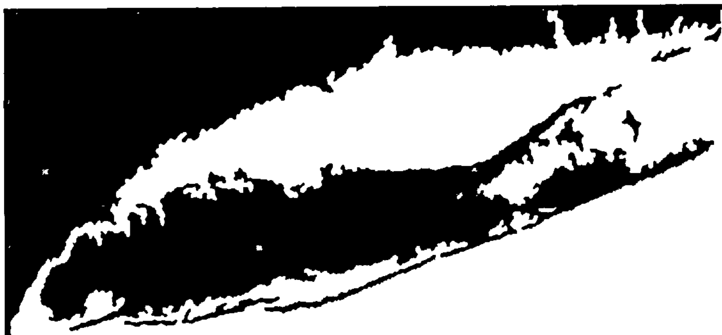
LONG ISLAND LIGHTING COMPANY

Annual

Report

1996



The Long Island Lighting Company's 5,413 employees provide electric and gas service to more than 1 million customers in New York's Nassau and Suffolk Counties and in the Rockaway Peninsula in Queens County. The Company's service territory covers 1,230 square miles with a population of approximately 2.7 million people.

COMPANY HIGHLIGHTS

Announced agreement to merge with Brooklyn Union to create a holding company with expected revenues of $4.5 billion.

Reached an agreement with the Long Island Power Authority (LIPA) for a partial LIPA buyout of LILCO, providing for electric rate reductions of 16–18 percent.

Generated sufficient cash from operations to meet all operating, construction and dividend requirements.

Redeemed $415 million of maturing General & Refunding bonds with cash on hand thereby reducing the Company's debt ratio to below 60 percent.

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DEAR FELLOW SHAREHOLDER

Few would contest that, despite a long list of accomplishments throughout 1996, the most compelling event of the year occurred just days before year's end.

On December 29, LILCO and The Brooklyn Union Gas Company (BU) announced a merger that would create a new, powerful energy company stretching from Staten Island to Montauk Point. The combined company, which will serve about 2.2 million customers, will have a new name and new opportunities in the rapidly changing energy marketplace.

On March 19, 1997, another significant event occurred. Governor George Pataki unveiled an agreement between LILCO and the Long Island Power Authority (LIPA) for LIPA to acquire a portion of LILCO's electric business, paving the way for a 16 to 18 percent reduction in Long Island's electric rates immediately upon completion of the transaction.

At the conclusion of these two transactions, the Long Island Lighting Company will be transformed into a new entity, a comprehensive energy services company with the resources to diversify and grow in the changing energy industry. I strongly believe that the emerging company will have tremendous potential in the marketplace of the 21st century.

A WINNING COMBINATION

Throughout the lengthy discussions that led to each of these agreements, your Board of Directors had a single priority — that any agreement reached would be a good business decision, one that benefits our investors, our customers and our employees. The LILCO/Brooklyn Union merger and the LIPA transaction each accomplish that goal.

The logistics of the merger are fairly straightforward. In a share exchange agreement, LILCO shareholders will receive 0.803 shares of the new company for each of their LILCO common shares. Brooklyn Union shareholders will receive one share in the new company for each common share they own. LILCO shareholders will own 66 percent of the new company; Brooklyn Union shareholders will own 34 percent. If the LIPA transaction is also completed, LILCO shareholders will receive 0.880 shares for each common share, increasing LILCO ownership of the new company to 68 percent. Under either scenario, the merged company will be organized as a holding company with subsidiaries to handle various energy products and services.

Upon completion of the merger, I will become chairman and chief executive officer (CEO) of the new company and Robert B. Catell, currently chairman and CEO of Brooklyn Union, will become president and chief operating officer. After a period of one year, Mr. Catell will succeed me as CEO of the merged company, while I continue as chairman. The board of directors of the new company will be comprised of 15 members, six from LILCO and six from Brooklyn Union, with three new members to be chosen jointly.

STRENGTHENING OUR POSITION

The benefits of the merger for both LILCO and Brooklyn Union are clear. By joining two utilities with adjacent territo-

1996 Earnings

Earnings for 1996 were $264 million or $2.20 per common share, higher than in 1995 for both the electric and gas businesses. The increase in electric earnings was primarily attributable to the company earning its allowed rate of return on increased investment in its electric system in 1996 as compared to 1995.

The increase in gas earnings was primarily due to higher revenues from new gas space heating customers and the 3.2 percent gas rate increase that became effective on December 1, 1995.

Electric revenues remained stable at $2.5 billion in 1996, and gas revenues increased by 16 percent to reach $684 million. The common stock dividend was maintained at $1.78 per share.

Reducing Costs

Throughout 1996, the company remained committed to controlling energy rates through aggressive cost-containment programs. As part of that effort, we cut operating and maintenance costs by approximately $12 million and construction expenditures by $4 million, as compared to 1995.

We continued to streamline our staffing level through attrition, reducing our employee population by an additional five percent in 1996. At the same time, we maximized remaining resources by bringing work previously done by contractors "in-house" whenever possible.

ries and complementary services, we create a stronger, more versatile player in an increasingly competitive energy market. The new company will be able to use its resources more effectively. Certain administrative functions can be combined to cut costs, and the larger entity will have greater economies of scale in such areas as fuels purchasing and energy trading. We expect that these economies of scale will result in more than $1 billion in efficiency savings in the first ten years of the merger.

In addition, customers of both utilities will benefit from the experienced workforce available to the merged utility. By cross-training its employees, the new company will have a larger pool of workers to respond to storms and other service demands, improving reliability to customers throughout the combined service territory.

BUILDING ON ACCOMPLISHMENT

The LIPA transaction offers additional benefits to the combined company. LIPA, a New York State agency authorized by statute during the Shoreham controversy to acquire all or part of LILCO's stock or assets, received an exemption from the 1986 Federal Tax Policy Act which allows it to issue tax-exempt debt to finance such an acquisition. It is the only state agency in the country with this exemption.

In the years since LIPA was created, several plans to use LIPA's unique, tax-free status to reduce Long Island electric rates have been proposed. In late 1995, Governor Pataki charged a newly reconstituted LIPA board with developing a new plan that would produce double-digit rate reductions. The challenge for LILCO was to work with LIPA to use its tax-free status in a way that lowered rates significantly while allowing customers to continue to receive reliable electric services. The proposed agreement with LIPA accomplishes this objective and more.

The agreement with LIPA is more complex than the LILCO/BU merger. Under the proposed transaction, LIPA will acquire LILCO's electric transmission and distribution system, its electric regulatory assets and its 18 percent share in the Nine Mile Point Two nuclear power plant. Through a stock transaction, LIPA will acquire these assets for approximately $2.5 billion in cash and assume the obligation for $339 million in preferred stock. It will also assume approximately $3.6 billion of LILCO debt securities.

LIPA has indicated that it will finance the transaction by issuing tax-exempt bonds. It is expected that the transaction will provide the combined LILCO/BU with about $2 billion in cash, after the payment of taxes and other transition costs. After we receive the approval of our shareholders, LILCO and Brooklyn Union will begin a strategic planning process to determine the best use of our joint assets to maximize shareholder value.

In the negotiated agreement, LIPA also will acquire the tax certiorari lawsuit on the Shoreham property and those pending on LILCO's other properties throughout Long Island. LIPA has indicated that it will settle the Shoreham lawsuit by creating a two percent rate differential between Nassau and

Suffolk Counties, since Suffolk has received the tax benefit from the Shoreham overassessment. The net result for customers will be an across-the-board rate reduction of between 16 and 18 percent, achieved through the combination of synergy savings from the merger, the Shoreham property tax settlement, and the full effects of LIPA's tax exemption and lower financing costs. LIPA has stated that the remaining tax suits will be resolved without any property tax increases for the community.

The merged LILCO/BU will retain the entire operations of Brooklyn Union, as well as LILCO's natural gas distribution system, non-nuclear generation, office buildings, customer offices, computer systems, and other common plant items.

MAINTAINING RELIABLE SERVICE

As part of the LIPA agreement, the new company created from the LILCO/BU merger will operate the LIPA-owned electric transmission and distribution system under an eight-year management contract. LILCO has entered into a power supply agreement with LIPA under which LILCO/BU will supply and manage LIPA's power requirements for a 15-year period. LIPA will contract to purchase approximately 3,900 megawatts of generation capacity annually from the merged company — essentially all of LILCO's current Long Island-based generation. LIPA will also assume all existing LILCO firm power purchase contracts and transmission agreements.

After the third year of the power supply agreement, LIPA will have a one-year option to purchase all of LILCO/BUs electric generating assets for fair market value. If they choose not to exercise this option, they have the ability to gradually decrease the amount of power purchased from the LILCO/BU company beginning in the eighth year of the agreement.

Although the transaction itself is complicated, the benefits are simple. With the completion of the LIPA agreement, the new company will continue to distribute natural gas, generate electricity and manage the electric business on Long Island, but will also have the capital to invest in other businesses.

VISION FOR THE FUTURE

Customers benefit through reduced rates, greater economic development potential for our region, and protection from property tax increases. Shareholders can benefit through the increased opportunities available to the merged company. With the combined resources of LILCO and Brooklyn Union, as well as the proceeds from the LIPA transaction, the merged utility can develop and market innovative energy products and services in the years ahead. We will be a formidable player in the competitive energy market.

There are still a number of steps to be taken before either the merger or the LIPA transaction can take place. The first step is approval by both LILCO and Brooklyn Union shareholders of the merger and by LILCO common and certain preferred shareholders for the LIPA transaction. In addition to the shareholder votes, the merger must also be approved by the New York State Public Service Commission, the Federal Energy Regulatory Commission, the Federal Trade Commission, and the Nuclear Regulatory Commission.

Continued Growth

The improving Long Island economy presented the company with renewed opportunities in the electric business in 1996. We added approximately 7,000 new electric customers to the system, as well as reconnected service to businesses that had closed due to financial difficulties. As a result, electric sales increased 1.2 percent last year on a weather-normalized basis, and we project similar growth in 1997.

We also aggressively pursued non-traditional gas markets such as off-system sales, gas brokering, gas management services, energy swaps and synthetic storage agreements. Revenue from these markets was $73 million in 1996, up from $27 million the previous year.

The LIPA transaction also requires state and federal approvals, including a favorable ruling by the Internal Revenue Service. We expect to be able to finalize the merger and the LIPA transaction concurrently, with the entire process taking between 12 and 18 months to complete.

The changing energy marketplace will be our challenge in the years beyond the merger and the LIPA transaction. We have been given the opportunity to truly take advantage of the deregulated energy industry. We will still provide quality energy services to the customers we now service, and we will have the resources to acquire diverse energy assets that can greatly expand the scope of our business.

These are truly exciting times. Oliver Wendell Holmes, Jr., said, "The greatest thing in this world is not so much where we are, but in which direction we are moving." LILCO is moving in a direction that has immeasurable potential in the new energy frontier.

I look forward to helping create this new entity. I hope you share my anticipation and excitement for the future.

W. J. Catacosinos

William J. Catacosinos
Chairman and Chief Executive Officer
May 28 , 1997

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Financial Review

Results of Operations

Earnings

Earnings for the years 1996, 1995 and 1994 were as follows:

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

	1996	1995	1994
Net income	$ 316.5	$ 303.3	$ 301.8
Preferred stock dividend requirements	52.2	52.6	53.0
Earnings for Common Stock	$ 264.3	$ 250.7	$ 248.8
Average common shares outstanding	120.4	119.2	115.9
Earnings per Common Share	$ 2.20	$ 2.10	$ 2.15

The Company's 1996 earnings are higher for both the electric and gas businesses as compared to 1995. While the Company's allowed rate of return in 1996 was the same as 1995, the higher earnings for the electric business are a result of the Company's increased investment in electric plant in 1996, as compared to 1995. Factors contributing to the increase in electric business earnings include the Company's continued efforts to reduce operations and maintenance expenses and the efficient use of cash generated by operations to retire maturing debt.

The increase in earnings in the gas business was the result of additional revenues due to the continued growth in the number of gas space heating customers. Also contributing to the increase in gas business earnings was a 3.2% rate increase which became effective December 1, 1995, and an increase in off-system sales.

The Company's 1995 earnings per common share were lower than 1994 earnings per common share as a result of the New York State Public Service Commission's (PSC) electric rate order, effective December 1, 1994, that lowered the allowed return on common equity from 11.6% to 11.0% and modified certain performance-based incentives. Partially offsetting the effects on earnings of the electric rate order was higher gas business earnings in 1995 when compared to 1994.

Revenues

Electric Revenues

Revenues from the Company's electric operations totaled $2.5 billion in each of the years ended December 31, 1996, 1995 and 1994.

The Company experienced a growth in electric system sales in 1996 on a weather normalized basis compared to 1995 and in 1995 compared to 1994. This growth is primarily attributable to the addition of new electric customers. The Company's electric revenues fluctuate as a result of system growth, variations in weather, and fuel costs, as electric base rates have remained unchanged since December 1993. However, these variations have no impact on earnings due to the current electric rate structure which includes a revenue reconciliation mechanism which eliminates the impact on earnings caused by sales volumes that are above or below adjudicated levels. Total electric sales volumes were 16,414 million kilowatt hours (kWh) in 1996, compared to 16,572 million kWh in 1995 and 16,382 million kWh in 1994.

For a further discussion on electric rates, see Notes 1 and 3 of Notes to Financial Statements.

Gas Revenues

Revenues from the Company's gas operations for the years 1996, 1995 and 1994 were $684 million, $591 million and $586 million, respectively.

The increase in 1996 gas revenues when compared to 1995 is attributable to a 3.2% gas rate increase which became effective on December 1, 1995, an increase in sales volumes, an increase in gas fuel expense recoveries and revenues generated through the Company's continuing efforts to provide non-traditional services, including off-system sales. The increase in 1995 revenues when compared to 1994 is attributable to a 3.8% gas rate increase, effective December 1, 1994, offset by a decrease in fuel expense recoveries.

The Company experienced a 6.3% increase in firm sales volumes in 1996 compared to 1995, due to the addition of approximately 5,100 gas space heating customers and colder weather during the 1996 heating season when compared to the prior year. The increase in sales volumes caused by variations in weather has a limited impact on revenues as the Company's current gas rate structure includes a weather normalization clause which mitigates the impact on revenues of experiencing weather that is warmer or colder than normal.

The Company continues to increase its space heating penetration through various marketing programs, and as a result of these efforts has added approximately 20,000 gas space heating customers over the past three years.

The recovery of gas fuel expenses in 1996 when compared to 1995 increased approximately $31 million as a result of higher average gas prices and increased per customer usage due to colder weather than experienced in the prior year. In 1995, the Company experienced a decrease of $24 million in the recoveries of gas fuel expenses when compared to the same period of 1994, primarily due to lower average gas prices.

In 1996, non-traditional revenues totaled $46 million, including $37 million for off-system sales. In 1995 and 1994, revenues from off-system sales totaled $24 million and $26 million, respectively. Profits generated from off-system sales are allocated 85% to the firm gas ratepayer and 15% to the shareowners, in accordance with PSC mandates.

Operating Expenses

Fuel and Purchased Power

Fuel and purchased power expenses for the years 1996, 1995 and 1994 were as follows:

(In millions of dollars)	1996	1995	1994
Fuel for Electric Operations			
Oil	$ 158	$ 98	$ 145
Gas	138	149	101
Nuclear	15	14	15
Purchased power	329	310	308
Total	640	571	569
Gas fuel	323	264	279
Total	$ 963	$ 835	$ 848

Electric fuel and purchased power mix for the years 1996, 1995 and 1994 were as follows:

(In thousands of MWH)	1996		1995		1994	
	MWH	*%*	*MWH*	*%*	*MWH*	*%*
Oil	4,219	24	3,099	17	4,480	25
Gas	4,542	25	6,344	36	4,056	23
Nuclear	1,558	9	1,301	7	1,498	9
Purchased power	7,388	42	7,143	40	7,640	43
Total	17,707	100%	17,887	100%	17,674	100%

During 1996, the Company completed the first of two planned conversions of oil fired steam generating units at its Port Jefferson Power Station to dual firing units, bringing the total number of steam units capable of burning natural gas to eight. Of the Company's eight steam generation units capable of burning natural gas, six are dual-fired, providing the Company with the ability to burn the most cost efficient fuel available, consistent with seasonal environmental requirements, thereby providing customers with the lowest possible cost energy. The conversion of the second unit at Port Jefferson has a projected completion date of May 1997.

As a result of a sharp increase in the cost of natural gas during the year, generation with oil became more economical than generation with gas. The total barrels of oil consumed for electric operations were 7.1 million, 5.2 million, and 7.5 million for the years 1996, 1995 and 1994, respectively.

Cogenerators, Independent Power Producers (IPPs) and energy supplied from a facility in Holtsville, New York, owned by the New York Power Authority (NYPA), and constructed for the benefit of the Company, provided approximately 16% of the total energy made available by the Company in 1996 and 1995, compared to approximately 14% in 1994. Increases in purchased power expenses in 1996 compared to 1995 is due to increases in the average unit price and in the quantity purchased. The increase in purchased power expenses in 1995 compared to 1994 is primarily attributable to increased purchases from the NYPA Holtsville facility which began commercial operations in 1994.

Gas system fuel expense increased in 1996 by $58 million when compared with 1995, due to higher firm sales volumes and a 26% increase in the Company's average price of gas. In 1995, this expense decreased by $15 million when compared with 1994, as a result of a decline in the average price of gas, despite higher sales volumes.

Variations in fuel costs have no impact on operating results as the Company's current rate structures include fuel adjustment clauses whereby variations between actual fuel costs and fuel costs included in base rates are deferred and subsequently returned to or collected from customers. However, in a period when base electric fuel costs are in excess of actual electric fuel costs, such amounts are credited to the RMC.

Operations and Maintenance Expenses

Operations and maintenance (O&M) expenses, excluding fuel and purchased power, were $499 million, $511 million and $541 million, for the years 1996, 1995 and 1994, respectively. The decrease in O&M for 1996 compared to 1995 and 1995 compared to 1994 was primarily due to the Company's continuing cost containment program which resulted in lower plant maintenance expenses, lower distribution expenses and lower administrative and general expenses.

Rate Moderation Component

The Rate Moderation Component (RMC) represents the difference between the Company's revenue requirements under conventional ratemaking and the revenues provided by its electric rate structure. The RMC is adjusted monthly for the operation of the Company's Fuel Moderation Component (FMC) mechanism and the difference between the Company's share of actual operating costs at Nine Mile Point Nuclear Power Station, Unit 2 (NMP2) and amounts provided for in electric rates.

In 1996, the Company recorded a non-cash credit to income of approximately $50 million, representing the amount by which revenue requirements exceeded revenues provided for under the current electric rate structure. Partially offsetting this accretion were the effects of the FMC mechanism and the differences between actual and adjudicated operating costs for NMP2, as discussed above. The adjustments to the accretion of the RMC totaled $26 million, of which $24 million was derived from the operation of the FMC mechanism.

In 1995 and 1994, the Company recorded non-cash charges to income of approximately $22 million and $198 million, respectively, after giving effect to the credits generated principally by the operation of the FMC mechanism. FMC credits for 1995 and 1994 totaled $87 million and $83 million, respectively.

Based on the Company's current long-range projections for energy sales, operations and maintenance costs, property taxes, construction and other expenditures, the RMC balance will be fully amortized by year-end 2001. The assumptions used in the forecast are as follows: (i) the Company's base electric rates remain at current levels through the year 2001; (ii) the Company receives PSC permission to credit the Phase I Shoreham property tax litigation proceeds that the Company received in January 1996 to the RMC balance in 1997, at which time the proceeds plus interest are expected to be $83 million; and (iii) $360 million of the total judgment awarded the Company in Phase II of the Shoreham property tax case is received by the Company during the 1999 to 2001 time frame and will be applied to reduce the RMC balance. Based upon the assumptions used in this forecast, RMC non-cash charges to income will be approximately $52 million in 1997, $89 million in 1998, $143 million in 1999, $57 million in 2000 and $57 million in 2001. These estimates are based on the multi-year rate plan (Plan) submitted to the PSC in September 1996.

If the assumptions outlined immediately above are not adopted by the PSC, the Company proposed as an alternative in the September 1996 filing that, in order to insure the timely and certain recovery of any remaining RMC balance at November 30, 1999, that the Company recover any such balance through rates over a two year period using its Fuel Adjustment Clause. By using the Fuel Adjustment Clause, which it has used in the past to recover other regulatory assets, customer bills would be automatically adjusted in order to amortize on a straight-line-basis any remaining RMC balance over a two year period ending November 30, 2001.

Based upon the above, and the fact that actions of the PSC continue to support the full recovery of the Shoreham related regulatory assets, as provided in the Rate Moderation Agreement (RMA), the Company believes that future revenues will be provided specifically for the recovery of the RMC balance. For a further discussion of the Plan, see Rate Matters, under the heading "Electric."

For a further discussion of the RMC, see Note 3 of Notes to Financial Statements.

Other Regulatory Amortization

In 1996, the net total of other regulatory amortization was a non-cash charge to income of $127 million, compared to $162 million in 1995 and $4 million in 1994.

The change from 1996 to 1995 is primarily attributable to the operation of the revenue reconciliation mechanism included in the Company's electric rate structure, partially offset by a non-cash charge to income recorded to reduce the Company's earnings to the levels provided for in rates for both the electric and gas businesses.

The electric revenue reconciliation mechanism, as established under the LILCO Ratemaking and Performance Plan (LRPP), eliminates the impact on earnings of experiencing sales that are above or below adjudicated levels by providing a fixed annual net margin level (defined as sales revenue, net of fuel and gross receipts taxes). Variations in electric revenue resulting from differences between actual and adjudicated net margin sales levels are deferred on a monthly basis during the rate year. The Company recorded a non-cash charge to income of approximately $3 million and $64 million for the years 1996 and 1995, respectively, representing a net margin level in excess of that provided for in rates. The decrease between 1996 and 1995 was the result of an increase in the adjudicated net margin sales levels and cooler summer weather in 1996 when compared to 1995.

Earnings in excess of the Company's allowed return on common equity generated by the electric business was approximately $9 million for the 1996 rate year compared to approximately $6 million for the 1995 rate year. In accordance with the Company's electric rate structure, earnings above the allowed return on common equity are applied against the RMC balance. The ratepayers' portion of gas earnings in excess of a 10.6% allowed return on common equity totaled $10 million for the 1996 rate year compared to $1 million in 1995.

In 1995, other regulatory amortization was higher than 1994 as a result of the operation of the revenue reconciliation mechanism and an increase in the amortization of prior period LRPP deferrals, as more fully discussed in Note 3 of Notes to Financial Statements.

Operating Taxes

Operating taxes were $472 million, $448 million and $407 million for the years 1996, 1995 and 1994, respectively. The increase in 1996 compared to 1995 is primarily attributable to increased property taxes, as well as higher gross receipts taxes due to increased revenues. The increase in 1995 when compared to 1994 is primarily attributable to higher property taxes.

Federal Income Tax

Federal income tax was $209 million, $206 million and $177 million for the years 1996, 1995 and 1994, respectively. The increase in federal income tax in 1996 when compared to 1995 was primarily attributable to higher earnings, partially offset by the utilization of investment tax credits. The increase in 1995 when compared to 1994 was primarily attributable to higher earnings and the amortization of previously deferred taxes resulting from a change in corporate tax rates.

Other Income and Deductions

Other income and deductions, totaled $19 million for 1996, compared to $34 million and $35 million for 1995 and 1994, respectively. The decrease in 1996 when compared to 1995 is primarily attributable to the recognition of nonrecurring expenditures associated with one of the Company's wholly-owned subsidiaries, a decrease in non-cash carrying charge income associated with regulatory assets not currently in rate base and the recognition in 1995 of certain litigation proceeds related to the construction of the Shoreham Nuclear Power Station. The change from 1995 when compared to 1994, in addition to the effects of the litigation proceeds, resulted from lower non-cash carrying charges and lower incentive income as a result of the PSC rate order for the rate year ended November 30, 1995, which eliminated certain performance-based incentives.

Interest Expense

Lower interest expense in 1996 compared to 1995, and in 1995 compared to 1994 is primarily attributable to lower outstanding debt levels, partially offset by higher letter of credit and commitment fees associated with the change in the Company's credit rating in 1996. For a further discussion of the Company's investment ratings, see the discussion below under the heading "Investment Rating". The Company's strategy continues to be the application of available cash balances toward the satisfaction of maturing debt whenever practicable. Accordingly, in 1996, the Company used cash on hand and cash previously deposited with the Trustee of the General & Refunding (G&R) Mortgage to satisfy the mandatory redemption of $415 million of the Company's G&R Bonds. During 1995, the Company used approximately $75 million of cash on hand to redeem, prior to maturity, the remaining outstanding First Mortgage Bonds.

Liquidity and Capital Resources

Liquidity

During 1996, cash generated from operations exceeded the Company's operating, construction and dividend requirements. This positive cash flow is the result of, among other things: (i) the Company's continuing efforts to reduce both O&M expenses and construction expenditures; (ii) lower interest payments resulting from lower debt levels; and (iii) increased revenues from off-system gas sales.

At December 31, 1996, the Company's cash and cash equivalents amounted to approximately $280 million, compared to $351 million at December 31, 1995. In addition, the Company has available for its use a revolving line of credit through October 1, 1997, provided by its 1989 Revolving Credit Agreement (1989 RCA). In July 1996, at the Company's request, the amount committed by the banks participating in the facility was reduced from $300 million to $250 million. The Company believes this action is appropriate given the levels of cash on hand, projected future cash generated from operations and modest debt and preferred stock maturities through 1998. This line of credit is secured by a first lien upon the Company's accounts receivable and fuel oil inventories. For a further discussion of the 1989 RCA, see Note 7 of Notes to Financial Statements.

In January 1996, the Company received approximately $81 million, including interest, from Suffolk County pursuant to a judgment in the Company's favor that found that the Shoreham property was overvalued for property tax purposes between 1976 and 1983 (excluding 1979 which had previously been settled). The Company has petitioned the PSC to allow the Company to reduce the RMC balance by the amount received, net of litigation costs incurred by the Company. The PSC has not yet acted on the Company's petition and, therefore, such amounts continue to be deferred on the Company's balance sheet as other regulatory liabilities.

In November 1996, the New York State Supreme Court ruled that Shoreham had also been over-assessed for real property tax purposes for the years 1984 through 1992. Based on this over-assessment, the Company has preliminarily estimated that it is entitled to a tax refund of approximately $500 million plus interest. If the assessment for the 1991-92 tax year is used to determine the proper amount of payments-in-lieu-of-taxes (PILOTs), this ruling should also result in a refund of approximately $260 million plus interest for PILOTs for the years 1992-1996.

The refund of any real property taxes, PILOTs, and interest thereon, net of litigation costs, will be used to reduce electric rates in the future. However, the court's ruling is subject to appeal and, as a result, the Company is unable to determine the amount and timing of any real property tax and PILOT refunds.

The Company does not intend to access the financial markets during 1997 to meet any of its operating, construction or refunding requirements, including the retirement of its $250 million of maturing debt on February 15, 1997. However, if necessary, the Company will avail itself of interim financing via the 1989 RCA to satisfy a portion of the debt maturing in February 1997. The Company will avail itself of any tax-exempt financing made available to it by the New York State Energy Research and Development Authority (NYSERDA). With respect to the repayment of $101 million of maturing debt in 1998 and the repayment of $454 million of maturing debt and $22 million of mandatory redemption requirements of preferred stock in 1999, the Company intends to use cash generated from operations to the maximum extent practicable.

In 1990 and 1992, the Company received Revenue Agents' Reports disallowing certain deductions and credits claimed by the Company on its federal income tax returns for the years 1981 through 1989. The Revenue Agents' Reports reflect proposed adjustments to the Company's federal income tax returns for this period which, if sustained, would give rise to tax deficiencies totaling approximately $227 million. The Company believes that any such deficiencies as finally determined would be significantly less than the amounts proposed in the Revenue Agents' Reports. The Company has protested some of the proposed adjustments which are presently under review by the Regional Appeals Office of the Internal Revenue Service. The Company believes that cash balances at the time of settlement will be sufficient to satisfy any settlement reached. However, if necessary, the Company will avail itself of interim financing via the 1989 RCA to meet this obligation. The Company currently believes that a settlement of the 1981 through 1989 years should be reached with the Regional Appeals Office sometime in 1997.

Capitalization

The Company's capitalization, including current maturities of long-term debt and current redemption requirements of preferred stock, at December 31, 1996 and 1995, was $7.9 billion and $8.3 billion, respectively. At December 31, 1996 and 1995, the Company's capitalization ratios were as follows:

	1996	*1995*
Long-term debt	59.3%	61.8%
Preferred stock	8.9	8.6
Common shareowners' equity	31.8	29.6
	100.0%	100.0%

In support of the Company's continuing goal to reduce its debt ratio, the Company, in 1996, retired at maturity $415 million of G&R Bonds, with cash on hand and cash previously deposited with the Trustee of the G&R Mortgage.

The Company expects to use cash on hand to satisfy the $250 million of G&R Bonds scheduled to mature in February 1997. However, if necessary, the Company will avail itself of interim financing via the 1989 RCA to satisfy a portion of this obligation.

Investment Rating

The Company's securities are rated by Standard and Poor's (S&P), Moody's Investors Service, Inc. (Moody's), Fitch Investors Service, L.P. (Fitch) and Duff & Phelps Credit Rating Co. (D&P). The rating agencies have been watching the electric utility industry closely and have expressed concern regarding the ability of high cost utilities, such as the Company, to recover all of their fixed costs in a competitive, deregulated marketplace.

In June 1996, Moody's downgraded its rating of the Company's G&R Bonds from minimum investment grade to one notch below minimum investment grade. Moody's also downgraded its ratings of the Company's debentures and preferred stock, which were already below minimum investment grade.

In November 1996, Moody's revised its outlook on the Company's G&R Bonds, debentures and preferred stock from negative to stable, as a result of a New York State Supreme Court ruling that found that Shoreham had been overvalued for real property taxes for the years 1984 through 1992. For a further discussion of this ruling, see Item 3, Legal Proceedings.

As a result of the announcement of the merger agreement on December 29, 1996 between the Company and The Brooklyn Union Gas Company, the Company's bond ratings "outlook"/"Credit Watch" was raised to "positive" by Moody's, S & P and Fitch. D&P has reaffirmed the Company's ratings but maintains a rating watch with uncertain implications.

At December 31, 1996 the ratings for each of the Company's principal securities were as follows:

	S&P	*Moody's*	*Fitch*	*D&P*
G&R Bonds	BBB-	Ba1	BBB-	BBB
Debentures	BB+	Ba3	BB+	BB+
Preferred Stock	BB+	ba3	BB-*	BB
Minimum Investment Grade	BBB-	Baa3	BBB-	BBB-

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

** In December 1996, Fitch announced that it will begin rating preferred stock on the same scale as investment grade and speculative bonds and, as a result, the Company's preferred stock is now rated BB-.*

Capital Requirements and Capital Provided

Capital requirements and capital provided for 1996 and 1995 were as follows:

(In millions of dollars)	*1996*	*1995*
Capital Requirements		
Construction*		
Electric	$ 142	$ 144
Gas	71	79
Common	27	21
Total Construction	240	244
Refundings and Dividends		
Long-term debt	415	100
Preferred stock	5	5
Common stock dividends	214	211
Preferred stock dividends	52	53
Total Refundings and Dividends	686	369
Shoreham post-settlement costs	52	71
Total Capital Requirements	**$ 978**	**$ 684**
Capital Provided		
Cash generated from operations	$ 892	$ 772
Long-term debt issued	–	49
Common stock issued	19	20
Other investing activities	(4)	9
Increase (decrease) in cash	71	(166)
Total Capital Provided	**$ 978**	**$ 684**

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

For further information, see the Statement of Cash Flows.

For 1997, total capital requirements (excluding common stock dividends) are estimated to be $629 million, of which maturing debt is $251 million, construction requirements are $282 million, preferred stock dividends are $52 million, preferred stock sinking funds are $1 million and Shoreham post-settlement costs are $43 million (including $41 million for payments-in-lieu-of-taxes). The Company believes that cash generated from operations coupled with beginning cash balances will be sufficient to meet all capital requirements in 1997.

Based upon the projections of peak demand for electric power, the Company believes it will need to acquire additional generating or demand-side resources starting in 1998 in order to maintain satisfactory electric supply. The Company's Integrated Electric Resource Plan (IERP), recommends a combination of a peak load reduction demand-side management program and a capacity purchase as the most economical method of meeting this need. The IERP projects that new electric generating capacity will need to be installed on Long Island to meet peak demand in the summer of 2001. It is anticipated that such new capacity would be acquired through a competitive bidding process.

Other Matters

Merger Agreement with The Brooklyn Union Gas Company

On December 29, 1996, the Company and The Brooklyn Union Gas Company (Brooklyn Union) entered into an Agreement and Plan of Exchange (Share Exchange Agreement), pursuant to which the companies will be merged in a transaction that will result in the formation of a new holding company. The new holding company, which has not yet been named, will serve approximately 2.2 million customers and have annual revenues of more than $4.5 billion. The merger is expected to be accomplished through a tax-free exchange of shares.

The description of the Share Exchange Agreement set forth herein does not purport to be complete and is qualified in its entirety by the provisions of the Share Exchange Agreement, filed as an exhibit to the Company's Current Report on Form 8-K dated December 30, 1996.

The proposed transaction, which has been approved by both companies' boards of directors, would unite the resources of the Company with the resources of Brooklyn Union. Brooklyn Union, with approximately 3,300 employees, distributes natural gas at retail, primarily in a territory of approximately 187 square miles which includes the boroughs of Brooklyn and Staten Island and approximately two-thirds of the borough of Queens, all in New York City. Brooklyn Union has energy-related investments in gas exploration, production and marketing in the United States and Canada, as well as energy services in the United States, including cogeneration products, pipeline transportation and gas storage.

Under the terms of the proposed transaction, the Company's common shareowners will receive .803 shares (the Ratio) of the new holding company's common stock for each share of the Company's common stock that they currently hold. Brooklyn Union common shareowners will receive one share of common stock of the new holding company for each common share of Brooklyn Union they currently hold. Shareowners of the Company will own approximately 66% of the common stock of the new holding company while Brooklyn Union shareowners will own approximately 34%. The proposed transaction will have no effect on either company's debt issues or outstanding preferred stock.

The Share Exchange Agreement contains certain covenants of the parties pending the consummation of the transaction. Generally, the parties must carry on their businesses in the ordinary course consistent with past practice, may not increase dividends on common stock beyond specified levels and may not issue capital stock beyond certain limits. The Share Exchange Agreement also contains restrictions on, among other things, charter and by-law amendments, capital expenditures, acquisitions, dispositions, incurrence of indebtedness, certain increases in employee compensation and benefits, and affiliate transactions. Accordingly, the Company's ability to engage in certain activity described herein may be limited or prohibited by the Share Exchange Agreement.

Upon completion of the merger, Dr. William J. Catacosinos will become chairman and chief executive officer of the new holding company; Mr. Robert B. Catell, currently chairman and chief executive officer of Brooklyn Union, will become president and chief operating officer of the new holding company. One year after the closing, Mr. Catell will succeed Dr. Catacosinos as chief executive officer, with Dr. Catacosinos continuing as chairman. The board of directors of the new company will be composed of 15 members, six from the Company, six from Brooklyn Union and three additional persons previously unaffiliated with either company and jointly selected by them.

The companies will continue their respective current dividend policies until the closing, consistent with the provisions of the Share Exchange Agreement. It is expected that the new holding company's dividend policy will be determined prior to closing.

The merger is conditioned upon, among other things, the approval of the merger by the holders of two-thirds of the outstanding shares of common stock of each of the Company and Brooklyn Union and the receipt of all required regulatory approvals. The Company is unable to determine when or if all required approvals will be obtained.

In 1995, the Long Island Power Authority (LIPA), an agency of the State of New York (NYS), was requested by the Governor of NYS to develop a plan, pursuant to its authority under NYS law, to provide an electric rate reduction of at least 10%, provide a framework for long-term competition in power production and protect property taxpayers on Long Island.

The Share Exchange Agreement contemplates that discussions, which are currently in progress, will continue with LIPA to arrive at an agreement mutually acceptable to the Company, Brooklyn Union and LIPA, pursuant to which LIPA would acquire certain assets or securities of the Company, the consideration for which would inure to the benefit of the new holding company. In the event that such a transaction is completed, the Ratio would become .880. In connection with discussions with LIPA, LIPA has indicated that it may exercise its power of eminent domain over all or a portion of the Company's assets or securities, in order to achieve its objective of reducing current electric rates, if a negotiated agreement cannot be reached. The Company is unable to determine when or if an agreement with LIPA will be reached, or what action, if any, LIPA will take if such an agreement is not reached.

Rate Matters

Electric

In 1995, the Company submitted a compliance filing requesting that the PSC extend the provisions of its 1995 electric rate order, discussed below, through November 30, 1996. This filing was updated by the Company in August 1996 and approved by the PSC in January 1997.

During 1996, the PSC instituted numerous initiatives intended to lower electric rates on Long Island. The Company shares the PSC's concern regarding electric rate levels and is prepared to assist the PSC in pursuing any reasonable opportunity to reduce electric rates. The initiatives instituted were as follows:

- An Order to Show Cause, issued in February 1996, to examine various opportunities to reduce the Company's electric rates;
- An Order, issued in April 1996, expanding the scope of the Order to Show Cause proceeding in an effort to provide "immediate and substantial rate relief." This order directed the Company to file financial and other information sufficient to provide a legal basis for setting new rates for both the single rate year (1997) and the three-year period 1997 through 1999; and
- An Order, issued in July 1996, to institute an expedited temporary rate phase in the Order to Show Cause proceeding to be conducted in parallel with the ongoing phase concerning permanent rates.

The Order issued in July requested that interested parties file testimony and exhibits sufficient to provide a basis for the PSC to decide whether the Company's electric rates should be made temporary and, if so, the proper level of such temporary rates. The Staff of the PSC (Staff), in response to this Order, recommended that the Company's rates be reduced on a temporary basis by 4.2% effective October 1, 1996, until the permanent rate case is decided. In its filing, the Company sought to demonstrate that current electric rate levels were appropriate and that there was no justification for reducing them. Although evidentiary hearings on the Company's, Staff's and other interested parties' submissions were subsequently held on an expedited basis to enable the PSC to render a decision on the Company's rates, as of the date of this report, the PSC has yet to take any action.

In September 1996, the Company completed the filing of a multi-year rate plan (Plan) in compliance with the April 1996 Order. Major elements of the Plan include: (i) a base rate freeze for the three-year period December 1, 1996 through November 30, 1999; (ii) an allowed return on common equity of 11.0% through the term of the Plan with the Company fully retaining all earnings up to 12.66%, and sharing with the customer any earnings above 12.66%; (iii) the continuation of existing LRPP revenue and expense reconciliation mechanisms and performance incentive programs; (iv) crediting all net proceeds from the Shoreham property tax litigation to the RMC to reduce its balance; and (v) a mechanism to fully recover any outstanding RMC balance at the end of the 1999 rate year through inclusion in the Fuel Cost Adjustment (FCA), over a two-year period.

1995 Electric Rate Order

The basis of the 1995 Order included minimizing future electric rate increases while continuing to provide for the recovery of the Company's regulatory assets and retaining consistency with the Rate Moderation Agreement's (RMA) objective of restoring the Company to financial health.

The 1995 Order, which became effective December 1, 1994, froze base electric rates, reduced the Company's allowed return on common equity from 11.6% to 11.0% and modified or eliminated certain performance-based incentives, as discussed below.

The LRPP, originally approved by the PSC in November 1991, contained three major components: (i) revenue reconciliation; (ii) expense attrition and reconciliation; and (iii) performance-based incentives. In the 1995 Order, the PSC continued the three major components of the LRPP with modifications to the expense attrition and reconciliation mechanism and the performance-based incentives. The revenue reconciliation mechanism remains unchanged.

Revenue reconciliation provides a mechanism that eliminates the impact of experiencing sales that are above or below adjudicated levels by providing a fixed annual net margin level (defined as sales revenues, net of fuel expenses and gross receipts taxes). The difference between actual and adjudicated net margin levels are deferred on a monthly basis during the rate year.

The expense attrition and reconciliation component permits the Company to make adjustments for certain expenses recognizing that these cost increases are unavoidable due to inflation and changes outside the control of the Company. Pursuant to the 1995 Order, the Company is permitted to reconcile expenses for property taxes only, whereas under the original LRPP the Company was able to reconcile expenses for wage rates, property taxes, interest costs and demand side management (DSM) costs.

The original LRPP had also provided for the deferral and amortization of certain cost variances for enhanced reliability, production operations and maintenance expenses and the application of an inflation index to other expenses. Under the 1995 Order, these deferrals have been eliminated and any unamortized balances were credited to the RMC during 1995.

The modified performance-based incentive programs include the DSM program, the customer service performance program and the transmission and distribution reliability program. Under these revised programs, the Company is subject to a maximum penalty of 38 basis points of the allowed return on common equity and can earn up to 4 basis points under the customer service program. This 4 basis point incentive can only be used to offset a penalty under the transmission and distribution reliability program. Under the original LRPP, the Company was allowed to earn up to 40 basis points or forfeit up to 18 basis points under these incentive programs.

The partial pass-through fuel incentive program remains unchanged. Under this incentive, the Company can earn or forfeit up to 20 basis points of the allowed return on common equity.

For the rate year ended November 30, 1996, the Company earned 20 basis points, or approximately $4.3 million, net of tax effects, as a result of its performance under all incentive programs. For the rate years ended November 30, 1995 and 1994, the Company earned 19 and 50 basis points, respectively, or approximately $4.0 million and $9.2 million, respectively, net of tax effects, under the incentive programs in effect at those times.

The deferred balances resulting from the net margin and expense reconciliations, and earned performance-based incentives are netted at the end of each rate year, as established under the LRPP and continued under the 1995 Order. The first $15 million of the total deferral is recovered from or credited to ratepayers by increasing or decreasing the RMC balance. Deferrals in excess of the $15 million, upon approval of the PSC, are refunded to or recovered from the customers through the FCA mechanism over a 12-month period.

For the rate year ended November 30, 1996, the amount to be returned to customers resulting from the revenue and expense reconciliations, performance-based incentive programs and associated carrying charges totaled $14.5 million. Consistent with the mechanics of the LRPP, it is anticipated that the entire balance of the deferral will be used to reduce the RMC balance upon approval by the PSC of the Company's reconciliation filing which was submitted to the PSC in January 1997. For the rate year ended November 30, 1995, the Company recorded a net deferred LRPP credit of approximately $41 million. The first $15 million of the deferral was applied as a reduction to the RMC while the remaining portion of the deferral of $26 million will be returned to customers through the FCA when approved by the PSC. For the rate year ended November 30, 1994, the Company recorded a net deferred charge of approximately $79 million. The first $15 million of the deferral was applied as an increase to the RMC while the remaining deferral of $64 million was recovered from customers.

Another mechanism of the LRPP provides that earnings in excess of the allowed return on common equity, excluding the impacts of the various incentive and/or penalty programs, are used to reduce the RMC. For the rate years ended November 30, 1996 and 1995, the Company earned $9.1 million and $6.2 million, respectively, in excess of its allowed return on common equity. These excess earnings were applied as reductions to the RMC. In 1994, the Company did not earn in excess of its allowed return on common equity.

The Company is currently unable to predict the outcome of any of the rate proceedings currently before the PSC and their effect, if any, on the Company's financial position, cash flows or results of operations.

Gas

In December 1993, the PSC approved a three-year gas rate settlement between the Company and the Staff of the PSC. The gas rate settlement provided annual gas rate increases of 4.7%, 3.8% and 3.2% for each of the three rate years beginning December 1, 1993, 1994, and 1995, respectively. In the determination of the revenue requirements for the gas rate settlement, an allowed return on common equity of 10.1% was used.

The gas rate settlement also provided that earnings in excess of a 10.6% return on common equity be shared equally between the Company's firm gas customers and its shareowners. For the rate years ended November 30, 1996, 1995 and 1994, the firm gas customers' portion of gas earnings in excess of the allowed return on common equity totaled approximately $10 million, $1 million and $7 million, respectively. In 1996, the Company was granted permission by the PSC to apply the customers' portion of the gas excess earnings and associated carrying charges for the 1995 and 1994 rate years to the recovery of deferred costs associated with postretirement benefits other than pensions and costs incurred for investigation and remediation of manufactured gas plant (MGP) sites. The Company has requested that the same treatment be granted for the disposition of the customers' portion of the 1996 rate year gas excess earnings.

The Company currently has no gas rate filings before the PSC and does not intend to file a gas rate case during the current rate year, unless required to do so in connection with the proposed merger with Brooklyn Union.

Competitive Environment

The electric industry continues to undergo fundamental changes as regulators, elected officials and customers seek lower energy prices. These changes, which may have a significant impact on future financial performance of electric utilities, are being driven by a number of factors including a regulatory environment in which traditional cost-based regulation is seen as a barrier to lower energy prices. In 1996, both the PSC and the Federal Energy Regulatory Commission (FERC) continued their separate, but in some cases parallel, initiatives with respect to developing a framework for a competitive electric marketplace.

The Electric Industry - State Regulatory Issues
In 1994, the PSC began the second phase of its Competitive Opportunities Proceedings to investigate issues related to the future of the regulatory process in an industry which is moving toward competition. The PSC's overall objective was to identify regulatory and ratemaking practices that would assist New York State utilities in the transition to a more competitive environment designed to increase efficiency in providing electricity while maintaining safe, affordable and reliable service.

As a result of the Competitive Opportunities Proceedings, in May 1996, the PSC issued an order (Order) which stated its belief that introducing competition to the electric industry in New York has the potential to reduce electric rates over time, increase customer choice and encourage economic growth. The Order calls for a competitive wholesale power market to be in place by early 1997 which will be followed by the introduction of retail access for all customers by early 1998.

The PSC stated that competition should be transitioned on an individual company basis, due to differences in individual service territories, the level and type of strandable investments (i.e., costs that utilities would have otherwise recovered through rates under traditional cost of service regulation that, under market competition, would not be recoverable) and utility specific financial conditions.

The Order contemplates that implementation of competition will proceed on two tracks. The Order requires that each major electric utility file a rate/restructuring plan which is consistent with the PSC's policy and vision for increased competition. Those plans were submitted by October 1, 1996, in compliance with the Order. However, the Company was exempted from this requirement due to the PSC's separate investigation of the Company's rates and LIPA's examination of the Company's structure. Since October 1, 1996, proceedings have commenced for the five electric utilities which filed restructuring plans in accordance with track one and the Company has intervened in each of these proceedings.

The PSC order also anticipated that certain other filings would be made on October 1, 1996, by all New York State utilities, to both the PSC and the FERC. The filings were to address the delineation of transmission and distribution facilities jurisdiction between the FERC or the PSC, a pricing of each company's transmission services, and a joint filing by all the utilities to address the formation of an Independent System Operator (ISO) and the creation of a market exchange that will establish spot market prices. Although there were extensive collaborative meetings among the parties, it was not possible for the additional filings to be completed by October 1, 1996. While these discussions are continuing in an attempt to narrow the differences among the parties, on December 31, 1996, the NYPP members submitted a compliance filing to the FERC which provides open membership and comparable services to eligible entities in accordance with FERC Order 888, discussed below. The New York State utilities submitted the full ISO/Power Exchange filing to the FERC, in January 1997 which proposes to establish a competitive wholesale marketplace in New York State for electric energy and transmission pricing at market based rates.

The PSC envisions that a fully operational wholesale competitive structure will foster the expeditious movement to full retail competition. The PSC's vision of the retail competitive structure, known as the Flexible Retail Poolco Model, consists of: (i) the creation of an ISO to coordinate the safe and reliable operation of electric generation and transmission; (ii) open access to the transmission system, which would be regulated by the FERC; (iii) the continuation of a regulated distribution company to operate and maintain the distribution system; (iv) the deregulation of energy/customer services such as meter reading and customer billing; (v) the ability of customers to choose among suppliers of electricity; and (vi) the allowance of customers to acquire electricity either by long-term contracts, purchases on the spot market or a combination of the two.

One issue discussed in the Order that could affect the Company is strandable investments. The PSC stated in its Order that it is not required to allow recovery of all prudently incurred investments, that it has considerable discretion to set rates that balance ratepayer and shareholder interests, and that the amount of strandable investments that a utility will be permitted to recover will depend on the particular circumstances of each utility. Additionally, the Order provided that every effort should be made by utilities to mitigate these costs prior to seeking recovery.

Certain aspects of the restructuring envisioned by the PSC — particularly the PSC's apparent determinations that it may deny the utilities recovery of prudent investments made on behalf of the public, order retail wheeling, require divestiture of generation assets and deregulate certain sectors of the energy market — could, if implemented, have a negative impact on the operations and financial conditions of New York's investor-owned electric utilities, including the Company.

The Company is party to a lawsuit commenced in September 1996 by the Energy Association of New York State and the state's other investor-owned electric utilities (collectively, Petitioners) against the PSC in New York Supreme Court, Albany County (The Energy Association of New York State, et al. v. Public Service Commission of the State of New York, et al.). The Petitioners have requested that the Court declare that the Order is unlawful or, in the alternative, that the Court clarify that the PSC's statements in the Order constitute simply a policy statement with no binding legal effect. In November 1996, the Court issued a Decision and Order denying the Petitioners' request to invalidate the Order. Although the Court stated that most of the Order is a non-binding statement of policy, the Court rejected the Petitioners' substantive challenges to the Order. In December 1996, Petitioners filed a notice of appeal with the Third Department of the Appellate Division of the New York State Supreme Court. The litigation is ongoing and the Company is unable at this time to predict the likelihood of success or the impact of the litigation on the Company's financial position, cash flows or results of operations. Oral argument in the Appellate Division has not yet been scheduled, but a decision is expected by the end of 1997.

The Electric Industry - Federal Regulatory Issues
In April 1996, in response to its Notice of Proposed Rulemaking issued in March 1995, the FERC issued two orders relating to the development of competitive wholesale electric markets.

Order 888 is a final rule on open transmission access and stranded cost recovery and provides that the FERC has exclusive jurisdiction over interstate wholesale wheeling and that utility transmission systems must now be open to qualifying sellers and purchasers of power on a non-discriminatory basis.

Order 888 allows utilities to recover legitimate, prudent and verifiable stranded costs associated with wholesale transmission, including the circumstances where full requirements customers become wholesale transmission customers, such as where a municipality establishes its own electric system.

With respect to retail wheeling, the FERC concluded that it has jurisdiction over rates, terms and conditions of service, but would leave the issue of recovery of the costs stranded by retail wheeling to the states.

Order 888 required utilities to file open access tariffs under which they would provide transmission services, comparable to those which they provide themselves and to third parties on a non-discriminatory basis. Additionally, utilities must use these same tariffs for their own wholesale sales. The Company filed its open access tariff in July 1996.

In September 1996, the FERC ordered Rate Hearings on 28 utility transmission tariffs, including the Company's. On the basis of a preliminary review, the FERC was not satisfied that the tariff rates were just and reasonable. Settlement discussions have been held between the Company and various intervenors concerning the Company's transmission rates. In December 1996, the parties reached a tentative settlement on the rate issues. The procedural schedule was suspended pending filing of the settlement agreement, which is anticipated during the first quarter of 1997. Non-rate issues associated with the Company's open access tariff have not yet been addressed by the FERC.

Order 889, which is a final rule on a transmission pricing bulletin board, addresses the rules and technical standards for operation of an electronic bulletin board that will make available, on a real-time basis, the price, availability and other pertinent information concerning each transmission utility's services. It also addresses standards of conduct to ensure that transmission utilities functionally separate their transmission and wholesale power merchant functions to prevent discriminatory self-dealing. In December 1996, the Company filed its standards of conduct in accordance with the Order.

With other members of the industry, the Company has participated in several joint petitions for rehearing and/or clarification of the FERC's Orders 888 and 889. Among other issues, these petitions address the FERC's obligation to exercise its jurisdiction to provide for the recovery of strandable investments in any retail wheeling situations. The outcome and timing of the FERC Orders on rehearing are uncertain.

It is not possible to predict the ultimate outcome of these proceedings, the timing thereof, or the amount, if any, of stranded costs that the Company would recover in a competitive environment. The outcome of the state and federal regulatory proceedings could adversely affect the Company's ability to apply Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," which, pursuant to SFAS No. 101, "Accounting for Discontinuation of Application of SFAS No. 71," could then require a significant write-down of all or a portion of the Company's net regulatory assets. If the Company were unable to continue to apply the provisions of SFAS No. 71 at December 31, 1996, the Company estimates that approximately $4.6 billion would have been required to be written off at such time.

The Company's Service Territory
The Company's geographic location and the limited electrical interconnections to Long Island serve to limit the accessibility of its transmission grid to potential competitors from off the system. However, the changing utility regulatory environment has affected the Company by requiring the Company to co-exist with state and federally mandated competitors. These competitors are non-utility generators (NUGS), NYPA and Municipal Distribution Agencies (MDAs).

The Public Utility Regulatory Policies Act of 1978 (PURPA), the goal of which is to reduce the United States' dependency on foreign oil, to encourage energy conservation and to promote diversification of the fuel supply, has negatively impacted the Company through the encouragement of the NUG industry. PURPA provides for the development of a new class of electric generators which rely on either cogeneration technology or alternate fuels. Utilities are obligated under PURPA to purchase the output of certain of these generators, which are known as qualified facilities (QFs).

In 1996, the Company lost sales to NUGs totaling 422 gigawatt-hours (GWh) representing a loss in electric revenues net of fuel (net revenues) of approximately $34 million, or 1.9% of the Company's net revenues. In 1995, the Company lost sales to NUGs totaling 366 GWh or approximately $28 million or 1.5% of the Company's net revenues.

The increase in lost net revenues resulted principally from the completion of seven facilities that became commercially operational during 1996 and the full year operation of the IPP located at the State University of New York at Stony Brook, NY. The Company estimates that in 1997, sales losses to NUGs will be 429 GWh, or approximately 1.8% of projected net revenues.

The Company believes that load losses due to NUGs have stabilized. This belief is based on the fact that the Company's customer load characteristics, which lack a significant industrial base and related large thermal load, will mitigate load loss and thereby make cogeneration economically unattractive.

Additionally, as mentioned above, the Company is required to purchase all the power offered by QFs which in 1996 approximated 218 megawatts (MW) and in early 1995 approximated 205 MW. The increase was the result of the SUNY Stony Brook facility going on line in mid 1995. The Company estimates that purchases from QFs required by federal and state law cost the Company $63 million and $53 million in 1996 and 1995, respectively, more than it would have cost had the Company generated this power.

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

The Company has also experienced a revenue loss as a result of its policy of voluntarily providing wheeling of NYPA power for economic development. The Company estimates that in 1996 and 1995 NYPA power displaced approximately 417 GWh and 429 GWh of annual energy sales, respectively. Net revenue loss associated with these volumes of sales is approximately $26 million, or 1.4% of the Company's 1996 net revenues, and $30 million, or 1.6% of the Company's 1995 net revenues. Currently, the potential loss of additional load is limited by conditions in the Company's transmission agreements with NYPA.

A number of customer groups are seeking to hasten consideration and implementation of full retail competition. For example, an energy consultant has petitioned the PSC, seeking alternate sources of power for Long Island school districts. The County of Nassau has also petitioned the PSC to authorize retail wheeling for all classes of electric customers in the county.

In addition, several towns and villages on Long Island are investigating municipalization, in which customers form a government-sponsored electric supply company. This is one form of competition that is likely to increase as a result of the National Energy Policy Act of 1992 (NEPA). NEPA sought to increase economic efficiency in the creation and distribution of power by relaxing restrictions on the entry of new competitors to the wholesale electric power market. NEPA does so by creating exempt wholesale generators that can sell power in wholesale markets without the regulatory constraint placed on utility generators such as on the Company. NEPA also expanded the FERC's authority to grant access to utility transmission systems to all parties who seek wholesale wheeling for wholesale competition. While it should be noted that the FERC's position favoring stranded cost recovery from retail turned wholesale customers will reduce utility risk from municipalization, significant issues associated with the removal of restrictions on wholesale transmission system access have yet to be resolved.

There are numerous towns and villages in the Company's service territory that are considering the formation of a municipally owned and operated electric authority to replace the services currently provided by the Company.

In 1995, Suffolk County issued a request for proposal from suppliers for up to 300 MW of power which the County would then sell to its residential and commercial customers. The County has awarded the bid to two off-Long Island suppliers and has requested the Company to deliver the power. After the Company challenged Suffolk County's eligibility for such service, the County petitioned the FERC to order the Company to provide the requested transmission service.

In December 1996, the FERC ordered the Company to provide transmission services to Suffolk County to the extent necessary to accommodate proposed sales to customers to which it was providing service on the date of enactment of NEPA (this Order could provide Suffolk County with the ability to import up to 200 MW of power on a daily basis). The FERC reserved decision on the remaining 100 MW of

Suffolk County's request until the County identifies the ownership or control of distribution facilities that it alleges qualifies it for a wheeling order to Suffolk County customers who were not receiving service on the date of NEPA's enactment. The Company may ask the FERC to reconsider their decision once that decision becomes final, which is not expected for several months. The FERC has yet to determine the pricing of that service. As previously noted, FERC Order 888 allows utilities to recover legitimate, prudent and verifiable stranded costs associated with wholesale transmission, including the circumstances where full requirements customers become wholesale transmission customers, such as where a municipality establishes its own electric system.

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

Notwithstanding the outcome of the state or federal regulatory proceedings, or any other state action, the Company believes that, among other obligations, the State has a contractual obligation to allow the Company to recover its Shoreham-related assets.

Environmental Matters

The Company is subject to federal, state and local laws and regulations dealing with air and water quality and other environmental matters. Environmental matters may expose the Company to potential liabilities which, in certain instances, may be imposed without regard to fault or for historical activities which were lawful at the time they occurred. The Company continually monitors its activities in order to determine the impact of its activities on the environment and to ensure compliance with various environmental laws. Except as set forth below, no material proceedings have been commenced or, to the knowledge of the Company, are contemplated against the Company with respect to any matter relating to the protection of the environment.

The New York State Department of Environmental Conservation (DEC) has required the Company and other New York State utilities to investigate and, where necessary, remediate their former manufactured gas plant (MGP) sites. Currently, the Company is the owner of six pieces of property on which the Company or certain of its predecessor companies are believed to have produced manufactured gas. Operations at these facilities in the late 1800's and early 1900's may have resulted in the disposal of certain waste products on these sites. Research is underway to determine the existence and nature of operations and their relationship, if any, to the Company or its predecessor companies.

The Company has entered into discussions with the DEC which may lead to the issuance of one or more Administrative Consent Orders (ACO) regarding the management of environmental activities at these properties. Although the exact amount of the Company's remediation costs cannot yet be determined, based on the findings of investigations at two of these six sites, estimates indicate that it will cost approximately $51 million to remediate all of these sites through the year 2005. Accordingly, the Company has recorded a $35 million liability and a corresponding regulatory asset to reflect its belief that the PSC will provide for the future recovery of these costs through rates as it has for other New York State utilities. The $35 million liability reflects the present value of the future stream of payments to investigate and remediate these sites. The Company used a risk-free rate of 7.25% to discount this obligation.

In December 1996, the Company filed a complaint in the United States District Court for the Southern District of New York against 14 of the Company's insurers which issued general comprehensive liability (GCL) policies to the Company. The Company is seeking recovery under the GCL policies for the costs incurred to date and future costs associated with the clean-up of the Company's former MGP sites and Superfund sites for which the Company has been named a potentially responsible party (PRP). The Company is seeking a declaratory judgement that the defendant insurers are bound by the terms of the GCL policies, subject to the stated coverage limits, to reimburse the Company for the remediation costs. The outcome of this proceeding cannot yet be determined.

The Company has been notified by the United States Environmental Protection Agency (EPA) that it is one of many PRPs that may be liable for the remediation of three licensed treatment, storage and disposal sites to which the Company may have shipped waste products and which have subsequently become environmentally contaminated.

At one site, located in Philadelphia, Pennsylvania, and operated by Metal Bank of America, the Company and nine other PRPs, all of which are public utilities, have entered into an ACO with the EPA to conduct a Remedial Investigation and Feasibility Study (RI/FS), which has been completed and is currently being reviewed by the EPA. Under a PRP participation agreement, the Company is responsible for 8.2% of the costs associated with this RI/FS. The level of remediation required will be determined when the EPA issues its decision, but based on information available to date, the Company currently anticipates that the total cost to remediate this site will be between $14 million and $30 million. The Company has recorded a liability of $1.1 million representing its estimated share of the cost to remediate this site based upon its 8.2% responsibility under the RI/FS.

The Company has also been named a PRP for disposal sites in Kansas City, Kansas, and Kansas City, Missouri. The two sites were used by a company named PCB, Inc. from 1982 until 1987 for the storage, processing, and treatment of electric equipment, dielectric oils and materials containing PCBs. According to the EPA, the buildings and certain soil areas outside the buildings are contaminated with PCBs.

In 1994, the EPA requested certain of the large PRPs, which include several other utilities, to form a group, sign an ACO, and conduct a remediation program for the sites under the Toxic Substances Control Act, or in the alternative, to perform a Superfund cleanup for the sites. The EPA has provided the Company with documents indicating that the Company was responsible for less than 1% of the materials that were shipped to the Missouri site. The EPA has not yet completed compiling the documents for the Kansas site. The Company intends to join a PRP Group which includes other utilities, which has been organized for the purpose of developing and implementing acceptable remediation programs for the sites. The Company is currently unable to determine its share of the cost to remediate these sites.

In addition, the Company was notified that it is a PRP at a Superfund site located in Farmingdale, New York. Portions of the site are allegedly contaminated with PCBs, solvents and metals. The Company was also notified by other PRPs that it should be responsible for remediation expenses in the amount of approximately $100,000 associated with removing PCB-contaminated soils from a portion of the site which formerly contained electric transformers. The Company is unable to determine its share of costs of remediation at this site.

During 1996, the Connecticut Department of Environmental Protection (DEP) issued a modification to an ACO previously issued in connection with an investigation of an electric transmission cable located under the Long Island Sound (Sound Cable) that is jointly owned by the Company and the Connecticut Light and Power Company (Owners). The modified ACO requires the Owners to submit to the DEP and DEC a series of reports and studies describing cable system condition, operation and repair practices, alternatives for cable improvements or replacement and environmental impacts associated with leaks of fluid into the Long Island Sound, which have occurred from time to time. The Company continues to compile required information and coordinate the activities necessary to perform these studies and, at the present time, is unable to determine the costs it will incur to complete the requirements of the modified ACO or to comply with any additional requirements.

Previously, the U.S. Attorney for the District of Connecticut had commenced an investigation regarding occasional releases of fluid from the Sound Cable, as well as associated operating and maintenance practices. The Owners have provided the U.S. Attorney with all requested documentation. The Company believes that all activities associated with the response to occasional releases from the Sound Cable were consistent with legal and regulatory requirements.

In addition, during 1996 the Long Island Soundkeeper Fund, a non-profit organization, filed a suit against the Owners of the Sound Cable in Federal District Court in Connecticut alleging that the Sound Cable fluid leaks constitute unpermitted discharges of pollutants in violation of the Clean Water Act (CWA) and that such pollutants present a threat to the environment and public health. The suit seeks, among other things, injunctive relief prohibiting the Owners from continuing to operate the Sound Cable in alleged violation of the CWA and civil penalties of $25,000 per day for each violation from each of the Owners.

In December 1996, a barge, owned and operated by a third party, dropped anchor, causing extensive damage to the Sound Cable and a release of dielectric fluid into the Long Island Sound. Temporary clamps and leak abaters have been placed on the cables which have stopped the leaks. Permanent repairs are expected to be undertaken in the late spring of 1997. The preliminary estimate of the cost of these repairs is $15 million. The Company intends to seek recovery from third parties for all costs incurred by the Company as a result of this incident. The timing and amount of recovery, if any, cannot yet be determined. In addition, the Owners maintain insurance coverage for the Sound Cable which the Company believes will be sufficient to cover any repair costs. In any event, costs not reimbursed by a third party or not covered by insurance will be shared equally by the Owners.

The Company believes that none of the environmental matters, discussed above, will have a material adverse impact on the Company's financial position, cash flows or results of operations. In addition, the Company believes that all significant costs incurred with respect to environmental investigation and remediation activities, not recoverable from insurance carriers, will be recoverable through rates.

Conservation Services

The Company's 1996 Demand Side Management (DSM) Plan focused on the pursuit of energy efficiency and peak load reduction in a way that had minimal impact on electric rate increases. To assure the success of this strategy, the Company implemented a balanced and cost-effective mix of DSM programs that continued to represent a limited reliance on broad-based rebates and a concentrated emphasis on programs that provided education and information, targeted business development, improved the efficiency of the Company's facilities, induced market transformation and provided financing for energy efficiency. The Company was successful in meeting the PSC energy penalty threshold of 26.7 GWh (80% of 33.3 GWh goal) at a cost less than that provided for in electric rates.

In 1997, the Company plans to continue this strategy with an increased emphasis on programs which facilitate the retention, attraction and expansion of major commercial/industrial customers. Specifically these programs will provide incentives to encourage companies to invest in energy-efficiency as a means to remain, expand or relocate to Long Island. Overall, they will help to improve the economic climate on Long Island as well as the Company's competitiveness as an energy provider. The 1997 Plan targets an annualized energy savings of 28.7 GWh. The Company believes that it will meet the target and avoid any earnings penalty.

Cautionary Statement Regarding Forward-Looking Statements

This report contains statements which, to the extent they are not recitations of historical fact, constitute "forward-looking statements" within the meaning of the Securities Litigation Reform Act of 1995 (Reform Act). In this respect, the words "estimate," "project," "anticipate," "expect," "intend," "believe" and similar expressions are intended to identify forward-looking statements. All such forward-looking statements are intended to be subject to the safe harbor protection provided by the Reform Act. A number of important factors affecting the Company's business and financial results could cause actual results to differ materially from those stated in the forward-looking statements. Those factors include the proposed merger with Brooklyn Union and a possible transaction with LIPA as discussed under the heading "Merger Agreement with The Brooklyn Union Gas Company," state and federal regulatory rate proceedings, competition, and certain environmental matters each as discussed herein.

Selected Financial Data

Additional information respecting revenues, expenses, electric and gas operating income and operations data and balance sheet information for the last five years is provided in Tables 1 through 11 of Selected Financial Data. Information with regard to the Company's business segments for the last three years is provided in Note 12 of Notes to Financial Statements.

Financial Statements

Balance Sheet	*(In thousands of dollars)*	
Assets at December 31	*1996*	*1995*
Utility Plant		
Electric	$ 3,882,297	$ 3,786,540
Gas	1,154,543	1,086,145
Common	260,268	244,828
Construction work in progress	112,184	100,521
Nuclear fuel in process and in reactor	15,454	16,456
	5,424,746	5,234,490
Less – Accumulated depreciation and amortization	1,729,576	1,639,492
Total Net Utility Plant	3,695,170	3,594,998
Regulatory Assets		
Base financial component (less accumulated amortization of $757,282 and $656,311)	3,281,548	3,382,519
Rate moderation component	402,213	383,086
Shoreham post-settlement costs	991,795	968,999
Shoreham nuclear fuel	69,113	71,244
Unamortized cost of issuing securities	194,151	222,567
Postretirement benefits other than pensions	360,842	383,642
Regulatory tax asset	1,772,778	1,802,383
Other	199,879	229,809
Total Regulatory Assets	7,272,319	7,444,249
Nonutility Property and Other Investments	18,597	16,030
Current Assets		
Cash and cash equivalents	279,993	351,453
Special deposits	38,266	63,412
Customer accounts receivable (less allowance for doubtful accounts of $25,000 and $24,676)	255,801	282,218
LRPP receivable	–	74,281
Other accounts receivable	65,764	107,387
Accrued unbilled revenues	169,712	184,440
Materials and supplies at average cost	55,789	63,595
Fuel oil at average cost	53,941	32,090
Gas in storage at average cost	73,562	53,076
Deferred tax asset	145,205	191,000
Prepayments and other current assets	8,569	8,986
Total Current Assets	1,146,602	1,411,938
Deferred Charges	76,991	60,382
Total Assets	$ 12,209,679	$ 12,527,597

See Notes to Financial Statements.

Capitalization and Liabilities at December 31	1996	1995
	(In thousands of dollars)	
Capitalization		
Long-term debt	$ 4,471,675	$ 4,722,675
Unamortized discount on debt	(14,903).	(16,075)
	4,456,772	4,706,600
Preferred stock – redemption required	638,500	639,550
Preferred stock – no redemption required	63,664	63,934
Total Preferred Stock	702,164	703,484
Common stock	603,921	598,277
Premium on capital stock	1,127,971	1,114,508
Capital stock expense	(49,330)	(50,751)
Retained earnings	840,867	790,919
Treasury stock, at cost	(60)	–
Total Common Shareowners' Equity	2,523,369	2,452,953
Total Capitalization	7,682,305	7,863,037
Regulatory Liabilities		
Regulatory liability component	198,398	277,757
1989 Settlement credits	127,442	136,655
Regulatory tax liability	102,887	116,060
Other	146,852	132,891
Total Regulatory Liabilities	575,579	663,363
Current Liabilities		
Current maturities of long-term debt	251,000	415,000
Current redemption requirements of preferred stock	1,050	4,800
Accounts payable and accrued expenses	289,141	260,879
LRPP payable	40,499	17,240
Accrued taxes (including federal income tax of $25,884 and $28,736)	63,640	60,498
Accrued interest	160,615	158,325
Dividends payable	58,378	57,899
Class Settlement	55,833	45,833
Customer deposits	29,471	29,547
Total Current Liabilities	949,627	1,050,021
Deferred Credits		
Deferred federal income tax	2,442,606	2,337,732
Class Settlement	98,497	129,809
Other	32,105	34,499
Total Deferred Credits	2,573,208	2,502,040
Operating Reserves		
Pensions and other postretirement benefits	381,996	396,490
Claims and damages	46,964	52,646
Total Operating Reserves	428,960	449,136
Commitments and Contingencies	–	–
Total Capitalization and Liabilities	$ 12,209,679	$ 12,527,597

See Notes to Financial Statements.

Statement of Income

(In thousands of dollars except per share amounts)

For year ended December 31	*1996*	*1995*	*1994*
Revenues			
Electric	$ 2,466,435	$ 2,484,014	$ 2,481,637
Gas	684,260	591,114	585,670
Total Revenues	3,150,695	3,075,128	3,067,307
Operating Expenses			
Operations – fuel and purchased power	963,251	834,979	847,986
Operations – other	381,076	383,238	406,014
Maintenance	118,135	128,155	134,640
Depreciation and amortization	153,925	145,357	130,664
Base financial component amortization	100,971	100,971	100,971
Rate moderation component amortization	(24,232)	21,933	197,656
Regulatory liability component amortization	(79,359)	(79,359)	(79,359)
1989 Settlement credits amortization	(9,214)	(9,214)	(9,214)
Other regulatory amortization	127,288	161,605	4,328
Operating taxes	472,076	447,507	406,895
Federal income tax – current	42,197	14,596	10,784
Federal income tax – deferred and other	168,000	193,742	170,997
Total Operating Expenses	2,414,114	2,343,510	2,322,362
Operating Income	736,581	731,618	744,945
Other Income and (Deductions)			
Rate moderation component carrying charges	25,259	25,274	32,321
Other income and deductions	19,197	34,400	35,343
Class Settlement	(20,772)	(21,669)	(22,730)
Allowance for other funds used during construction	2,888	2,898	2,716
Federal income tax – deferred and other	940	2,800	5,069
Total Other Income and (Deductions)	27,512	43,703	52,719
Income Before Interest Charges	764,093	775,321	797,664
Interest Charges			
Interest on long-term debt	384,198	412,512	437,751
Other interest	67,130	63,461	62,345
Allowance for borrowed funds used during construction	(3,699)	(3,938)	(4,284)
Total Interest Charges	447,629	472,035	495,812
Net Income	316,464	303,286	301,852
Preferred stock dividend requirements	52,216	52,620	53,020
Earnings for Common Stock	$ 264,248	$ 250,666	$ 248,832
Average Common Shares Outstanding (000)	120,361	119,195	115,880
Earnings per Common Share	$ 2.20	$ 2.10	$ 2.15
Dividends Declared per Common Share	$ 1.78	$ 1.78	$ 1.78

See Notes to Financial Statements.

Statement of Cash Flows

(In thousands of dollars)

For year ended December 31	*1996*	*1995*	*1994*
Operating Activities			
Net Income	$ 316,464	$ 303,286	$ 301,852
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	153,925	145,357	130,664
Base financial component amortization	100,971	100,971	100,971
Rate moderation component amortization	(24,232)	21,933	197,656
Regulatory liability component amortization	(79,359)	(79,359)	(79,359)
1989 Settlement credits amortization	(9,214)	(9,214)	(9,214)
Other regulatory amortization	127,288	161,605	4,328
Rate moderation component carrying charges	(25,259)	(25,274)	(32,321)
Amortization of cost of issuing and redeeming securities	34,611	39,589	46,237
Class Settlement	20,772	21,669	22,730
Provision for doubtful accounts	23,119	17;751	19,542
Federal income tax – deferred and other	167,060	190,942	165,928
Other	66,624	61,576	46,531
Changes in operating assets and liabilities			
Accounts receivable	69,215	(67,213)	(17,353)
Class Settlement	(42,084)	(33,464)	(30,235)
Accrued unbilled revenues	14,728	(20,061)	5,663
Accounts payable and accrued expenses	28,258	19,100	(44,598)
Other	(50,574)	(77,194)	6,727
Net Cash Provided by Operating Activities	892,313	772,000	835,749
Investing Activities			
Construction and nuclear fuel expenditures	(239,896)	(243,586)	(276,954)
Shoreham post-settlement costs	(51,722)	(70,589)	(167,367)
Other investing activities	(4,806)	8,019	(1,349)
Net Cash Used in Investing Activities	(296,424)	(306,156)	(445,670)
Financing Activities			
Proceeds from issuance of securities	18,837	68,726	449,434
Redemption of securities	(419,800)	(104,800)	(639,858)
Common stock dividends paid	(213,753)	(211,630)	(205,086)
Preferred stock dividends paid	(52,264)	(52,667)	(52,927)
Other financing activities	(369)	529	(4,723)
Net Cash Used in Financing Activities	(667,349)	(299,842)	(453,160)
Net (Decrease) Increase in Cash and Cash Equivalents	**$ (71,460)**	**$ 166,002**	**$ (63,081)**
Cash and cash equivalents at January 1	$ 351,453	$ 185,451	$ 248,532
Net (Decrease) Increase in cash and cash equivalents	(71,460)	166,002	(63,081)
Cash and Cash Equivalents at December 31	**$ 279,993**	**$ 351,453**	**$ 185,451**
Interest paid, before reduction for the allowance for borrowed funds used during construction	$ 404,663	$ 427,988	$ 446,340
Federal income tax paid	$ 45,050	$ 14,200	$ 10,780

See Notes to Financial Statements.

Statement of Retained Earnings

(In thousands of dollars)

	1996	1995	1994
Balance at January 1	$ 790,919	$ 752,480	$ 711,432
Net income for the year	316,464	303,286	301,852
	1,107,383	1,055,766	1,013,284
Deductions			
Cash dividends declared on common stock	214,255	212,181	207,794
Cash dividends declared on preferred stock	52,240	52,647	53,046
Other	21	19	(36)
Balance at December 31	$ 840,867	$ 790,919	$ 752,480

See Notes to Financial Statements.

Statement of Capitalization

(In thousands of dollars)

At December 31	1996 Shares Issued	1995 Shares Issued	1996	1995
Common Shareowners' Equity				
Common stock, $5.00 par value	120,784,277	119,655,441	$ 603,921	$ 598,277
Premium on capital stock			1,127,971	1,114,508
Capital stock expense			(49,330)	(50,751)
Retained earnings			840,867	790,919
Treasury stock, at cost	3,485	-	(60)	-
Total Common Shareowners' Equity			2,523,369	2,452,953
Preferred Stock – Redemption Required				
Par value $100 per share				
7.40% Series L	161,000	171,500	16,100	17,150
8.50% Series R	–	37,500	–	3,750
7.66% Series CC	570,000	570,000	57,000	57,000
Less – Sinking fund requirement			1,050	4,800
			72,050	73,100
Par value $25 per share				
7.95% Series AA	14,520,000	14,520,000	363,000	363,000
$1.67 Series GG	880,000	880,000	22,000	22,000
$1.95 Series NN	1,554,000	1,554,000	38,850	38,850
7.05% Series QQ	3,464,000	3,464,000	86,600	86,600
6.875% Series UU	2,240,000	2,240,000	56,000	56,000
			566,450	566,450
Total Preferred Stock – Redemption Required			638,500	639,550
Preferred Stock – No Redemption Required				
Par value $100 per share				
5.00% Series B	100,000	100,000	10,000	10,000
4.25% Series D	70,000	70,000	7,000	7,000
4.35% Series E	200,000	200,000	20,000	20,000
4.35% Series F	50,000	50,000	5,000	5,000
5 1/8% Series H	200,000	200,000	20,000	20,000
5 3/4% Series I – Convertible	16,637	19,336	1,664	1,934
Total Preferred Stock - No Redemption Required			63,664	63,934
Total Preferred Stock			$ 702,164	$ 703,484

Statement of Capitalization (continued) *(In thousands of dollars)*

At December 31	*Maturity*	*Interest Rate*	*Series*	*1996*	*1995*
General and Refunding Bonds					
	May 1, 1996	8 3/4%		$ –	$ 415,000
	February 15, 1997	8 3/4%		250,000	250,000
	April 15, 1998	7 5/8%		100,000	100,000
	May 15, 1999	7.85%		56,000	56,000
	April 15, 2004	8 5/8%		185,000	185,000
	May 15, 2006	8.50%		75,000	75,000
	July 15, 2008	7.90%		80,000	80,000
	May 1, 2021	9 3/4%		415,000	415,000
	July 1, 2024	9 5/8%		375,000	375,000
Total General and Refunding Bonds				1,536,000	1,951,000
Debentures					
	July 15, 1999	7.30%		397,000	397,000
	January 15, 2000	7.30%		36,000	36,000
	July 15, 2001	6.25%		145,000	145,000
	March 15, 2003	7.05%		150,000	150,000
	March 1, 2004	7.00%		59,000	59,000
	June 1, 2005	7.125%		200,000	200,000
	March 1, 2007	7.50%		142,000	142,000
	July 15, 2019	8.90%		420,000	420,000
	November 1, 2022	9.00%		451,000	451,000
	March 15, 2023	8.20%		270,000	270,000
Total Debentures				2,270,000	2,270,000
Authority Financing Notes					
Industrial Development Revenue Bonds					
	December 1, 2006	7.50%	1976 A,B	2,000	2,000
Pollution Control Revenue Bonds					
	December 1, 2006	7.50%	1976 A	28,375	28,375
	December 1, 2009	7.80%	1979 B	19,100	19,100
	October 1, 2012	8 1/4%	1982	17,200	17,200
	March 1, 2016	3.25%	1985 A,B	150,000	150,000
Electric Facilities Revenue Bonds					
	September 1, 2019	7.15%	1989 A,B	100,000	100,000
	June 1, 2020	7.15%	1990 A	100,000	100,000
	December 1, 2020	7.15%	1991 A	100,000	100,000
	February 1, 2022	7.15%	1992 A,B	100,000	100,000
	August 1, 2022	6.90%	1992 C,D	100,000	100,000
	November 1, 2023	4.05%	1993 A	50,000	50,000
	November 1, 2023	4.00%	1993 B	50,000	50,000
	October 1, 2024	4.00%	1994 A	50,000	50,000
	August 1, 2025	4.00%	1995 A	50,000	50,000
Total Authority Financing Notes				916,675	916,675
Unamortized Discount on Debt				(14,903)	(16,075)
Total				4,707,772	5,121,600
Less Current Maturities				251,000	415,000
Total Long-Term Debt				4,456,772	4,706,600
Total Capitalization				$ 7,682,305	$ 7,863,037

See Notes to Financial Statements.

Notes to Financial Statements

Note 1. Summary of Significant Accounting Policies

Nature of Operations

Long Island Lighting Company (Company) was incorporated in 1910 under the Transportation Corporations Law of the State of New York and supplies electric and gas service in Nassau and Suffolk Counties and to the Rockaway Peninsula in Queens County, all on Long Island, New York. The Company's service territory covers an area of approximately 1,230 square miles. The population of the service area, according to the Company's 1996 estimate, is about 2.7 million persons, including approximately 98,000 persons who reside in Queens County within the City of New York.

The Company serves approximately 1.03 million electric customers of which approximately 921,000 are residential. The Company receives approximately 49% of its electric revenues from residential customers, 48% from commercial/industrial customers and the balance from sales to other utilities and public authorities. The Company also serves approximately 460,000 gas customers, 412,000 of which are residential, accounting for 61% of the gas revenues, with the balance of the gas revenues made up by the commercial/industrial customers and off-system sales.

The Company's geographic location and the limited electrical interconnections to Long Island serve to limit the accessibility of the transmission grid to potential competitors from off the system. In addition, the Company does not expect any new major independent power producers (IPPs) or cogenerators to be built on Long Island in the foreseeable future. One of the reasons supporting this conclusion is based on the Company's belief that the composition and distribution of the Company's remaining commercial and industrial customers would make it difficult for large electric projects to operate economically. Furthermore, under federal law, the Company is required to buy energy from qualified producers at the Company's avoided cost. Current long-range avoided cost estimates for the Company have significantly reduced the economic advantage to entrepreneurs seeking to compete with the Company and with existing IPPs. For a further discussion of the competitive issues facing the Company, see Note 11.

Regulation

The Company's 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). Its financial statements reflect the ratemaking policies and actions of these commissions in conformity with generally accepted accounting principles for rate-regulated enterprises.

Accounting for the Effects of Rate Regulation

General

The Company is subject to the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation". This statement recognizes the economic ability of regulators, through the ratemaking process, to create future economic benefits and obligations affecting rate-regulated companies. Accordingly, the Company records these future economic benefits and obligations as regulatory assets and regulatory liabilities.

Regulatory assets represent probable future revenues associated with previously incurred costs that are expected to be recovered from customers. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be refunded to customers through the ratemaking process. Regulatory assets net of regulatory liabilities amounted to approximately $6.7 billion and $6.8 billion at December 31, 1996 and 1995, respectively.

In order for a rate-regulated entity to continue to apply the provisions of SFAS No. 71, it must continue to meet the following three criteria: (i) the enterprise's rates for regulated services provided to its customers must be established by an independent third-party regulator; (ii) the regulated rates must be designed to recover the specific enterprise's costs of providing the regulated services; and (iii) in view of the demand for the regulated services and the level of competition, it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers.

Based upon the Company's evaluation of the three criteria discussed above in relation to its operations, the effect of competition on its ability to recover its costs, including its allowed return on common equity and the regulatory environment in which the Company operates, the Company believes that SFAS No. 71 continues to apply to the Company's electric and gas operations. The Company formed its conclusion based upon several factors including: (i) the Company's continuing ability to earn its allowed return on common equity for both its electric and gas operations; and (ii) the PSC's continued commitment to the Company's full recovery of the Shoreham Nuclear Power Station (Shoreham) related assets and all other prudently incurred costs.

Notwithstanding the above, rate regulation is undergoing significant change as regulators and customers seek lower prices for electric and gas service. As discussed more fully in Note 11, the PSC has made a decision in the Competitive Opportunities Proceedings to transition the electric industry to a wholesale power market in early 1997 followed by the introduction of retail access for all customers by early 1998. In the event that regulation significantly changes the opportunity for the Company to recover its costs in the future, all or a portion of the Company's operations may no longer meet the criteria discussed above. In that event, a significant write-down of all or a portion of the Company's existing regulatory assets and liabilities could result. For additional information respecting the Company's Shoreham-related assets, see below and Notes 2, 3 and 11.

In 1996, the Company adopted SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" which amends SFAS No. 71. Under SFAS No. 121, costs which were capitalized in accordance with regulatory practices, because it was probable that future recovery would be allowed by the regulator, must be charged against current period earnings, if it appears that the criterion for capitalization no longer applies. The carrying amount of such assets would be reduced by amounts for which recovery is unlikely. SFAS No. 121 also provides for the restoration of previously disallowed costs that are subsequently allowed by a regulator. With respect to assets recognized under SFAS No. 71 and all other long-lived assets, the adoption of SFAS No. 121 did not have an effect on the Company's financial position, cash flows or results of operations. However, if the Company had been unable to continue to apply the provisions of SFAS No. 71, at December 31, 1996, the Company estimates that approximately $4.6 billion would have been written off at such time.

Discussed below are the Company's significant regulatory assets and regulatory liabilities.

Base Financial Component and Rate Moderation Component

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

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

The RMC reflects the difference between the Company's revenue requirements under conventional ratemaking and the revenues resulting from the implementation of the rate moderation plan provided for in the RMA. The RMC is currently adjusted, on a monthly basis, for the Company's share of certain Nine Mile Point Nuclear Power Station, Unit 2 (NMP2) operations and maintenance expenses, fuel credits resulting from the Company's electric fuel cost adjustment clause and gross receipts tax adjustments related to the FRA. For a further discussion of the 1989 Settlement and FRA, see Notes 2 and 3.

Shoreham Post-Settlement Costs

Consists of Shoreham decommissioning costs, fuel disposal costs, payments-in-lieu-of-taxes, carrying charges and other costs. These costs are being capitalized and amortized and recovered through rates over a forty-year period on a straight-line remaining life basis which began July 1, 1989. For a further discussion of Shoreham post-settlement costs, see Note 2.

Shoreham Nuclear Fuel

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

Unamortized Cost of Issuing Securities

Represents the unamortized premiums or discounts and expenses related to the issues of long-term debt that have been retired prior to maturity and the costs associated with the early redemption of those issues. In addition, this balance includes the unamortized capital stock expense and redemption costs related to certain series of preferred stock that have been refinanced. These costs are amortized and recovered through rates over the shorter of the life of the redeemed issue or the new issue as provided by the PSC.

Postretirement Benefits Other Than Pensions

The Company defers as a regulatory asset the difference between postretirement benefit expense recorded in accordance with SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions", and postretirement benefit expense reflected in current rates. Pursuant to a PSC order, the ongoing annual SFAS No. 106 benefit expense must be phased into and fully reflected in rates by November 30, 1997, with the accumulated deferred asset being recovered in rates over the next fifteen-year period. For a further discussion of SFAS No. 106, see Note 8.

Regulatory Tax Asset and Regulatory Tax Liability

The Company has recorded a regulatory tax asset for amounts that it will collect in future rates for the portion of its deferred tax liability that has not yet been recognized for ratemaking purposes. The regulatory tax asset is comprised principally of the tax effect of the difference in the cost basis of the BFC for financial and tax reporting purposes, depreciation differences not normalized and the allowance for equity funds used during construction.

The regulatory tax liability is primarily attributable to deferred taxes previously recognized at rates higher than current enacted tax law, unamortized investment tax credits and tax credit carryforwards.

Regulatory Liability Component

Pursuant to the 1989 Settlement, certain tax benefits attributable to the Shoreham abandonment are to be shared between electric ratepayers and shareowners.

A regulatory liability of approximately $794 million was recorded in June 1989 to preserve an amount equivalent to the customer tax benefits attributable to the Shoreham abandonment. This amount is being amortized over a ten-year period on a straight-line basis which began July 1, 1989.

1989 Settlement Credits

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

Utility Plant

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

Allowance for Funds Used During Construction

The Uniform Systems of Accounts defines the Allowance For Funds Used During Construction (AFC) as the net cost of borrowed funds used 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 the FERC on a portion of construction work in progress. The average annual AFC rate, without giving effect to compounding, was 9.02%, 9.36% and 9.18% for the years 1996, 1995 and 1994, respectively.

Depreciation

The provisions for depreciation result from the application of straight-line rates to the original cost, by groups, of depreciable properties in service. The rates are determined by age-life studies performed annually on depreciable properties. Depreciation for electric properties was equivalent to approximately 3.0% of respective average depreciable plant costs for each of the years 1996, 1995 and 1994. Depreciation for gas properties was equivalent to approximately 2.0% of respective average depreciable plant costs for each of the years 1996, 1995 and 1994.

Cash and Cash Equivalents

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

LRPP Receivable/Payable

Represents the current portion of amounts recoverable from or due to ratepayers that result from the revenue and expense reconciliations, performance-based incentives and associated carrying charges as established under the LILCO Ratemaking and Performance Plan (LRPP). For further discussion of the LRPP, see Note 3.

Fair Values of Financial Instruments

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

Revenues

Revenues are based on cycle billings rendered to certain customers monthly and others bi-monthly. The Company also accrues electric and gas revenues for services rendered to customers but not billed at month-end.

The Company's electric rate structure, as discussed in Note 3, provides for a revenue reconciliation mechanism which eliminates the impact on earnings of experiencing electric sales that are above or below the levels reflected in rates.

The Company's gas rate structure provides for a weather normalization clause which reduces the impact on revenues of experiencing weather which is warmer or colder than normal.

Fuel Cost Adjustments

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

Federal Income Tax

The Company provides deferred federal income tax with respect to certain items of income and expense that are reported in different years for federal income tax purposes and financial statement purposes and with respect to items with different bases for financial and tax reporting purposes, as discussed in Note 9.

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

For ratemaking purposes, the Company provides deferred federal income tax with respect to certain differences between income before income tax for financial reporting purposes and taxable income for federal income tax purposes. Also, certain accumulated deferred federal income tax is deducted from rate base and amortized or otherwise applied as a reduction in federal income tax expense in future years.

Reserves for Claims and Damages

Losses arising from claims against the Company, including workers' compensation claims, property damage, extraordinary storm costs and general liability claims, are partially self-insured. Reserves for these claims and damages are based on, among other things, experience, risk of loss and the ratemaking practices of the PSC. Extraordinary storm losses incurred by the Company are partially insured by various commercial insurance carriers. These insurance carriers provide partial insurance coverage for individual storm losses to the Company's transmission and distribution system between $15 million and $25 million. Storm losses which are outside of this range are self-insured by the Company.

Use of Estimates

The preparation of the financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Reclassifications

Certain prior year amounts have been reclassified in the financial statements to conform with the current year presentation.

Note 2. The 1989 Settlement

In February 1989, the Company and the State of New York entered into the 1989 Settlement resolving certain issues relating to the Company and providing, among other matters, for the financial recovery of the Company and for the transfer of Shoreham to the Long Island Power Authority (LIPA), an agency of the State of New York, for its subsequent decommissioning.

Upon the effectiveness of the 1989 Settlement, in June 1989, the Company recorded the FRA on its Balance Sheet and the retirement of its investment of approximately $4.2 billion, principally in Shoreham. The FRA has two components, the BFC and the RMC. For a further discussion of the FRA, see Note 1.

In February 1992, the Company transferred ownership of Shoreham to LIPA. Pursuant to the 1989 Settlement, the Company was required to reimburse LIPA for all of its costs associated with the decommissioning of Shoreham. Effective May 1, 1995, the Nuclear Regulatory Commission (NRC) terminated LIPA's possession-only license for Shoreham. The termination signified the NRC's approval that decommissioning was complete and that the site is suitable for unrestricted use. At December 31, 1996, Shoreham post-settlement costs totaled approximately $1.103 billion, consisting of $536 million of property taxes and payments-in-lieu-of-taxes, and $567 million of decommissioning costs, fuel disposal costs and all other costs incurred at Shoreham after June 30, 1989.

The PSC has determined that all costs associated with Shoreham which are prudently incurred by the Company subsequent to the effectiveness of the 1989 Settlement are decommissioning costs. The RMA provides for the recovery of such costs through electric rates over the balance of a forty-year period ending 2029.

Note 3. Rate Matters

Electric

In 1995, the Company submitted a compliance filing requesting that the PSC extend the provisions of its 1995 electric rate order, discussed below, through November 30, 1996. This filing was updated by the Company in August 1996 and approved by the PSC in January 1997.

During 1996, the PSC instituted numerous initiatives intended to lower electric rates on Long Island. The Company shares the PSC's concern regarding electric rate levels and is prepared to assist the PSC in pursuing any reasonable opportunity to reduce electric rates. The initiatives instituted were as follows:

- An Order to Show Cause, issued in February 1996, to examine various opportunities to reduce the Company's electric rates;
- An Order, issued in April 1996, expanding the scope of the Order to Show Cause proceeding in an effort to provide "immediate and substantial rate relief." This order directed the Company to file financial and other information sufficient to provide a legal basis for setting new rates for both the single rate year (1997) and the three-year period 1997 through 1999; and
- An Order, issued in July 1996, to institute an expedited temporary rate phase in the Order to Show Cause proceeding to be conducted in parallel with the ongoing phase concerning permanent rates.

The Order issued in July requested that interested parties file testimony and exhibits sufficient to provide a basis for the PSC to decide whether the Company's electric rates should be made temporary and, if so, the proper level of such temporary rates. The Staff of the PSC (Staff), in response to this Order, recommended that the Company's rates be reduced on a temporary basis by 4.2% effective October 1, 1996, until the permanent rate case is decided. In its filing, the Company sought to demonstrate that current electric rate levels were appropriate and that there was no justification for reducing them. Although evidentiary hearings on the Company's, Staff's and other interested parties' submissions were subsequently held on an expedited basis to enable the PSC to render a decision on the Company's rates, as of the date of this report, the PSC has yet to take any action.

In September 1996, the Company completed the filing of a multi-year rate plan (Plan) in compliance with the April 1996 Order. Major elements of the Plan include: (i) a base rate freeze for the three-year period December 1, 1996 through November 30, 1999; (ii) an allowed return on common equity of 11.0% through the term of the Plan with the Company fully retaining all earnings up to 12.66%, and sharing with the customer any earnings above 12.66%; (iii) the continuation of existing LRPP revenue and expense reconciliation mechanisms and performance incentive programs; (iv) crediting all net proceeds from the Shoreham property tax litigation to the RMC to reduce its balance; and (v) a mechanism to fully recover any outstanding RMC balance at the end of the 1999 rate year through inclusion in the Fuel Cost Adjustment (FCA), over a two-year period.

1995 Electric Rate Order

The basis of the 1995 Order included minimizing future electric rate increases while continuing to provide for the recovery of the Company's regulatory assets and retaining consistency with the RMA's objective of restoring the Company to financial health. The 1995 Order, which became effective December 1, 1994, froze base electric rates, reduced the Company's allowed return on common equity from 11.6% to 11.0% and modified or eliminated certain performance-based incentives, as discussed below.

The LRPP, originally approved by the PSC in November 1991, contained three major components: (i) revenue reconciliation; (ii) expense attrition and reconciliation; and (iii) performance-based incentives. In the 1995 Order, the PSC continued the three major components of the LRPP with modifications to the expense attrition and reconciliation mechanism and the performance-based incentives. The revenue reconciliation mechanism remains unchanged.

Revenue reconciliation provides a mechanism that eliminates the impact of experiencing sales that are above or below adjudicated levels by providing a fixed annual net margin level (defined as sales revenues, net of fuel expenses and gross receipts taxes). The difference between actual and adjudicated net margin levels are deferred on a monthly basis during the rate year.

The expense attrition and reconciliation component permits the Company to make adjustments for certain expenses recognizing that these cost increases are unavoidable due to inflation and changes outside the control of the Company. Pursuant to the 1995 Order, the Company is permitted to reconcile expenses for property taxes only, whereas under the original LRPP the Company was able to reconcile expenses for wage rates, property taxes, interest costs and demand side management (DSM) costs.

The original LRPP had also provided for the deferral and amortization of certain cost variances for enhanced reliability, production operations and maintenance expenses and the application of an inflation index to other expenses. Under the 1995 Order, these deferrals have been eliminated and any unamortized balances were credited to the RMC during 1995.

The modified performance-based incentive programs include the DSM program, the customer service performance program and the transmission and distribution reliability program. Under these revised programs, the Company is subject to a maximum penalty of 38 basis points of the allowed return on common equity and can earn up to 4 basis points under the customer service program. This 4 basis point incentive can only be used to offset a penalty under the transmission and distribution reliability program. Under the original LRPP, the Company was allowed to earn up to 40 basis points or forfeit up to 18 basis points under these incentive programs.

The partial pass-through fuel incentive program remains unchanged. Under this incentive, the Company can earn or forfeit up to 20 basis points of the allowed return on common equity.

For the rate year ended November 30, 1996, the Company earned 20 basis points, or approximately $4.3 million, net of tax effects, as a result of its performance under all incentive programs. For the rate years ended November 30, 1995 and 1994, the Company earned 19 and 50 basis points, respectively, or approximately $4.0 million and $9.2 million, respectively, net of tax effects, under the incentive programs in effect at those times.

The deferred balances resulting from the net margin and expense reconciliations, and earned performance-based incentives are netted at the end of each rate year, as established under the LRPP and continued under the 1995 Order. The first $15 million of the total deferral is recovered from or credited to ratepayers by increasing or decreasing the RMC balance. Deferrals in excess of the $15 million, upon approval of the PSC, are refunded to or recovered from the customers through the FCA mechanism over a 12-month period.

For the rate year ended November 30, 1996, the amount to be returned to customers resulting from the revenue and expense reconciliations, performance-based incentive programs and associated carrying charges totaled $14.5 million. Consistent with the mechanics of the LRPP, it is anticipated that the entire balance of the deferral will be used to reduce the RMC balance upon approval by the PSC of the Company's reconciliation filing which was submitted to the PSC in January 1997. For the rate year ended November 30, 1995, the Company recorded a net deferred LRPP credit of approximately $41 million. The first $15 million of the deferral was applied as a reduction to the RMC while the remaining portion of the deferral of $26 million will be returned to customers through the FCA when approved by the PSC. For the rate year ended November 30, 1994, the Company recorded a net deferred charge of approximately $79 million. The first $15 million of the deferral was applied as an increase to the RMC while the remaining deferral of $64 million was recovered from customers.

Another mechanism of the LRPP provides that earnings in excess of the allowed return on common equity, excluding the impacts of the various incentive and/or penalty programs, are used to reduce the RMC. For the rate years ended November 30, 1996 and 1995, the Company earned $9.1 million and $6.2 million, respectively, in excess of its allowed return on common equity. These excess earnings were applied as reductions to the RMC. In 1994, the Company did not earn in excess of its allowed return on common equity.

The Company is currently unable to predict the outcome of any of the rate proceedings currently before the PSC and their effect, if any, on the Company's financial position, cash flows or results of operations.

Gas

In December 1993, the PSC approved a three year gas rate settlement between the Company and the Staff of the PSC. The gas rate settlement provided annual gas rate increases of 4.7%, 3.8% and 3.2% for each of the three rate years beginning December 1, 1993, 1994 and 1995, respectively. In the determination of the revenue requirements for the gas rate settlement, an allowed return on common equity of 10.1% was used.

The gas rate settlement also provided that earnings in excess of a 10.6% return on common equity be shared equally between the Company's firm gas customers and its shareowners. For the rate years ended November 30, 1996, 1995 and 1994, the firm gas customers' portion of gas earnings in excess of the allowed return on common equity totaled approximately $10 million, $1 million and $7 million, respectively. In 1996, the Company was granted permission by the PSC to apply the customers' portion of the gas excess earnings and associated carrying charges for the 1995 and 1994 rate years to the recovery of deferred costs associated with postretirement benefits other than pensions and costs incurred for investigation and remediation of manufactured gas plant (MGP) sites. The Company has requested that the same treatment be granted for the disposition of the customers' portion of the 1996 rate year gas excess earnings.

The Company currently has no gas rate filings before the PSC and does not intend to file a gas rate case during the current rate year, unless required to do so in connection with the proposed merger with Brooklyn Union.

Note 4. The Class Settlement

The Class Settlement, which became effective on June 28, 1989, resolved a civil lawsuit against the Company brought under the federal Racketeer Influenced and Corrupt Organizations Act. The lawsuit, which the Class Settlement resolved, had alleged that the Company made inadequate disclosures before the PSC concerning the construction and completion of nuclear generating facilities.

The Class Settlement provides the Company's electric customers with rate reductions aggregating $390 million that are being reflected as adjustments to their monthly electric bills over a ten-year period which began on June 1, 1990. Upon its effectiveness, the Company recorded its liability for the Class Settlement on a present value basis at $170 million. The Class Settlement obligation at December 31, 1996 reflects the present value of the remaining reductions to be refunded to customers. The remaining reductions to customers bills, amounting to approximately $201 million as of December 31, 1996, consists of approximately $21 million for the five-month period beginning January 1, 1997, and $60 million for each of the 12-month periods beginning June 1, 1997, 1998 and 1999.

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

The Company has an undivided 18% interest in NMP2, located near Oswego, New York which is operated by Niagara Mohawk Power Corporation (NMPC). 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%). The Company's share of the rated capability is approximately 206 MW. The Company's net utility plant investment, excluding nuclear fuel, was approximately $715 million and $740 million at December 31, 1996 and 1995, respectively. The accumulated provision for depreciation, excluding decommissioning costs, was approximately $169 million and $153 million at December 31, 1996 and 1995, respectively. Generation from NMP2 and operating expenses incurred by NMP2 are shared in the same proportions as the cotenants' respective ownership interests. The Company's share of operating expenses is included in the corresponding operating expenses on its Statement of Income. The Company is required to provide its respective share of financing for any capital additions to NMP2. Nuclear fuel costs associated with NMP2 are being amortized on the basis of the quantity of heat produced for the generation of electricity.

NMPC has contracted with the United States Department of Energy for the disposal of spent nuclear fuel. The Company reimburses NMPC for its 18% share of the cost under the contract at a rate of $1.00 per megawatt hour of net generation less a factor to account for transmission line losses. For 1996, 1995 and 1994, this totaled $1.4 million, $1.2 million, and $1.4 million, respectively.

Nuclear Plant Decommissioning

NMPC expects to commence the decommissioning of NMP2 in 2026, shortly after the cessation of plant operations, using a method which provides for the removal of all equipment and structures and the release of the property for unrestricted use. The Company's share of decommissioning costs, based upon a "Site-Specific" 1995 study (1995 study), is estimated to be $368 million in 2026 dollars ($148 million in 1996 dollars). The Company's estimate for decommissioning costs decreased in 1996 as compared to 1995 principally as a result of a reduction in the estimated annual inflation factor. The Company's share of the estimated decommissioning costs is currently being provided for in electric rates and is being charged to operations as depreciation expense over the service life of NMP2. The amount of decommissioning costs recorded as depreciation expense in 1996, 1995 and 1994 was $3.9 million, $2.3 million and $1.6 million, respectively. The accumulated decommissioning costs collected in rates through December 31, 1996, 1995 and 1994 amounted to $14.9 million, $11.0 million and $8.7 million, respectively.

The Company has established trust funds for the decommissioning of the contaminated portion of the NMP2 plant. It is currently estimated that the cost to decommission the contaminated portion of the plant will be approximately 76% of the total decommissioning costs. These funds comply with regulations issued by the NRC and the FERC governing the funding of nuclear plant decommissioning costs. The Company's policy is to make quarterly contributions to the funds based upon the amount of decommissioning costs reflected in rates. As of December 31, 1996, the balance in these funds, including reinvested net earnings, was approximately $15.3 million. These amounts are included on the Company's Balance Sheet in Nonutility Property and Other Investments. The trust funds investment consists of U.S. Treasury debt securities and cash equivalents. The carrying amounts of these instruments approximate fair market value.

The Financial Accounting Standards Board issued an exposure draft in 1996 entitled "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets". Under the provisions of the exposure draft, the Company would be required to change its current accounting practices for decommissioning costs as follows: (i) the Company's share of the total estimated decommissioning costs would be accounted for as a liability, based on discounted future cash flows; (ii) the recognition of the liability for decommissioning costs would result in a corresponding increase to the cost of the nuclear plant rather than as depreciation expense; and (iii) investment earnings on the assets dedicated to the external decommissioning trust fund would be recorded as investment income rather than as an increase to accumulated depreciation. If the Company was required to record the present value of its share of NMP2 decommissioning costs on its Balance Sheet as of December 31, 1996, the Company would have to recognize a liability and corresponding increase to nuclear plant of approximately $54 million.

Nuclear Plant Insurance

NMPC procures public liability and property insurance for NMP2, and the Company reimburses NMPC for its 18% share of those costs.

The Price-Anderson Act mandates that nuclear power plants secure financial protection in the event of a nuclear accident. This protection must consist of two levels. The primary level provides liability insurance coverage of $200 million (the maximum amount available) in the event of a nuclear accident. If claims exceed that amount, a second level of protection is provided through a retrospective assessment of all licensed operating reactors. Currently, this "secondary financial protection" subjects each of the 110 presently licensed nuclear reactors in the United States to a retrospective assessment up to $76 million for each nuclear incident, payable at a rate not to exceed $10 million per year. The Company's interest in NMP2 could expose it to a maximum potential loss of $13.6 million, per incident, through assessments of $1.8 million per year in the event of a serious nuclear accident at NMP2 or another licensed U.S. commercial nuclear reactor. These assessments are subject to periodic inflation indexing and to a 5% surcharge if funds prove insufficient to pay claims.

NMPC has also procured $500 million primary nuclear property insurance with the Nuclear Insurance Pools and approximately $2.3 million of additional protection (including decontamination costs) in excess of the primary layer through Nuclear Electric Insurance Limited (NEIL). Each member of NEIL, including the Company, is also subject to retrospective premium adjustments in the event losses exceed accumulated reserves. For its share of NMP2, the Company could be assessed up to approximately $1.9 million per loss. This level of insurance is in excess of the NRC's required $1.06 billion of coverage.

The Company has obtained insurance coverage from NEIL for the extra expense incurred in purchasing replacement power during prolonged accidental outages. Under this program, should losses exceed the accumulated reserves of NEIL, each member, including the Company, would be liable for its share of deficiency. The Company's maximum liability per incident under the replacement power coverage, in the event of a deficiency, is approximately $842,000.

Recent Actions of the Nuclear Regulatory Commission

In October 1996, NMPC, along with other companies, received a letter from the NRC requiring them to provide the NRC with information on the "adequacy and availability" of design basis documentation on their nuclear plants within 120 days. Such information will be used by the NRC to verify that companies are in compliance with the terms and conditions of their license(s) and NRC regulations. In addition, it will allow the NRC to determine if other inspection activities or enforcement actions should be taken on a particular company. NMPC plans to respond to the NRC by the February 9, 1997 due date.

NMPC believes that the NRC is becoming more stringent as indicated by this request and that a direct cost impact on companies with nuclear plants may result. The Company is unable to predict how such a higher risk operating environment may affect its financial position, cash flows or results of operations.

Note 6. Capital Stock

Common Stock

The Company has 150,000,000 shares of authorized common stock, of which 120,784,277 were issued and 3,485 shares were held in Treasury at December 31, 1996. The Company has 1,678,208 shares reserved for sale through its Employee Stock Purchase Plan, 2,728,486 shares committed to the Automatic Dividend Reinvestment Plan and 97,093 shares reserved for conversion of the Series I Convertible Preferred Stock at a rate of $17.15 per share. In addition, in connection with the Share Exchange Agreement, as discussed in Note 10, the Company has granted Brooklyn Union the right, under certain circumstances, to purchase 23,981,964 shares of common stock at a price of $19.725 per share.

Preferred Stock

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

Preferred Stock Subject to Mandatory Redemption
The aggregate fair value of redeemable preferred stock with mandatory redemptions at December 31, 1996 and 1995 amounted to approximately $637 million and $598 million, respectively, compared to their carrying amounts of $640 million and $644 million, respectively. For a further discussion on the basis of the fair value of the securities discussed above, see Note 1.

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

Series	Redemption Provision Beginning	Redemption Provision Ending	Number of Shares	Redemption Price
L	7/31/79	7/31/11	10,500	$100
NN	3/1/99	3/1/19	77,700	25
UU	10/15/99	10/15/19	112,000	25

The Company has the non-cumulative option to double the number of shares to be redeemed pursuant to the sinking fund provisions in any year for the preferred stock series NN and UU. The aggregate par value of preferred stock required to be redeemed through sinking funds is $1.1 million in 1997 and 1998 and $5.8 million in each of the years 1999, 2000 and 2001.

The Company is also required to redeem all shares of certain series of preferred stock which are not subject to sinking fund requirements. The mandatory redemption requirements for these series are as follows:

Series		Redemption Date	Number of Shares	Redemption Amounts
$1.67	Series GG	3/1/99	880,000	$ 22,000,000
7.95%	Series AA	6/1/00	14,520,000	363,000,000
7.05%	Series QQ	5/1/01	3,464,000	86,600,000
7.66%	Series CC	8/1/02	570,000	57,000,000

Preferred Stock Not Subject to Mandatory Redemption
The Company has the option to redeem certain series of its preferred stock. For the series subject to optional redemption at December 31, 1996, the call prices were as follows:

Series		Call Price
5.00%	Series B	$101
4.25%	Series D	102
4.35%	Series E	102
4.35%	Series F	102
5 1/8%	Series H	102
5 3/4%	Series I – Convertible	100

Preference Stock

At December 31, 1996, none of the authorized 7,500,000 shares of nonparticipating preference stock, par value $1 per share, which ranks junior to preferred stock, were outstanding.

Note 7. Long-Term Debt

G&R Mortgage

The General and Refunding (G&R) Bonds are the Company's only outstanding secured indebtedness. The G&R Mortgage is a lien on substantially all of the Company's properties.

The annual G&R Mortgage sinking fund requirement for 1996, due not later than June 30, 1997, is estimated at $25 million. The Company expects to satisfy this requirement with retired G&R Bonds, property additions, or any combination thereof.

1989 Revolving Credit Agreement

The Company has available through October 1, 1997, $250 million under its 1989 Revolving Credit Agreement (1989 RCA). In July 1996, at the Company's request, the amount committed by the banks participating in the facility was reduced from $300 million to $250 million. This line of credit is secured by a first lien upon the Company's accounts receivable and fuel oil inventories. At December 31, 1996, no amounts were outstanding under the 1989 RCA. The 1989 RCA may be extended for one-year periods upon the acceptance by the lending banks of a request by the Company, which must be delivered to the lending banks prior to April 1 of each year. It is the Company's intent to request an extension prior to April 1, 1997.

Authority Financing Notes

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

Tender requirements of Authority Financing Notes at December 31, 1996 were as follows:

(In thousands of dollars)

	Interest Rate	Series	Principal	Tendered
PCRBs	8 1/4%	1982	$ 17,200	Tendered every three years, next tender October 1997
	3.25%	1985 A,B	150,000	Tendered annually on March 1
EFRBs	4.05%	1993 A	50,000	Tendered weekly
	4.00%	1993 B	50,000	Tendered weekly
	4.00%	1994 A	50,000	Tendered weekly
	4.00%	1995 A	50,000	Tendered weekly

The 1995, 1994 and 1993 EFRBs and the 1985 PCRBs are supported by letters of credit pursuant to which the letter of credit banks have agreed to pay the principal, interest and premium, if applicable, in the aggregate, up to approximately $381 million in the event of default. The obligation of the Company to reimburse the letter of credit banks is unsecured.

The expiration dates for these letters of credit are as follows:

	Series	Expiration Date
PCRBs	1985 A,B	3/16/99
EFRBs	1993 A,B	11/17/99
	1994 A	10/26/97
	1995 A	8/24/98

Prior to expiration, the Company is required to obtain either an extension of the letters of credit or a substitute credit facility. If neither can be obtained, the authority financing notes supported by letters of credit must be redeemed.

Fair Values of Long-Term Debt

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

(In thousands of dollars)

1996	Fair Value	Carrying Amount
General and Refunding Bonds	$ 1,571,745	$ 1,536,000
Debentures	2,271,095	2,270,000
Authority Financing Notes	950,758	916,675
Total	$ 4,793,598	$ 4,722,675
1995		
General and Refunding Bonds	$ 1,968,173	$ 1,951,000
Debentures	2,245,138	2,270,000
Authority Financing Notes	928,967	916,675
Total	$ 5,142,278	$ 5,137,675

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

Debt Maturity Schedule

The total long-term debt maturing in each of the next five years is as follows: 1997, $251 million; 1998, $101 million; 1999, $454 million; 2000, $37 million; and 2001, $146 million.

Note 8. Retirement Benefit Plans

Pension Plans

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

Primary Plan

The Company's funding policy is to contribute annually to the Primary Plan a minimum amount consistent with the requirements of the Employee Retirement Income Security Act of 1974 plus such additional amounts, if any, as the Company may determine to be appropriate from time to time. Pension benefits are based upon years of participation in the Primary Plan and compensation.

The Primary Plan's funded status and amounts recognized on the Balance Sheet at December 31, 1996 and 1995 were as follows:

(In thousands of dollars)	1996	1995
Actuarial present value of benefit obligation		
Vested benefits	$ 547,002	$ 518,487
Nonvested benefits	55,157	54,305
Accumulated Benefit Obligation	$ 602,159	$ 572,792
Plan assets at fair value	$ 746,400	$ 685,300
Actuarial present value of projected benefit obligation	689,661	662,360
Projected benefit obligation less than plan assets	56,739	22,940
Unrecognized net obligation	71,085	77,831
Unrecognized net gain	(123,759)	(97,285)
Net Prepaid (Accrued) Pension Cost	$ 4,065	$ 3,486

Periodic pension cost for the Primary Plan included the following components:

(In thousands of dollars)	1996	1995	1994
Service cost - benefits earned during the period	$ 17,384	$ 15,385	$ 16,465
Interest cost on projected benefit obligation and service cost	47,927	45,987	43,782
Actual return on plan assets	(81,165)	(102,099)	(12,431)
Net amortization and deferral	33,541	57,665	(31,633)
Net Periodic Pension Cost	$ 17,687	$ 16,938	$ 16,183

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

	1996	1995	1994
Discount rate	7.25%	7.25%	7.75%
Rate of future compensation increases	5.00%	5.00%	5.00%
Long-term rate of return on assets	7.50%	7.50%	7.50%

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

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

Supplemental Plan

The Supplemental Plan, the cost of which is borne by the Company's shareowners, provides supplemental death and retirement benefits for officers and other key executives without contribution from such employees. The Supplemental Plan is a non-qualified plan under the Internal Revenue Code. Death benefits are currently provided by insurance. The provision for plan benefits, which are unfunded, totaled approximately $2.7 million in 1996 and $2.3 million in both 1995 and 1994.

Directors' Plan

The Directors' Plan provides benefits to directors who are not officers of the Company. Directors who have served in that capacity for more than five years qualify as participants under the plan. The Directors' Plan is a non-qualified plan under the Internal Revenue Code. The provision for retirement benefits, which are unfunded, totaled approximately $127,000, $114,000 and $148,000 in 1996, 1995 and 1994, respectively.

Postretirement Benefits Other Than Pensions

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

The PSC requires the Company to defer as a regulatory asset the difference between postretirement benefit expense recorded for accounting purposes in accordance with SFAS No. 106 and the postretirement benefit expense reflected in rates. The ongoing annual postretirement benefit expense will be phased into and fully reflected in rates within a five-year period from the year of adoption, which began December 1, 1993, with the accumulated regulatory asset being recovered in rates over a 15-year period, beginning December 1, 1997. In addition, the Company is required to recognize any deferred net gains or losses over a ten-year period.

In 1994, the Company established Voluntary Employee's Beneficiary Association trusts for union and non-union employees for the funding of incremental costs collected in rates for postretirement benefits. For the years ended December 31, 1996 and 1995, the Company funded the trusts with approximately $18 million and $50 million, respectively.

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

	(In thousands of dollars) 1996	1995
Retirees	$ 156,181	$ 135,497
Fully eligible plan participants	56,950	52,028
Other active plan participants	152,627	142,035
Accumulated postretirement benefit obligation	365,758	329,560
Plan assets	(74,692)	(53,646)
Accumulated postretirement benefit obligation in excess of plan assets	291,066	275,914
Unrecognized prior service costs	(188)	-
Unrecognized net gain	75,309	100,335
Accrued Postretirement Benefit Cost	$ 366,187	$ 376,249

At December 31, 1996, and 1995, the Plan assets, which are recorded at fair value, include cash and cash equivalents, fixed income investments and approximately $100,000 of listed equity securities of the Company.

Periodic postretirement benefit cost other than pensions for the years were as follows:

	(In thousands of dollars) 1996	1995	1994
Service cost - benefits earned during the period	$ 10,690	$ 9,082	$ 11,275
Interest cost on projected benefit obligation and service cost	25,030	22,412	25,713
Actual return on plan assets	(3,046)	(1,034)	-
Net amortization and deferral	(12,175)	(14,699)	(5,213)
Periodic Postretirement Benefit Cost	$ 20,499	$ 15,761	$ 31,775

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

	1996	1995	1994
Discount rate	7.25%	7.25%	7.75%
Rate of future compensation increases	5.00%	5.00%	5.00%
Long-term rate of return on assets	7.50%	7.50%	-

The assumed health care cost trend rates used in measuring the accumulated postretirement benefit obligation at December 31, 1996 and 1995 were 8.0% and 8.5%, respectively, gradually declining to 6.0% in 2001 and thereafter. A one percentage point increase in the health care cost trend rate would increase the accumulated postretirement benefit obligation as of December 31, 1996 and 1995 by approximately $43 million and $36 million, respectively, and the sum of the service and interest costs in 1996 and 1995 by $5 million and $4 million, respectively.

Note 9. Federal Income Tax

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

	(In thousands of dollars)	
	1996	*1995*
Deferred Tax Assets		
Net operating loss carryforwards	$ 145,205	$ 338,921
Reserves not currently deductible	58,981	66,825
Tax depreciable basis in excess of book	34,314	41,428
Nondiscretionary excess credits	27,700	29,826
Credit carryforwards	135,902	149,545
Other	186,907	125,246
Total Deferred Tax Assets	$ 589,009	$ 751,791
Deferred Tax Liabilities		
1989 Settlement	$ 2,163,239	$ 2,155,418
Accelerated depreciation	642,702	628,475
Call premiums	44,846	50,062
Rate case deferrals	2,127	28,971
Other	33,496	35,597
Total Deferred Tax Liabilities	2,886,410	2,898,523
Net Deferred Tax Liability	$ 2,297,401	$ 2,146,732

SFAS No. 109 requires utilities to establish regulatory assets and liabilities for the portion of its deferred tax assets and liabilities that have not yet been recognized for ratemaking purposes. The major components of these regulatory assets and liabilities are as follows:

	(In thousands of dollars)	
	1996	*1995*
Regulatory Assets		
1989 Settlement	$ 1,660,871	$1,666,744
Plant items	125,976	149,520
Other	(14,069)	(13,881)
Total Regulatory Assets	$ 1,772,778	$1,802,383
Regulatory Liabilities		
Carryforward credits	$ 68,421	$ 82,330
Other	34,466	33,730
Total Regulatory Liabilities	$ 102,887	$ 116,060

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

	(In thousands of dollars)		
	1996	*1995*	*1994*
Income before federal income tax	$ 525,721	$ 508,824	$ 478,564
Statutory federal income tax rate	35%	35%	35%
Statutory federal income tax	$ 184,002	$ 178,088	$ 167,497
Additions (reductions) in federal income tax			
Excess of book over tax depreciation	18,339	18,588	14,745
1989 Settlement	4,212	4,213	4,213
Interest capitalized	2,270	2,218	2,449
Tax credits	(4,383)	(1,025)	(2,058)
Tax rate change amortization	3,686	3,752	(4,779)
Allowance for funds used during construction	(2,305)	(2,392)	(2,450)
Other items	3,436	2,096	(2,905)
Total Federal Income Tax Expense	$ 209,257	$ 205,538	$ 176,712
Effective Federal Income Tax Rate	39.8%	40.4%	36.9%

The Company's net operating loss (NOL) carryforwards for federal income tax purposes are estimated to be approximately $415 million at December 31, 1996. These NOL carryforwards are scheduled to expire in the years 2004 through 2007. The Company currently has tax credit carryforwards of approximately $136 million. This balance is composed of investment tax credit (ITC) carryforwards, net of the 35% reduction required by the Tax Reform Act of 1986, totaling approximately $128 million and research and development credits totaling approximately $8 million. In 1990 and 1992, the Company received Revenue Agents' Reports disallowing certain deductions and credits claimed by the Company on its federal income tax returns for the years 1981 through 1989. The Revenue Agents' Reports proposed ITC adjustments which if sustained, would reduce the ITC carryforwards to approximately $63 million.

Additionally, the Revenue Agents' Reports reflect proposed adjustments to the Company's federal income tax returns for the years 1981 through 1989 which, if sustained, would give rise to tax deficiencies totaling approximately $227 million. The Company believes that any such deficiencies as finally determined would be significantly less than the amounts proposed in the Revenue Agents' Reports. The Company has protested some of the proposed adjustments which are presently under review by the Regional Appeals Office of the Internal Revenue Service. If this review does not result in a settlement that is satisfactory to the Company, the Company intends to seek a judicial review. The Company believes that its reserves are adequate to cover any tax deficiency that may ultimately be determined and that cash from operations will be sufficient to satisfy any settlement reached. However, if necessary, the Company will avail itself of interim financing via the 1989 RCA to meet this obligation. The Company currently believes that a settlement of the 1981 through 1989 years should be reached with the Regional Appeals Office sometime in 1997.

Note 10. Merger Agreement with The Brooklyn Union Gas Company

On December 29, 1996, the Company and The Brooklyn Union Gas Company (Brooklyn Union) entered into an Agreement and Plan of Exchange (Share Exchange Agreement), pursuant to which the companies will be merged in a transaction that will result in the formation of a new holding company. The new holding company, which has not yet been named, will serve approximately 2.2 million customers and have annual revenues of more than $4.5 billion. The merger is expected to be accomplished through a tax-free exchange of shares.

The proposed transaction, which has been approved by both companies' boards of directors, would unite the resources of the Company with the resources of Brooklyn Union. Brooklyn Union, with approximately 3,300 employees, distributes natural gas at retail, primarily in a territory of approximately 187 square miles which includes the boroughs of Brooklyn and Staten Island and approximately two-thirds of the borough of Queens, all in New York City. Brooklyn Union has energy-related investments in gas exploration, production and marketing in the United States and Canada, as well as energy services in the United States, including cogeneration products, pipeline transportation and gas storage.

Under the terms of the proposed transaction, the Company's common shareowners will receive .803 shares (the Ratio) of the new holding company's common stock for each share of the Company's common stock that they currently hold. Brooklyn Union common shareowners will receive one share of common stock of the new holding company for each share of Brooklyn Union common stock that they currently hold. Shareowners of the Company will own approximately 66% of the common stock of the new holding company while Brooklyn Union shareowners will own approximately 34%. The proposed transaction will have no effect on either company's debt issues or outstanding preferred stock.

The Share Exchange Agreement contains certain covenants of the parties pending the consummation of the transaction. Generally, the parties must carry on their businesses in the ordinary course consistent with past practice, may not increase dividends on common stock beyond specified levels and may not issue capital stock beyond certain limits. The Share Exchange Agreement also contains restrictions on, among other things, charter and by-law amendments, capital expenditures, acquisitions, dispositions, incurrence of indebtedness, certain increases in employee compensation and benefits, and affiliate transactions. Accordingly, the Company's ability to engage in certain activity described herein may be limited or prohibited by the Share Exchange Agreement.

Upon completion of the merger, Dr. William J. Catacosinos will become chairman and chief executive officer of the new holding company; Mr. Robert B. Catell, currently chairman and chief executive officer of Brooklyn Union, will become president and chief operating officer of the new holding company. One year after the closing, Mr. Catell will succeed Dr. Catacosinos as chief executive officer, with Dr. Catacosinos continuing as chairman. The board of directors of the new company will be composed of 15 members, six from the Company, six from Brooklyn Union and three additional persons previously unaffiliated with either company and jointly selected by them.

The companies will continue their respective current dividend policies until the closing, consistent with the provisions of the Share Exchange Agreement. It is expected that the new holding company's dividend policy will be determined prior to closing.

The merger is conditioned upon, among other things, the approval of the merger by the holders of two-thirds of the outstanding shares of common stock of each of the Company and Brooklyn Union and the receipt of all required regulatory approvals. The Company is unable to determine when or if all required approvals will be obtained.

In 1995, the Long Island Power Authority (LIPA), an agency of the State of New York (NYS), was requested by the Governor of NYS to develop a plan, pursuant to its authority under NYS law, to provide an electric rate reduction of at least 10%, provide a framework for long-term competition in power production and protect property taxpayers on Long Island.

The Share Exchange Agreement contemplates that discussions, which are currently in progress, will continue with LIPA to arrive at an agreement mutually acceptable to the Company, Brooklyn Union and LIPA, pursuant to which LIPA would acquire certain assets or securities of the Company, the consideration for which would inure to the benefit of the new holding company. In the event that such a transaction is completed, the Ratio would become .880. In connection with discussions with LIPA, LIPA has indicated that it may exercise its power of eminent domain over all or a portion of the Company's assets or securities, in order to achieve its objective of reducing current electric rates, if a negotiated agreement cannot be reached. The Company is unable to determine when or if an agreement with LIPA will be reached, or what action, if any, LIPA will take if such an agreement is not reached.

Note 11. Commitments and Contingencies

Commitments

Electric

The Company has entered into contracts with numerous Independent Power Producers (IPPs) and the New York Power Authority (NYPA) for electric generating capacity. Under the terms of the agreement with NYPA, which is set to expire in May 2014, the Company may purchase up to 100% of the electric energy produced at the NYPA facility located within the Company's service territory at Holtsville, NY. The Company is required to reimburse NYPA for the minimum debt service payments, and to make fixed non-energy payments and expenses associated with operating and maintaining the plant.

With respect to contracts entered into with the IPPs, the Company is obligated to purchase all the energy they make available to the Company (at prices that often exceed current market prices). However, the Company has no obligation to the IPPs if they fail to deliver energy. For purposes of the table below, the Company has assumed full performance by the IPPs, as no event has occurred to suggest anything less than full performance by these parties.

The Company also has contracted with NYPA for firm transmission (wheeling) capacity in connection with a transmission cable which was constructed, in part, for the benefit of the Company. In accordance with the provisions of this agreement which expire in 2020, the Company is required to reimburse NYPA for debt service payments and the cost of operating and maintaining the cables. The cost of such contracts is included in electric fuel expense and is recoverable through rates.

The following table represents the Company's commitments under purchase power contracts.

Electric Operations *(In millions of dollars)*

	NYPA Holtsville					
	Debt Service	Other Fixed Charges	Energy*	Firm Transmission	IPPs*	Total Business*
1997	$ 20.3	$ 15.0	$ 7.7	$ 27.8	$ 110.7	$ 181.5
1998	21.6	15.2	9.0	27.8	115.3	188.9
1999	21.7	16.3	7.2	27.2	118.3	190.7
2000	21.8	16.4	8.0	27.0	123.3	196.5
2001	21.9	16.6	11.3	29.0	126.7	205.5
Subsequent Years	259.9	254.9	137.0	557.4	1,161.6	2,370.8
Total	$ 367.2	$ 334.4	$ 180.2	$ 696.2	$ 1,755.9	$ 3,333.9
Less: Imputed Interest	188.0	183.7	96.9	426.4	841.8	1,736.8
Present Value of Payments	$ 179.2	$ 150.7	$ 83.3	$ 269.8	$ 914.1	$ 1,597.1

**Assumes full performance by the IPPs and NYPA.*

Gas
In order to provide sufficient supplies of gas for the Company's gas customers, the Company has entered into long-term firm gas transporation, storage and supply contracts which contain provisions that require the Company to make payments even if the services are not provided (take-or-pay.) The cost of such contracts is included in gas fuel expense and is recoverable through rates. The table below sets forth the Company's aggregate obligation under these commitments which extend through 2012.

Gas Operations	*(In millions of dollars)*
1997	$ 38.7
1998	37.6
1999	37.6
2000	37.6
2001	34.7
Subsequent Years	232.5
Total	$ 418.7
Less: Imputed Interest	182.1
Present Value of Payments	$ 236.6

Continuous Emission Monitoring
The Company expended approximately $1 million in 1996 to meet continuous emission monitoring requirements, to meet Phase II nitrogen oxide (NOx) reduction requirements under the federal Clean Air Act (CAA). Subject to requirements that are expected to be promulgated in forthcoming regulations, the Company estimates that it may be required to expend approximately $44 million by 2003 to meet Phase II and Phase III NOx reduction requirements and approximately $2 million by 1999 to meet potential requirements for the control of hazardous air pollutants from power plants. The Company believes that all of the above costs will be recoverable through rates.

Competitive Environment

The electric industry continues to undergo fundamental changes as regulators, elected officials and customers seek lower energy prices. These changes, which may have a significant impact on future financial performance of electric utilities, are being driven by a number of factors including a regulatory environment in which traditional cost-based regulation is seen as a barrier to lower energy prices. In 1996, both the PSC and the FERC continued their separate, but in some cases parallel, initiatives with respect to developing a framework for a competitive electric marketplace.

The Electric Industry - State Regulatory Issues
In 1994, the PSC began the second phase of its Competitive Opportunities Proceedings to investigate issues related to the future of the regulatory process in an industry which is moving toward competition. The PSC's overall objective was to identify regulatory and ratemaking practices that would assist New York State utilities in the transition to a more competitive environment designed to increase efficiency in providing electricity while maintaining safe, affordable and reliable service.

As a result of the Competitive Opportunities Proceedings, in May 1996, the PSC issued an order (Order) which stated its belief that introducing competition to the electric industry in New York has the potential to reduce electric rates over time, increase customer choice and encourage economic growth. The Order calls for a competitive wholesale power market to be in place by early 1997 which will be followed by the introduction of retail access for all customers by early 1998.

The PSC stated that competition should be transitioned on an individual company basis, due to differences in individual service territories, the level and type of strandable investments (i.e., costs that utilities would have otherwise recovered through rates under traditional cost of service regulation that, under market competition, would not be recoverable) and utility specific financial conditions.

The Order contemplates that implementation of competition will proceed on two tracks. The Order requires that each major electric utility file a rate/restructuring plan which is consistent with the PSC's policy and vision for increased competition. Those plans were submitted by October 1, 1996, in compliance with the Order. However, the Company was exempted from this requirement due to the PSC's separate investigation of the Company's rates and LIPA's examination of the Company's structure. Since October 1, 1996, proceedings have commenced for the five electric utilities which filed restructuring plans in accordance with track one and the Company has intervened in each of these proceedings.

The PSC order also anticipated that certain other filings would be made on October 1, 1996, by all New York State utilities, to both the PSC and the FERC. The filings were to address the delineation of transmission and distribution facilities jurisdiction between the FERC or the PSC, a pricing of each company's transmission services, and a joint filing by all the utilities to address the formation of an Independent System Operator (ISO) and the creation of a market exchange that will establish spot market prices. Although there were extensive collaborative meetings among the parties, it was not possible for the additional filings to be completed by October 1, 1996. While these discussions are continuing in an attempt to narrow the differences among the parties, on December 31, 1996, the New York Power Pool (NYPP) members submitted a compliance filing to the FERC which provides open membership and comparable services to eligible entities in accordance with FERC Order 888, discussed below. It is anticipated that the New York State utilities will submit the full ISO/Power Exchange filing to the FERC during the first quarter of 1997.

The PSC envisions that a fully operational wholesale competitive structure will foster the expeditious movement to full retail competition. The PSC's vision of the retail competitive structure, known as the Flexible Retail Poolco Model, consists of: (i) the creation of an ISO to coordinate the safe and reliable operation of electric generation and transmission; (ii) open access to the transmission system, which would be regulated by the FERC; (iii) the continuation of a regulated distribution company to operate and maintain the distribution system; (iv) the deregulation of energy/customer services such as meter reading and customer billing; (v) the ability of customers to choose among suppliers of electricity; and (vi) the allowance of customers to acquire electricity either by long-term contracts, purchases on the spot market or a combination of the two.

One issue discussed in the Order that could affect the Company is strandable investments. The PSC stated in its Order that it is not required to allow recovery of all prudently incurred investments, that it has considerable discretion to set rates that balance ratepayer and shareholder interests, and that the amount of strandable investments that a utility will be permitted to recover will depend on the particular circumstances of each utility. Additionally, the Order provided that every effort should be made by utilities to mitigate these costs prior to seeking recovery.

Certain aspects of the restructuring envisioned by the PSC—particularly the PSC's apparent determinations that it may deny the utilities recovery of prudent investments made on behalf of the public, order retail wheeling, require divestiture of generation assets and deregulate certain sectors of the energy market—could, if implemented, have a negative impact on the operations and financial conditions of New York's investor-owned electric utilities, including the Company.

The Company is party to a lawsuit commenced in September 1996 by the Energy Association of New York State and the state's other investor-owned electric utilities (collectively, Petitioners) against the PSC in New York Supreme Court, Albany County (The Energy Association of New York State, et al. v. Public Service Commission of the State of New York, et al.). The Petitioners have requested that the Court declare that the Order is unlawful or, in the alternative, that the Court clarify that the PSC's statements in the Order constitute simply a policy statement with no binding legal effect. In November 1996, the Court issued a Decision and Order denying the Petitioners' request to invalidate the Order. Although the Court stated that most of the Order is a non-binding statement of policy, the Court rejected the Petitioners' substantive challenges to the Order. In December 1996, Petitioners filed a notice of appeal with the Third Department of the Appellate Division of the New York State Supreme Court. The litigation is ongoing and the Company is unable at this time to predict the likelihood of success or the impact of the litigation on the Company's financial position, cash flows or results of operations. Oral argument in the Appellate Division has not yet been scheduled, but a decision is expected by the end of 1997.

The Electric Industry - Federal Regulatory Issues

In April 1996, in response to its Notice of Proposed Rulemaking issued in March 1995, the FERC issued two orders relating to the development of competitive wholesale electric markets.

Order 888 is a final rule on open transmission access and stranded cost recovery and provides that the FERC has exclusive jurisdiction over interstate wholesale wheeling and that utility transmission systems must now be open to qualifying sellers and purchasers of power on a non-discriminatory basis.

Order 888 allows utilities to recover legitimate, prudent and verifiable stranded costs associated with wholesale transmission, including the circumstances where full requirements customers become wholesale transmission customers, such as where a municipality establishes its own electric system.

With respect to retail wheeling, the FERC concluded that it has jurisdiction over rates, terms and conditions of service, but would leave the issue of recovery of the costs stranded by retail wheeling to the states.

Order 888 required utilities to file open access tariffs under which they would provide transmission services, comparable to those which they provide themselves and to third parties on a non-discriminatory basis. Additionally, utilities must use these same tariffs for their own wholesale sales. The Company filed its open access tariff in July 1996.

In September 1996, the FERC ordered Rate Hearings on 28 utility transmission tariffs, including the Company's. On the basis of a preliminary review, the FERC was not satisfied that the tariff rates were just and reasonable. Settlement discussions have been held between the Company and various intervenors concerning the Company's transmission rates. In December 1996, the parties reached a tentative settlement on the rate issues. The procedural schedule was suspended pending filing of the settlement agreement, which is anticipated during the first quarter of 1997. Non-rate issues associated with the Company's open access tariff have not yet been addressed by the FERC.

Order 889, which is a final rule on a transmission pricing bulletin board, addresses the rules and technical standards for operation of an electronic bulletin board that will make available, on a real-time basis, the price, availability and other pertinent information concerning each transmission utility's services. It also addresses standards of conduct to ensure that transmission utilities functionally separate their transmission and wholesale power merchant functions to prevent discriminatory self-dealing. In

December 1996, the Company filed its standards of conduct in accordance with the Order.

With other members of the industry, the Company has participated in several joint petitions for rehearing and/or clarification of the FERC's Orders 888 and 889. Among other issues, these petitions address the FERC's obligation to exercise its jurisdiction to provide for the recovery of strandable investments in any retail wheeling situations. The outcome and timing of the FERC Orders on rehearing are uncertain.

It is not possible to predict the ultimate outcome of these proceedings, the timing thereof, or the amount, if any, of stranded costs that the Company would recover in a competitive environment. The outcome of the state and federal regulatory proceedings could adversely affect the Company's ability to apply Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," which, pursuant to SFAS No. 101, "Accounting for Discontinuation of Application of SFAS No. 71," could then require a significant write-down of all or a portion of the Company's net regulatory assets. If the Company were unable to continue to apply the provisions of SFAS No. 71, at December 31, 1996, the Company estimates that approximately $4.6 billion would have been written off at such time.

The Company's Service Territory

The Company's geographic location and the limited electrical interconnections to Long Island serve to limit the accessibility of its transmission grid to potential competitors from off the system. However, the changing utility regulatory environment has affected the Company by requiring the Company to co-exist with state and federally mandated competitors. These competitors are non-utility generators (NUGS), NYPA and Municipal Distribution Agencies (MDAs).

The Public Utility Regulatory Policies Act of 1978 (PURPA), the goal of which is to reduce the United States' dependency on foreign oil, to encourage energy conservation and to promote diversification of the fuel supply, has negatively impacted the Company through the encouragement of the NUG industry. PURPA provides for the development of a new class of electric generators which rely on either cogeneration technology or alternate fuels. Utilities are obligated under PURPA to purchase the output of certain of these generators, which are known as qualified facilities (QFs).

In 1996, the Company lost sales to NUGs totaling 422 gigawatt-hours (GWh) representing a loss in electric revenues net of fuel (net revenues) of approximately $34 million, or 1.9% of the Company's net revenues. In 1995, the Company lost sales to NUGs totaling 366 GWh or approximately $28 million or 1.5% of the Company's net revenues.

The increase in lost net revenues resulted principally from the completion of seven facilities that became commercially operational during 1996 and the full year operation of the IPP located at the State University of New York at Stony Brook, NY. The Company estimates that in 1997, sales losses to NUGs will be 429 GWh, or approximately 1.8% of projected net revenues.

The Company believes that load losses due to NUGs have stabilized. This belief is based on the fact that the Company's customer load characteristics, which lack a significant industrial base and related large thermal load, will mitigate load loss and thereby make cogeneration economically unattractive.

Additionally, as mentioned above, the Company is required to purchase all the power offered by QFs which in 1996 approximated 218 megawatts (MW) and in early 1995 approximated 205 MW. The increase was the result of the SUNY Stony Brook facility going on line in mid 1995. The Company estimates that purchases from QFs required by federal and state law cost the Company $63 million and $53 million in 1996 and 1995, respectively, more than it would have cost had the Company generated this power.

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

The Company has also experienced a revenue loss as a result of its policy of voluntarily providing wheeling of NYPA power for economic development. The Company estimates that in 1996 and 1995 NYPA power displaced approximately 417 GWh and 429 GWh of annual energy sales, respectively. Net revenue loss associated with these volumes of sales is approximately $26 million, or 1.4% of the Company's 1996 net revenues, and $30 million, or 1.6% of the Company's 1995 net revenues. Currently, the potential loss of additional load is limited by conditions in the Company's transmission agreements with NYPA.

A number of customer groups are seeking to hasten consideration and implementation of full retail competition. For example, an energy consultant has petitioned the PSC, seeking alternate sources of power for Long Island school districts. The County of Nassau has also petitioned the PSC to authorize retail wheeling for all classes of electric customers in the County.

In addition, several towns and villages on Long Island are investigating municipalization, in which customers form a government-sponsored electric supply company. This is one form of competition that is likely to increase as a result of the National Energy Policy Act of 1992 (NEPA). NEPA sought to increase economic efficiency in the creation and distribution of power by relaxing restrictions on the entry of new competitors to the wholesale electric power market. NEPA does so by creating exempt wholesale generators that can sell power in wholesale markets without the regulatory constraint placed on utility generators such as on the Company. NEPA also expanded the FERC's authority to grant access to utility transmission systems to all parties who seek wholesale wheeling for wholesale competition. While it should be noted that the FERC's position favoring stranded cost recovery from retail-turned-wholesale customers will reduce utility risk from municipalization, significant issues associated with the removal of restrictions on wholesale transmission system access have yet to be resolved.

There are numerous towns and villages in the Company's service territory that are considering the formation of a municipally owned and operated electric authority to replace the services currently provided by the Company.

In 1995, Suffolk County issued a request for proposal from suppliers for up to 300 MW of power which the County would then sell to its residential and commercial customers. The County has awarded the bid to two off-Long Island suppliers and has requested the Company to deliver the power. After the Company challenged Suffolk County's eligibility for such service, the County petitioned the FERC to order the Company to provide the requested transmission service.

In December 1996, the FERC ordered the Company to provide transmission services to Suffolk County to the extent necessary to accommodate proposed sales to customers to which it was providing service on the date of enactment of NEPA (this Order could provide Suffolk County with the ability to import up to 200 MW of power on a daily basis). The FERC reserved decision on the remaining 100 MW of Suffolk County's request until the County identifies the ownership or control of distribution facilities that it alleges qualifies it for a wheeling order to Suffolk County customers who were not receiving service on the date of NEPA's enactment. The Company may ask the FERC to reconsider their decision once that decision becomes final, which is not expected for several months. The FERC has yet to determine the pricing of that service. As previously noted, FERC Order 888 allows utilities to recover legitimate, prudent and verifiable stranded costs associated with wholesale transmission, including the circumstances where full requirements customers become wholesale transmission customers, such as where a municipality establishes its own electric system.

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

Notwithstanding the outcome of the state or federal regulatory proceedings, or any other state action, the Company believes that, among other obligations, the state has a contractual obligation to allow the Company to recover its Shoreham-related assets.

Environmental Matters

The Company is subject to federal, state and local laws and regulations dealing with air and water quality and other environmental matters. Environmental matters may expose the Company to potential liabilities which, in certain instances, may be imposed without regard to fault or for historical activities which were lawful at the time they occurred. The Company continually monitors its activities in order to determine the impact of its activities on the environment and to ensure compliance with various environmental laws. Except as set forth below, no material proceedings have been commenced or, to the knowledge of the Company, are contemplated against the Company with respect to any matter relating to the protection of the environment.

The New York State Department of Environmental Conservation (DEC) has required the Company and other New York State utilities to investigate and, where necessary, remediate their former manufactured gas plant (MGP) sites. Currently, the Company is the owner of six pieces of property on which the Company or certain of its predecessor companies are believed to have produced manufactured gas. Operations at these facilities in the late 1800's and early 1900's may have resulted in the disposal of certain waste products on these sites. Research is underway to determine the existence and nature of operations and their relationship, if any, to the Company or its predecessor companies.

The Company has entered into discussions with the DEC which may lead to the issuance of one or more administrative Consent Orders (ACO) regarding the management of environmental activities at these properties. Although the exact amount of the Company's remediation costs cannot yet be determined, based on the findings of investigations at two of these six sites, estimates indicate that it will cost approximately $51 million to remediate all of these sites through the year 2005. Accordingly, the Company has recorded a $35 million liability and a corresponding regulatory asset to reflect its belief that the PSC will provide for the future recovery of these costs through rates as it has for other New York State utilities. The $35 million liability reflects the present value of the future stream of payments to investigate and remediate these sites. The Company used a risk-free rate of 7.25% to discount this obligation.

In December 1996, the Company filed a complaint in the United States District Court for the Southern District of New York against 14 of the Company's insurers which issued general comprehensive liability (GCL) policies to the Company. The Company is seeking recovery under the GCL policies for the costs incurred to date and future costs associated with the clean-up of the Company's former MGP sites and Superfund sites for which the Company has been named a potentially responsible party (PRP). The Company is seeking a declaratory judgment that the defendant insurers are bound by the terms of the GCL policies, subject to the stated coverage limits, to reimburse the Company for the remediation costs. The outcome of this proceeding cannot yet be determined.

The Company has been notified by the United States Environmental Protection Agency (EPA) that it is one of many PRPs that may be liable for the remediation of three licensed treatment, storage and disposal sites to which the Company may have shipped waste products and which have subsequently become environmentally contaminated.

At one site, located in Philadelphia, Pennsylvania, and operated by Metal Bank of America, the Company and nine other PRPs, all of which are public utilities, have entered into an ACO with the EPA to conduct a Remedial Investigation and Feasibility Study (RI/FS), which has been completed and is currently being reviewed by the EPA. Under a PRP participation agreement, the Company is responsible for 8.2% of the costs associated with this RI/FS. The level of remediation required will be determined when the EPA issues its decision, but based on information available to date, the Company currently anticipates that the total cost to remediate this site will be between $14 million and $30 million. The Company has recorded a liability of $1.1 million representing its estimated share of the cost to remediate this site based upon its 8.2% responsibility under the RI/FS.

The Company has also been named a PRP for disposal sites in Kansas City, Kansas, and Kansas City, Missouri. The two sites were used by a company named PCB, Inc. from 1982 until 1987 for the storage, processing, and treatment of electric equipment, dielectric oils and materials containing PCBs. According to the EPA, the buildings and certain soil areas outside the buildings are contaminated with PCBs.

In 1994, the EPA requested certain of the large PRPs, which include several other utilities, to form a group, sign an ACO, and conduct a remediation program for the sites under the Toxic Substances Control Act, or in the alternative, to perform a Superfund cleanup for the sites. The EPA has provided the Company with documents indicating that the Company was responsible for less than 1% of the materials that were shipped to the Missouri site. The EPA has not yet completed compiling the documents for the Kansas site. The Company intends to join a PRP Group which includes other utilities, which has been organized for the purpose of developing and implementing acceptable remediation programs for the sites. The Company is currently unable to determine its share of the cost to remediate these sites.

In addition, the Company was notified that it is a PRP at a Superfund site located in Farmingdale, New York. Portions of the site are allegedly contaminated with PCBs, solvents and metals. The Company was also notified by other PRPs that it should be responsible for remediation expenses in the amount of approximately $100,000 associated with removing PCB-contaminated soils from a portion of the site which formerly contained electric transformers. The Company is currently unable to determine its share of costs of remediation at this site.

During 1996, the Connecticut Department of Environmental Protection (DEP) issued a modification to an ACO previously issued in connection with an investigation of an electric transmission cable located under the Long Island Sound (Sound Cable) that is jointly owned by the Company and the Connecticut Light and Power Company (Owners). The modified ACO requires the Owners to submit to the DEP and DEC a series of reports and studies describing cable system condition, operation and repair practices, alternatives for cable improvements or replacement and environmental impacts associated with leaks of fluid into the Long Island Sound, which have occurred from time to time. The Company continues to compile required information and coordinate the activities necessary to perform these studies and, at the present time, is unable to determine the costs it will incur to complete the requirements of the modified ACO or to comply with any additional requirements.

Previously, the U.S. Attorney for the District of Connecticut had commenced an investigation regarding occasional releases of fluid from the Sound Cable, as well as associated operating and maintenance practices. The Owners have provided the U.S. Attorney with all requested documentation. The Company believes that all activities associated with the response to occasional releases from the Sound Cable were consistent with legal and regulatory requirements.

In addition, during 1996 the Long Island Soundkeeper Fund, a non-profit organization, filed a suit against the Owners of the Sound Cable in Federal District Court in Connecticut alleging that the Sound Cable fluid leaks constitute unpermitted discharges of pollutants in violation of the Clean Water Act (CWA) and that such pollutants present a threat to the environment and public health. The suit seeks, among other things, injunctive relief prohibiting the Owners from continuing to operate the Sound Cable in alleged violation of the CWA and civil penalties of $25,000 per day for each violation from each of the Owners.

In December 1996, a barge, owned and operated by a third party, dropped anchor, causing extensive damage to the Sound Cable and a release of dielectric fluid into the Long Island Sound. Temporary clamps and leak abaters have been placed on the cables and have stopped the leaks. Permanent repairs are expected to be undertaken in the late spring of 1997. The preliminary estimate of the cost of these repairs is $15 million. The Company intends to seek recovery from third parties for costs incurred by the Company as a result of this incident. The timing and amount of recovery, if any, cannot yet be determined. In addition, the Owners maintain insurance coverage for the Sound Cable which the Company believes will be sufficient to cover any repair costs. In any event, costs not reimbursed by a third party or not covered by insurance will be shared equally by the Owners.

The Company believes that none of the environmental matters, discussed above, will have a material adverse impact on the Company's financial position, cash flows or results of operations. In addition, the Company believes that all significant costs incurred with respect to environmental investigation and remediation activities, not recoverable from insurance carriers, will be recoverable through rates.

Note 12. Segments of Business

Identifiable assets by segment include net utility plant, regulatory assets, materials and supplies, accrued unbilled revenues, gas in storage, fuel and deferred charges. Assets utilized for overall Company operations consist primarily of cash and cash equivalents, accounts receivable, common net utility plant and unamortized cost of issuing securities.

(In millions of dollars)

For year ended December 31	*1996*	*1995*	*1994*
Operating revenues			
Electric	$ 2,467	$ 2,484	$ 2,481
Gas	684	591	586
Total	$ 3,151	$ 3,075	$ 3,067
Operating expenses (excludes federal income tax)			
Electric	$ 1,644	$ 1,657	$ 1,640
Gas	560	478	500
Total	$ 2,204	$ 2,135	$ 2,140
Operating income (before federal income tax)			
Electric	$ 823	$ 827	$ 842
Gas	124	113	85
Total operating income	947	940	927
AFC	(6)	(7)	(7)
Other income and deductions	(23)	(38)	(45)
Interest charges	451	476	500
Federal income tax	209	206	177
Net Income	$ 316	$ 303	$ 302
Depreciation and amortization			
Electric	$ 129	$ 122	$ 112
Gas	25	23	19
Total	$ 154	$ 145	$ 131
Construction and nuclear fuel expenditures*			
Electric	$ 165	$ 162	$ 155
Gas	78	84	125
Total	$ 243	$ 246	$ 280

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

(In millions of dollars)

At December 31	*1996*	*1995*	*1994*
Identifiable assets			
Electric	$ 9,835	$ 10,020	$ 10,285
Gas	1,232	1,181	1,181
Total identifiable assets	11,067	11,201	11,466
Assets utilized for overall Company operations	1,143	1,326	1,013
Total Assets	$12,210	$ 12,527	$ 12,479

Note 13. Quarterly Financial Information (Unaudited)

(In thousands of dollars except earnings per common share)

	1996	*1995*
Operating revenues		
For the quarter ended March 31	$ 864,214	$ 791,188
June 30	694,602	653,824
September 30	849,775	875,794
December 31	742,104	754,322
Operating income		
For the quarter ended March 31	$ 190,421	$ 180,875
June 30	141,065	143,246
September 30	235,402	239,561
December 31	169,693	167,936
Net income		
For the quarter ended March 31	$ 81,753	$ 70,299
June 30	40,524	41,392
September 30	130,023	131,221
December 31	64,164	60,374
Earnings for common stock		
For the quarter ended March 31	$ 68,682	$ 57,127
June 30	27,453	28,220
September 30	116,972	118,069
December 31	51,141	47,250
Earnings per common share		
For the quarter ended March 31	$ .57	$ .48
June 30	.23	.24
September 30	.97	.99
December 31	.43	.39

Note 14. Event Subsequent To The Date Of The Report Of Independent Auditors (Unaudited)

Long Island Power Authority Proposed Transaction

On April 30, 1997, the Long Island Power Authority (LIPA) submitted to the New York State Public Authorities Control Board for approval, unexecuted copies of agreements related to LIPA's proposed acquisition (via the purchase of the Company's common stock) of the Company's transmission and distribution system and certain other assets and liabilities (LIPA Transaction). Prior to LIPA's acquisition of the common stock, the Company's gas assets, electric generating facility assets and certain other assets and liabilities will be transferred to affiliates of the holding company to be formed in connection with the Share Exchange Agreement with Brooklyn Union.

While the specific allocation of assets and liabilities has not yet been finally determined, it is currently contemplated that the holding company would, subject to obtaining all required consents, assume the Company's (i) 7.30% Debentures due July 15, 1999; (ii) 8.20% Debentures due March 15, 2023; and (iii) Preferred Stock, 7.95%, Series AA.

Consumation of the Share Exchange Agreement is not conditioned upon the consumation of the LIPA Transaction, and consumation of the LIPA Transaction is not conditioned upon consumation of the Share Exchange Agreement.

The Company is unable to determine when or if the agreements related to the LIPA Transaction will be executed by the parties or when or if all consents and approvals required to consummate the LIPA Transaction will be obtained.

Report of Ernst & Young LLP, Independent Auditors

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

We have audited the accompanying balance sheet of Long Island Lighting Company and the related statement of capitalization as of December 31, 1996 and 1995 and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1996. 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, 1996 and 1995, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1996, in conformity with generally accepted accounting principles.

Ernst + Young LLP

Melville, New York
January 31, 1997

Selected Financial Data

	1996	1995	1994	1993	1992
Table 1					*(In thousands of dollars except per share amounts)*
Summary of Operations					
Revenues	$ 3,150,695	$ 3,075,128	$ 3,067,307	$ 2,880,995	$2,621,839
Operating expenses	2,414,114	2,343,510	2,322,362	2,125,444	1,880,734
Operating income	736,581	731,618	744,945	755,551	741,105
Other income and (deductions)	27,512	43,703	52,719	70,874	66,330
Income before interest charges	764,093	775,321	797,664	826,425	807,435
Interest charges	447,629	472,035	495,812	529,862	505,461
Net income	316,464	303,286	301,852	296,563	301,974
Preferred stock dividend requirements	52,216	52,620	53,020	56,108	63,954
Earnings for Common Stock	$ 264,248	$ 250,666	$ 248,832	$ 240,455	$ 238,020
Average common shares outstanding (000)	120,361	119,195	115,880	112,057	111,439
Earnings per Common Share	$ 2.20	$ 2.10	$ 2.15	$ 2.15	$ 2.14
Common stock dividends declared per share	$ 1.78	$ 1.78	$ 1.78	$ 1.76	$ 1.72
Common stock dividends paid per share	$ 1.78	$ 1.78	$ 1.78	$ 1.75	$ 1.71
Book value per common share at December 31	$ 20.89	$ 20.50	$20.21	$ 19.88	$19.58
Common shares outstanding at December 31 (000)	120,781	119,655	118,417	112,332	111,600
Common shareowners of record at December 31	86,607	93,088	96,491	94,877	86,111

Table 2	1996	1995	1994	1993	1992
*Capitalization Ratios**					
Long-term debt	59.3%	61.8%	62.5%	65.0%	64.7%
Preferred stock	8.9	8.6	8.6	8.5	8.8
Common equity	31.8	29.6	28.9	26.5	26.5
Total	100.0%	100.0%	100.0%	100.0%	100.0%

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

Table 3	1996	1995	1994	1993	1992
					(In thousands of dollars)
Operations and Maintenance Expense Details					
Payroll and employee benefits	$ 440,587	$ 440,721	$ 435,830	$ 418,766	$ 420,297
Less – Charged to construction and other	146,162	165,733	155,766	130,432	131,447
Payroll and employee benefits charged to operations	294,425	274,988	280,064	288,334	288,850
Fuel and Purchased Power					
Fuel – electric operations	313,607	266,039	261,154	287,349	282,138
Fuel – gas operations	319,773	246,837	267,629	253,511	206,344
Purchased power costs	331,736	309,807	307,584	292,136	280,914
Fuel cost adjustments deferred	(1,865)	12,296	11,619	(5,405)	(27,612)
Total fuel and purchased power	963,251	834,979	847,986	827,591	741,784
All other	204,786	236,405	260,590	233,326	209,095
Total Operations and Maintenance Expense	$ 1,462,462	$ 1,346,372	$ 1,388,640	$ 1,349,251	$1,239,729
Full-time Employees at December 31	5,413	5,688	5,947	6,215	6,438

Table 4	1996	1995	1994	1993	1992
					(In thousands of dollars)
Electric Operating Income					
Revenues					
Residential	$1,205,133	$ 1,204,987	$ 1,202,124	$ 1,145,891	$1,045,799
Commercial and industrial	1,174,499	1,194,014	1,196,422	1,132,487	1,076,302
Other system revenues	50,513	52,472	52,477	49,790	49,395
Total system revenues	2,430,145	2,451,473	2,451,023	2,328,168	2,171,496
Sales to other utilities	20,927	19,104	14,895	12,872	9,997
Other revenues	15,363	13,437	15,719	11,069	13,139
Total Revenues	2,466,435	2,484,014	2,481,637	2,352,109	2,194,632
Operating Expenses					
Operations – fuel and purchased power	640,610	570,697	568,738	579,032	559,583
Operations – other	288,315	293,184	310,438	306,116	294,909
Maintenance	98,007	106,031	107,573	111,765	105,341
Depreciation and amortization	128,534	121,980	111,996	106,149	104,034
Base financial component amortization	100,971	100,971	100,971	100,971	100,971
Rate moderation component amortization	(24,232)	21,933	197,656	88,667	(30,444)
Regulatory liability component amortization	(79,359)	(79,359)	(79,359)	(79,359)	(79,359)
1989 Settlement credits amortization	(9,214)	(9,214)	(9,214)	(9,214)	(9,214)
Other regulatory amortization	109,532	155,532	(4,883)	(17,082)	(21,984)
Operating taxes	390,861	375,164	336,263	326,407	331,122
Federal income tax – current	42,197	14,596	10,784	6,324	530
Federal income tax – deferred and other	138,307	168,377	156,646	158,941	158,908
Total Operating Expenses	1,824,529	1,839,892	1,807,609	1,678,717	1,514,397
Electric Operating Income	$ 641,906	$ 644,122	$ 674,028	$ 673,392	$ 680,235

Table 5	1996	1995	1994	1993	1992
					(In thousands of dollars)
Gas Operating Income					
Revenues					
Residential – space heating	$ 367,721	$ 323,729	$ 326,474	$ 310,109	$ 243,950
– other	47,028	42,046	42,263	39,515	33,035
Commercial and industrial – space heating	144,807	130,964	126,092	106,140	90,363
– other	36,549	34,293	35,275	33,181	29,094
Total firm revenues	596,105	531,032	530,104	488,945	396,442
Interruptible revenues	37,927	32,837	26,804	24,028	19,658
Total system revenues	634,032	563,869	556,908	512,973	416,100
Off-system revenues, net	26,254	16,213	20,904	5,812	–
Other revenues	23,974	11,032	7,858	10,101	11,107
Total Revenues	684,260	591,114	585,670	528,886	427,207
Operating Expenses					
Operations – fuel	322,641	264,282	279,248	248,559	182,201
Operations – other	92,761	90,054	95,576	81,692	77,300
Maintenance	20,128	22,124	27,067	22,087	20,395
Depreciation and amortization	25,391	23,377	18,668	16,322	15,103
Other regulatory amortization	17,756	6,073	9,211	(962)	(88)
Operating taxes	81,215	72,343	70,632	59,440	57,866
Federal income tax – deferred and other	29,693	25,365	14,351	19,589	13,560
Total Operating Expenses	589,585	503,618	514,753	446,727	366,337
Gas Operating Income	$ 94,675	$ 87,496	$ 70,917	$ 82,159	$ 60,870

	1996	1995	1994	1993	1992
Table 6					
Electric Sales and Customers					
Sales – millions of kWh					
Residential	7,203	7,156	7,159	7,118	6,788
Commercial and industrial	8,242	8,336	8,394	8,257	8,181
Other system sales	441	460	457	449	471
Total system sales	15,886	15,952	16,010	15,824	15,440
Sales to other utilities	528	620	372	304	227
Total Sales	**16,414**	**16,572**	**16,382**	**16,128**	**15,667**
Customers – monthly average					
Residential	920,930	915,162	908,490	905,997	902,885
Commercial and industrial	104,488	103,669	102,490	102,254	101,838
Other	4,595	4,549	4,583	4,553	4,593
Total Customers – monthly average	**1,030,013**	**1,023,380**	**1,015,563**	**1,012,804**	**1,009,316**
Customers at December 31	1,031,205	1,025,107	1,016,739	1,011,965	1,009,028
Residential					
kWh per customer	7,821	7,819	7,880	7,857	7,518
Revenue per kWh	16.73¢	16.84¢	16.79¢	16.10¢	15.41¢
Commercial and Industrial					
kWh per customer	78,880	80,410	81,901	80,750	80,333
Revenue per kWh	14.25¢	14.32¢	14.25¢	13.72¢	13.16¢
System					
kWh per customer	15,423	15,588	15,765	15,624	15,297
Revenue per kWh	15.30¢	15.37¢	15.31¢	14.71¢	14.06¢

	1996	1995	1994	1993	1992
Table 7					
Gas Sales and Customers					
Sales – thousands of Dth					
Residential – space heating	37,697	35,336	35,693	37,191	35,089
– other	3,153	2,929	3,151	3,297	3,203
Commercial and industrial – space heating	16,763	16,170	15,679	14,366	13,662
– other	4,291	4,269	4,366	4,329	4,338
Total firm sales	61,904	58,704	58,889	59,183	56,292
Interruptible sales	7,869	9,176	6,914	5,920	5,090
Off-system sales	7,457	7,743	7,232	2,894	–
Total Sales	**77,230**	**75,623**	**73,035**	**67,997**	**61,382**
Customers – monthly average					
Residential – space heating	249,758	245,452	239,857	233,882	227,834
– other	161,164	162,114	163,608	166,974	169,189
Commercial and industrial – space heating	35,803	35,027	33,776	32,783	31,666
– other	10,084	10,313	10,448	10,631	10,777
Total firm customers	456,809	452,906	447,689	444,270	439,466
Interruptible customers	651	623	576	542	531
Total Customers – monthly average	**457,460**	**453,529**	**448,265**	**444,812**	**439,997**
Customers at December 31	460,028	455,869	449,906	446,384	442,117
Residential					
Dth per customer	99.4	93.9	96.3	101.0	96.4
Revenue per Dth	$ 10.15	$ 9.56	$ 9.49	$ 8.64	$ 7.23
Commercial and Industrial					
Dth per customer	458.8	450.8	453.3	430.6	424.1
Revenue per Dth	$ 8.61	$ 8.09	$ 8.05	$ 7.45	$ 6.64
System					
Dth per customer	152.5	149.7	146.8	146.4	139.5
Revenue per Dth	$ 9.09	$ 8.31	$ 8.46	$ 7.88	$ 6.78

	1996	1995	1994	1993	1992
Table 8					
Electric Operations					
Energy – millions of kWh					
Net generation	10,319	10,744	10,034	10,514	10,592
Power purchased	7,388	7,143	7,640	7,023	6,438
Total Energy Available	17,707	17,887	17,674	17,537	17,030
System sales	15,886	15,952	16,010	15,824	15,440
Company use and unaccounted for	1,293	1,315	1,292	1,409	1,363
Total system energy requirements	17,179	17,267	17,302	17,233	16,803
Sales to other utilities	528	620	372	304	227
Total Energy Available	17,707	17,887	17,674	17,537	17,030
Peak Demand – MW					
Station coincident demand	2,848	3,591	3,253	2,931	2,975
Power purchased – net	757	486	629	1,036	636
System Peak Demand	3,605	4,077	3,882	3,967	3,611
System Capability – MW					
Company stations	3,978	3,957	4,063	4,063	4,091
Nine Mile Point 2 (18% share)	206	203	189	188	188
Firm purchases – net	710	713	616	548	432
Total Capability	4,894	4,873	4,868	4,799	4,711
Fuel Consumed for Electric Operations					
Oil – thousands of barrels	7,063	5,154	7,518	9,740	10,656
Gas – thousands of Dth	50,173	69,826	44,308	36,269	34,475
Nuclear – thousands of MW days – thermal	200	169	203	175	124
Fuel Mix (Percentage of total energy available)					
Oil	24%	17%	25%	34%	37%
Gas	25	36	23	19	19
Purchased power	42	40	43	40	38
Nuclear fuel	9	7	9	7	6
Total	100%	100%	100%	100%	100%

	1996	1995	1994	1993	1992
Table 9					
Gas Operations					
Company Requirements – thousands of Dth					
System sales	69,773	67,880	65,803	65,103	61,382
Off-system sales	7,457	7,743	7,232	2,894	–
Company use and unaccounted for	3,738	2,054	2,516	1,905	3,577
Total Company Requirements	80,968	77,677	75,551	69,902	64,959
Maximum Day Sendout – Dth	524,762	564,874	585,227	485,896	448,726
System Capability – Dth per day					
Natural gas	648,695	592,335	579,897	561,584	561,584
LNG manufactured or LP gas	123,300	124,700	125,700	120,700	120,700
Total Capability	771,995	717,035	705,597	682,284	682,284
Heating Degree Days					
(30 year average 4,942)	5,132	4,906	4,839	4,899	5,066

	1996	1995	1994	1993	1992
Table 10					*(In thousands of dollars)*
Balance Sheet					
Assets					
Net utility plant	$ 3,695,170	$ 3,594,998	$ 3,498,346	$ 3,347,557	$3,161,148
Regulatory Assets					
Base financial component	3,281,548	3,382,519	3,483,490	3,584,461	3,685,432
Rate moderation component	402,213	383,086	463,229	609,827	651,657
Shoreham post-settlement costs	991,795	968,999	922,580	777,103	586,045
Shoreham nuclear fuel	69,113	71,244	73,371	75,497	77,629
Unamortized cost of issuing securities	194,151	222,567	254,482	174,694	195,524
Postretirement benefits other than pensions	360,842	383,642	412,727	402,921	-
Regulatory tax asset	1,772,778	1,802,383	1,831,689	1,848,998	-
Other	199,879	229,809	250,804	247,858	190,008
Total Regulatory Assets	7,272,319	7,444,249	7,692,372	7,721,359	5,386,295
Nonutility property and other investments	18,597	16,030	24,043	23,029	20,730
Current assets	1,146,602	1,411,938	1,090,230	1,088,831	979,131
Deferred charges	76,991	60,382	174,298	272,995	305,819
Total Assets	**$12,209,679**	**$12,527,597**	**$12,479,289**	**$12,453,771**	**$9,853,123**
Capitalization and Liabilities					
Long-term debt	$ 4,471,675	$ 4,722,675	$ 5,162,675	$ 4,887,733	$4,755,733
Unamortized discount on debt	(14,903)	(16,075)	(17,278)	(17,393)	(14,731)
	4,456,772	4,706,600	5,145,397	4,870,340	4,741,002
Preferred stock – redemption required	638,500	639,550	644,350	649,150	557,900
Preferred stock – no redemption required	63,664	63,934	63,957	64,038	154,276
Total Preferred Stock	702,164	703,484	708,307	713,188	712,176
Common stock	603,921	598,277	592,083	561,662	558,002
Premium on capital stock	1,127,971	1,114,508	1,101,240	1,010,283	998,089
Capital stock expense	(49,330)	(50,751)	(52,175)	(50,427)	(39,304)
Retained earnings	840,867	790,919	752,480	711,432	667,988
Treasury stock, at cost	(60)	-	-	-	-
Total Common Shareowners' Equity	2,523,369	2,452,953	2,393,628	2,232,950	2,184,775
Total Capitalization	7,682,305	7,863,037	8,247,332	7,816,478	7,637,953
Regulatory Liabilities					
Regulatory liability component	198,398	277,757	357,117	436,476	515,835
1989 Settlement credits	127,442	136,655	145,868	155,081	164,294
Regulatory tax liability	102,887	116,060	111,218	114,748	-
Other	146,852	132,891	147,041	142,455	102,718
Total Regulatory Liabilities	575,579	663,363	761,244	848,760	782,847
Current liabilities	949,627	1,050,021	601,311	1,188,972	1,177,130
Deferred credits	2,573,208	2,502,040	2,365,780	2,166,405	237,893
Operating reserves	428,960	449,136	503,622	433,156	17,300
Total Capitalization and Liabilities	**$12,209,679**	**$12,527,597**	**$12,479,289**	**$12,453,771**	**$9,853,123**

Table 11					*(In thousands of dollars)*
*Construction Expenditures**					
Electric	$ 143,435	$ 145,472	$ 136,041	$ 137,583	$ 141,752
Gas	71,690	79,536	120,019	124,859	104,028
Common	27,659	21,477	23,610	42,251	27,124
Total Construction Expenditures	**$ 242,784**	**$ 246,485**	**$ 279,670**	**$ 304,693**	**$ 272,904**

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

Corporate Information

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

Common Stock Listed
New York Stock Exchange
Pacific Stock Exchange

Ticker Symbol: LIL

Internet Address: HTTP://WWW.LILCO.COM

E-Mail Address: investor-relations@lilco.com

Transfer Agent and Registrar
Common stock and preferred stock
The Bank of New York

Address shareholder inquiries to:
Shareholder Services Department-11E
Church Street Station
P.O. Box 11258
New York, NY 10286-1612
1-800-482-3638

Send certificates for transfer
and address changes to:
Receive and Deliver Department-11W
P.O. Box 11002
Church Street Station
New York, NY 10286-1612

Internet Address: HTTP://STKXFER.BANKOFNY.COM
E-Mail Address: Shareowner-svcs@Email.bony.com

Investor Common Stock Plan
As of June 1, 1997, the Company has implemented the Investor Common Stock Plan, which allows any interested investor to purchase LILCO's common stock directly through the Plan. Features of the Plan includes full or partial reinvestment of dividends, monthly optional cash investments, automatic electronic investment, certificate safekeeping, direct deposit of cash dividends and direct sale of shares. Investors may become a LILCO shareholder through the Plan with a minimum investment of $250. For more information, and for a copy of the Plan prospectus, please call the Plan administrator, The Bank of New York, at 1-800-482-3638 or write to:

The Bank of New York
Shareholder Services Department - 11E
Church Street Station
P.O. Box 11258
New York, NY 10286-1258

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

Common Stock Prices and Dividends
The common stock of the Company is traded on the New York Stock Exchange and the Pacific Stock Exchange. Certain of the Company's preferred stock series are traded on the New York Stock Exchange. The quoted market prices for the years 1996 and 1995 were as follows:

Quarter	1996			1995		
	High	Low	Dividend	High	Low	Dividend
First	$\$18\frac{1}{8}$	$\$15\frac{7}{8}$	$0.445	$\$16\frac{3}{4}$	$\$13\frac{1}{4}$	$0.445
Second	$17\frac{7}{8}$	$16\frac{1}{8}$	0.445	$17\frac{1}{8}$	$14\frac{3}{8}$	0.445
Third	$17\frac{3}{4}$	$16\frac{5}{8}$	0.445	$17\frac{3}{4}$	$15\frac{3}{8}$	0.445
Fourth	$22\frac{3}{8}$	$17\frac{1}{8}$	0.445	$17\frac{3}{4}$	$15\frac{5}{8}$	0.445

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

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

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

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

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and Chief Executive Officer
Long Island Lighting Company

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

George Bugliarello
Chancellor
Polytechnic University

Renso L. Caporali
Senior Vice President
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Business Development
Raytheon Company

Peter O. Crisp
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Venrock, Inc.
Venture Capital Investments

James T. Flynn
President and Chief
Operating Officer
Long Island Lighting Company

Vicki L. Fuller
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Massachusetts Institute
of Technology

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

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

Officers

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Chairman of the Board
and Chief Executive Officer

James T. Flynn
President and Chief
Operating Officer

Michael E. Bray
Senior Vice President
Electric Business Unit

Robert X. Kelleher
Senior Vice President
Human Resources

Adam M. Madsen
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Corporate and
Strategic Planning

Joseph W. McDonnell
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Marketing and External Affairs

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Senior Vice President and
General Counsel

Anthony Nozzolillo
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Finance and Chief
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Vice President
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Services and Deputy
General Counsel

Werner J. Schweiger
Vice President
Electric Operations

Richard M. Siegel
Vice President
Information Systems &
Technology

William E. Steiger, Jr.
Vice President
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Real Estate

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

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