long-term debt	$ 5,001,016	$ 4,556,016
Unamortized premium and (discount) on debt	(14,850)	(23,125)
	4,986,166	4,532,891
Preferred stock — redemption required	524,912	527,550
Preferred stock — no redemption required	154,371	154,674
Total Preferred Stock	679,283	682,224
Common stock	556,825	556,620
Premium on capital stock	993,509	992,885
Capital stock expense	(40,216)	(42,676)
Retained earnings	620,373	560,405
Total Common Shareowners' Equity	2,130,491	2,067,234
Total Capitalization	7,795,940	7,282,349
Current Liabilities		
Current maturities of long-term debt	10,000	29,000
Current redemption requirements of preferred stock	10,616	13,616
Accounts payable and accrued expenses	223,589	189,029
Accrued taxes (including federal income taxes of $27,693 and $28,453)	60,174	56,248
Accrued interest	85,565	69,175
Dividends payable	6[illegible],287	53,279
Class Settlement	20,000	20,000
Customer deposits	22,664	19,483
Total Current Liabilities	492,895	449,830
Deferred Credits		
1989 Settlement credits	173,507	182,720
Class Settlement	173,564	167,569
Accumulated deferred income taxes	816,053	634,704
Other	84,035	117,172
Total Deferred Credits	1,247,159	1,102,165
Reserves for Claims, Damages, Pensions and Benefits	7,307	8,340
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 9,543,301	$ 8,842,684

See Notes to Financial Statements.

Shareowners' Equity

Statement of Retained Earnings *(In thousands of dollars)*	1991	1990	1989
Balance at January 1	$ **560,405**	$ 436,690	$ 679,579
Restricted for preferred stock dividend requirements at beginning of year	—	—	341,008
Net income (loss) for the year	**305,538**	331,317	(95,803)
	865,943	768,007	924,784
Deductions			
Cash dividends declared on preferred stock	**67,261**	68,218	429,749
Cash dividends declared on common stock	**178,169**	139,128	55,618
Capital stock expense	**140**	256	2,727
Balance at December 31	$ **620,373**	$ 560,405	$ 436,690

Preferred Stock

At December 31 *(In thousands of dollars)*	Call Price Per Share December 31, 1991	Call Price Per Share Final	1991	1990	1989
Par Value $100 per Share, Cumulative					
Shares authorized			**7,000,000**	7,000,000	7,000,000
Shares issued and outstanding			**2,438,993**	2,528,400	2,624,172
5.00% Series B	$101.00	$101.00	$ **10,000**	$ 10,000	$ 10,000
4.25% Series D	102.00	102.00	**7,000**	7,000	7,000
4.35% Series E	102.00	102.00	**20,000**	20,000	20,000
4.35% Series F	102.00	102.00	**5,000**	5,000	5,000
5 1/8% Series H	102.00	102.00	**20,000**	20,000	20,000
5 3/4% Series I Convertible	100.00	100.00	**2,371**	2,674	3,592
8.12% Series J	101.00	101.00	**25,000**	25,000	25,000
8.30% Series K	103.29	103.29	**30,000**	30,000	30,000
7.40% Series L*	103.44	100.00	**21,350**	22,400	23,450
8.40% Series M*	103.64	100.00	**25,200**	26,600	28,000
8.50% Series R*	101.50	100.00	**22,500**	26,250	30,000
9.80% Series S*	103.00	100.00	**55,478**	57,916	60,375
Total Par Value $100			$ **243,899**	$ 252,840	$ 262,417
Par Value $25 per Share, Cumulative					
Shares authorized			**30,000,000**	30,000,000	30,000,000
Shares issued and outstanding			**17,840,000**	17,720,000	17,920,000
$2.47 Series O*	$ 25.25	$ 25.25	$ **26,000**	$ 28,000	$ 30,000
$2.43 Series P	27.75	27.75	**[illegible],000**	35,000	35,000
$3.31 Series T*	—	—	—	60,000	63,000
$2.65 Series Y*	27.65	25.00	**320,000**	320,000	320,000
$2.35 Series Z*	27.35	25.00	**65,000**	—	—
Total Par Value $25			$ **446,000**	$ 443,000	$ 448,000
Less — Sinking fund requirements			$ **10,616**	$ 13,616	$ 13,638
Total Preferred Stock			$ **679,283**	$ 682,224	$ 696,779

Common Stock

At December 31 *(In thousands of dollars)*	1991	1990	1989
Par Value $5 per Share			
Shares authorized	**150,000,000**	150,000,000	150,000,000
Shares issued and outstanding	**111,365,056**	111,324,081	111,249,468
Increase in shares outstanding	**40,975**	74,613	56,460
Increase in $5 par value	$ **205**	$ 373	$ 282
Increase in premium on capital stock	$ **614**	$ 924	$ 608
Decrease in capital stock expense	$ **2,460**	$ 240	$ 13,235

**Redemption required, see Note 6.*

See Notes to Financial Statements.

Statement of Cash Flows

For year ended December 31 *(In thousands of dollars)*	1991	1990	1989
Operating Activities			
Net Income (Loss)	$ 305,538	$ 331,317	$ (95,803)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Cumulative effect of accounting change for unbilled gas revenues	—	(11,680)	—
Depreciation, depletion and amortization	124,820	112,7[illegible]4	103,430
Fuel moderation component	34,025	3,804	16,971
Provision for doubtful accounts	35,431	30,097	12,347
Base financial component amortization	100,971	100,971	50,485
Regulatory liability component amortization	(86,360)	(86,101)	(43,038)
Rate moderation component	(228,572)	(297,214)	(131,167)
Rate moderation component carrying charges	(40,456)	(15,683)	(682)
Regulatory liability component	—	—	793,592
Jamesport amortization	—	—	104,160
1989 Settlement	—	—	303,947
Class Settlement	25,467	22,574	186,000
Federal income taxes (credit) — deferred and other	181,138	179,643	(1,052,023)
Allowance for other funds used during construction	(2,202)	(2,940)	1,166
Other	46,640	29,919	23,189
Changes in operating assets and liabilities			
Accounts receivable	(26,045)	(22,463)	(53,324)
Accrued revenue	2,352	30,748	(97,983)
Materials and supplies, fuel oil and gas in storage	28,217	(48,040)	(6,681)
Prepayments and other current assets	(1,035)	23,752	23,890
Accounts payable and accrued expenses	34,560	2,345	42,818
Class Settlement	—	(20,129)	—
Accrued taxes	3,926	(42,187)	66,750
Other	(17,987)	(459)	(7,456)
Net Cash Provided by Operating Activities	5[illegible],428	321,058	240,588
Investing Activities			
Construction and nuclear fuel expenditures	(235,349)	(229,525)	(297,396)
Financial stability adjustment revenues	—	—	96,180
Construction and nuclear fuel expenditures, net of financial stability adjustment revenues	(235,349)	(229,525)	(201,216)
Shoreham post settlement costs	(158,432)	(152,675)	(75,044)
Other	(3,923)	81	(393)
Net Cash Used in Investing Activities	(397,704)	(382,119)	(276,653)
Financing Activities			
Proceeds from issuance of long-term debt	1,532,247	112,319	1,541,350
Proceeds from issuance of short-term debt	—	—	111,585
Redemption of long-term debt	(1,129,000)	(82,000)	(732,585)
Redemption of short-term debt	—	—	(111,585)
Proceeds from sale of preferred stock	63,130	—	309,120
Redemption of preferred stock	(70,638)	(13,659)	(307,738)
Preferred stock dividends paid	(65,838)	(68,046)	(418,387)
Common stock dividends paid	(172,584)	(125,192)	(27,807)
Cost of issuing long-term debt and preferred stock	(88,586)	(1,327)	(77,98[illegible])
Other	3,707	1,598	(2,150)
Net Cash Provided by (Used in) Financing Activities	72,438	(176,307)	283,820
Net Increase (Decrease) in Cash and Cash Equivalents	$ 195,162	$ (237,368)	$ 247,755
Cash and cash equivalents at beginning of year	$ 102,936	$ 340,304	$ 92,549
Net increase (decrease) in cash and cash equivalents	195,162	(237,368)	247,755
Cash and Cash Equivalents at End of Year	$ 298,098	$ 102,936	$ 340,304
Interest Paid, before reduction for the allowance for borrowed funds used during construction	$ 477,240	$ 479,278	$ 475,672
Federal Income Taxes Paid	$ 1,650	$ 900	—
Federal Income Taxes Refunded	$ 642	$ 23,588	$ 2,660

See Notes to Financial Statements.

Notes to Financial Statements

Note 1. Summary of Significant Accounting Policies

The Company's accounting policies conform to generally accepted accounting principles (GAAP) 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).

Financial Resource Asset

GAAP authorizes recognition of the existence of a regulatory asset when it is probable that a regulator will permit full recovery of a previously incurred cost. Pursuant to the 1989 Settlement, the Company recorded a regulatory asset known as the Financial Resource Asset (FRA). The FRA has two components, the Base Financial Component (BFC) and the Rate Moderation Component (RMC). The Rate Moderation Agreement (RMA), one of the constituent documents of the 1989 Settlement, provides for the full recovery of the FRA. For a further discussion of the 1989 Settlement and the FRA, see Note 2.

Utility Plant

Additions to and replacements of utility plant are capitalized at original cost, which includes material, labor, overhead 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 that portion of construction work in progress which is not included in the Company's rate base. The average annual AFC rate, without giving effect to compounding, was 10.74%, 11.03% and 12.20% for the years 1991, 1990 and 1989, respectively. From 1984 up to the effectiveness of the 1989 Settlement, the Company was provided with additional revenues through the operation of the financial stability adjustment (FSA) authorized by the PSC. FSA revenues were in excess of the amounts to which the Company was entitled under conventional ratemaking and resulted in an offset to AFC. Because the Company, effective January 1, 1989, ceased the accrual of AFC on the Shoreham Nuclear Power Station (Shoreham) in its GAAP basis financial statements, FSA revenues, net of tax effects, amounting to $96 million, exceeded AFC during the year ended December 31, 1989.

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 was equivalent to approximately 3.3%, 3.2% and 3.2% of respective average depreciable plant costs for the years 1991, 1990 and 1989. Depreciation for gas was equivalent to approximately 2.9%, 2.8% and 2.9% of respective average depreciable plant costs for the years 1991, 1990 and 1989.

Cash Equivalents

Cash equivalents are highly liquid investments with maturities of three months or less when purchased.

Unbilled Revenues

The Company accrues electric revenues for services rendered to customers but not billed at month-end.

Effective January 1, 1990, the Company adopted the full accrual method for unbilled gas revenues. Previously, unbilled gas revenues were recognized only for customers billed on a bi-monthly cycle basis for the month in which they were normally not billed. This change better matches revenues and expenses and provides consistency with the Company's revenue recognition method for electric revenues. The cumulative effect of this change at January 1, 1990 was $11.7 million, net of tax effects, or $.10 per share and had been included in net income for the year ended December 31, 1990. The effect of this change on income before the cumulative effect of accounting change and on earnings for common stock for the year ended December 31, 1990 was not material.

Fuel Cost Adjustments

The Company's electric and gas tariffs include fuel cost adjustment (FCA) clauses which provide for the difference between actual fuel costs and the fuel costs allowed in the Company's base tariff rates (base fuel costs). The Company, to achieve a proper matching of costs and revenues, defers these adjustments, net of tax effects, to future periods in which they will be billed or credited to customers. Prior to the effectiveness of the electric rate order discussed in Note 3, base fuel costs collected from ratepayers in excess of actual electric fuel costs were recorded as a liability subject to final disposition by the PSC. The Company will continue to collect the higher of actual electric fuel costs or the base fuel costs, pursuant to the RMA. Effective December 1, 1991, base fuel costs in excess of actual electric fuel costs will be credited to the RMC as incurred.

The electric rate order issued by the PSC in November 1991 authorized the adoption of a partial pass-through fuel cost incentive, effective December 1, 1991. The partial pass-through fuel cost incentive includes a mechanism that compares the Company's actual cost to produce electric energy against a targeted fuel value. The incentive measures the Company's ability to purchase fuel at the lowest possible cost, to purchase energy economically from other power suppliers and to operate its generating plants at optimum efficiency. The shareowners are allocated 40% of the impact between actual fuel costs and targeted fuel values up to a maximum benefit or penalty of 20 basis points of return on common equity. The shareowners' portion of these impacts will be deferred and passed through the FCA in the following rate year.

Gas Take or Pay Costs

FERC has ruled that, subject to its regulations, interstate gas pipeline companies may pass on to their customers certain costs which resulted when demand for natural gas from interstate gas pipeline companies declined due to changing market conditions. In 1989, the PSC determined that 87.5% of these costs, known as take-or-pay (TOP) costs, will be recovered from ratepayers. The Company wrote off in 1989 approximately $3.1 million, net of tax effects, which represents the estimated non-recoverable portion of TOP costs.

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 the redeemed or new issues. Capital stock expense related to that portion of preferred stock that is required to be redeemed is written-off as an adjustment to retained earnings upon redemption unless the preferred stock is redeemed below par value. In that case, any resulting gain, net of the related capital stock expense, is recorded as additional premium on capital stock. The capital stock expense and redemption costs associated with redeeming Preferred Stock Series T, U, V, W and X and the cost of issuance of Preferred Stock Series Y and Z are recorded as deferred charges and are being amortized and recovered through rates over the ten-year lives of Series Y and Z.

Federal Income Taxes

The Company provides deferred federal income taxes with respect to certain differences between net income before income taxes and taxable income in certain instances when approved by the PSC, as disclosed in Note 10. 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.

For ratemaking purposes, 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. Accumulated deferred investment tax credits are amortized ratably over the lives of the related properties.

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. The Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 96, Accounting for Income Taxes, is effective for fiscal years beginning after December 15, 1992. SFAS No. 96 will require, among other matters, recognition of the amount of current and deferred taxes payable or refundable at the date of the financial statements as a result of all events that have been recognized in the financial statements and adjustment of deferred income taxes for an enacted change in tax laws. For regulated enterprises, SFAS No. 96 will prohibit net of tax accounting and reporting and require recognition of a deferred tax liability for the tax benefits which are flowed through to its customers and the equity component of AFC. A regulatory asset or liability will be recognized relating to such items if it is probable that the future increase or decrease in taxes payable thereon shall be recovered from or returned to customers through future rates. The Company does not expect to adopt SFAS No. 96 prior to January 1, 1993, which will provide additional time for the Company to complete its evaluation and analysis of SFAS No. 96. The impact of SFAS No. 96 on the Statement of Income is not expected to be material. However, the Company estimates that had it adopted SFAS No. 96 at December 31, 1991, the Company would have recorded an accumulated deferred tax liability and an offsetting regulatory asset of approximately $1.5 billion.

In June 1991, the FASB issued an exposure draft (ED) of a proposed SFAS which, if adopted, would replace SFAS No. 96 and be effective for fiscal years beginning after December 15, 1992. While the ED, as currently proposed, contains certain provisions that differ from SFAS No. 96, the Company estimates that the impact of adopting the ED would not significantly differ from that of adopting SFAS No. 96.

Reserves for Claims, Damages, Pensions and Benefits

Losses arising from claims against the Company and extraordinary storm losses are partially self-insured. Amounts provided are credited to the reserves based upon experience, risk of loss, actuarial estimates and/or specific orders of the PSC.

Note 2. The 1989 Settlement

On [illegible] 3, 1989, the Company and the State of New York (by [illegible] Governor) entered into the 1989 Settlement resolving [illegible] in issues relating to the Company and [illegible] matters, for the transfer of Shoreham [illegible] decommissioning. The 1989 Settlement [illegible] the intention of the parties that the Company shall [illegible] d to investment grade financial condition and that the Company and the State of New York anticipate that the PSC shall ensure that the future impacts on rates are to be minimized to the maximum extent practicable. It is the Company's position that these objectives can be achieved, in part, through the continued receipt of adequate and timely rate relief.

Upon the effectiveness of the 1989 Settlement, the Company simultaneously recorded on its Balance Sheet the retirement of its investment of approximately $4.2 billion in Shoreham and Bokum Resources Corporation (Bokum) 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. At June 30, 1989, the BFC was approximately $4.0 billion. The BFC, which is granted rate base treatment under the terms of the RMA, is included in the Company's revenue requirements through an amortization included in rates over forty years on a straight-line basis beginning July 1, 1989. As of December 31, 1991 and 1990, the unamortized balance of the BFC was approximately $3.8 billion and $3.9 billion, respectively.

The RMC, a component of the FRA, which will provide the Company with a substantial amount of non-cash earnings over the next several years, 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. This rate moderation plan is designed to hold electric rate increases to the levels provided for in the RMA, subject to the adjustments provided for therein. The RMC is based on forecast data filed in connection with the RMA. As a result of the electric rate order, discussed in Note 3, effective December 1, 1991, the RMC is adjusted for certain Nine Mile Point Nuclear Power Station, Unit 2 (NMP2) operations and maintenance expenses and fuel credits resulting from the Company's electric fuel adjustment clause discussed in Note 1. Prior to December 1, 1991, the RMC was adjusted to reflect actual property taxes, cost of asbestos removal, interest expense, energy conservation and load management program costs, costs to provide added electric system reliability and inflation. The RMC initially increases 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 based on the allowed rate of return on rate base, are deferred and will subsequently decrease and is expected to be fully amortized by the year 2000 as these deferred revenue requirements are recovered.

The Company recognized a loss in June 1989, of approximately $62 million, net of tax effects, which primarily reflected the difference between the recorded costs of the Company's investment in Shoreham and Bokum and the BFC.

Under 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 from the effective date of the 1989 Settlement. The tax benefit arising from the abandonment loss deduction has been offset against the corresponding regulatory liability in the Company's Balance Sheet as it could not have been fully recognized under GAAP were it not for the fact that its recovery is assured under the 1989 Settlement through the regulatory liability offset.

The 1989 Settlement amount on the Statement of Income of approximately $304 million for the year ended December 31, 1989, principally reflects the net difference between the write-off of Shoreham and Bokum, the establishment of the BFC and an adjustment required to correspond with the negotiated settlement amount.

The Statement of Income reflects an amortization of the Company's investment in a proposed generating station in Jamesport of approximately $104 million for the year ended December 31, 1989, which was offset by deferred federal income tax credits of an equivalent amount.

Shoreham post settlement costs (decommissioning, payments in lieu of property taxes and other costs as incurred) are being capitalized and amortized and recovered through rates over a forty-year period on a straight-line remaining life basis.

Upon the effectiveness of the 1989 Settlement, Shoreham nuclear fuel was reclassified to deferred charges and is being amortized and recovered through rates over a forty-year period on a straight-line remaining life basis.

The 1989 Settlement credits on the Balance Sheet of approximately $174 million, net of amortization, reflect an adjustment of the book write-off to the negotiated 1989 Settlement amount and are being amortized over a ten-year period.

The Company believes that the accounting treatment afforded the FRA under the 1989 Settlement conforms to GAAP. For purposes of administering its Uniform Systems of Accounts, FERC has adopted the provisions of SFAS No. 90, Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs, which sets forth the criteria for recognition of regulatory created assets resulting from abandonments. Accordingly, the Company believes that the accounting treatment afforded the FRA conforms to FERC's standards for accounting and asset recognition of regulatory created assets.

The Company has settled certain disputes with a contractor in connection with the construction of Shoreham.

For a discussion of the pending transfer of Shoreham, see Note 9.

Note 3. Rate Matters

Electric

Pursuant to the 1989 Settlement, discussed in Note 2, the Company received electric rate increases contemplated by the RMA for each of the three rate years 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 response to the Company's rate filing in December 1990, the PSC approved the Long Island Lighting Company Ratemaking and Performance Plan (LRPP) in November 1991, which provides for annual electric rate increases, before giving effect to the rate reductions required by the Class Settlement discussed in Note 4, of 4.15%, 4.1% and 4.0%, effective December 1, 1991, 1992 and 1993, respectively. The LRPP is designed to be consistent with the RMA's long-term goals including: (a) the recovery of the BFC; (b) the recovery of the RMC in approximately ten years; (c) the Company's return to investment grade financial condition; and (d) the Company's receipt of adequate and timely rate relief. 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. 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 reduces the impact of experiencing electric sales that are significantly 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 over the three rate years under the LRPP. The differences between the actual electric net revenues and the annual net margin level will be deferred on a monthly basis during the rate year. The deferred balances resulting from the net margin, customer service performance plan, time-of-use incentive program, property taxes, interest expense and wage rates will be netted at the end of each rate year. The LRPP established a band whereby the first $15 million of the total net deferrals will be used to increase or decrease the RMC balance. The total net deferrals in excess of $15 million will be refunded to or recovered from the ratepayers in the following twelve-month period beginning in April, through the FCA.

The expense attrition component permits the Company to make adjustments for expenses including certain operation and maintenance expenses, property taxes and interest charges. These adjustments recognize 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 charges and demand side management (DSM) costs, the deferral and amortization of certain costs for enhanced reliability and operating and maintenance, and the application of an inflation index to other expenses for the rate years effective December 1, 1992 and 1993.

The LRPP provides for an 11.6% return on common equity for electric operations for the three years commencing December 1, 1991. Under the LRPP, the Company is allowed to earn up to 60 additional basis points, or forfeit up to 38 basis points, of the return on common equity as a result of its performance within certain incentive and/or penalty programs. These programs consist of a customer service performance plan, a DSM program, a time-of-use incentive program and a partial pass-through fuel cost incentive plan, discussed in Note 1. The LRPP contains a mechanism whereby earnings in excess of the allowed rate of return on common equity, excluding the impacts of the various incentive/penalty programs, will be shared equally between ratepayers and shareowners.

Prior to December 1, 1991, the RMA provided that earned returns on common equity in excess of targeted allowed rates of return, as adjusted, were to be applied to reduce the RMC or mitigate rates, as determined by the PSC, at the end of each rate year. The Company earned $15.3 million in excess of its targeted allowed rate of return for the rate year ended November 30, 1991 but did not earn in excess of its allowed rate of return for the rate years ended November 30, 1990 and 1989.

To assist in recovering the RMC within a ten-year period under the rates provided by the LRPP, the Company, in accordance with the LRPP, will credit the RMC with several deferred ratepayer benefits including any amounts collected in excess of actual fuel costs. In December 1991, the Company applied $57.6 million of previously deferred credits and related carrying charges for amounts collected in excess of actual fuel costs as a reduction to the RMC. Other miscellaneous deferred credits were also applied as a reduction to the RMC in December 1991.

Gas

In November 1991, the PSC issued a rate order granting a gas rate increase of 4.1% which became effective on December 1, 1991. The gas rate increase reflects costs related to expected levels of capital expenditures, operations and maintenance expenses and the Company's gas expansion program. The gas rate order contains a weather normalization clause which moderates the impact of variations in temperature on gas revenues.

On December 31, 1991, the Company filed a request with the PSC to increase its gas rates effective December 1, 1992 by 5.8% or $30 million in additional revenues. Although the Company calculated that an increase of 9.8% or $51 million is warranted, the Company proposes to collect only 5.8% in the rate year and defer the balance of the request for recovery in later years, together with a return thereon. This filing reflects the Company's latest projections of capital expenditures, operations and maintenance expenses and the continued expansion of its gas business.

Note 4. The Class Settlement

In February 1989, the Company and certain of its former officers entered into an agreement (Class Settlement) that resolved a civil lawsuit against the Company brought under the federal Racketeer Influenced and Corrupt Organizations Act (RICO 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 for rate reductions aggregating $390 million to be made to the ratepayers' monthly electric bills over a ten-year period, as well as approximately $10 million for attorneys' fees and expenses and certain other costs associated with the Class Settlement which were paid in 1990. As a result of the Class Settlement, the Company's electric rate increases after December 1990 on average will be approximately .2% to .3% per year lower than they would otherwise have been during the balance of the Class Settlement period which ends in the year 2000. The amounts recorded on the Statement of Income for 1991 and 1990 of approximately $25 million and $23 million, respectively, represent the increase in present value of the Class Settlement liability. The amount recorded on the Statement of Income for 1989 of $186 million represents the present value of the Class Settlement at June 30, 1989 plus the increase in present value of the Class Settlement liability for the remainder of 1989.

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, 1991, the Company's net utility plant investment in NMP2 was $796 million, net of accumulated depreciation of $80 million, which is included in the Company's rate base. Output of NMP2, which has a design capability of 1,084 megawatts, 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 the 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.

A settlement agreement reached in 1989 (NMP2 Settlement) among the cotenants of NMP2 and other parties and subsequently approved by the PSC, resolved certain ratemaking issues regarding the construction of NMP2 and its operation through January 19, 1990. In December 1989, the Company recorded $7.3 million, net of tax effects, as a charge to earnings, which represents the effect of the NMP2 Settlement. Under the terms of the NMP2 Settlement, the Company is limited to recovering $716 million of original plant costs from its ratepayers, net of tax effects.

NMPC has contracted with the United States Department of Energy for the disposal of nuclear fuel. In 1991, the Company reimbursed NMPC for its 18% share of the cost under the contract at a rate of $1.00 per megawatt hour of net generation.

Based upon a study performed by NMPC, the Company's share of the decommissioning costs for NMP2 is estimated to be $37 million (in 1989 dollars) ass···ning that decommissic ning will commence in 2027 or $237 million (in 2027 dollars). The Company's share of estimated decommissioning costs are being provided for in electric rates and are being charged to operations as depreciation expense. The amount of accumulated decommissioning costs collected from the Company's ratepayers through December 31, 1991 was $3.7 million. Amounts collected by the Company for the decommissioning of the contaminated portion of the NMP2 plant, which approximate 84% of total decommissioning costs, are held in an independent decommissioning trust fund. This fund complies with regulations issued by the Nuclear Regulatory Commission (NRC) governing the funding of nuclear plant decommissioning costs. The Company's funding plan for its share of decommissioning costs will provide reasonable assurance that, at the time of termination of operation, adequate funds for the decommissioning of the Company's share of the contaminated portion of NMP2 plant will be available. The Internal Revenue Service (IRS) has ruled that the Company's decommissioning trust meets the requirements of a qualified fund under applicable provisions of the federal income tax law. This IRS ruling allows the Company's contributions to the decommissioning trust to be deductible for income tax purposes for the tax year in which they are made.

Note 6. Capital Stock

Preferred Stock

Preferred stock dividends are cumulative. At December 31, 1991, 1990 and 1989 there were no preferred stock dividends in arrears. On September 1, 1989, the Company resumed regular dividend payments on its preferred stock by paying all dividends, then in arrears, amounting to approximately $390 million.

Redemption of various series of preferred stock is effected through the operation of various sinking fund provisions. On July 25, 1989, simultaneous with the declaration of all preferred stock dividends then in arrears, the Company satisfied sinking fund requirements totaling approximately $56 million then in arrears on all series of preferred stock by crediting previously acquired shares of preferred stock held in the Company's treasury. The aggregate par value of preferred stock required to be redeemed in each of the years 1992 through 1996 is $11 million.

In May 1991, the Company sold 2,600,000 shares of Preferred Stock, $2.35, Series Z, cumulative, par value $25 per share. The Company used the proceeds from the issuance of the Series Z Preferred Stock to call, at its applicable redemption price, Preferred Stock, $3.31, Series T.

Preference Stock

None of the authorized 7,500,000 shares of nonparticipating preference stock, par value $1 per share, which ranks junior to the preferred stock, are outstanding.

Common Stock

Of the 150,000,000 shares of authorized common stock at December 31, 1991, 1,882,586 shares were reserved for sale through the Company's Employee Stock Purchase Plan to employees with at least one year of service and 138,268 shares were reserved for conversion of the Series I Convertible Preferred Stock at a rate of $17.15 per share. In addition, the Company has reserved 6,802,247 shares for the Automatic Dividend Reinvestment Plan which has been suspended since February 1984. 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.

Note 7. Long-Term Debt

Each of the Company's four 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 G&R Mortgage (G&R Trustee) as additional security for General and 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 $957 million and $449 million at December 31, 1991 and 1990, respectively. The annual First Mortgage depreciation fund and sinking fund requirements for 1991, due not later than June 30, 1992, are estimated at $179 million and $18 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 1991, due not later than June 30, 1992, is estimated at $27 million. The Company expects to satisfy this requirement with retired G&R Bonds.

Third Mortgage/1989 Term Loan Agreement

The Third Mortgage is subordinate to the liens of the First Mortgage and the G&R Mortgage. The bank debt secured by the Third Mortgage was restructured on June 30, 1989, at which time, the Company entered into the 1989 Amended and Restated Restructuring Credit Agreement (1989 Term Loan Agreement) pursuant to which the Company is to pay to its lending banks approximately $446 million in sixteen substantially equal consecutive quarterly installments commencing on January 1, 1993 and ending on October 1, 1996. Pursuant to the 1989 Term Loan Agreement, the Company has the option to commit to one of three interest rates including: (a) the Adjusted Certificate of Deposit Rate (CD Rate) which is a rate based on the certificate of deposit rates of certain of the lending banks, (b) the Base Rate which is generally a rate based on Citibank, N.A.'s prime rate and (c) the Eurodollar Rate which is a rate based on the London Interbank Offering Rate (LIBOR).

Fourth Mortgage

The Fourth Mortgage secures $85 million of the Company's obligations under the letter of credit described below under the heading Authority Financing Notes. Through an Intercreditor Agreement, the letter of credit bank secured by the Fourth Mortgage holds a lien on Company property that is equal in rank to the lien held by the banks secured by the Third Mortgage.

1989 Revolving Credit Agreement

On June 30, 1989, the Company and certain of its lending banks entered into the 1989 Revolving Credit Agreement (1989 RCA). The Company has an estimated $114 million available under this $300 million revolving line of credit through October 1, 1992. All or part of the remaining $186 million has been dedicated for the purposes described below. This line of credit is secured by a first lien upon the Company's accounts receivable and fuel oil inventories. The Company has the option to commit to one of three interest rates including: (a) the CD Rate, (b) the Base Rate and (c) the Eurodollar Rate. The Company has agreed to pay a fee of one quarter of one percent per annum on the unused portion. At December 31, 1991, no amounts were outstanding under the 1989 RCA. The termination date of the 1989 RCA may be extended for one-year periods upon the acceptance by the lending banks of the Company's request delivered to the lending banks prior to April 1 in each year beginning in 1992.

The amount of credit available under the 1989 RCA after October 1, 1992 will be $264 million through October 1, 1993. The Company has, with the approval of the NRC, dedicated an amount of the 1989 RCA sufficient to cover estimated, not yet incurred, costs attributable to the decommissioning of Shoreham. At December 31, 1991, the Company estimates that $186 million would represent the amount of estimated, not yet incurred, decommissioning costs. After October 1, 1992, the amount available under the 1989 RCA, not required for the decommissioning of Shoreham, will be reduced from $114 million to approximately $78 million. However, the amount available under the 1989 RCA will increase as decommissioning costs are paid by the Company through means other than the 1989 RCA.

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 Pollution Control Revenue Bonds (PCRBs), Electric Facilities Revenue Bonds (EFRBs) and Industrial Development Revenue Bonds issued by NYSERDA. Certain of these bonds are supported by letters of credit and are subject to periodic tender at which time their interest rates are subject to redetermination. When such letters of credit expire, the Company is required to obtain either an extension of the letter of credit or substitute credit backup. If neither can be obtained, the bonds must be redeemed unless the Company purchases the bonds in lieu of redemption and subsequently remarkets them.

All of the outstanding EFRBs are supported by letters of credit pursuant to which the letter of credit banks have agreed to pay the principal, interest and premium on any tendered EFRBs, in the aggregate, up to approximately $109 million for each issue 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 January 24, 1994, June 3, 1993 and October 31, 1994 for the 1991 EFRBs, 1990 EFRBs and 1989 EFRBs, respectively.

The 1985 PCRBs are supported by a letter of credit, pursuant to which the letter of credit bank, partially secured by the Fourth Mortgage in the amount of $85 million, has agreed, in the event of default to pay the principal, interest and premium on the tendered PCRBs, in the aggregate, up to approximately $165 million. This letter of credit expires on March 31, 1993.

Long-Term Debt at December 31 *(In thousands of dollars)*

Maturity	Interest Rate	Series	1991	1990
First Mortgage Bonds *(excludes Pledged Bonds)*				
August 1, 1991	5%	L	$ —	$ 25,000
April 1, 1993	4.40%	M	**40,000**	40,000
June 1, 1994	4 5/8%	N	**25,000**	25,000
June 1, 1995	4.55%	O	**25,000**	25,000
March 1, 1996	5 1/4%	P	**40,000**	40,000
April 1, 1997	5 1/2%	Q	**35,000**	35,000
September 1, 1999	8.20%	R	**35,000**	35,000
September 1, 2000	9 1/8%	S	**25,000**	25,000
April 1, 2001	7 1/4%	U	**40,000**	40,000
December 1, 2001	7 1/2%	V	**50,000**	50,000
September 1, 2002	7 5/8%	W	**50,000**	50,000
December 1, 2003	8 1/8%	X	**60,000**	60,000
Total First Mortgage Bonds			**425,000**	450,000
General and Refunding Bonds				
June 1, 1995	13 1/4%		—	225,000
April 15, 1996	11 1/4%		—	250,000
May 1, 1996	8 3/4%		**415,000**	—
February 15, 1997	8 3/4%		**250,000**	—
March 1, 1999	9.75%		**63,000**	67,000
June 1, 2006	9 5/8%		**70,000**	70,000
December 1, 2006	8 5/8%		**50,000**	50,000
May 1, 2007	8 5/8%		**85,000**	85,000
April 1, 2008	9.20%		**75,000**	75,000
April 15, 2015	11 7/8%		—	275,000
May 1, 2021	9 3/4%		**415,000**	—
July 1, 2024	9 5/8%		**375,000**	—
Total General and Refunding Bonds			**1,798,000**	1,097,000
Third Mortgage				
1989 Term Loan Agreement *(LIBOR)*	5.3%		**446,341**	446,341
Debentures				
April 1, 1993	11 3/8%		**375,000**	375,000
November 15, 1993	11.70%		**175,000**	175,000
June 15, 1994	10.25%		**400,000**	400,000
November 15, 1994	11.75%		**175,000**	175,000
June 15, 1999	10.875%		**350,000**	350,000
November 15, 2014	11.50%		—	350,000
June 15, 2019	11.375%		**350,000**	350,000
Total Debentures			**1,825,000**	2,175,000
Authority Financing Notes				
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	8 1/4%*	1982	**17,200**	17,200
March 1, 2016	5.375%**	1985A,B	**150,000**	150,000
Electric Facilities Revenue Bonds				
September 1, 2019	5.35%***	1989A,B	**100,000**	100,000
June 1, 2020	6%***	1990A	**100,000**	100,000
December 1, 2020	5.4%***	1991A	**100,000**	—
Industrial Development Revenue Bonds				
December 1, 2006	7.5%	1976A,B	**2,000**	2,000
Total Authority Financing Notes			**516,675**	416,675
Total Long-Term Debt			**5,011,016**	4,585,016
Less — Current maturities			**10,000**	29,000
Total Long-Term Debt Less Current Maturities			**$5,001,016**	$4,556,016

**Tendered every three years, next tender October 1994* ***Tendered annually on March 1* ****Tendered weekly*

Long-term debt due in the next five years is $10,000 (1992), $705,585 (1993), $715,585 (1994), $140,585 (1995) and $570,585 (1996).

Note 8. Retirement Benefit Plans

The Company maintains a primary defined benefit pension plan (Primary Plan) which covers substantially all employees, a supplemental plan (Supplemental Plan) which covers key executives and a retirement plan which covers the Board of Directors (Directors' Plan). All pension costs are borne by the Company. 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. Pension benefits are established by crediting the employee with an amount determined using the base salary for each year the employee is a participant in the plan, plus an additional amount credited for each year the employee remains a participant beyond the age of 50. Employees are vested in the pension plan after five years of service with the Company.

Primary Plan

The Primary Plan's funded status and amounts recognized in the Balance Sheet at December 31, 1991 and 1990 were as follows:

(In thousands of dollars)	1991	1990
Actuarial present value of benefit obligation		
Vested benefits	**$ 375,326**	$ 383,805
Nonvested benefits	**5,315**	6,459
Accumulated benefit obligation	**$ 380,641**	$ 390,264
Plan assets at fair value	**$ 519,816**	$ 468,050
Actuarial present value of projected benefit obligation	**446,718**	464,797
Projected benefit obligation less than plan assets	**$ 73,098**	$ 3,253
Unrecognized January 1, net obligations	**33,113**	25,922
Unrecognized net gain	**(114,389)**	(30,741)
Net accrued pension cost	**$ (8,178)**	$ (1,566)

Periodic pension cost for 1991, 1990 and 1989 for the Primary Plan included the following components:

(In thousands of dollars)	1991	1990	1989
Service cost—benefits earned during the period	**$ 14,323**	$ 12,720	$ 10,797
Interest cost on projected benefit obligation and service cost	**33,698**	32,264	31,458
Actual return on plan assets	**(63,875)**	(23,121)	(49,316)
Net amortization and deferral	**33,569**	(5,449)	22,955
Net periodic pension cost	**$ 17,715**	$ 16,414	$ 15,894

Assumptions used in accounting for the Primary Plan were:

	1991	1990	1989
Discount rate	**7.75%**	7.25%	7.5%
Rate of future compensation increases	**5.5%**	6.0%	6.0%
Long-term rate of return on assets	**7.0%**	7.0%	7.0%

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

Pursuant to an order issued by the PSC in 1987, the Company had deferred approximately $7.3 million which was the excess of pension expense collected from its ratepayers through 1989 over that determined under SFAS No. 87, Employers' Accounting for Pensions. Subsequently, the Company's rates were based on pension expense determined under SFAS No. 87. The portion attributable to electric operations of approximately $4.6 million, was credited to the RMC on December 1, 1991 in accordance with the LRPP, discussed in Note 3. The portion that is attributable to gas operations of approximately $2.7 million, will be amortized to income over a three-year period beginning December 1, 1991, in accordance with the gas rate order.

Supplemental Plan

The Supplemental Plan 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 retirement benefits, which is unfunded, totaled approximately $675,000, $561,000 and $546,000 and were recognized as an expense in 1991, 1990 and 1989, respectively. The cost of this plan is borne by the Company's shareowners.

Directors' Plan

The Directors' Plan, adopted in February 1990, 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 nonqualified plan under the Internal Revenue Code. The provision for retirement benefits, which is unfunded, totaled approximately $101,000 and $99,000 and were recognized as expense in 1991 and 1990, respectively.

Postretirement Benefits Other Than Pensions

In addition to providing pension benefits, the Company provides certain health care 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 while working for the Company. These and similar benefits for active employees are provided through insurance companies whose premiums are based on the benefits paid during the year. The cost of providing these benefits on a pay-as-you-go method was $37,312,000, $29,410,000 and $27,155,000 for 1991, 1990 and 1989, respectively, and were recognized as an expense as premiums were paid. The cost of providing these benefits for approximately 2,100 retirees, is not separable from the cost of providing benefits for approximately 6,000 active employees for the years 1989 through 1991.

In December 1990, the FASB issued SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions. SFAS No. 106 establishes accounting standards for employers' accounting for such benefits. SFAS No. 106 will require the Company to change its method of accounting for such benefits from a pay-as-you-go basis to an accrual basis by requiring the accrual of the expected cost of providing postretirement benefits over the period the employee service is rendered. The Company believes it will be permitted to record a regulatory asset resulting from the adoption of this statement. The regulatory asset would be recovered through rates at the time these expenses are funded. This accounting treatment is subject to PSC approval. The Company must adopt SFAS No. 106 by January 1, 1993 and does not expect to do so prior to that date. The Company estimates that had it adopted SFAS No. 106 at December 31, 1991, it would have recorded an accumulated postretirement benefit obligation and a regulatory asset of approximately $350 million.

Note 9. Commitments and Contingencies

Litigation

Asbestos: The Company is one of several co-defendants in a number of consolidated asbestos actions pending in both New York State Supreme Court and the federal district courts for the Southern and Eastern Districts of New York (*In Re New York Asbestos Litigation*). The damages which have been demanded in each of these actions range up to $55 million, including punitive damages, against all defendants. In the State court, the Company is a party in some of the consolidated cases which proceeded to trial in 1992. In addition, on the federal level, trial to determine medical causation and the amount of plaintiffs' damages has been completed in 47 consolidated cases in which the Company and several other parties had been impleaded by an asbestos manufacturer. The Company is one of numerous defendants who may be found liable for a share of $38 million in damages awarded to 24 of these 47 plaintiffs. A second trial to determine the allocation of this liability began in late 1991.

Pursuant to court-ordered negotiations, the Company has been involved in settlement negotiations to resolve these State and federal claims. In addition, the Company has commenced fourth-party actions against certain of its insurers seeking indemnification for liability and defense costs in these cases and is also involved in court-ordered settlement discussions in these matters. Based upon the progress of these negotiations and other factors, the Company believes that the resolution of these cases will not materially impact the financial condition of the Company.

Contract Suit: The Company is also involved in litigation against Suffolk County in which both parties are seeking damages for the other's alleged breach of contract concerning the preparation of an offsite emergency response plan for Shoreham which, pursuant to the 1989 Settlement, the Company agreed to never operate. In its proposed counterclaims, Suffolk County seeks significant damages for alleged fraud in the inducement, breach of contract by the Company, tortious conduct and fraudulently procured utility rates, as well as $700 million in alleged punitive damages. The Company has moved the court to impose sanctions on Suffolk County relating to these claims on the basis that the allegations are frivolous and ignore significant precedent, including the NRC's approval of the Company's evacuation plan for Shoreham and various Second Circuit Court of Appeal's decisions in related litigation between the parties. In addition, the Company has argued that there is no basis for punitive damages in this case. The Company intends to vigorously prosecute its claims against Suffolk County and to defend against Suffolk County's counterclaims.

Transfer of Shoreham

The 1989 Settlement provides for the transfer of Shoreham to the Long Island Power Authority (LIPA) and for its decommissioning. The Company and LIPA have filed an application with the NRC, which is pending, to transfer Shoreham's possession-only license to LIPA. LIPA has also filed a decommissioning plan for Shoreham with the NRC.

Commitments

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

Nuclear Plant Insurance

The Company has property damage insurance and third-party bodily injury and property liability insurance for its 18% share in NMP2 and for Shoreham. The premiums for this coverage are not material. The policies for this coverage provide for retroactive premium assessments under certain circumstances. Maximum retroactive premium assessments could be as much as approximately $4.7 million. For property damage at each nuclear generating site, the NRC requires a minimum of $1.06 billion of coverage. The NRC has given the Company a partial exemption from these requirements for Shoreham.

Under certain circumstances, the Company may be assessed additional amounts in the event of a nuclear incident. Under agreements established pursuant to the Price Anderson Act, the Company could be assessed up to approximately $74 million per nuclear incident in any one year at any nuclear unit, but not in excess of approximately $12 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 $7.4 billion.

Note 10. Federal Income Taxes

On April 17, 1989, the Company received a private letter ruling from the IRS which stated that the Company would be entitled, for federal income tax purposes, to an abandonment loss deduction in connection with Shoreham, upon effectiveness of the 1989 Settlement. The Company claimed an abandonment loss deduction on its 1989 federal income tax return of approximately $1.8 billion. The Company's net operating loss carryforward is estimated to be approximately $2.2 billion at December 31, 1991.

On January 8, 1990, the Company received a Revenue Agent's Report disallowing certain deductions claimed by the Company on its tax returns for the years under audit. The Revenue Agent's Report reflects proposed adjustments to the Company's federal income tax returns for 1984 through 1987 which, if sustained, would give rise to tax deficiencies totaling approximately $87 million. The Company is protesting some of the adjustments and seeks an administrative and, if necessary, a judicial review of the conclusions reached in the Revenue Agent's Report. The Company cannot predict either the timing or the manner in which this matter will be resolved. If, however, the ultimate disposition of any or all matters raised in the Revenue Agent's Report is 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 Shoreham abandonment loss deduction and thus any impact would not have a material effect on the Company's financial condition or cash flows.

The amount of investment tax credit (ITC) carryforward for financial statement purposes after 1991 is approximately $206 million. These credits expire by the year 2002. In accordance with the Tax Reform Act of 1986 (TRA 86), ITC allowable as credits to tax returns for years after 1987 must be reduced by 35%. The amount of the reduction will not be allowed as a credit for any other taxable year.

The Company has not provided deferred taxes on approximately $500 million of various other deductions and depreciation method differences for property placed in service prior to 1981 which, in conformity with the ratemaking practices of the PSC, have been flowed through. These various other flow-through tax deductions, which are deductible currently for tax purposes but capitalized for accounting and ratemaking purposes, include certain taxes, a portion of AFC, pensions and certain other employee benefits. See Note 1 with respect to a change in the method of accounting for income taxes which the Company must adopt by no later than 1993.

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 net income (loss) before income taxes. The table below sets forth the reasons for such differences. The 1989 difference results principally because the tax basis attributable to Shoreham was less than its recorded basis for financial statement purposes and the FRA and certain other 1989 Settlement items recorded by the Company pursuant to the 1989 Settlement have no tax basis.

(In thousands of dollars)	1991		1990		1989	
	Amount	**% of Pre-tax Income**	Amount	% of Pre-tax Income	Amount	% of Pre-tax Income
Federal income tax, per Statement of Income — current	**$ 515**		$ 3,638		$ 14,612	
Deferred and other (see Note 1)						
1989 Settlement						
Shoreham abandonment	**10,677**		3,239		(907,467)	
Jamesport recovery	—		—		(104,160)	
Bokum Resources Corporation	**20,400**		—		(35,977)	
Rate moderation component	**77,715**		101,053		44,597	
Other 1989 Settlement items	**(13,638)**		(13,577)		(37,500)	
Shoreham post settlement costs	**50,375**		61,475		6,656	
Contractor litigation settlement	**(18,758)**		—		—	
Class Settlement	**(2,038)**		(534)		(63,240)	
Interest capitalized	**(2,562)**		(3,220)		(3,752)	
Accrued utility revenues	—		727		(2,803)	
Mortgage recording tax	**4,653**		(589)		(687)	
Accelerated tax depreciation	**30,447**		33,342		36,242	
Call premiums	**18,496**		(3,111)		12,452	
Fuel cost adjustments	**(2,289)**		4,879		4,451	
Nine Mile Point 2 deferred revenues	—		—		4,151	
Capitalized overheads	**180**		2,287		1,272	
Retired debt costs	**9,185**		—		—	
Other items, net	**(705)**		(6,328)		(6,258)	
Total Deferred	**181,138**		179,643		(1,052,023)	
Total federal income tax expense (credit)	**181,653**		183,281		(1,037,411)	
Income (loss) before cumulative effect of accounting change	**305,538**		319,637		(95,803)	
Income (Loss) Before Cumulative Effect of Accounting Change and Income Taxes	**$ 487,191**		$ 502,918		$ (1,133,214)	
Statutory federal income tax (credit)	**$ 165,645**	**34.0%**	$ 170,992	34.0%	$ (385,293)	34.0%
Additions (reductions) in federal income tax resulting from:						
1989 Settlement						
Shoreham abandonment	**4,003**	**0.8**	4,035	0.8	(691,242)	61.0
Jamesport recovery	—	—	—	—	20,101	(1.8)
Bokum Resources Corporation	—	—	—	—	(34,015)	3.0
Rate moderation component	—	—	—	—	(7,360)	0.7
Other 1989 Settlement items	—	—	—	—	(19,821)	1.8
Allowance for funds used during construction	**(1,310)**	**(0.3)**	(2,573)	(0.5)	31,527	(2.8)
Lien date property taxes	**277**	**0.1**	(8,757)	(1.8)	20,034	(1.8)
Tax credits	**(2,980)**	**(0.6)**	1,537	0.3	13,534	(1.2)
Excess of book depreciation over tax depreciation	**13,108**	**2.7**	11,987	2.4	10,842	(1.0)
Interest capitalized	**4,232**	**0.9**	6,031	1.2	3,251	(0.3)
Other items, net	**(1,322)**	**(0.3)**	29	0.0	1,031	(0.1)
Total Federal Income Tax Expense (Credit)	**$ 181,653**	**37.3%**	$ 183,281	36.4%	$ (1,037,411)	91.5%

Note 11. Segments of Business

The Company is a public utility operating company engaged in the generation, distribution and sale of electric energy and the purchase, distribution and sale of natural gas to residential and commercial 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, financial resource asset, materials and supplies (excluding common), accrued revenues, gas in storage, fuel and deferred charges (excluding common). Assets utilized for overall Company operations consist of other property and investments, cash, temporary cash investments, special deposits, accounts receivable, prepayments and other current assets, unamortized debt expense and other deferred charges.

For year ended December 31, *(In thousands of dollars)*	**1991**	1990	1989
Operating revenues			
Electric	**$ 2,197,689**	$ 2,085,605	$ 1,983,288
Gas	**351,161**	361,242	364,326
Total	**$ 2,548,850**	$ 2,446,847	$ 2,347,614
Operating expenses *(excluding income taxes)*			
Electric	**$ 1,252,405**	$ 1,141,050	$ 2,115,994
Gas	**338,295**	322,515	325,617
Total	**$ 1,590,700**	$ 1,463,565	$ 2,441,611
Operating income (loss) *(before income taxes)*			
Electric	**$ 945,284**	$ 944,555	$ (132,706)
Gas	**12,866**	38,727	38,709
Total	**958,150**	983,282	(93,997)
AFC, net of FSA revenues	**(5,794)**	(7,568)	98,267
Other income and deductions	**(47,063)**	(20,327)	456,317
Interest charges	**523,816**	508,259	484,633
Income taxes—operating	**169,452**	180,652	(714,420)
Income taxes—non operating	**12,201**	2,629	(322,991)
Income (loss) before cumulative effect of accounting change	**305,538**	319,627	(95,803)
Cumulative effect of accounting change (net of taxes)	—	11,680	—
Net income (loss)	**$ 305,538**	$ 331,317	$ (95,803)
Depreciation, depletion and amortization			
Electric	**$ 110,037**	$ 99,922	$ 91,759
Gas	**14,783**	12,862	11,671
Total	**$ 124,820**	$ 112,784	$ 103,430
Construction and nuclear fuel expenditures*			
Electric	**$ 144,356**	$ 151,425	$ 148,388
Gas	**93,195**	81,040	51,662
Total	**$ 237,551**	$ 232,465	$ 200,050

At December 31 *(In thousands of dollars)*	**1991**	1990	1989
Identifiable assets			
Electric	**$ 7,986,887**	$ 7,643,963	$ 7,133,161
Gas	**621,570**	540,355	451,447
Total	**8,608,457**	8,184,318	7,584,608
Assets utilized for overall Company operations	**934,844**	658,366	935,430
Total Assets	**$ 9,543,301**	$ 8,842,684	$ 8,520,038

**Includes non-cash allowance for other funds used during construction and excludes Shoreham post settlement costs.*

Note 12. Quarterly Financial Information

(Unaudited)

(In thousands of dollars except earnings per common share)		1991	1990
Operating revenues			
For the quarter ended	March 31	$ 667,294	$ 665,531
	June 30	541,356	510,788
	September 30	738,592	707,820
	December 31	601,608	562,708
Operating income			
For the quarter ended	March 31	$ 207,830	$ 202,899
	June 30	166,830	167,410
	September 30	268,041	282,104
	December 31	145,997	150,217
Net income			
For the quarter ended	March 31	$ 86,404	$ 90,356 (a)
	June 30	50,089	47,780
	September 30	144,449	156,848
	December 31	24,596	36,333
Earnings for common stock			
For the quarter ended	March 31	$ 69,567	$ 73,205 (a)
	June 30	33,013	30,681
	September 30	128,175	139,845
	December 31	8,389	19,425
Earnings per common share			
For the quarter ended	March 31	$ .62	$ .66 (a)
	June 30	.30	.28
	September 30	1.15	1.26
	December 31	.08	.16

(a) Effective January 1, 1990, the Company changed its method of accounting for unbilled gas revenues. The cumulative effect of this change increased net income by approximately $11.7 million, net of tax effects, or $.11 per common share, for the first quarter.

Selected Financial Data

Summary of Operations *(See Notes to Financial Statements)* — **Table 1**

	1991	1990	1989	1988	1987
Total revenues (000)	**$ 2,548,850**	$ 2,446,847	$ 2,347,614	$ 2,137,834	$ 2,072,077
Total operating income (loss) (000)					
Before federal income taxes	**$ 958,150**	$ 983,282	$ (93,997)	$ 701,049	$ 670,324
After federal income taxes	**$ 788,698**	$ 802,630	$ 620,423	$ 500,938	$ 382,604
Income (loss) before cumulative effect of accounting changes (000)	**$ 305,538**	$ 319,637	$ (95,803)	$ 298,490	$ 269,888
Cumulative effect of accounting change for unbilled gas revenues (net of taxes) (000)	—	$ 11,680	—	—	—
Cumulative effect of accounting change for disallowed costs (net of taxes) (000)	—	—	—	$ (1,345,110)	—
Earnings (loss) for common stock (000)	**$ 239,144**	$ 263,156	$ (175,035)	$ (2,121,[illegible]28)	$ 192,312
Average common shares outstanding (000)	**111,348**	111,290	111,215	111,177	111,129
Earnings (loss) per common share					
Before cumulative effect of accounting changes	**$ 2.15**	$ 2.26	$ (1.57)	$ 2.02	$ 1.73
Cumulative effect of accounting changes	—	.10	—	(12.10)	—
Earnings (loss) per common share	**$ 2.15**	$ 2.36	$ (1.57)	$ (10.08)	$ 1.73
Pro forma earnings — with accounting changes for unbilled gas revenues and disallowed project costs applied retroactively					
Earnings (loss) for common stock (000)		$ 251,476	$ (173,251)	$ 223,712	$ 177,414
Earnings (loss) per common share		$ 2.26	$ (1.56)	$ 2.01	$ 1.60
Common stock dividends declared per share	**$ 1.60**	$ 1.25	$ .50	—	—
Common stock dividends paid per share	**$ 1.55**	$ 1.125	$ .25	—	—
Book value per common share at year end	**$ 19.13**	$ 18.57	$ 17.45	$ 19.61	$ 29.71
Common shareowners at year end	**90,435**	82,903	85,142	[illegible]3,267	106,11[illegible]
Ratio of earnings to fixed charges	**1.93**	1.98	*	1.95	2.02
Ratio of earnings to combined fixed charges and preferred stock dividends	**1.60**	1.64	*	1.58	1.56
Ratio of earnings to fixed charges (excluding AFC and RMC)	**1.48**	1.39	*	1.60	1.60
Ratio of earnings to combined fixed charges and preferred stock dividends (excluding AFC and RMC)	**1.23**	1.15	*	1.30	1.24

**The Company had no earnings to cover fixed charges.*

Operations and Maintenance Expense Details *(In thousands of dollars)* — **Table 2**

	1991	1990	1989	1988	1987
Total payroll and employee benefits	**$ 420,293**	$ 378,831	$ 349,242	$ 333,359	$ 315,114
Less — Charged to construction and other	**123,838**	97,650	117,761	1[illegible]9,990	115,315
Payroll and Employee Benefits Charged to Operations	**296,455**	281,181	231,481	203,369	199,799
Fuels — electric operations	**354,859**	444,458	461,576	410,174	422,997
Fuels — gas operations	**175,046**	175,877	188,139	172,431	174,610
Purchased power costs	**197,154**	168,749	128,368	[illegible]8,465	93,186
Fuel cost adjustments deferred	**41,643**	(2,085)	(5,631)	3,359	(5,104)
Total Fuel and Purchased Power	**768,702**	786,999	772,452	674,[illegible]29	685,689
All other	**226,304**	194,628	195,825	154,527	142,201
Total Operations and Maintenance Expense	**$ 1,291,461**	$ 1,262,808	$ 1,19[illegible],758	$ 1,032,325	$ 1,027,689
Employees at December 31	**6,605**	6,630	[illegible],239	6,2[illegible]1	6,378

	1991	1990	1989	1988	1987
Electric Operating Income *(In thousands of dollars)*					**Table 3**
Revenues					
Residential	**$ 1,047,490**	$ 997,868	$ 915,644	$ 835,584	$ 800,952
Commercial and industrial	**1,070,098**	1,017,387	981,740	883,267	849,626
Other system revenues	**47,838**	46,673	42,232	40,518	49,791
Total system revenues	**2,165,426**	2,061,928	1,939,616	1,759,369	1,700,369
Sales to other utilities	**23,040**	24,140	42,880	24,152	11,889
Other revenues	**9,223**	(463)	792	3,412	6,603
Total Revenues	**2,197,689**	2,085,605	1,983,288	1,786,933	1,718,861
Expenses					
Operations — fuel and purchased power	**593,656**	611,122	584,313	501,998	511,079
Operations — other	**296,798**	271,608	237,931	195,283	187,573
Maintenance	**127,446**	118,545	115,502	96,599	88,431
Depreciation	**110,037**	99,922	91,759	82,811	63,840
Base financial component amortization	**100,971**	100,971	50,485	—	—
Regulatory liability component amortization	**(86,360)**	(86,101)	(43,038)	—	—
Rate moderation component	**(228,572)**	(297,214)	(131,167)	—	—
Regulatory liability component	—	—	793,592	—	—
Jamesport amortization	—	—	104,160	—	—
Operating taxes	**338,429**	322,197	312,456	262,644	250,047
Federal income tax — current	**515**	3,138	14,612	18,394	64,095
Federal income tax — deferred and other	**173,259**	169,274	(738,500)	166,557	208,954
Total Expenses	**1,426,179**	1,313,462	1,392,105	1,324,286	1,374,019
Electric Operating Income	**$ 771,510**	$ 772,143	$ 591,183	$ 462,647	$ 344,842

	1991	1990	1989	1988	1987
Gas Operating Income *(In thousands of dollars)*					**Table 4**
Revenues					
Residential, firm — space heating	**$ 190,976**	$ 198,734	$ 209,192	$ 201,312	$ 194,303
— other	**29,383**	30,654	31,692	31,803	32,877
Non-residential, firm — space heating	**70,938**	68,441	72,351	68,114	63,267
— other	**25,515**	26,501	28,674	28,078	28,443
Total firm revenues	**316,812**	324,530	341,909	329,307	318,890
Interruptible revenues	**21,686**	30,515	19,226	18,821	24,150
Total system revenues	**338,498**	355,045	361,135	348,128	343,040
Sales to other utilities	—	—	—	—	4,970
Other revenues	**12,663**	6,197	3,191	2,773	5,206
Total Revenues	**351,161**	361,242	364,326	350,901	353,216
Expenses					
Operations — fuel	**175,046**	175,877	188,139	172,431	174,610
Operations — other	**78,469**	68,910	59,587	53,415	53,140
Maintenance	**20,046**	16,746	14,286	12,599	12,856
Depreciation, depletion and amortization	**14,783**	12,862	11,671	10,785	10,065
Operating taxes	**49,951**	48,120	51,935	48,220	50,112
Federal income tax — current	—	500	—	—	19,482
Federal income tax — deferred and other	**(4,322)**	7,740	9,468	15,160	(4,811)
Total Expenses	**333,973**	330,755	335,086	312,610	315,454
Gas Operating Income	**$ 17,188**	$ 30,487	$ 29,240	$ 38,291	$ 37,762

	1991	1990	1989	1988	1987
Electric Sales and Customers					**Table 5**
Sales — millions of kWh					
Residential	**7,022**	7,022	7,063	6,979	6,603
Commercial and industrial	**8,322**	8,359	8,636	8,566	8,004
Other	**469**	472	470	495	439
System sales	**15,813**	15,853	16,169	16,040	15,046
Sales to other utilities	**598**	532	633	433	239
Total Sales	**16,411**	16,385	16,802	16,473	15,285
Customers — monthly average					
Residential	**898,974**	895,294	890,406	882,962	872,419
Commercial and industrial	**101,740**	101,562	100,481	98,450	95,871
Others	**4,540**	4,504	4,452	4,436	4,389
Customers — total monthly average	**1,005,254**	1,001,360	995,339	985,848	972,679
Customers — total at year end	**1,005,363**	1,001,441	996,488	989,097	976,928
Residential					
kWh per customer	**7,812**	7,844	7,932	7,905	7,569
Revenue per kWh	**14.92¢**	14.21¢	12.95¢	11.97¢	12.13¢
Commercial and Industrial					
kWh per customer	**81,797**	82,304	85,943	87,005	83,487
Revenue per kWh	**12.86¢**	12.17¢	11.37¢	10.31¢	10.62¢
System					
kWh per customer	**16,326**	16,363	16,881	16,709	15,714
System revenue per kWh	**13.69¢**	13.01¢	12.00¢	10.97¢	11.30¢

Gas Sales and Customers					**Table 6**
Sales — thousands of dth					
Residential — space heating	**29,687**	29,810	32,024	31,276	29,239
— other	**3,195**	3,448	3,491	3,589	3,952
Non-residential — space heating	**11,636**	11,271	11,548	11,054	10,055
— other	**4,171**	4,352	4,539	4,580	4,389
Total firm sales	**48,689**	48,881	51,602	50,499	47,635
Interruptible sales	**4,538**	6,347	5,300	5,078	6,456
Total system sales	**53,227**	55,228	56,902	55,577	54,091
Sales to other utilities	—	—	—	—	2,218
Total Sales	**53,227**	55,228	56,902	55,577	56,309
Customers — monthly average					
Residential — space heating	**220,562**	211,400	204,982	198,949	192,550
— other	**171,581**	176,000	179,415	181,926	184,411
Non-residential — space heating	**30,453**	29,072	27,733	25,979	24,234
— other	**11,003**	11,310	11,517	11,725	11,778
Total firm customers	**433,599**	427,782	423,647	418,579	412,973
Interruptible customers	**472**	410	359	325	301
Customers — total monthly average	**434,071**	428,192	424,006	418,904	413,274
Customers — total at year end	**436,853**	430,571	426,060	421,429	415,629
Residential					
dth per customer	**83.9**	85.8	92.4	91.5	88.0
Revenue per dth	**$ 6.70**	$ 6.70	$ 6.78	$ 6.69	$ 6.84
Non-residential, firm					
dth per customer	**381.3**	386.9	409.9	414.6	401.1
Revenue per dth	**$ 6.10**	$ 6.08	$ 6.28	$ 6.15	$ 6.35
System					
dth per customer	**122.6**	128.9	134.2	132.7	136.3
System revenue per dth	**$ 6.36**	$ 6.43	$ 6.35	$ 6.26	$ 6.34

	1991	1990	1989	1988	1987
Electric Operations					**Table 7**
Energy — millions of kWh					
Net generation	**13,570**	13,981	15,220	15,228	14,004
Power purchased and (sold) — net	**3,638**	2,989	2,087	1,940	2,516
Total system requirements	**17,208**	16,970	17,307	17,168	16,520
Company use and unaccounted for	**(1,395)**	(1,117)	(1,138)	(1,128)	(1,474)
System sales	**15,813**	15,853	16,169	16,040	15,046
Sales to other utilities	**598**	532	633	433	239
Total Energy Available	**16,411**	16,385	16,802	16,473	15,285
Peak Demand — mW					
Station coincident demand	**3,085**	3,260	3,178	3,347	3,333
Purchased or (sold) — net	**819**	426	510	475	243
System Peak Demand	**3,904**	3,686	3,688	3,822	3,576
System Capability — mW					
LILCO stations	**4,078**	4,077	4,066	3,834	3,799
Nine Mile Point 2 (LILCO's 18% share)	**194**	194	194	194	—
Firm purchases — net	**244**	300	400	482	550
Total Capability	**4,516**	4,571	4,660	4,510	4,349
Fuel Consumed for Electric Operations					
Oil — thousands of barrels	**15,314**	16,401	20,480	19,927	18,624
Gas — thousands of dth	**32,924**	36,477	26,490	29,126	29,762
Nuclear — thousands of mW days	**154**	108	105	87	—
Total — billions of Btu	**129,937**	139,874	154,669	153,828	146,536
Dollars per million Btu	**$ 2.61**	$ 3.07	$ 2.86	$ 2.53	$ 2.86
Cents per kWh of net generation	**2.73¢**	3.24¢	3.06¢	2.67¢	3.01¢
Heat rate — Btu per net kWh	**10,484**	10,564	10,704	10,545	10,509
Fuel Mix *(Percentage of system requirements)*					
Oil	**50%**	56%	67%	68%	69%
Gas	**18**	20	13	15	16
Purchased Power	**25**	20	16	13	15
Nuclear Fuel	**7**	4	4	4	—
Total	**100%**	100%	100%	100%	100%

	1991	1990	1989	1988	1987
Gas Operations					**Table 8**
Energy — thousands of dth					
Natural gas	**55,579**	55,407	60,359	58,743	58,832
Manufactured gas and change in storage	**60**	(15)	53	(18)	(63)
Total Natural and Manufactured Gas	**55,639**	55,392	60,412	58,725	58,769
Total system requirements	**55,639**	55,392	60,412	58,725	56,551
Company use and unaccounted for	**(2,412)**	(164)	(3,510)	(3,148)	(2,460)
System sales	**53,227**	55,228	56,902	55,577	54,091
Sales to other utilities	**—**	—	—	—	2,218
Total Energy Available	**53,227**	55,228	56,902	55,577	56,309
Maximum Day Sendout — dth	**435,050**	406,177	462,610	431,940	404,679
System Capability — dth per day					
Natural gas	**507,344**	507,344	461,788	411,596	388,400
LNG manufactured or LP gas	**128,200**	128,200	145,600	145,600	145,600
Total Capability	**635,544**	635,544	607,388	557,196	534,000
Calendar Degree Days (65-year average 5,032)	**4,378**	4,139	5,169	5,162	4,805

	1991	1990	1989	1988	1987
Construction Expenditures* *(In thousands of dollars)*					**Table 9**
Electric					
Production	$ 32,541	$ 36,400	$ 59,880	$ 419,028	$ 153,544
Transmission	12,452	23,418	9,022	13,379	23,668
Distribution	74,770	82,975	66,679	64,653	32,209
General *(includes nuclear fuel)*	9,880	(1,765)	3,615	17,227	19,689
Electric Total	129,643	141,028	139,196	514,287	529,110
Gas Total	89,950	78,766	49,847	37,518	34,270
Common Total	17,958	12,671	11,007	9,352	17,795
Total Construction Expenditures	$ 237,551	$ 232,465	$ 200,050	$ 561,157	$ 581,175

**Includes non-cash allowance for other funds used during construction and excludes Shoreham post settlement costs.*

	1991	1990	1989	1988	1987
Balance Sheet *(In thousands of dollars)*					**Table 10**
Assets					
Utility plant	$ 4,334,736	$ 4,150,822	$ 3,939,410	$ 8,017,047	$ 9,274,103
Less — Accumulated depreciation, depletion and amortization	1,332,003	1,262,743	1,158,253	1,071,923	980,066
Total Net Utility Plant	3,002,733	2,888,079	2,781,157	6,945,124	8,294,037
Regulatory asset	3,786,403	3,887,373	3,988,344	—	—
Nonutility property and other investments	9,788	6,381	6,050	69,271	68,763
Current assets	884,017	726,060	982,032	571,934	606,579
Deferred charges					
Rate moderation component	602,053	411,443	102,971	—	—
Shoreham post settlement costs	378,386	225,818	75,044	—	—
Shoreham nuclear fuel	79,760	92,069	97,925	—	—
Accumulated deferred income taxes	439,235	359,768	262,298	525,029	127,061
Other	360,926	245,693	224,217	214,979	227,247
Total Deferred Charges	1,860,360	1,334,791	762,455	740,008	354,308
Total Assets	$ 9,543,301	$ 8,842,684	$ 8,520,038	$ 8,326,337	$ 9,323,687
Capitalization and Liabilities					
Capitalization					
Long-term debt	$ 5,001,016	$ 4,556,016	$ 4,560,016	$ 3,449,821	$ 3,724,601
Unamortized premium and (discount) on debt	(14,850)	(23,125)	(28,587)	(25,011)	(26,646)
Preferred stock — redemption required	524,912	527,556	541,187	513,924	520,788
Preferred stock — no redemption required	154,371	154,674	155,592	221,050	221,051
Treasury stock, at cost	—	—	—	(58,430)	(40,[illegible]81)
Retained earnings restricted for preferred stock dividend requirements	—	—	—	341,008	265,288
Common stock and premium	1,550,334	1,549,505	1,547,971	1,557,293	1,556,928
Capital stock expense	(40,216)	(42,676)	(42,916)	(56,151)	(56,144)
Retained earnings	620,373	560,405	436,690	679,579	1,801,919
Total Capitalization	7,795,940	7,282,349	7,169,953	6,623,083	7,966,904
Current Liabilities	492,895	449,830	470,885	583,017	339,573
Deferred Credits					
1989 Settlement credits	173,507	182,720	191,933	—	—
Class Settlement	173,564	167,569	164,040	—	—
Accumulated deferred income taxes	816,053	634,704	430,933	963,975	921,397
Other	84,035	117,172	81,443	144,015	83,217
Total Deferred Credits	1,247,159	1,102,165	868,349	1,107,990	1,004,614
Reserves for Claims, Damages, Pensions and Benefits	7,307	8,340	10,851	12,247	12,596
Total Capitalization and Liabilities	$ 9,543,3[illegible]	$ 8,842,684	$ 8,520,038	$ 8,326,337	$ 9,323,687

	1991	1990	1989	1988	1987
Capitalization Ratios*					**Table 11**
Long-term debt	**64%**	62%	63%	53%	47%
Preferred stock	**9**	10	10	15	12
Common equity	**27**	28	27	32	41
Total Capitalization	**100%**	100%	100%	100%	100%

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

Common and Preferred Stock Prices **Table 12**

The Common Stock of the Company is traded on the New York Stock Exchange and the Pacific Stock Exchange. The Preferred Stock $100 par value, Series B, E, I, J, K and S and the Preferred Stock $25 par value, Series O, P, Y and Z of the Company are, and Series T was traded on the New York Stock Exchange. The table below indicates the high and low prices on the New York Stock Exchange listing of composite transactions for the years 1991 and 1990.

		1991 Quarter				1990 Quarter			
		First	Second	Third	Fourth	First	Second	Third	Fourth
Common Stock	High	23¼	23⅝	24½	25	20¼	19⅝	21¾	21⅜
	Low	19	21½	22⅛	23⅛	18⅝	17¾	17¾	17½
Preferred Stock									
Series B 5.00%	High	53½	54	56¾	58	50⅛	49⅞	50	49½
	Low	48	51½	53	52	49	46	48	47⅝
Series E 4.35%	High	47	46¼	49	53	44¾	42½	44	44½
	Low	43½	44½	45	47½	42	40½	41	41¼
Series I 5¾%	High	136	131	136	141⅜	116	112	118	115
	Low	125	131	134	139	110½	109	114	109
Series J 8.12%	High	85¼	86	91	94	82	79	81¾	78⅞
	Low	78	82¾	83	88⅞	77	74	75	77
Series K 8.36%	High	85	88	91	97	85	79¾	83	81
	Low	78	83½	85	91	78	77½	78½	77½
Series O $2.47	High	25¾	26½	27	27⅝	24⅞	24⅞	25¼	25½
	Low	24¼	24¾	25	26	23¾	23¾	24⅝	23¾
Series P $2.43	High	25¾	27½	27⅝	28	25⅛	24	25	24¾
	Low	24½	24⅜	25½	26⅝	23⅜	22¾	21⅞	23½
Series S 9.80%	High	99⅝	101	102½	105	97⅛	96½	99⅛	97
	Low	96½	100	101	102	93⅝	92	95	94
Series T $3.31	High	27¾	27¼	—	—	26¾	26⅝	26⅞	27
	Low	26	26⅛	—	—	25⅝	25½	25¾	25⅞
Series Y $2.65	High	27	27¼	28	28½	26⅝	26	26⅝	26⅛
	Low	25	25⅞	26⅜	26⅛	24¾	24⅝	24½	24¾
Series Z $2.35	High	—	25½	26⅝	28⅜	—	—	—	—
	Low	—	25⅛	24⅞	26	—	—	—	—

The Preferred Stock $100 par value, Series D 4.25% is traded in the over-the-counter market and no price data is available. The Preferred Stock $100 par value, Series F, H, L, M and R Preferred Stock are held privately.

Corporate Information

Executive Offices
175 East Old Country Road
Hicksville, NY 11801

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 Dept.
11th Floor
101 Barclay Street
New York, NY 10286-1258
1-800-524-4458

Shareowners' Agent for Automatic Dividend Reinvestment Plan
The Bank of New York
Dividend Reinvestment Dept.
11th Floor
101 Barclay Street
New York, NY 10286-1258
1-800-524-4458

Annual Meeting
The Annual Meeting of Shareowners will be held on Monday, April 13, 1992 at 3:00 p.m. In connection with this meeting, proxies will be solicited by the Company. A notice of the meeting, a proxy statement and a proxy will be mailed to shareowners in March.

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: Long Island Lighting Company, Investor Relations, 175 East Old Country Road, Hicksville, NY 11801

Directors

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

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

George Bugliarello
President
Polytechnic University

Anthony F. Earley, Jr.
President and
Chief Operating Officer
Long Island Lighting Company

Winfield E. Fromm
Retired Vice President
Eaton Corporation
Electrical Engineering

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

Eben W. Pyne
Corporate Director
and Consultant
W.R. Grace and Company
Retired Senior Vice President
Citibank, N.A.

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
Director
Long Island Community
Foundation

Officers

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

Anthony F. Earley, Jr.
President and
Chief Operating Officer

James T. Flynn
Group Vice President
Engineering and Operations

Ralph T. Brandifino
Vice President
Finance

William N. Dimoulas
Vice President
Information Systems
and Technology

Robert X. Kelleher
Vice President
Human Resources

John D. Leonard, Jr.
Vice President
Corporate Services and
Nuclear Operations

Adam M. Madsen
Vice President
Corporate Planning

Arthur C. Marquardt
Vice President
Strategic Business Planning

Brian R. McCaffrey
Vice President
Administration

Joseph W. McDonnell
Vice President
Communications

William G. Schiffmacher
Vice President
Electric Operations

Robert B. Steger
Vice President
Fossil Production

William E. Steiger, Jr.
Vice President
Engineering and Construction

Christian G. Wilding
Vice President
Conservation and
Load Management

Walter F. Wilm, Jr.
Vice President
Gas Operations

Edward J. Youngling
Vice President
Customer Relations

Victor A. Staffieri
General Counsel and
Corporate Secretary

Audrey R. Ragogna
Treasurer

Thomas J. Vallely, III
Controller

Herbert M. Leiman
Assistant General Counsel
and Assistant Corporate
Secretary

Kathleen A. Marion
Assistant Corporate
Secretary and Assistant
to the Chairman

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

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