1996 Annual Report

Notice of 1997 Annual Meeting

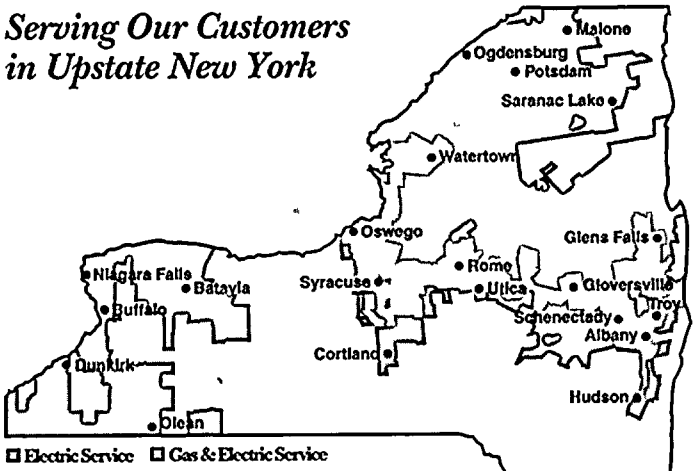
Proxy Statement

Niagara Mohawk
Power Corporation

Contents

Directors and Officers are listed on the inside back cover

Serving Our Customers in Upstate New York



Niagara Mohawk Power Corp. is an investor-owned utility providing energy to the largest customer service area in New York.

Our electric system meets the needs of more than 1.5 million residential, commercial, and industrial customers, with power supplied by hydroelectric, coal, oil, natural gas, and nuclear generating units. Electricity is transmitted through an integrated operating network that is linked to other systems in the Northeast for economic exchange and mutual reliability.

Our natural gas system provides service to more than 500,000 residential and business customers on a retail basis, as well as a growing number of customers for whom we transport gas that they purchase directly from suppliers.

This report was produced by Niagara Mohawk employees.

Printed on recycled paper

Corporate Information

Annual Meeting
The Annual Meeting of shareholders will be held at the OnCenter, 800 S. State Street, Syracuse, NY, at 10:30 a.m., Tuesday, May 6, 1997. A notice of the meeting, proxy statement and form of proxy is included in this document.

SEC Form 10-K Report
A copy of the company's Form 10-K report, filed annually with the Securities and Exchange Commission, is available without charge by writing the Investor Relations Department at 300 Erie Boulevard West, Syracuse, NY 13202.

Shareholder Inquiries
Questions regarding shareholder accounts may be directed to the company's Shareholder Services Department:

(315) 428-6750 (Syracuse)

1-800-448-5450 (elsewhere in the continental U.S.)

Analyst Inquiries
Analyst inquiries should be directed to:
Leon T. Mazur, Director-Investor Relations, (315) 428-5876.

Stock Exchange Listings
Ticker Symbol: NMK
Common stock and most preferred series are listed and traded on the New York Stock Exchange.
Bonds are traded on the New York Stock Exchange.

Disbursing Agent

Common and preferred stocks:
Niagara Mohawk Power Corp.
300 Erie Boulevard West
Syracuse, NY 13202

Bonds:
Marine Midland Bank, N.A.
140 Broadway
New York, NY 10015

Transfer Agent and Registrars

Common and preferred stocks:
The Bank of New York
P.O. Box 11002
Church Street Station
New York, NY 10286
1-800 524-4458

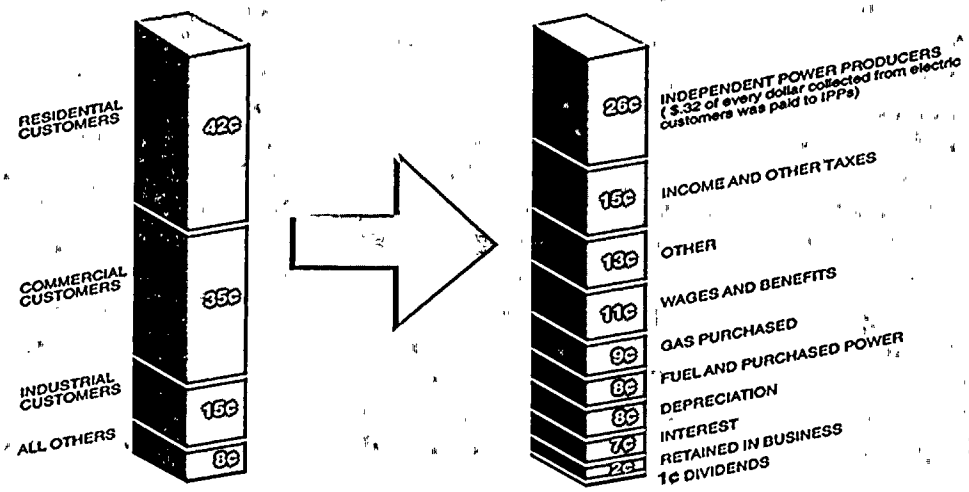
Bonds:
Marine Midland Bank, N.A.
140 Broadway
New York, NY 10015

Highlights

	1996	1995	%Change
[illegible] operating revenues	$ 3,990,653,000	$ 3,917,338,000	1.9
Income available for common stockholders	$ 72,109,000*	$ 208,440,000	(65.4)
Earnings per common share	$ 0.50*	$ 1.44	(65.3)
Dividends per common share	$ —	$ 1.12	—
Common shares outstanding (*average*)	144,350,000	144,329,000	—
Utility plant (*gross*)	$10,839,341,000	$10,649,301,000	1.8
Construction work in progress	$ 279,992,000	$ 289,604,000	(3.3)
Gross additions to utility plant	$ 352,049,000	$ 345,804,000	1.8
Public kilowatt-hour sales	33,393,000,000	33,011,000,000	1.2
Total kilowatt-hour sales	39,127,000,000	37,684,000,000	3.8
Electric customers at end of year	1,556,000	1,555,000	0.1
Electric peak load (*kilowatts*)	6,021,000	6,211,000	(3.1)
[illegible]ral gas sales (*dekatherms*)	84,881,000	78,481,000	8.2
Natural gas transported (*dekatherms*)	134,671,000	144,613,000	(6.9)
Gas customers at end of year	526,000	518,000	1.5
Maximum day gas deliveries (*dekatherms*)	1,152,996	1,211,252	(4.8)

**Includes extraordinary item*

The 1996 Revenue Dollar and Where it Went



A Letter to Our Shareholders

Dear Shareholder:

The pace of change quickened in 1996, both at Niagara Mohawk and throughout the utility industry. Barely a week passed without major developments in the regulatory, legislative or competitive arenas. Through it all, we continued to focus on our primary goal: finding a solution to the problem of mandated contracts with Independent Power Producers (IPPs).

Although settlement remained elusive in 1996, our efforts culminated in our March 10, 1997, announcement of an agreement in principle to terminate or restructure 44 IPP contracts held by 19 developers.

Removing the IPP Burden

As I have reported in the past, our payments to IPPs – about $1 billion annually – have become a serious and growing burden on our customers and shareholders. The clearest and most troubling indication of that burden was the Board's painful but necessary decision to suspend the dividend on our common stock.

The IPP problem also threatened to block progress on our *PowerChoice* proposal to create a competitive electricity market and open new avenues for growth in our business. That is why we initiated discussions with the IPPs in late 1995, with assistance from the office of New York Governor George Pataki and Public Service Commission Chairman John O'Mara.

By August 1996, these discussions had advanced to the point where we believed it was appropriate to propose a specific transaction to resolve the IPP problem. We offered to terminate 44 IPP contracts – representing 90 percent of our over-market payments to IPPs – in exchange for a combination of cash and securities. We immediately began negotiations that continued until an agreement in principle was reached in March.

In exchange for terminating or restructuring their contracts, the IPPs would receive $3.6 billion of cash and debt securities, and 46 million shares of Niagara Mohawk common stock. In addition, the company and the IPPs would enter into new agreements that would further compensate the IPPs and hedge the prices for specified amounts of power. The anticipated savings in purchased power costs would allow us to pay off the new debt over a seven-to-eight year period and truly put the IPP cost burden behind us.

Financial Results

The negative impact of escalating IPP payments, and the need to change accounting principles in anticipation of the onset of competition, weighed heavily on our 1996 financial results. Results were further dampened by the continued sluggishness of the economy in our service area and an increase in bad debt expense. Earnings for 1996 were $72.1 million, or 50 cents per share, compared to 1995 earnings of $208.4 million, or $1.44 per share.

The achievement of an agreement in principle to terminate or restructure the largest IPP contracts positions the company to move forward in compliance with the state Public Service Commission's plan, discussed more fully later, to restructure the electricity marketplace in the state. Our *PowerChoice* proposal, which is very close to the PSC's own plan, would have our fossil and hydro plants selling power at competitive rates in a deregulated wholesale market.

Accordingly, earnings for the past year reflect the decision to discontinue use of cost-based regulatory accounting principles for those assets. That resulted in a write-off of $103.6 million of regulatory assets associated with the fossil and hydro business, which is recorded as an extraordinary loss after tax of $67.4 million, or 47 cents per share. An increase in bad debt expense also negatively affected earnings by 43 cents per share.

For the year, our electricity sales rose 3.8 percent, while electric revenues fell 0.8 percent due to a decrease in miscellaneous revenues. Our natural gas business continues to grow steadily, with retail gas sales up 8.3 percent from last year. Total gas deliveries, including gas transported for customer-owned gas, rose 2.3 percent. Gas revenues were up 17.2 percent from 1995.

The achievement of an agreement in principle to terminate or restructure the largest IPP contracts positions the company to move forward in compliance with the state Public Service Commission's plan ... to restructure the electricity marketplace in the state.

1996 Highlights

Although our attention and resources were focused most intently on resolving the IPP problem, we achieved noteworthy accomplishments during 1996.

Our Performance

Our nuclear plants performed exceedingly well in 1996. Nine Mile Two posted a 379-day run of continuous operation, the longest in the plant's history. For the fourth consecutive year both Nine Mile One and Two qualified for General Electric Company's capacity-factor honor roll.

Both plants ended the year with an 87 percent capacity factor, the highest ever for Nine Mile Two in a refueling year, and the third-highest capacity factor in Nine Mile One's 27-year history. The average capacity factor for U.S. nuclear plants is approximately 78 percent. In addition, a comprehensive assessment of performance released in July by the Nuclear Regulatory Commission praised the plants for the safety focus of day-to-day operations.

We are in the process of forming a nuclear operating company with Rochester Gas & Electric. We are also talking to the New York Power Authority and Consolidated Edison about joining us in a company encompassing all of New York's nuclear facilities. We believe creating an organization with the singular focus of safely and efficiently operating New York's nuclear plants would benefit our shareholders and customers.

Natural Gas Plan Approved

In December, we reached agreement on a three-year natural gas rate plan that will result in overall savings to customers of about $10 million per year and give us an excellent opportunity to expand market share. The rate plan will shift more costs to basic service charges while lowering the cost per unit of gas used. As a result, prices will more closely reflect the cost of service, and cross-class subsidies will be reduced. This will lower rates to our largest customers, while modestly increasing the bills of smaller residential heat customers and those who use gas for cooking or water heating.

Unregulated Business

Our unregulated businesses within Plum Street Enterprises are pursuing a number of opportunities both in the U.S. and overseas. In October, we named J. Phillip Frazier president of Plum Street Enterprises. With his extensive experience in competitive industries, Phil is a tremendous addition to our senior management team.

In another step to prepare for competition, we sold half of Canadian Niagara Power – owned by our Opinac subsidiary – to Fortis, Inc. Fortis is a Canadian company with deep experience in that country's electricity industry. The partnership with Fortis will position Canadian Niagara Power to capitalize on the transition to a competitive marketplace in Ontario.

Bank Credit Facility

In March 1996, the company closed on an $804 million bank credit facility from a consortium of 15 banks, providing us with both necessary working capital for the present and financial flexibility for the future. The bank agreement allows the company to borrow up to $125 million under a revolving line of credit and up to an additional $255 million on a long-term basis.

You have my commitment that our overriding concern will continue to be restoring the overall value of your investment ... In 1997, we will renew our commitment to work professionally, ethically and tirelessly to reward your faith in Niagara Mohawk.

Customer Service

Consistent with our commitment to provide excellent customer service, we have embarked upon a comprehensive effort to upgrade the technology that serves as the backbone of our customer service system. This far-reaching initiative will address virtually every business process in energy delivery as we continue to look for ways to do things more efficiently. We have targeted the end of 1998 to have the new customer service system up and running.

PowerChoice

We continued to refine our *PowerChoice* proposal for creating a competitive electricity market. In May, the state Public Service Commission issued its "Competitive Opportunities" order, which calls for establishment of a competitive electricity market in New York by early 1998. We have joined with other state utilities in challenging the PSC's order because we believe certain provisions would unfairly penalize our shareholders.

On balance, however, the Competitive Opportunities order reflects the approach to competition we proposed in *PowerChoice.* Although many issues still need to be resolved, it is clear that our vision of a competitive utility market is both workable and consistent with the direction of New York regulation. We believe that a competitive electricity market should provide growth opportunities for Niagara Mohawk, which would, in turn, provide benefits to shareholders.

Outlook

During the remainder of 1997 we will concentrate on finalizing the IPP agreement, obtaining needed approvals and closing the transaction by year-end. Although a final agreement will not eliminate all of our financial challenges, it will give us far greater control of our destiny. And it will clear the way for implementation of *PowerChoice.*

To hear more about plans for the future of Niagara Mohawk, I would like to invite each of you to attend our Annual Meeting. This year's meeting will be held on Tuesday, May 6, at 10:30 a.m., at the OnCenter in Syracuse.

You have my commitment that our overriding concern will continue to be restoring the overall value of your investment. Last year, our employees perf[illegible]d remarkably well under adverse conditions. In 19[illegible] will renew our commitment to work professionally, ethically and tirelessly to reward your faith in Niagara Mohawk.

William E. Davis

William E. Davis
Chairman of the Board and
Chief Executive Officer
Niagara Mohawk Power Corporation

Financial Results

Contents

Management's Discussion and Analysis of Financial Condition and Results of Operations

Certain statements included in this Annual Report regarding expected capital expenditures, statements of management's plans and objectives for the Company's future operations and statements of future economic performance, including those contained in or implied by the discussion in this section ("Management's Discussion and Analysis of Financial Condition and Results of Operations"), are forward-looking statements as defined in Section 21E of the Securities Exchange Act of 1934. Those forward-looking statements include information on the financial condition of the Company, the agreement-in-principle to terminate or restructure selected IPP contracts, recovery of regulatory assets with a non-bypassable charge, the Company's financing capacity to fund the termination or restructuring of the IPP contracts, as well as expected future construction expenditures, debt repayments to deleverage the Company and working capital deficits, expected PSC approval of cost-of-service based electric rates, including recovery of costs associated with the expected termination or restructuring of selected IPP contracts, continued application of SFAS No. 71 to the electric transmission and distribution, and nuclear operations, recovery of costs of its generating assets under *PowerChoice*, an expected decrease in future bad debt expense as compared to 1996 results, and the assumptions described in the Annual Report underlying such forward-looking statements. The Company's actual results and developments may differ materially from the results discussed in or implied by such forward-looking statements, due to a number of important factors. Those factors include, but are not limited to, matters described in the context of such forward-looking statements, as well as such other factors as set forth in the "Notes to Consolidated Financial Statements" contained herein.

Events Affecting 1996 and the Future

- On March 10, 1997, announced a jointly developed agreement-in-principle to terminate or restructure IPP power purchase contracts in exchange for approximately $3.6 billion in cash and marketable debt securities, and 46 million shares of common stock of the Company, and enter into new agreements that would further compensate the IPPs and hedge prices for specific amounts of power.
- Discontinued application of SFAS No. 71 to fossil/hydro operations, and wrote off fossil/hydro generation regulatory assets of $103.6 million (extraordinary loss of 47 cents per share).
- 1996 earnings after the extraordinary item declined 65% to 50 cents per share.
- Increase in bad debt expense of $96.4 million as compared to 1995 (43 cents per share).
- Common dividends omitted.
- Securities ratings downgraded.
- $804 million senior debt facility established.
- Request for 1996 rate increase rejected. 1997 rate request temporarily stayed pending further proceedings.
- FERC issued open access transmission order, which, with certain exceptions, provides for full recovery of stranded wholesale costs, leaving it up to the states to decide recovery of retail stranded costs.
- PSC issued order to restructure New York State electric industry, calling for a competitive wholesale power market in 1997 and introduction of retail access for all electric customers in 1998. Stranded cost recovery to be determined on a utility-by-utility basis.
- Reached a conditional multi-year gas rate settlement with the PSC in December 1996.

Announced Agreement-in-Principle to Terminate or Restructure 44 IPP Contracts

The drive to introduce competition by both federal and state regulators, as well as the threat of self-generation and relocation by industrial customers, has intensified the Company's focus on costs that significantly influence the price of its products. The Company proposed *PowerCh* in October 1995 to achieve stable retail prices, custom choice and an open, competitive electric generation market. However, the implementation of *PowerChoice* depends upon reducing the cost of power the Company is required to purchase from IPPs.

On March 10, 1997, the Company and 19 developers of IPP projects jointly announced an agreement-in-principle to terminate or restructure 44 power purchase contracts. These contracts represent more than 90% of the Company's above-market power costs under all existing IPP contracts. Subject to regulatory approval, the agreement-in-principle contemplates that electricity prices for all customer classes would be reduced, with larger reductions allocated to large commercial and industrial customers to retain and attract jobs in upstate New York.

The agreement-in-principle contemplates that the Company would terminate or restructure the 44 power contracts in exchange for approximately $3.6 billion in cash and/or marketable debt securities, and 46 million shares of the Company's common stock, representing approximately 25% of the anticipated fully diluted outstanding common shares. The new debt will be subordinate to existing first mortgage bonds. The value of the common equity component will vary depending on the market value of the shares at closing. In addition, the Company and several IPPs would enter into new agreements that would further compensate the IPPs and hedge prices for specific amounts of power.

The amount of subordinated debt expected to be issued is approximately $3.2 billion, with terms from two to seven years. It is the Company's objective to achieve at least a BB-/Ba3 rating on the subordinated debt, although achieving such a rating is not a condition of the agreement. Achievement of such a rating is not assured and if not achieved could result in higher interest costs than presently estimated.

Although subject to final negotiation and execution, the agreement-in-principle contemplates that the Company will enter into price-hedging agreements or contracts with certain IPPs that may be in the form of financial contracts for differences and physical bilateral agreements, options contracts, indexed financial instruments, or a combination thereof. Contracts for coal and waste-fired projects will have a 17 year term with total annual energy of approximately 350 GwHrs. Hydro contracts will range in length from 20 to 35 years with total annual energy of approximately 900 GwHrs or less than 3% of total load. Over the term of the new contracts, prices for hydro generated electricity would range between $85 to $130 per Mwh, subject to final negotiation, while prices for coal and waste would range between $28 and $45 per Mwh. For gas-fired projects, the amount of energy under contract would begin at 4,630 GwHrs and increase to 8,000 GwHrs in twelve years. The price for a portion of the energy would be fixed, and the remainder would be indexed to reflect competitive market gas prices. Of the load under existing contracts, approximately 5,000 GwHrs would no longer be subject to a contract, with the Company meeting its requirements through market purchases. These arrangements will enable the Company to substantially reduce the cost of purchased power in the future, while managing the price risks of purchased power. Initially a substantial portion of the cost reduction will be offset by interest on subordinated debt issued to carry out the termination and restructuring of the IPP contracts, and the amortization of the resulting regulatory asset.

The transaction is subject to several contingencies, including negotiations with each IPP of specific terms of the new agreements that may be executed; execution of binding agreements including the master restructuring agreement; approval of the Company's shareholders; PSC approval of the agreement, including an acceptable long-term price structure and a non-bypassable charge providing for recovery of strandable costs, including the termination or restructuring costs of the IPP contracts; other state and federal approvals and successful completion of all financing transactions on reasonable terms; the resolution of all tax issues and obtaining required amendments or waivers under existing credit agreements and third-party contracts.

The Company will work to achieve a financial closing of the agreement-in-principle by year-end 1997.

Changing Competitive Environment

The accelerating pace of competition is driving dramatic changes throughout the utility industry. Regulators on both the state and federal levels have issued orders to restructure the electric industry. (See "PSC Competitive Opportunities Proceeding – Electric" and "FERC Rulemaking on Open Access and Stranded Cost Recovery"). The Company believes that the price of electricity may be the most important element of future success in the restructured industry and has intensified its efforts to reduce various costs that significantly influence the price of electricity.

The Company is challenged by state-imposed burdens, especially state-mandated contracts that have required the Company to buy electricity from IPPs in amounts that exceed customer needs and at an average price which is more than twice as high as the cost of power that could be purchased in the wholesale market. In addition, the Company and other New York utilities bear an excessive tax burden that is more than twice the average for utilities nationwide.

The Company has pursued a number of actions to mitigate the impact of these factors on prices. These actions have included renegotiating and buying out some IPP contracts (including those discussed above) and canceling others when contract terms were not being adhered to. The Company has also sought regulatory relief from the PSC, seeking curtailment rights, the ability to monitor IPP compliance with federal legislation, and firm security rights for contracts with advance payment provisions. The Company has been successful in obtaining the ability to monitor compliance, but has not received approval to implement curtailment or obtain firm security. (See – Other Federal and State Regulatory Initiatives – "PSC Proposal of New IPP and PPA Management Procedures").

The Company has also been actively seeking reductions in its state and local tax obligations by working with utility, customer and state representatives to explain the negative impact that all utility taxes, including the GRT, are having on prices and the economy. At the same time, the Company is contesting the high real estate taxes it is assessed by the many taxing authorities in its service territory, particularly those imposed upon its generating facilities.

Nevertheless, mandated IPP purchases and high taxes have, in the past, combined to create upward pressure on prices. Further price increases would make it more difficult for the Company to retain its customers in the longer term and an increasing number of customers are pursuing other supply options including self-generation, alternate supply sources, and municipalization. As a result, electric margins have narrowed and sales have been flat, damaging the Company's financial condition and putting further pressure on the Company to seek even more rate increases under traditional cost-of-service ratemaking.

Other actions taken by the Company during the past four years to address the increasing competitive environment include sharply reducing internal costs. The Company has reduced the size of its work force by about 3,300 employees, or 28%, and has eliminated, consolidated or modernized many of its operations. The Company has also sharply reduced capital spending. Electric construction spending in future years is budgeted to be at or below the level of depreciation expense, thereby resulting in little or no growth in rate base with a corresponding impact on earnings.

These cost control efforts have produced significant savings. However, the savings have been outpaced by continuing escalation in the externally imposed costs discussed above. Recognizing that major changes in the electricity marketplace in New York State were needed, the Company undertook an exhaustive analytical process with the goal of creating a rational energy market that would link supply, demand and price, provide customers with better and broader services, and provide greater opportunities for building shareholder value. That process resulted in the filing of the Company's *PowerChoice* proposal on October 6, 1995, which the Company subsequently amended to include the implementation of the agreement-in-principle (see "*PowerChoice* Proposal").

The Company believes the pursuit of *PowerChoice* is the best course of action to deal with emerging competition and address the factors that have been pushing up prices. The Company believes that the state must play a role in reducing costs as a way of enhancing benefits to be derived from implementation of *PowerChoice*. The State's participation could include reducing or eliminating the state GRT, which taxes revenue rather than income, timely passage of a securitization bill that would permit lower cost financing of regulatory assets, including costs associated with the IPP agreement-in-principle, and/or reducing mandated social programs. Addressing these issues will be difficult and will almost certainly require regulatory and/or legislative action, the outcome of which is uncertain. The *PowerChoice* proposal is not dependent on such State participation.

PowerChoice Proposal

On October 6, 1995, the Company filed its *PowerChoice* proposal with the PSC. The *PowerChoice* proposal, which now includes the implementation of the agreement-in-principle, would:

- **Create a competitive wholesale electricity market and allow direct access by retail customers.** To give customers their choice of power suppliers and pricing terms, the Company will open its system to competing electricity generators as early as 1998. The timing of full implementation depends on resolution of technical, administrative and regulatory issues. Envisioned is the formation of a competitive wholesale spot market in the Company's service area under the supervision of the FERC that is consistent with the PSC COPS decision (see – "PSC Competitive Opportunities Proceeding – Electric" and "FERC Rulemaking on Open Access and Stranded Cost Recovery"). Beginning with its largest customers, the Company would allow full direct access to alternative suppliers of electricity. The Company would deliver that power over its transmission and distribution system. Access for the remaining customers would be phased in over several years.

- **Provide relief from overpriced IPP contracts that were mandated by public policy.** As a result of state and federal policy, the Company has 157 contracts to buy power from IPPs at above-market prices, even when the power is not needed. The Company's payments to IPPs increased from less than $200 million in 1990 to $1.1 billion in 1996, and if no action were taken would continue to grow by an average of approximately $50 million per year over the next five years as contract prices increase. To create an open and competitive market and achieve a reduction in average prices, the Company recently announced an agreement-in-principle to terminate or restructure 44 IPP contracts, which represent more than 90% of the above-market cost of mandated purchases by the Company.

  The Company proposes, and believes it is probable that the PSC will approve, deferral and recovery of the IPP contract termination or restructuring cost and recovery of this asset as well as other stranded costs through a non-bypassable charge tied to distribution and transmission services. The Company believes that a non-bypassable charge is necessary during the transition to competition to ensure its financial stability. The PSC has been kept informed throughout the course of the negotiations of the agreement-in-principle. If the PSC does not approve the deferral and recovery of the IPP contract termination or restructuring cost through a non-bypassable charge, the Company may be unable to complete the associated financing and closing. In that event (or if the IPP agreement-in-principle is not effectuated for any other reason) the Company would face continued financial decline.

- **Separate the Company's non-nuclear power generation business from the remainder of the business.** The Company has proposed that one company would own and operate its present non-nuclear power plants. All the Company's assets and businesses other than non-nuclear generation would be held by a holding company that would provide cost-based rate-regulated transmission, distribution, nuclear and gas services through a regulated subsidiary. The holding company would also provide competitive unregulated services, such as energy marketing and other services through a second subsidiary. The companies would be financially restructured so that stockholders and other constituencies would be treated in a fair and equitable fashion. Any release of assets under the Company's mortgage indenture would be effected in accordance with the terms of the indenture. The Company will continue to evaluate alternative structural options considering actual development of competitive markets and regulatory policy. The Company believes New York State can be helpful in this restructuring process, through the purchasing or refinancing of the Company's nuclear plants or through the use of other risk-mitigation strategies associated with those facilities. (See "Governor Pataki's Proposed Legislation").

- **Reduce average prices for Company electric customers, with reductions to industrial customers to facilitate economic and job growth in the service territory.** If the proposal is agreed to by all necessary parties, the average prices paid by residential and commercial customers could be reduced slightly, with more sub

tial reductions for industrial customers. The Company has proposed that strandable costs be recoverable by the Company through non-bypassable charges on rates for remaining distribution and transmission services. Stranded costs are utility costs that may become unrecoverable due to a change in the regulatory environment. To ensure maximum recovery of these costs, the Company has proposed that the strandable costs be recovered in rates in a manner which minimizes the Company's exposure due to sales volume variations. Recovery of strandable costs by the owner of the Company's fossil/hydro generation facilities is intended to be accomplished through an option pricing contract for a period of approximately five years so as not to impede each unit from being an efficient participant in the competitive generation market. Nuclear generation costs would be recoverable through a financial instrument tied to the market price of electricity or similar incentive mechanism not to exceed the term of the operating license of the plant.

Accounting Implications of PowerChoice and Agreement-in-Principle to Terminate or Restructure IPP Contracts

The Company has concluded that the agreement-in-principle to terminate or restructure IPP contracts and the implementation of *PowerChoice*, or a similar proposal, is the probable outcome of negotiations that have taken place over the past 18 months. Under *PowerChoice*, the separated non-nuclear generation business would no longer be rate-regulated and, accordingly, existing regulatory assets at December 31, 1996 related to the non-nuclear power generation business, amounting to approximately $103.6 million ($67.4 million after tax or 47 cents per share) have been charged against 1996 income as an extraordinary non-cash charge.

Of the remaining electric business, under *PowerChoice*, the Company expects that its nuclear generation and electric transmission and distribution business will continue to be rate-regulated on a cost-of-service basis and, accordingly, it will continue to apply SFAS No. 71 to these lines of business. The Company currently expects to retain ownership of its nuclear assets, and will continue to investigate various options that may be available to mitigate the risk of ownership of these assets. As described under "Announced Agreement-In-Principle to Terminate or Restructure 44 IPP Contracts," the conclusion of the agreement-in-principle, as well as implementation of *PowerChoice*, is subject to a number of contingencies.

In the event the Company is unable to successfully bring these events to conclusion, it would pursue a traditional rate request. However, notwithstanding such a rate request, it is likely that application of SFAS No. 71 would be discontinued for the remaining electric business. The resulting after-tax charges against income, based on regulatory assets associated with the nuclear generation, and transmission and distribution businesses as of December 1996, would be approximately $503.2 million or $3.48 per share. Various requirements under applicable law and regulations and under corporate instruments, including those with respect to issuance of debt and equity securities, payment of common and preferred dividends, the continued availability of the Company's senior debt facility and certain types of transfers of assets could be adversely impacted by any such write-downs.

The Company expects the PSC will continue to apply the concepts of cost-of-service based ratemaking (including the financial consequences of the termination or restructuring of IPP contracts) to the transmission, distribution and nuclear generation business and approve the reduced prices contemplated under *PowerChoice*. The Company proposes, and believes it is probable that the PSC will approve, deferral and recovery of the termination or restructuring costs of IPP contracts over a period not to exceed ten years. To the extent that recovery of the termination or restructuring cost is not approved by the PSC, that amount would be charged to expense, which could have a material adverse effect on the financial condition and results of operations of the Company. Furthermore, the Company does not expect the PSC to provide a return on the regulatory asset associated with IPP termination or restructuring costs. SFAS No. 71 does not require the Company to earn a return on regulatory assets in assessing its applicability. The Company believes that it is probable that the prices it will charge for electric service, including a non-bypassable transition charge, over the ten-year period will be sufficient to recover the regulatory asset for the termination or restructuring costs of IPP contracts and provide recovery of and a return on the remainder of its regulated assets, as appropriate. The Company expects that the reported amounts of future net income will be adversely affected by a lack of a return on the regulatory asset and expected lower returns of the unregulated non-nuclear generating business.

The Company has been made aware of a recent request by the SEC Chief Accountant to the Public Utilities Committee of the American Institute of Certified Public Accountants to develop guidance on applying SFAS No. 101. It is the Company's understanding that the guidance requested may include when to discontinue SFAS No. 71, as well as the accounting applicable to recovering strandable costs on rates charged by the transmission and distribution business that originate from generation assets. The Company cannot predict whether and when such guidance will be issued, or the attendant consequences on the Company's financial condition or results of operations.

The Company adopted SFAS No. 121 in 1996. This Statement requires that long-lived assets and certain identifiable intangibles held and used by an entity be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. In performing the review for recoverability, the Company is required to estimate future undiscounted cash flows expected to result from the use of the asset and its eventual disposition.

With the probable implementation of *PowerChoice*, specifically the separation of non-nuclear generation as an entity that will face market prices, the Company is

required to assess the carrying amounts of its long-lived assets in accordance with SFAS No. 121. The Company has determined that there is no impairment of its non-nuclear generating plant assets. In certain instances, the Company has considered opportunities to invest in changes in fuel sources that are technologically available, to improve future cash flow. In one instance, the Company has considered the value of relocating a unit to a region where demand is greater. To the extent an impairment loss could not otherwise be avoided, the Company believes it will be able to recover the loss through a non-bypassable transition charge proposed in *PowerChoice*. In reaching this conclusion, the Company must make significant estimates and judgments as to the future price of electricity, capacity factors and cost of operation of each of its generating units and, where necessary, the fair market value of each unit. As *PowerChoice* is implemented and generation markets become open to competition, these estimates and judgments may change.

Traditional Rate Request

In the event *PowerChoice* could not be implemented in a timely manner or at all, in February 1996, the Company filed a request to increase electric rates. This rate increase request of 4.1% for 1996 and 4.2% for 1997 was based on the Company's cost of providing service. These rate increases are predicated on a requested ROE of approximately 11% on an annual basis and recover the Company's cost of providing electric service. At a public session on May 2, 1996, the PSC rejected the Company's request for a 1996 temporary rate increase primarily on the basis that the request did not meet the PSC's legal standard for approving emergency rate increases. The PSC Chairman stated that an increase in electric rates would have a negative impact on economic conditions in the regions served by the Company, which he stated that the Company itself recognized in its *PowerChoice* proposal. The PSC Chairman also stated that the *PowerChoice* proposal better addresses the long-term viability of the Company, whereas a temporary rate increase does not. Accordingly, results for 1996 reflected regulatory lag and resulting reduced ROE. (See – "Results of Operations").

With announcement of the agreement-in-principle to terminate or restructure 44 IPP contracts and assessment of the probable implementation of *PowerChoice*, the Company temporarily stayed its 1997 rate filing pending further proceedings. 1997 earnings will be significantly below the Company's allowed ROE, since tariff prices will remain unchanged and sales forecasts are below those levels used in determining such prices. In the event the IPP agreement-in-principle and/or *PowerChoice* fails, the Company will pursue traditional rate relief, as necessary.

PSC Competitive Opportunities Proceeding – Electric

On May 16, 1996 the PSC issued its decision in its COPS case to restructure New York State's electric industry. The decision calls for a competitive wholesale power market 1997 and the introduction of retail access for all electric customers in early 1998.

The goals cited in its decision included lowering consumer rates, increasing choice, continuing reliability of service, continuing environmental and public policy programs, mitigating concerns about market power and continuing customer protections and the obligation to serve.

To implement its policies, the PSC directed major utilities, excluding the Company and Long Island Lighting Company, to file restructuring proposals and rate plans by October 1, 1996, consistent with these goals. Although exempt from this filing as a result of the *PowerChoice* restructuring proposal, the Company made a filing to address several retail issues. The Company's filing also urged the PSC to be as permissive as possible in allowing the natural development of the competitive marketplace. In addition, it argued that regulated and unregulated companies should be permitted to coexist under the same holding company. The PSC has set a schedule for negotiation or litigation for the other utilities that extends into the second quarter of 1997.

The PSC decision in the COPS proceeding states that recovery of utility stranded costs may be accomplished by a non-bypassable "wires charge" to be imposed by distribution companies. The PSC decision states that a careful balancing of customer and utility interests and expectations is necessary, and that the level of stranded cost recovery will ultimately depend upon the particular circumstances of each utility.

In September 1996, the Energy Association of New York State (Energy Association) and its member companies filed a lawsuit in the NYS Supreme Court that asked the court to order a review of the PSC's COPS decision. The Energy Association includes the Company and seven other investor-owned utilities as members. Even though the Company believes that the PSC's objectives in its COPS decision are consistent with the Company's *PowerChoice* proposal, the Company wanted to protect its legal rights until all issues relating to competition in the New York State electric industry are settled fairly. On November 26, 1996, the NYS Supreme Court ruled against the Energy Association and its member companies. On December 24, 1996 the Energy Association and its member companies filed a notice of appeal with the Appellate Division, Third Department, of the New York State Supreme Court. The Company is unable to predict the outcome of this matter.

On February 12, 1997, the PSC took additional steps toward furthering electric competition by (1) approving a petition to initiate a potential multi-utility, electric retail access pilot program for commercial farmers and food processors and (2) allowing utilities to use their flexible rate programs to compete against the economic development power offered by NYPA. The PSC approved the

petition from Dairylea Cooperative, Inc. (Dairylea) that proposed a retail access pilot program, since it cuts across multiple service territories and involves several rate classifications, among other things.

The potential Dairylea pilot will include the service territories of Rochester Gas and Electric, New York State Electric & Gas, Central Hudson Gas and Electric Company and the Company. The potential pilot program will be open to commercial farms and food processors except those that already have flexible rate contracts. On February 25, 1997, the PSC issued its Order on this potential pilot program and stated that the utilities will have 45 days to work together and submit refined terms and conditions of the program. The PSC expects the program to be implemented within 90 days after such submission. Alternatively, utilities may file a settlement agreement or testimony in the individual rates and restructuring cases that includes a retail access proposal similar to the Dairylea proposal. The Company is unable to predict what effect, if any, the potential pilot program will have on its results of operations and financial condition, since the terms and the conditions of such program have not been finalized.

FERC Rulemaking on Open Access and Stranded Cost Recovery

In April 1996, the FERC issued FERC Order 888. Order 888 promotes competition by requiring that public utilities owning, operating, or controlling interstate transmission facilities file tariffs which offer others the same transmission services they provide for themselves, under comparable terms and conditions. The Company has complied with this requirement by filing its open access transmission tariff with FERC on July 7, 1996; the tariff was accepted by FERC subject to refund, and hearings are scheduled for August 1997.

Under FERC Order 888, the NYPP was required to file reformed power pooling agreements that establish open, non-discriminatory membership provisions and modify any provisions that are unduly discriminatory or preferential. The NYPP Member Systems submitted a comprehensive proposal to establish an ISO, a New York State Reliability Council (NYSRC) and a New York Power Exchange (NYPE). The ISO would provide for the reliable operation of the transmission system in New York State and provide nondiscriminatory open access to transmission services under a single ISO tariff. Through the ISO, the transmission owners, including the Company, would be compensated for the use of their transmission systems on a cost-of-service basis. The NYSRC would establish the reliability rules and standards by which the ISO operates the bulk power system. The ISO would also administer the daily electric energy market and the NYPE would facilitate electric energy market on a day-ahead basis. While the Company believes the filing meets the objectives of Order 888, the Company is unable to predict when FERC will act on the NYPP compliance filing or the ISO filing, or whether it will approve either filing with or without modifications.

In Order 888, the FERC also stated that it would provide for the recovery of prudent and verifiable wholesale stranded costs where the wholesale customer was able to obtain alternative power supplies as a result of Order 888's open access mandate. Order 888 left to the states the issue of retail stranded cost recovery. Where newly created municipal electric utilities required transmission service from the displaced utility, the FERC stated that it would entertain requests for stranded cost recovery since such municipalization is made possible by open access. The FERC also reserved the right to consider stranded costs on a case-by-case basis if it appeared that open access was being used to circumvent stranded cost review by any regulatory agency.

Numerous parties, including the Company, filed requests for rehearing of Order 888. In March 1997, the FERC issued Order 888-A, which generally affirmed Order 888 and granted rehearing on only a handful of issues. One of those issues was whether the FERC would review stranded costs in annexation cases as it committed to do in municipalization cases. In Order 888-A the FERC stated that it would review stranded costs resulting from territorial annexation by an existing municipal electric system, provided that system relied on transmission from the displaced utility. The FERC denied the Company's request for rehearing on how stranded costs would be calculated and other issues. The Company is considering whether to seek review of Order 888-A in federal court.

In late January 1997, the Company provided 26 communities in St. Lawrence and Franklin counties with estimates they requested of the stranded costs they might be expected to pay if they withdraw from the Company's system to create government-controlled utilities. The preliminary estimate of the combined potential stranded cost liability for the communities ranges from a low of $225 million to a high of $452 million, depending upon the forecast of electricity market prices that is used. These amounts do not include the costs of creating and operating a municipal utility.

The stranded cost calculations were based on a methodology prescribed by the FERC. Because no municipality has moved forward with condemnation, the value of the Company's facilities has not been deducted from the stranded cost estimates. The stranded costs included in these estimates are the communities' share of obligations that were incurred on behalf of all customers to fulfill the Company's legal obligations to ensure adequate, reliable electricity service. Such legitimate and prudent costs are currently included in electricity rates. Government-mandated payments to IPPs represent the largest single component of these costs. The Company is unable to predict the outcome of this matter.

Governor Pataki's Proposed Legislation

In June 1996, Governor Pataki introduced two proposals designed to lower electric rates and to build a short-term "bridge" to a fully competitive electric power market. The proposed "Electric Ratepayer Relief Act" would provide

utilities a tool to address possible stranded costs and reduce rates through credit-enhanced structured refinancing of any qualifying "intangible asset." Passage of this bill would facilitate the Company's ability to finance the IPP agreement-in-principle and minimize its financing costs. The proposed "Power for Prosperity Bill" would allocate low-cost power from investor-owned electric utilities and the NYPA to eligible businesses for job retention and development purposes. Any resulting revenue loss to utilities would be offset by a tax credit against the utility's regressive State GRT.

The New York State Senate passed both measures during the final days of the 1996 regular legislative session and passed slightly revised versions of both bills during the December 1996 "special" legislative session. The New York State Assembly has yet to introduce either measure, arguing in favor of more comprehensive electric industry restructuring legislation, such as their "Competition Plus/Energy 2000 Fund" proposal.

The Company supported the Governor's proposals and lobbied intensively for both during the regular and "special" 1996 legislative sessions. The Electric Ratepayer Relief Act would enhance the customer benefits of the IPP termination and restructuring agreement-in-principle, a fundamental premise of the Company's *PowerChoice* proposal, as it proposes "significant rate savings" for all of the Company's customers. Further, it gives the Legislature the opportunity to address a problem (rising energy costs) it helped create, at no cost to New York State taxpayers. The Power for Prosperity Bill would free up immediately an additional 400 MWs of low-cost economic development power for businesses to remain competitive or expand their operations. Also, it would not harm the Company's other customers, employees or shareholders because of the GRT credit provision and would represent the first real step by New York State to begin the process of reducing or repealing the State GRT.

Both measures will be considered during the 1997 regular legislative session in the context of the overall electric industry restructuring debate; however, the Company is unable to predict whether these two bills will be enacted into law. Neither bill is a prerequisite for implementation of *PowerChoice*.

Other Federal and State Regulatory Initiatives

PSC Proposal of New IPP Operating and PPA Management Procedures. In August 1996, the PSC proposed to examine the circumstances under which a utility, including the Company, may legally curtail purchases from IPPs; whether utilities should be permitted to collect data that will assist in monitoring IPPs' compliance with federal QF requirements, which are standards that IPPs must satisfy under PURPA; and if utilities should be allowed to demand security from IPPs to ensure the repayment of advance payments made under their purchased power contracts.

The PSC noted that some of the current IPP contracts are far above market prices and are causing utilities to seek rate increases. In addition, the PSC stated that its proposal was initiated to protect ratepayers, since it would ensure just and reasonable rates in the event ongoing negotiations between utilities and IPPs fail.

In December 1996, the PSC gave the New York State utilities, including the Company, the authority to collect data to assist them in monitoring IPPs' compliance with both federal QF standards and state requirements. The PSC stated that if QFs are not meeting requirements, the obligation to pay the full contract rate, which is funded by utility ratepayers, is generally excused or mitigated. Furthermore, if the data collected through a QF monitoring program indicates a facility is not meeting federal standards, the utility could petition the FERC to decertify the QF, which could result in penalties that could include cancellation of the contract. A similar penalty could be imposed if it is determined a QF has failed to maintain compliance with state law. Under the monitoring program, QFs will be required to submit data as of March 1 each year for the previous calendar year.

The Company cannot predict the outcome of the remaining IPP issues currently being examined by the PSC, but is encouraged by the PSC's recent decision on the procedures for monitoring QF status and its proposal to implement additional IPP procedures. A number of these contracts will be addressed by the agreement-in-principle reached between the Company and certain IPPs. See "Announced Agreement-In-Principle to Terminate or Restructure 44 IPP Contracts".

Multi-Year Gas Rate Settlement Agreement. In December 1996, the Company and PSC staff reached a three year settlement that was conditionally approved by the PSC on December 19, 1996. The PSC ordered conditional approval on the three year settlement agreement until a final, redrafted agreement, which includes changes ordered by the PSC, is submitted for final approval. The settlement results in a $10 million annual reduction or a $30 million reduction over the term of the settlement. This reflects a $19 million reduction in the amount of fixed non-commodity costs to be recoverable in base rates, offset by a $9 million increase in annual base rates. The Company estimates that the combination of in-hand supplier refunds and further reductions in upstream pipeline costs will be sufficient to fund the $19 million annual reduction in non-commodity cost recovery.

If the non-commodity cost reductions exceed $57 million ($19 million annually) during the settlement period, the excess, up to $40 million will be credited to a Contingency Reserve Account (CRA) to be utilized for ratepayer benefit in the rate year ending October 31, 2000 or beyond. To the extent the actual non-commodity cost reductions exceed $57 million by more than $40 million, the Company may retain any excess subject to a return on equity sharing provision. In the event the non-commodity reductions fall short of the $57 million estimate, the Company will bear the risk of any shortfall. In the event that the termination or restructuring of IPP contracts results in margin or peak shaving losses, the margin losses would be collected currently subject to 80%/20% (ratepayer/shareholder sharing) and the peak shaving losses will be

deferred to the CRA, subject to limits specified in the settlement.

In return for taking on this risk, the Company has achieved a portion of the revised rate structure that had been proposed to reduce its throughput risk. The Company obtained a return on equity cap of 13.5% with 75/50 sharing between ratepayers and shareholders in excess of the cap. The Company also has an opportunity to earn up to $2.25 million annually if its gas commodity costs are lower than a market based target without being subject to the ROE cap. The Company has an equal $2.25 million risk if gas commodity costs exceed the target. An additional major benefit of the revised rate design is that the margin made on each additional new customer will significantly increase to the extent additional throughput does not require additional upstream pipeline capacity for service. This, along with the approval of the Company's Progress Fund, which allows the Company to use utility revenues in an amount not to exceed $11 million in total for the purpose of providing financing for large customers to convert or increase their gas use, will provide new opportunities for growth.

With respect to the Company's site investigation and restoration costs (see Note 9. Commitments and Contingencies – "Environmental Contingencies"), the settlement provides for 100% recovery of these costs.

In March 1996, in a generic rate proceeding, the PSC ordered all New York utilities to refile their tariffs to implement a service unbundling by May 1996 (March 1996 Order). The Company refiled its tariff on April 29, 1996, which became effective on a temporary basis on June 1, 1996. Under the approved tariff, all of the Company's gas customers, including residential and commercial customers, have the opportunity to buy natural gas from other sources with the Company providing delivery service for a separate fee. These changes have not had a material impact on the Company's margins since the margin is derived from the delivery service and not from the commodity sale. The margin for delivery for residential and commercial aggregation services equals the margin on the traditional sales service classes.

In addition to the tariff filing to implement service unbundling, the Company and other utilities filed a petition for rehearing of certain of the determinations made in the PSC's March 1996 Order. These determinations included the PSC's requirement that customers converting to a transportation customer are responsible for pipeline capacity held by the utility on their behalf for only a three-year period. In addition, the March 1996 Order states that the utility is obligated to provide back-up service to a converting customer or provide service to a new customer even if the utility does not currently have sufficient pipeline capacity needed to service that customer. On September 13, 1996 the PSC issued its order on rehearing. The September 1996 Order did little to clarify how the costs of such capacity would be recovered by the utility after the three-year period or the "test" the PSC would use to determine whether the utility has adequately demonstrated its efforts to relieve itself of "excess" stranded capacity.

NRC Seeks to Confirm Adequacy of Nuclear Design Basis Documentation. In October 1996, the NRC required companies with nuclear plants to provide the NRC with added confidence and assurance that their plants are operated and maintained within the design basis, and any deviations are reconciled in a timely manner. Such information, which was filed within the required 120 days, 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.

In the letter transmitting the requested information to the NRC, the Company concluded that it has reasonable assurance that (i) design basis requirements are being translated into operating, maintenance, and testing procedures; and (ii) system, structure and component configuration and performance are consistent with the design basis. Also, the Company has an effective administrative tool for the identification, documentation, notification, evaluation, correction, and reporting of conditions, events, activities, and concerns that have the potential for adversely affecting the safe and reliable operation of Unit 1 and Unit 2.

In February 1997, the Company met with the NRC staff to discuss alleged violations of regulations at Unit 1 and Unit 2. No decisions on the alleged violations have been made to date.

The Company believes that NRC safety enforcement is becoming more stringent as indicated by the NRC's request for information and its recent meeting with the Company and that there may be a direct cost impact on companies with nuclear plants as a result. The Company is unable to predict how such a changed operating environment may affect its results of operations or financial condition.

Owners of older General Electric Co. boiling water reactors, including the Company, have experienced cracking near welds in the plants' core shrouds. In response to industry findings, the Company installed modifications in the Unit 1 core shroud during a 1995 refueling and maintenance outage.

Inspections conducted as part of the March 1997 refueling and maintenance outage detected cracking in areas not directly reinforced by the 1995 repairs, which may require additional core shroud modifications. Preliminary analysis indicates the Company may be able to restart the reactor from the current refueling and maintenance outage without a significant extension of the outage duration. Additional modifications, if required, would be installed during a mid-cycle outage or as part of Unit 1's next refueling and maintenance outage (February, 1999). If modifications are required before the restart of Unit 1 from the current refueling and maintenance outage, a 2-3 month extension of the outage would be anticipated. The Company's action plan on this issue requires consent from the NRC.

Other Company Efforts to Address Competitive Challenges

Tax Initiatives. The Company is working with utility, customer and state representatives to explain the negative impact that all utility taxes, including the GRT, are having on rates and the state of the economy. Governor Pataki and other state officials have identified reductions in the GRT as an element in improving the business climate in New York. At the same time, the Company is contesting the high real estate taxes it is assessed by many taxing authorities, particularly those imposed upon generating facilities.

As noted above, the Company has reduced its work force over the past four years, resulting in a decrease in the amount of payroll taxes incurred over that period. Meanwhile, the reduction in revenues experienced by the Company resulting from reduced sales and a phase out of the GRT surcharge, has caused the amount of GRT paid by the Company to be reduced.

The following table sets forth a summary of the components of other taxes (exclusive of income taxes) incurred by the Company in the years 1994 through 1996:

	In millions of dollars		
	1996	1995	1994
Property tax expense	$249.4	$264.8	$262.6
Sales tax	14.1	13.9	14.2
Payroll tax	36.4	37.3	42.5
Gross Receipts tax	184.1	190.2	198.1
Other taxes	0.5	5.2	4.3
Total tax expense	484.5	511.4	521.7
Charged to construction, subsidiaries and regulatory recognition	(8.7)	6.1	(24.8)
Total other taxes	$475.8	$517.5	$496.9

Customer Discounts. In recent years, industrial customers have found alternative suppliers or are generating their own power. In other cases a weakened economy or attractive energy prices elsewhere have contributed to customer decisions to relocate or close.

In addressing the threat of further loss of industrial load, the PSC established guidelines to govern flexible electric rates offered by utilities to retain qualified industrial customers. Under these guidelines, the Company filed for a new service tariff in August 1994 (SC-11), under which all new contract rates are administered based on demonstrated industrial and commercial competitive pricing alternatives including, but not limited to, on-site generation, fuel switching, facility relocation and partial plant production shifting. Contracts are for terms not to exceed seven years without PSC approval. In addition, the Company has economic development programs which provide tariff based incentives to retain and grow load.

As of January 1997, the Company has 114 executed contracts under its flexible tariff offerings. These contracts have been signed to mitigate the lost margin impacts associated with customers executing the competitive alternatives mentioned above. In addition, many of these contracts include an increase in production levels and/or attract new customers to the Company's service territory.

In 1996, the total amount of customer discounts (economic development programs and flexible pricing) was $75.5 million. Of this amount, the Company recovered approximately $56.7 million in rates, which included an additional amount of $10.1 million that the PSC allowed the Company to recover in 1996 as a result of a petition that it had filed. Pending implementation of *PowerChoice*, the Company budgeted its discounts to increase to approximately $100 million in 1997 as some discounts granted in 1996 are in effect for an entire year and further discounts are granted. The Company is aggressively using SC-11 to increase sales to existing customers and to attract new customers to its service territory. With the reduction in industrial prices proposed in *PowerChoice*, the level of discounts may decline thereafter.

Generating Asset Management Studies. The Company continues to study the economics of continued operation of its fossil-fueled generating plants, given current forecasts of excess capacity. Substantial IPP supply sources, compliance requirements of the Clean Air Act and low wholesale market prices are key considerations in evaluating the Company's internal generation needs. Due to projected excess capacity and Clean Air Act requirements, a total of 340 MWs of aging coal fired capacity is expected to be retired by the end of 1999 and 850 MWs of oil fired capacity was placed in long-term cold standby in 1994. In one instance, the Company has considered the value of relocating a unit to a region where demand is greater. These decisions are reevaluated as facts and circumstances change. These actions permit the reduction of operating costs and capital expenditures for retired and standby plants.

These asset management studies have enabled the Company to make significant reductions in capital spending, and with increased output and lower operating costs, to improve the cost-efficiency of the units which is important as the Company continues to examine its competitive situation and future strategic direction. As discussed in Note 2. Rate and Regulatory Issues and Contingencies – the Company has determined that there is no impairment of its non-nuclear generating assets.

Regulatory Agreements/Proposals

1995 Rate Order. (See Note 2. Rate and Regulatory Issues and Contingencies.)

On April 21, 1995, the Company received a rate decision (1995 rate order) from the PSC which approved an approximately $47 million increase in electric revenues and a $4.9 million increase in gas revenues.

Prior Regulatory Agreements. The Company's results during the past several years have been strongly influenced by several agreements with the PSC. A brief discussion of the key terms of certain of these agreements is provided below.

The 1991 Financial Recovery Agreement implemented NERAM and MERIT. (See Note 1. Summary of Significant Accounting Policies.)

NERAM required the Company to reconcile actual results to the forecasted electric public sales gross margin used in establishing rates. NERAM was discontinued in 1995.

The MERIT program is an incentive mechanism. Overall goal targets and criteria for the 1993-1995 MERIT periods were results-oriented and intended to measure improvement in key performance areas. The total possible awards are $34 million and $41 million for 1994 and 1995, respectively. The Company has recognized approximately $20.8 million and $16.9 million of MERIT revenues in 1994 and 1995, respectively. The Company believes that it has earned approximately $18 million with respect to the 1995 MERIT award. However, it has only recorded $10.8 million of this amount in 1995, since that amount represented the objectively determinable portion of the anticipated award. Due to the uncertainty surrounding *PowerChoice*, the Company decided not to record additional revenues related to the remaining 1995 MERIT award in the amount of $7 million.

Results of Operations

Earnings for 1996 were $72.1 million, or 50 cents per share, as compared to $208.4 million, or $1.44 per share, in 1995, and $143.3 million, or $1.00 per share, in 1994. Earnings for 1996 include the discontinued application of regulatory accounting principles to the Company's fossil and hydro generation business. The Company reached this conclusion because the recently announced agreement-in-principle to terminate or restructure power contracts with certain IPPs makes probable the implementation of *PowerChoice* in which the Company has proposed to have its non-nuclear generation sell power at competitive prices in the wholesale market. The discontinuance results in the write-off of $103.6 million of regulatory assets associated with the fossil and hydro business which is included in the income statement as an extraordinary loss after tax of $67.4 million, or 47 cents per share. Earnings before the extraordinary loss were $139.5 million or 97 cents per share. Excluding the extraordinary loss, earnings for 1996 were lower because of an increase in bad debt expense of $96.4 million or 43 cents per share (see – "Financial Position, Liquidity and Capital Resources – Liquidity and Capital Resources"). This was partially offset by a $15.0 million gain on the sale of a 50% interest in CNP that contributed 10 cents per share to 1996 earnings. In addition, 1995 earnings included the recording of a one-time, non-cash adjustment of prior years' DSM incentive revenues, revenues earned under the Unit 1 operating incentive sharing mechanism and a gain on the sale of HYDRA-CO that collectively increased 1995 earnings by 17 cents per share. The Company's request for a temporary rate increase in 1996 was denied by the PSC.

Earnings for 1995 were hurt by lower sales quantities of electricity and natural gas, as compared with amounts used to establish 1995 prices. Sales were primarily affected by the continuing weak economic conditions in upstate New York, loss of industrial customers' load to NYPA and discounts granted. These factors similarly impacted 1996 results. In January 1995 NERAM was discontinued.

Earnings for 1994 included $101.2 million, or 46 cents per share, of electric margin recorded under NERAM, but were adversely affected by the charge to earnings of approximately $197 million (89 cents per share) for nearly all of the cost of the VERP. The VERP was initiated in 1994 to bring the Company's staff levels and work practices into line with peer utilities and to create a more competitive cost structure. From January 1, 1993 to December 31, 1994, the Company reduced its employment by approximately 3,100, or 27%.

The Company's 1996 earned ROE was 2.8% (5.4% before extraordinary loss), compared to 8.4% in 1995 and 5.8% (10.7% without the VERP charge) in 1994. The Company's return on common equity authorized in the rate setting process is 11.0% for the electric business and 11.4% for the gas business. Besides the extraordinary loss, factors contributing to earnings below authorized levels in 1996 included, among other things, significantly higher bad debt expense and sales below those forecasted in determining rates.

The following discussion and analysis highlights items that significantly affected operations during the three-year period ended December 31, 1996. This discussion and analysis may not be indicative of future operations or earnings, particularly in view of the probable termination or restructuring of IPP contracts and implementation of *PowerChoice*. It also should be read in conjunction with the "Notes to Consolidated Financial Statements" and other financial and statistical information appearing elsewhere in this report.

Electric revenues decreased by $26.6 million, or 0.8% in 1996, and decreased by $193.4 million, or 5.5%, in 1995.

As shown in the following table, electric revenues decreased in 1996, primarily due to a decrease in miscellaneous electric revenues. Miscellaneous electric revenues were lower in 1996 primarily because 1995 electric revenues included the recording of $71.5 million of unbilled, non-cash revenues in accordance with the 1995 rate order, $13.0 million of revenues earned under MERIT and a one-time, non-cash adjustment of prior year's DSM incentive revenues and a reduction in the DSM rebate cost program. However, higher electric sales due to colder weather, an increase in sales to other electric systems, an increase in FAC revenues and higher electric rates (effective April 26, 1995) partly offset those factors that contributed to lower electric revenues. FAC revenues increased $28.3 million, which primarily reflects the Company's increased payments to the IPPs recovered through the FAC.

Electric operating revenues decreased $193.4 million, or 5.5%, in 1995 primarily due to the elimination of NERAM after 1994, and the decrease in sales to other electric systems and in sales to ultimate consumers. In addition, FAC revenues decreased $86.4 million, in part due to a decrease in fuel and purchased power costs that are recoverable through the FAC as compared to 1994. Despite a decrease in fuel costs, the Company absorbed a loss of approximately $11.8 million in 1995 through the FAC sharing mechanism, since its actual costs in 1995 were higher than the amounts forecasted in rates. The amount forecasted in rates in 1995 reflected a lower fuel cost than 1994. In 1994, the Company retained a maximum benefit of $15 million, since its actual costs were lower than the amounts forecasted in rates. The decrease in FAC revenues also reflects a higher amount of transmission revenues ($21.6 million) realized in 1995 that were passed on to customers. These decreases were partially offset by higher electric rates that took effect April 26, 1995, and by the recording of $71.5 million unbilled, non-cash revenues in 1995 in accordance with the 1995 rate order. The increase in DSM revenues relates to a one-time, non-cash adjustment of prior years' DSM incentives, partially offset by a reduction in the cost of DSM rebates.

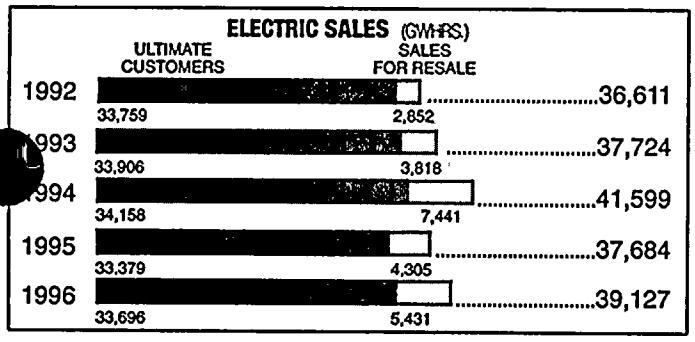
	Increase (decrease) from prior year (In millions of dollars)		
Electric revenues	1996	1995	Total
Amortization of unbilled revenues	$(77.1)	$ 71.5	$ (5.6)
Increase in base rates	65.3	68.2	133.5
Fuel adjustment clause revenues	28.3	(86.4)	(58.1)
Changes in volume and mix of sales to ultimate consumers	(28.1)	(70.0)	(98.1)
Sales to other electric systems	24.5	(71.3)	(46.8)
MERIT revenue	(13.0)	(5.6)	(18.6)
DSM revenue	(26.5)	1.4	(25.1)
NERAM revenues	—	(101.2)	(101.2)
	$(26.6)	$(193.4)	$(220.0)

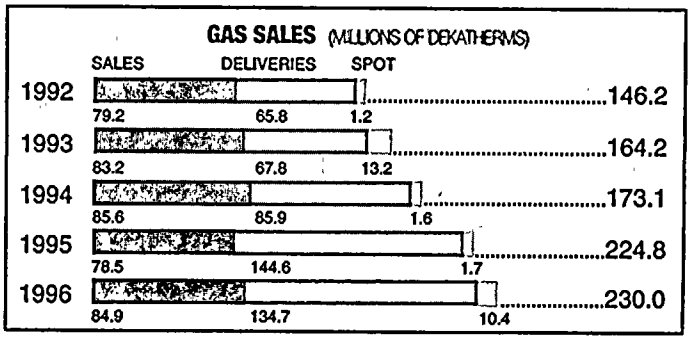
Changes in FAC revenues are generally margin-neutral (subject to an incentive mechanism discussed in Note 1. Summary of Significant Accounting Policies), while sales to other utilities, because of regulatory sharing mechanisms and relatively low prices, generally result in low margin contributions to the Company. Thus, fluctuations in these revenue components do not generally have a significant impact on net operating income. Electric revenues reflect the billing of a separate factor for DSM programs, which provide for the recovery of program related rebate costs.

Electric kilowatt-hour sales were 39.1 billion in 1996, 37.7 billion in 1995 and 41.6 billion in 1994. (See "Electric and Gas Statistics – Electric Statistics"). The 1996 increase of 1.4 billion Kwh, or 3.8% as compared to 1995, reflects a 26.2% increase in sales to other electric systems and a 1.2% increase in sales to ultimate customers due to the colder weather. Sales to other electric systems was higher due to increased demand for electricity in the northeast. The 1995 decrease of 3.9 billion Kwh, or 9.4% as compared to 1994, reflects a 42.1% decrease in sales to other electric systems and a 2.3% decrease in sales to ultimate consumers. The decline reflects reduced demand due to the continued stagnant economy, loss of several large industrial customers due primarily to relocations and closings, as well as a 1994 PSC Order that allowed Sithe Independent Power Partners, Inc. to sell a portion of its electricity to Alcan Rolled Products, loss of sales to NYPA, and more competitive pricing caused by excess supply. Excluding the effects of the weather, the Company anticipates 1997 sales to ultimate customers to decline slightly, before picking up in 1998.

Details of the changes in electric revenues and Kwh sales by customer group are highlighted in the table below:

	1996	% Increase (decrease) from prior years			
		1996		1995	
Class of service	% of Electric Revenues	Revenues	Sales	Revenues	Sales
Residential	37.8%	3.1%	0.5%	(0.9)%	(2.5)%
Commercial	37.4	—	(0.4)	(2.4)	(1.1)
Industrial	15.9	0.2	1.2	(8.8)	(4.3)
Industrial – Special	1.8	3.9	6.7	14.3	(1.6)
Municipal service	1.6	5.8	7.4	(1.1)	0.9
Total to ultimate consumers	94.5	1.4	1.2	(2.7)	(2.3)
Other electric systems	3.4	27.5	26.2	(43.6)	(42.1)
Miscellaneous	2.1	(57.8)	(17.7)	(23.6)	(2.1)
Total	100.0%	(0.8)%	3.8%	(5.5)%	(9.4)%





As indicated in the table below, internal generation increased in 1996, principally in nuclear and hydro. In 1996, Unit 2 was out of service for a 35 day planned refueling and maintenance outage while in 1995, both units were taken out of service for approximately two months each for planned refueling and maintenance outages. The amount of electricity delivered to the Company by the IPPs decreased by approximately 226 GwHrs or 1.6%, but total IPP costs increased by approximately $108.6 million or 11.1%, as discussed below. (For a discussion of an event that is expected to change the cost and amount of energy delivered by IPPs, see "Announced Agreement-in-Principle to Terminate or Restructure 44 IPP Contracts").

	1996		1995		1994		% Change from prior year			
							1996 to 1995		1995 to 1994	
(In millions of dollars)	GwHrs.	Cost	GwHrs.	Cost	GwHrs.	Cost	GwHrs.	Cost	GwHrs.	Cost
Fuel for electric generation:										
Coal	7,095	$ 100.6	6,841	$ 97.9	6,783	$ 107.3	3.7%	2.8%	0.9%	(8.8)%
Oil	462	21.1	537	21.3	1,245	40.9	(14.0)	(0.9)	(56.9)	(47.9)
Natural gas	319	9.2	996	20.2	700	16.1	(68.0)	(54.5)	42.3	25.5
Nuclear	8,243	47.7	7,272	43.3	8,327	49.5	13.4	10.2	(12.7)	(12.5)
Hydro	3,679	—	2,971	—	3,485	—	23.8	—	(14.7)	—
	19,798	178.6	18,617	182.7	20,540	213.8	6.3	(2.2)	(9.4)	(14.5)
Electricity purchased:										
Capacity	—	212.8	—	181.2	—	84.6	—	17.4	—	114.2
Energy and taxes	13,797	875.7	14,023	798.7	14,794	875.5	(1.6)	9.6	(5.2)	(8.8)
Total IPP purchases	13,797	1,088.5	14,023	979.9	14,794	960.1	(1.6)	11.1	(5.2)	2.1
Other	9,569	130.6	9,463	126.5	10,382	140.3	1.1	3.2	(8.9)	(9.8)
	23,366	1,219.1	23,486	1,106.4	25,176	1,100.4	(0.5)	10.2	(6.7)	0.5
Total generated and purchased	43,164	1,397.7	42,103	1,289.1	45,716	1,314.2	2.5	8.4	(7.9)	(1.9)
Fuel adjustment clause	—	(33.3)	—	14.8	—	12.7	—	(325.0)	—	16.5
Losses/Company use	4,037	—	4,419	—	4,117	—	(8.6)	—	7.3	—
	39,127	$1,364.4	37,684	$1,303.9	41,599	$1,326.9	3.8%	4.6%	(9.4)%	(1.7)%

The above table presents the total costs for purchased electricity, while reflecting only fuel costs for Company generation. Other costs of generation, such as taxes, other operating expenses and depreciation are included within other income statement line items.

The Company's management of its IPP power supply generally divides the projects into three groups; hydroelectric, "must run" cogeneration and schedulable cogeneration projects. Due to high precipitation and spring run-off levels in 1996, hydroelectric IPP projects produced and delivered an increase of 635 GwHrs or 56.1% under PPAs resulting in increased payments to those IPPs of $57.5 million. In addition, a major new hydroelectric IPP came on line in November 1995, contributing to the increase in hydroelectric deliveries.

A substantial portion of the Company's portfolio of IPP projects operate on a "must run" basis. This means that they tend to run to the maximum production levels regardless of the need or economic value of the electricity produced. Despite delivering 585 GwHrs less or 5.9%, due to higher weighted average price, payments to "must run" IPPs increased by $15.2 million. With respect to "must run" IPP cogeneration projects, a number of elements combined to reduce the aggregate deliveries from "must run" IPPs. These elements included limited term agreements negotiated by the Company and a catastrophic failure of one of the IPP plants.

The Company has renegotiated PPAs with a number of IPP cogeneration projects in order to obtain the right to schedule the electricity deliveries of the project. The terms of these PPAs allow the Company to schedule energy deliveries from

the facilities and then pay for the energy delivered. The Company is also required to make fixed payments so long as the IPP plants are available for service. (See Note 9. Commitments and Contingencies – "Long-term Contracts for the Purchase of Electric Power").

Quantities from schedulable cogeneration IPPs decreased 276 GwHrs or 9.3%. Payments to schedulable IPPs increased $35.9 million, primarily due to increased fixed payments of approximately $31.6 million. The increase in fixed payments is caused by a new schedulable IPP whose plant came on line in May 1995 and due to escalation factors included in the PPA. In addition, payments to schedulable IPPs reflect the increase in the cost of natural gas.

Gas revenues increased by $99.9 million, or 17.2%, in 1996, and decreased by $41.4 million, or 6.6%, in 1995. As shown by the table below, gas revenues increased in 1996 primarily due to increased sales to ultimate customers due to colder weather, increased spot market sales, higher gas adjustment clause recoveries, an increase in revenues from the transportation of customer-owned gas and an increase in base rates of $3.1 million in accordance with the 1995 rate order.

In 1995, the revenue decrease was primarily attributable to decreased sales to ultimate customers, which reflects reduced demand due to the weak economy and warmer weather, and lower gas adjustment clause recoveries. This decrease was partially offset by an increase in revenues from the transportation of customer-owned gas of approximately $9.9 million which was primarily caused by the Sithe gas-fired generating project coming on-line in the Company's service territory and an increase in base rates of $4.7 million in accordance with the 1995 rate order.

Rates for transported gas (excluding aggregation services) yield lower margins than gas sold directly by the Company. Therefore, increases in the volume of gas transportation services have not had a proportionate impact on earnings, particularly in instances where customers that took direct service from the Company move to a transportation-only class. In addition, changes in purchased gas adjustment clause revenues are generally margin-neutral.

	Increase (decrease) from prior year *(In millions of dollars)*		
Gas revenues	1996	1995	Total
Increase in base rates	$ 3.1	$ 4.7	$ 7.8
Transportation of customer-owned gas	2.1	9.9	12.0
Purchased gas adjustment clause revenues	30.8	(10.7)	20.1
Spot market sales	34.0	(1.3)	32.7
Changes in volume and mix of sales to ultimate consumers	29.9	(44.0)	(14.1)
	$99.9	$(41.4)	$58.5

Gas sales, excluding transportation of customer-owned gas and spot market sales, were 84.9 million Dth in 1996, an 8.2% increase from 1995, and a (0.9)% decrease from 1994. (See "Electric and Gas Statistics – Gas Statistics"). The increase in 1996 was in all ultimate consumer classes due to the colder weather. In addition, spot market sales (sales for resale), which are generally from the higher priced gas available to the Company and therefore yield margins that are substantially lower than traditional sales to ultimate customers, increased 8.7 million Dth. This was partially offset by a decrease of transportation volumes of 9.9 million Dth or 6.9% to customers purchasing gas directly from producers. The Company has experienced an increase in customers of approximately 20,000 since 1994, primarily in the residential class, an increase of 3.9%.

Changes in gas revenues and Dth sales by customer group are detailed in the table below:

	1996 % of Gas Revenues	% Increase (decrease) from prior year			
		1996		1995	
Class of service		Revenues	Sales	Revenues	Sales
Residential	61.2%	13.3%	9.4%	(7.5)%	(8.2)%
Commercial	23.8	13.0	6.4	(9.7)	(7.6)
Industrial	2.0	15.6	4.1	(21.0)	(14.1)
Total to ultimate consumers	87.0	13.3	8.3	(8.5)	(8.3)
Other gas systems	—	(81.9)	(81.4)	(34.3)	(34.0)
Transportation of customer-owned gas	7.4	4.3	(6.9)	25.9	68.3
Spot market sales	5.4	1,099.1	507.0	(29.2)	9.6
Miscellaneous	0.2	(82.2)	—	(16.7)	—
Total	100.0%	17.2%	2.3%	(6.6)%	29.9%

The total cost of gas purchased increased 34.0% in 1996 and decreased 12.5% in 1995 and 3.2% in 1994. The cost fluctuations generally correspond to sales volume changes, as spot market sales activity increased, as well as changes in gas prices. The Company sold 10.5, 1.7 and 1.6 million Dth on the spot market in 1996, 1995 and 1994, respectively. The total cost of gas increased $93.8 million in 1996. This was the result of a 9.3 million increase in Dth purchased and withdrawn

from storage for ultimate consumer sales ($29.6 million), a $25.6 million increase in Dth purchased for spot market sales and a 12.9% increase in the average cost per Dth purchased ($38.7 million). The purchased gas cost decrease associated with purchases for ultimate consumers in 1995 resulted from a 4.3 million decrease in Dth purchased and withdrawn from storage for ultimate consumer sales ($15.1 million) and a 10.8% decrease in the average cost per Dth purchased ($32.8 million). This was partially offset by an increase of $10.1 million in purchased gas costs and certain other items recognized and recovered through the GAC. Gas purchased for spot market sales increased $25.6 million in 1996 and decreased $1.4 million and $24.4 million in 1995 and 1994, respectively. The Company's net cost per Dth sold, as charged to expense and excluding spot market purchases, increased to $3.62 in 1996 from $3.17 in 1995 and was $3.44 in 1994.

Through the electric and purchased gas adjustment clauses, costs of fuel, purchased power and gas purchased, above or below the levels allowed in approved rate schedules, are billed or credited to customers. The Company's electric FAC provides for a partial pass-through of fuel and purchased power cost fluctuations from those forecast in rate proceedings, with the Company absorbing a portion of increases or retaining a portion of decreases to a maximum of $15 million per rate year. The Company retained the maximum benefit of $15 million in 1994, but absorbed losses of approximately $11.8 million and $1.4 million in 1995 and 1996, respectively.

Other operation and maintenance expense increased in 1996 by $110.3 million, or 13.5%, as compared to a increase of $139.5 million or 14.6% in 1995. The 1996 increase was primarily as a result of an increase in bad debt expense of $96.4 million, including a $32.1 million net increase in the Company's allowance for doubtful accounts to recognize the increased risk of collection inherent in significantly higher levels of past-due customer bills (See – "Financial Position, Liquidity and Capital Resources – Liquidity and Capital Resources") and year-to-year differences in the accounting for regulatory deferrals. This was partially offset by a decrease in Unit 1 operation and maintenance costs which were higher in 1995 as a result of planned refueling and maintenance outages.

Despite the costs related to the 1995 scheduled nuclear refueling outages of Units 1 and 2 of approximately $36 million, other operation expense decreased in 1995 primarily as a result of the Company's cost reduction program. In addition to lower labor costs, the Company also reduced 1995 non-labor costs, such as research and development expenditures ($21 million), general office expenses ($8 million), and DSM rebate costs ($19 million).

Other items, net increased by $30.3 million in 1996 and decreased by $13.0 million in 1995. The 1996 increase was primarily due to higher interest income ($10.9 million) as a result of an increase in temporary cash investments and the gain on the sale of a 50% interest in CNP ($15.0 million). In addition, other items, net was higher since there were customer service penalties and certain other items written off because they were disallowed in rates in 1995. The 1995 decrease was primarily due to the recognition of customer service penalties, certain other items disallowed in rates and lower subsidiary earnings, offset in part by the pre-tax gain ($21.6 million) recognized on the sale of HYDRA-CO.

Net Federal and foreign income taxes decreased by $56.9 million in 1996 primarily due to a decrease in pre-tax income and increased by $47.9 million in 1995. The 1995 increase was due to an increase in pre-tax income, which included the increase related to the sale of HYDRA-CO. Other taxes decreased by $41.6 million in 1996 and increased by $20.6 million in 1995. The 1996 decrease was primarily as a result of lower real estate taxes ($15.4 million), lower GRTs ($6.1 million) primarily due to a reduction in the GRT surcharge during 1996, lower New York State excess dividend tax accrual due to a suspension of the common stock dividend ($4.6 million) and year-to-year differences in the accounting for regulatory deferrals ($15.2 million) associated primarily with a settlement of tax issues with respect to the Company's Dunkirk facility. The 1995 increase was primarily as a result of an increase in the amortization of amounts deferred in prior years ($19.7 million) related to real estate taxes. This increase was partially offset by a reduction of approximately $7.9 million in GRTs as a result of lower revenues in 1995 as compared to 1994, and a reduction in the GRT surcharge during 1995, as well as a reduction in payroll taxes ($5.2 million) due to a decrease in the number of employees.

Net interest charges remained fairly constant for the years 1994 through 1996. However, dividends on preferred stock decreased by $1.3 million in 1996 and increased by $5.9 million in 1995. Dividends on preferred stock decreased in 1996 primarily due to a decrease in the cost of variable rate issues and increased $5.9 million in 1995 primarily as a result of an increase in the cost of variable rate issues. The weighted average long-term debt interest rate and preferred dividend rate paid, reflecting the actual cost of variable rate issues, changed to 7.71% and 7.09%, respectively, in 1996 from 7.77% and 7.19%, respectively, in 1995, and from 7.79% and 6.84%, respectively, in 1994.

Effects of Changing Prices

The Company is especially sensitive to inflation because of the amount of capital it typically needs and because its prices are regulated using a rate base methodology that reflects the historical cost of utility plant.

The Company's consolidated financial statements are based on historical events and transactions when the purchasing power of the dollar was substantially different than now. The effects of inflation on most utilities, including the Company, are most significant in the areas of depreciation and utility plant. The Company could not replace its non-nuclear utility plant and equipment for the historical cost value at which they are recorded on the Company's books. In addition, the Company would not replace these

with identical assets due to technological advances and competitive and regulatory changes that have occurred. In light of these considerations, the depreciation charges in operating expenses do not reflect the cost of providing service if new generating facilities were installed. The Company will seek additional revenue or reallocate resources, if possible, to cover the costs of maintaining service as assets are replaced or retired.

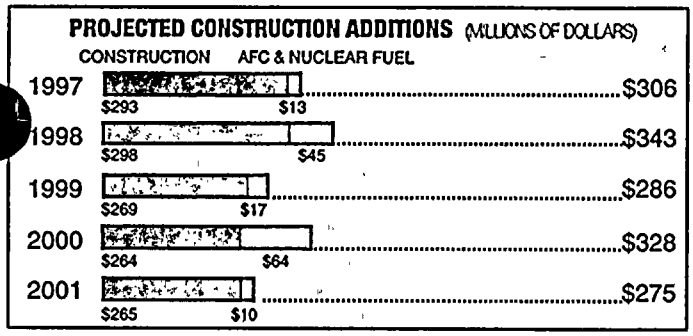
Financial Position, Liquidity and Capital Resources

Financial Position. The Company's capital structure at December 31, 1996 was 53.1% long-term debt, 7.9% preferred stock and 39.0% common equity, as compared to 54.5%, 8.0% and 37.5% respectively, at December 31, 1995. The culmination of the termination or restructuring of IPP contracts will significantly increase the leverage of the Company to nearly 65% at the time of closing. The planned rapid repayment of new debt will deleverage the Company over time. Book value of the common stock was $17.91 per share at December 31, 1996, as compared to $17.42 per share at December 31, 1995. With the issuance of equity at below book value to the IPPs as part of the agreement-in-principle, book value per share will be diluted by an amount which will depend upon the market value of the Company's common stock at the time of issuance to the IPP developers. Also, earnings per share will be diluted by the effect of the issuance to the IPP developers of 46 million shares of the Company's common stock. Market analysts have observed that the Company's low market to book ratio, 55.1% at December 31, 1996, results from a weak New York State economy and regulatory attitudes, and from uncertainty about the pace of regulatory change, which could increase competition and reduce prices, rendering the Company particularly vulnerable. In addition, market analysts have expressed concern about the uncertainty and potential negative impact of the *PowerChoice* proposal on the Company, as well as the possibility of bankruptcy. The Company believes the implementation of *PowerChoice* is in the best interests of shareholders, bondholders and customers, because a substantial portion of the IPP over-market problem will have been eliminated and replaced by fixed-debt obligations and it will enable the Company to deliver power through 2000 at slightly lower prices to its customers, with larger decreases in prices to large commercial and industrial customers to retain and attract business to its service territory.

The 1996 ratio of earnings to fixed charges was 1.57 times. The ratios of earnings to fixed charges for 1995 and 1994 were 2.29 times and 1.91 times, respectively. Security rating firms have imputed certain items into the Company's interest coverage calculations and capital structure, the most significant of which is the inclusion of a "leverage" factor for IPP contracts. The rating firms believe the financial structure of the IPPs (which typically have very high debt-to-equity ratios) and the character of their PPA increase the financial risk to utilities. The Company's reported interest coverage and debt-to-equity ratios have been discounted by varying amounts for purposes of establishing credit ratings. Because of existing commitments for IPP purchases, the imputation has had a materially negative impact on the Company's financial ratings. Assuming the IPP agreement-in-principle is implemented, the imputed leveraged debt would be replaced by issued debt.

Common Stock Dividend. The board of directors omitted the common stock dividend for all of 1996 and the first quarter of 1997. This action was taken to help stabilize the Company's financial condition and provide flexibility as the Company addresses growing pressure from mandated power purchases and weaker sales and is the primary reason for the increase in the cash balance. In making future dividend decisions, the board will evaluate, along with standard business considerations, the financial condition and contractual obligations of the Company, the progress on concluding negotiations and implementing the termination or restructuring of IPP contracts and *PowerChoice*, or the failure to implement such actions, the degree of competitive pressure on its prices, the level of available cash flow and retained earnings and other strategic considerations. The Company expects to dedicate a substantial portion of its positive cash flow to pay down senior subordinated debt to be issued in connection with the implementation of the agreement-in-principle. Furthermore, the Company believes that its reported return on equity will be substantially reduced, particularly during the next few years as non-cash amortization of the regulatory asset occasioned by the IPP agreement-in-principle is occuring and the interest costs on the IPP debt is the greatest. See "Accounting Implications of *PowerChoice* and Agreement-in-Principle to Terminate or Restructure IPP Contracts."

Construction and Other Capital Requirements. The Company's total capital requirements consist of amounts for the Company's construction program (see Note 9. Commitments and Contingencies – "Construction Program"), compliance with the Clean Air Act and other environmental requirements (as discussed below and in Note 9. "Environmental Contingencies"), nuclear decommissioning funding requirements (See Note 3. Nuclear Operations – "Nuclear Plant Decommissioning" and "NRC Draft Policy Statement"), working capital needs, maturing debt issues and sinking fund provisions on preferred stock, as well as requirements to complete the termination or restructuring of IPP contracts and accomplish the restructuring contemplated by the *PowerChoice* proposal. Annual expenditures for the years 1994 to 1996 for construction and nuclear fuel, including related AFC and overheads capitalized, were $485.4 million, $345.8 million and $352.1 million, respectively, and are expected to be approximately $306 million for 1997 and to range from $275 to $343 million for each of the subsequent four years. These estimates include construction expenditures for non-nuclear generation costs at $22 to $31 million per year.



In addition to the assumed cost of the IPP agreement-in-principle requirements, mandatory debt and preferred stock retirements and other requirements are expected to add approximately another $57 million to the 1997 estimate of capital requirements. The estimate of construction additions included in capital requirements for the period 1997 to 2001 will continue to be reviewed by management with the objective of further reducing these amounts where possible. See discussion in – "Liquidity and Capital Resources" section below, which describes how management intends to meet its financing needs for this five-year period.

The above requirements do not include amounts required to complete the termination or restructuring of IPP contracts and accomplish the restructuring contemplated by *PowerChoice*. Under the agreement-in-principle the Company will pay in cash or debt securities of the Company $3.6 billion. The Company expects to sell in the public market subordinated debentures to fund all or a portion of this requirement. The Company will also be required to replace or amend its existing $804 million senior debt facility, discussed below.

The provisions of the Clean Air Act are expected to have an impact on the Company's fossil generation plants during the period through 2001 and beyond. The Company has complied with Phase I of the Clean Air Act, which includes reductions of NOx and SO2. Phase I became effective on January 1, 1995 and will continue through 1999. The Company spent approximately $0.1 million and $5 million in 1996 and 1995, respectively, on projects at the fossil generation plants associated with Phase I compliance. The Company has included $6 million in its 1997 through 1999 construction forecast for Phase II compliance which will become effective January 1, 2000. The Company anticipates that additional expenditures of approximately $74 million may be incurred for Phase III beyond 2000. These estimates are dependent upon finalization of rulemakings that implement the Clean Air Act, the results of which could increase or lower expenditures. The asset management studies, described above, consider spending estimates for Clean Air Act compliance.

Liquidity and Capital Resources. On May 22, 1996, S&P lowered its ratings on the Company's senior secured debt to BB- from BB; senior unsecured debt to B from B+; its preferred stock to B- from B; and commercial paper to not rated from B. The present ratings remain below investment grade and remain on "CreditWatch" with negative implications. S&P stated that the downgrade resulted from the inability of the financially weak Company and the IPPs to make substantive progress in their renegotiation of IPP contracts. In addition, S&P stated that the lack of progress after several months of negotiations between the Company and the IPPs increases the uncertainty that a settlement can be achieved.

On March 10, 1997, S&P stated that its present ratings of the Company remain on CreditWatch, however, the implications have been revised to positive. S&P stated that the CreditWatch revision was made following the Company's announcement that it has reached an agreement-in-principle to terminate or restructure 44 of the Company's most significant IPP contracts. (See "Announced Agreement-in-Principle to Terminate or Restructure 44 IPP Contracts"). S&P stated that it did not expect the Company's senior secured debt ratings to achieve an investment-grade rating for several years. However, S&P noted that there is a stronger possibility that the Company will achieve investment-grade ratings if New York State passes the securitization legislation. S&P further noted that the revised implications reflects the significantly reduced chance of bankruptcy that might have resulted from unsuccessful negotiations with IPPs, and the prospect of improved cash flow coverages.

On April 25, 1996, Moody's lowered its ratings on the Company's senior secured debt, to Ba3 from Ba1; senior unsecured debt to B2 from Ba2; and its preferred stock to b3 from ba3. Moody's "Not Prime" rating for the Company's commercial paper remains unchanged. The present ratings remain below investment grade. Moody's stated that it downgraded the long-term credit ratings of the Company, based on the limited progress made in achieving the goals identified in the Company's *PowerChoice* proposal, among other financial concerns, which may ultimately lead to a voluntary bankruptcy filing. In addition, Moody's stated that due to the level of uncertainty and potential volatility of the situation, its rating outlook on the Company remained negative.

On March 10, 1997, Moody's revised its outlook of the Company to reflect the stabilizing effect of the announced agreement-in-principle to terminate or restructure 44 of the Company's most significant IPP contracts. Moody's stated that there is still a substantial amount of negotiating to be done, but the specter of a voluntary bankruptcy filing has been lessened. In addition, Moody's stated that it views the announcement as a positive step to stabilize the Company's cash flow with favorable implications to the Company's first mortgage bonds and secured pollution control bonds.

On August 2, 1996, Fitch placed the Company's first mortgage bonds and secured pollution control bonds (rated BB) and preferred stock (rated B+) on FitchAlert status with evolving implications, following the Company's announced proposal to terminate or restructure 44 IPP contracts in exchange for a combination of cash and securities from a newly restructured Company. (See

"Announced Agreement-in-Principle to Terminate or Restructure 44 IPP Contracts"). Previously, the credit trend was declining. However, FitchAlert status means that a change in ratings is likely and the evolving status may be either raised or lowered depending on the outcome of the IPP agreement-in-principle. The present ratings are below investment grade.

On March 10, 1997, Fitch revised its ratings to Fitch-Alert positive. This action reflects the Company's announced agreement-in-principle to terminate or restructure 44 above-market power contracts with 19 IPPs. Fitch stated that a change in ratings is likely and the improving status indicates that ratings may be raised or affirmed depending on the outcome of events within the next 6 to 12 months. Fitch stated that the successful negotiation of these contracts paves the way for the approval of a rate plan by the PSC, which could stabilize the Company's financial condition and allow it to implement a competitive retail access plan while eliminating a major risk of insolvency.

A summary of the Company's securities ratings at December 31, 1996, was:

	Secured Debt	Preferred Stock	Commercial Paper	Unsecured Debt
Standard & Poor's Corporation	BB-	B-	Not Rated	B
Moody's Investors Service.....	Ba3	b3	Not Prime	B2
Fitch Investors Service.....	BB	B+	Not applicable	Not applicable

Although no assurance can be provided, the Company believes that the termination or restructuring of the IPP contracts and implementation of *PowerChoice* will result in credit statistics that will support improved credit ratings for senior secured debt (First Mortgage Bonds), although not likely investment grade at the outset. There is risk throughout the electric industry that credit ratings could decline if the issue of stranded cost recovery is not satisfactorily solved. In the event *PowerChoice* is not adopted, and comparable solutions are not available, the Company will undertake any other actions necessary to act in the best interests of stockholders and other constituencies.

Ordinarily, construction related short-term borrowings are refunded with long-term securities on a periodic basis. This approach generally results in the Company showing a working capital deficit. Working capital deficits may also be a result of the seasonal nature of the Company's operations as well as timing differences between the collection of customer receivables and the payment of fuel and purchased power costs. The Company is experiencing a significant deterioration in its collections as compared to prior years' experience and is taking steps to improve collection, as discussed below. The Company believes it has sufficient borrowing capacity to fund such deficits as necessary in the near term. However, the Company's borrowing capacity to fund such deficits may be affected by the factors discussed below relating to the Company's external financial plans.

As previously disclosed by the Company, there was a significant increase in past-due accounts receivable since 1995. A number of factors have contributed to the increase, including rising prices (particularly to residential customers). Rising prices have been driven by increased payments to IPPs and high taxes and have been passed on in customers' bills. The stagnant economy in the Company's service territory since the early 1990's has adverse affected collection of past-due accounts. Also, laws, regulations and regulatory policies impose more stringent collection limitations on the Company than those imposed on business in general; for example, the Company cannot terminate service during the winter heating season. The Company's collection efforts were also affected by employee turnover with the relocation to the new Collection Center in Buffalo, New York and the VERP in 1994. The Company is developing and implementing a variety of strategies to improve its collection experience and reduce its bad debt expense. While a number of strategies can and will be implemented by the Company unilaterally, other strategies will require the support of the PSC regarding interpretation or alteration of the PSC's rules and regulations, and still others may require legislative action. The Company has initiated discussions with the staff of the PSC to explore changes in practices that require the PSC's support, and is formulating strategies to address legislative impediments.

The information gathered in developing these strategies enabled management to update its risk assessment of the accounts receivable portfolio. Based on this assessment, management determined that the level of risk associated primarily with the older accounts had increased and the historical loss experience no longer applied. Accordingl the Company determined that a significant portion of t past-due accounts receivable (principally of residential customers) might be uncollectible, and has written-off a substantial number of these accounts as well as increased its allowance for doubtful accounts by $32.1 million (14 cents per share) to $52.1 million as of December 31, 1996. In 1996 and 1995, the Company had charged $127.6 million and $31.3 million, respectively to bad debt expense. The allowance for doubtful accounts is based on assumptions and judgments as to the effectiveness of collection efforts. However, future results with respect to collecting the past-due receivables may prove to be different from those anticipated. The Company expects that future bad debt expense will be lower than that experienced in 1996, but remain higher than in prior years. Such a result is necessarily dependent upon the following factors, including, among other things, the effectiveness of the strategies discussed above, the support of regulators and legislators to allow utilities to move towards commercial collection practices and improvement in the condition of the economy in the Company's service territory. The Company has been pursuing *PowerChoice* to address high prices that are the result of traditional price regulation, but the introduction of competition requires that policies and practices that were central to traditional regulation, including those involving collections, be changed so as not to jeopardize the benefits of competition.

External financing plans are subject to periodic revisi as underlying assumptions are changed to reflect devel

ments, market conditions and, most importantly, conclusion of the termination or restructuring of IPP contracts and implementation of the Company's *PowerChoice* proposal. The ultimate level of financing during the period 1997 through 2000 will be affected by, among other things: the timing and outcome of the IPP termination and restructure agreement-in-principle and the implementation of *PowerChoice* proposal (or a similar proposal), levels of common dividend payments, if any, and preferred dividend payments; the Company's competitive position and the extent to which competition penetrates the Company's markets; uncertain energy demand due to the weather and economic conditions; and the extent to which the Company reduces non-essential programs and manages its cash flow during this period. The Company could also be affected by the outcome of the NRC's consideration of new rules for adequate financial assurance of nuclear decommissioning obligations. (See Note 3. Nuclear Operations – "NRC Draft Policy Statement"). In the longer term, in the absence of *PowerChoice* or some reasonably equivalent solution, financing will depend on the amount, if any, of rate relief that may be granted. Without adequate relief, or any substantial relief from its existing cost structure as described herein, the Company's financial condition will continue to deteriorate.

During March 1996, the Company completed an $804 million senior debt facility with a bank group for the purposes of consolidating and refinancing certain of the Company's existing working capital lines of credit and letter of credit facilities and providing additional reserves of bank credit. This senior debt facility will enhance the Company's financial flexibility during the period 1997 through June 1999. The senior debt facility consists of a $255 million term loan facility, a $125 million revolving credit facility and $424 million for letters of credit. The letter of credit facility provides credit support for the adjustable rate pollution control revenue bonds issued through the NYSERDA. The interest rate applicable to the senior debt facility is variable based on certain rate options available under the agreement and currently approximates 7.4% (but capped at 15%). As of December 31, 1996, the amount outstanding under the senior debt facility was $542 million, consisting of $105 million under the term loan facility, a $424 million letter of credit and a $13 million letter of credit under the revolving credit facility, leaving the Company with $262 million of borrowing capability under the facility. The facility expires on June 30, 1999 (subject to earlier termination upon the implementation of the Company's *PowerChoice* proposal or any other significant restructuring plan).

This facility is collateralized by first mortgage bonds which were issued on the basis of additional property under the earnings test required under the mortgage trust indenture. As of December 31, 1996, the Company could issue an additional $1,356 million aggregate principal amount of first mortgage bonds under the Company's mortgage trust indenture. This amount is based upon retired bonds without regard to an interest coverage test. As a result of the recording of the extraordinary item in December 1996, the Company is presently precluded from issuing first mortgage bonds based on additional property and the earnings test.

The Company also has $200 million of Preference Stock authorized for sale. Current market conditions preclude the Company from issuing preferred or preference stock due to the downgrading of the Company's security ratings. The Company's charter also limits the amount of unsecured indebtedness that may be incurred by the Company to 10% of consolidated capitalization plus $50 million. At December 31, 1996, this charter restriction is approximately $702 million and the Company's unsecured debt outstanding is $20 million.

Net cash provided by operating activities increased slightly in 1996 due to an increase in working capital items, despite a decrease in net income in the amount of $137.6 million.

Net cash used in investing activities increased $54.6 million in 1996 since 1995 included the net cash generated from the sale of HYDRA-CO ($161.1 million). This increase was partially offset by the net cash generated from the sale of CNP (approximately $15 million) and a decrease in other cash investments in the amount of $115.3 million.

Net cash used in financing activities decreased $167.0 million, since the Company paid-off and converted its short-term debt to long-term debt in 1995, and did not rely on any short-term debt in 1996. In addition, the Company eliminated its common stock dividend in 1996.

Report of Management

The consolidated financial statements of the Company and its subsidiaries were prepared by and are the responsibility of management. Financial information contained elsewhere in this Annual Report is consistent with that in the financial statements.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls, which is designed to provide reasonable assurance, on a cost effective basis, as to the integrity, objectivity and reliability of the financial records and protection of assets. This system includes communication through written policies and procedures, an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program. In addition, the Company has a Corporate Policy Register and a Code of Business Conduct (Code) that supply employees with a framework describing and defining the Company's overall approach to business and requires all employees to maintain the highest level of ethical standards as well as requiring all management employees to formally affirm their compliance with the Code.

The financial statements have been audited by Price Waterhouse LLP, the Company's independent accountants, in accordance with generally accepted auditing standards. In planning and performing its audit, Price Waterhouse considered the Company's internal control structure in order to determine auditing procedures for the purpose of expressing an opinion on the financial statements, and not to provide assurance on the internal control structure. The independent accountants' audit does not limit in any way management's responsibility for the fair presentation of the financial statements and all other information, whether audited or unaudited, in this Annual Report. The Audit Committee of the Board of Directors, consisting of six outside directors who are not employees, meets regularly with management, internal auditors and Price Waterhouse to review and discuss internal accounting controls, audit examinations and financial reporting matters. Price Waterhouse and the Company's internal auditors have free access to meet individually with the Audit Committee at any time, without management being present.

William E. Davis

William E. Davis
Chairman of the Board and
Chief Executive Officer
Niagara Mohawk Power Corporation

Report of Independent Accountants

To the Stockholders and
Board of Directors of
Niagara Mohawk Power Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and retained earnings and of cash flows present fairly, in all material respects, the financial position of Niagara Mohawk Power Corporation and its subsidiaries at December 31, 1996 and 1995, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1996, in conformity with generally accepted accounting principles. 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 of these statements in accordance with generally accepted auditing standards which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

As discussed in Note 2, the Company believes that it continues to meet the requirements for application of Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS No. 71) for its nuclear generation, electric transmission and distribution and gas businesses. In the event that the Company is unable to complete the termination or restructuring of unregulated generator contracts and implement PowerChoice, this conclusion could change in 1997 and beyond, resulting in material adverse effects on the Company's financial condition and results of operations.

As discussed in Note 2, the Company discontinued application of SFAS No. 71 for its non-nuclear generation business in 1996.

Price Waterhouse LLP

Syracuse, New York March 13, 1997

Consolidated Statements of Income and Retained Earnings

For the year ended December 31,	1996	1995	1994
	In thousands of dollars		
Operating revenues:			
Electric	$ 3,308,979	$3,335,548	$3,528,987
Gas	681,674	581,790	623,191
	3,990,653	3,917,338	4,152,178
Operating expenses:			
Fuel for electric generation	181,486	165,929	219,849
Electricity purchased	1,182,892	1,137,937	1,107,133
Gas purchased	370,040	276,232	315,714
Other operation and maintenance expenses	928,224	817,897	957,377
Employee reduction program	—	—	196,625
Depreciation and amortization (*Note 1*)	329,827	317,831	308,351
Federal and foreign income taxes (*Note 7*)	105,583	156,008	117,834
Other taxes	475,846	517,478	496,922
	3,573,898	3,389,312	3,719,805
Operating income	416,755	528,026	432,373
Other income and deductions:			
Allowance for other funds used during construction (*Note 1*)	3,665	1,063	2,159
Federal and foreign income taxes (*Note 7*)	3,089	(3,385)	6,365
Other items (net)	32,278	2,006	15,045
	39,032	(316)	23,569
Income before interest charges	455,787	527,710	455,942
Interest charges:			
Interest on long-term debt	272,706	267,019	264,891
Other interest	9,017	20,642	20,987
Allowance for borrowed funds used during construction	(3,690)	(7,987)	(6,920)
	278,033	279,674	278,958
Income before extraordinary item	177,754	248,036	176,984
Extraordinary item for the discontinuance of regulatory accounting principles, net of income taxes of $36,273 (Note 2)	(67,364)	—	—
Net income	110,390	248,036	176,984
Dividends on preferred stock	38,281	39,596	33,673
Balance available for common stock	72,109	208,440	143,311
Dividends on common stock	—	161,650	156,060
	72,109	46,790	(12,749)
Retained earnings at beginning of year	585,373	538,583	551,332
Retained earnings at end of year	$ 657,482	$ 585,373	$ 538,583
Average number of shares of common stock outstanding (*in thousands*)	144,350	144,329	143,261
Balance available per average share of common stock before extraordinary item	$ 0.97	$ 1.44	$ 1.00
Extraordinary item	$ (0.47)	$ —	$ —
Balance available per average share of common stock	$ 0.50	$ 1.44	$ 1.00
Dividends paid per share	$ —	$ 1.12	$ 1.09

( ) Denotes deduction

The accompanying notes are an integral part of these financial statements

Consolidated Balance Sheets

At December 31,	In thousands of dollars 1996	1995
ASSETS		
Utility plant (*Note 1*):		
Electric plant	$ 8,611,419	$8,543,429
Nuclear fuel	573,041	517,681
Gas plant	1,082,298	1,017,062
Common plant	292,591	281,525
Construction work in progress	279,992	289,604
Total utility plant	10,839,341	10,649,301
Less: Accumulated depreciation and amortization	3,881,726	3,641,448
Net utility plant	6,957,615	7,007,853
Other property and investments	257,145	218,417
Current assets:		
Cash, including temporary cash investments of $223,829 and $114,415, respectively	325,398	153,475
Accounts receivable (less allowance for doubtful accounts of $52,100 and $20,000, respectively) (*Notes 1 and 9*)	373,305	494,503
Materials and supplies, at average cost:		
Coal and oil for production of electricity	20,788	27,509
Gas storage	43,431	26,431
Other	120,914	141,820
Prepaid taxes	11,976	17,239
Other	25,329	22,773
	921,141	883,750
Regulatory assets (*Note 2*):		
Regulatory tax asset	390,994	470,198
Deferred finance charges	239,880	239,880
Deferred environmental restoration costs (*Note 9*)	225,000	225,000
Unamortized debt expense	65,993	92,548
Postretirement benefits other than pensions	60,482	68,933
Other	206,352	204,253
	1,188,701	1,300,812
Other assets	77,428	67,037
	$9,402,030	$9,477,869

The accompanying notes are an integral part of these financial statements

Consolidated Balance Sheets

At December 31,	In thousands of dollars 1996	1995
CAPITALIZATION AND LIABILITIES		
Capitalization (*Note 6*):		
Common stockholders' equity:		
Common stock, issued 144,365,214 and 144,332,123 shares, respectively	$ 144,365	$ 144,332
Capital stock premium and expense	1,783,725	1,784,247
Retained earnings	657,482	585,373
	2,585,572	2,513,952
Non-redeemable preferred stock	440,000	440,000
Mandatorily redeemable preferred stock	86,730	96,850
Long-term debt	3,477,879	3,582,414
Total capitalization	6,590,181	6,633,216
Current liabilities:		
Long-term debt due within one year (*Note 6*)	48,084	65,064
Sinking fund requirements on redeemable preferred stock (*Note 6*)	8,870	9,150
Accounts payable	271,830	268,603
Payable on outstanding bank checks	32,008	36,371
Customers' deposits	15,505	14,376
Accrued taxes	4,216	14,770
Accrued interest	63,252	64,448
Accrued vacation pay	36,436	35,214
Other	52,455	57,748
	532,656	565,744
Regulatory liabilities (*Note 2*):		
Deferred finance charges	239,880	239,880
Other	—	732
	239,880	240,612
Other liabilities:		
Accumulated deferred income taxes (*Notes 1 and 7*)	1,331,913	1,388,799
Employee pension and other benefits (*Note 8*)	238,688	245,047
Deferred pension settlement gain	19,269	32,756
Unbilled revenues (*Note 1*)	49,881	28,410
Other	174,562	118,285
	1,814,313	1,813,297
Commitments and contingencies (*Notes 2 and 9*):		
Liability for environmental restoration	225,000	225,000
	$9,402,030	$9,477,869

The accompanying notes are an integral part of these financial statements

Consolidated Statements of Cash Flows
Increase (Decrease) in Cash

For the year ended December 31,	In thousands of dollars 1996	1995	1994
Cash flows from operating activities:			
Net income	$110,390	$248,036	$176,984
Adjustments to reconcile net income to net cash provided by operating activities:			
Extraordinary item for the discontinuance of regulatory accounting principles, net of income taxes	67,364	—	—
Depreciation and amortization	329,827	317,831	308,351
Amortization of nuclear fuel	38,077	34,295	37,887
Provision for deferred income taxes	(6,870)	114,917	7,866
Electric margin recoverable	—	58,588	(45,428)
Employee reduction program	—	—	196,625
Gain on sale of subsidiary	(15,025)	(11,257)	—
Unbilled revenues	21,471	(71,258)	—
Sale of accounts receivable	—	50,000	—
(Increase) decrease in net accounts receivable	121,198	6,748	(59,145)
Decrease in materials and supplies	2,265	13,663	6,290
Increase (decrease) in accounts payable and accrued expenses	8,224	(47,048)	(5,991)
Decrease in accrued interest and taxes	(11,750)	(35,440)	(19,914)
Changes in other assets and liabilities	35,231	20,930	(6,304)
Net cash provided by operating activities	700,402	700,005	597,221
Cash flows from investing activities:			
Construction additions	(296,689)	(332,443)	(439,289)
Nuclear fuel	(55,360)	(13,361)	(46,134)
Less: Allowance for other funds used during construction	3,665	1,063	2,159
Acquisition of utility plant	(348,384)	(344,741)	(483,264)
Decrease in materials and supplies related to construction	8,362	3,346	5,143
Increase (decrease) in accounts payable and accrued expenses related to construction	2,056	(7,112)	(1,498)
(Increase) decrease in other investments	541	(115,818)	(23,375)
Proceeds from sale of subsidiary (net of cash sold)	14,600	161,087	—
Other	(8,786)	26,234	(17,979)
Net cash used in investing activities	(331,611)	(277,004)	(520,973)
Cash flows from financing activities:			
Proceeds from sale of common stock	—	283	29,514
Proceeds from long-term debt	105,000	346,000	424,705
Issuance of preferred stock	—	—	150,000
Redemption of preferred stock	(10,400)	(10,950)	(33,450)
Reductions of long-term debt	(244,341)	(73,415)	(526,584)
Net change in short-term debt	—	(416,750)	48,734
Dividends paid	(38,281)	(201,246)	(189,733)
Other	(8,846)	(7,778)	(9,455)
Net cash used in financing activities	(196,868)	(363,856)	(106,269)
Net increase (decrease) in cash	171,923	59,145	(30,021)
Cash at beginning of year	153,475	94,330	124,351
Cash at end of year	$325,398	$153,475	$ 94,330
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest	$286,497	$290,352	$300,242
Income taxes	$ 95,632	$ 47,378	$136,876

The accompanying notes are an integral part of these financial statements

NOTE 1. Summary of Significant Accounting Policies

The Company is subject to regulation by the PSC and FERC with respect to its rates for service under a methodology which establishes prices based on the Company's cost. The Company's accounting policies conform to GAAP, as applied to regulated public utilities, and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities (see Note 2). In order to be in conformity with GAAP, management is required to use estimates in the preparation of the Company's financial statements.

Principles of Consolidation: The consolidated financial statements include the Company and its wholly-owned subsidiaries. Intercompany balances and transactions have been eliminated.

Utility Plant: The cost of additions to utility plant and replacements of retirement units of property are capitalized. Cost includes direct material, labor, overhead and AFC. Replacement of minor items of utility plant and the cost of current repairs and maintenance is charged to expense. Whenever utility plant is retired, its original cost, together with the cost of removal, less salvage, is charged accumulated depreciation.

Allowance for Funds Used During Construction: The Company capitalizes AFC in amounts equivalent to the cost of funds devoted to plant under construction. AFC rates are determined in accordance with FERC and PSC regulations. The AFC rate in effect at December 31, 1996 was 9.28%. AFC is segregated into its two components, borrowed funds and other funds, and is reflected in the "Interest charges" and the "Other income and deductions" sections, respectively, of the Consolidated Statements of Income.

Depreciation, Amortization and Nuclear Generating Plant Decommissioning Costs: For accounting and regulatory purposes, depreciation is computed on the straight-line basis using the license lives for nuclear and hydro classes of depreciable property and the average service lives for all other classes. The percentage relationship between the total provision for depreciation and average depreciable property was approximately 3% for the years 1994 through 1996. The Company performs depreciation studies to determine service lives of classes of property and adjusts the depreciation rates when necessary.

Estimated decommissioning costs (costs to remove a nuclear plant from service in the future) for the Company's Unit 1 and its share of Unit 2 are being accrued over the service lives of the units, recovered in rates through an annual allowance and currently charged to operations through depreciation. The Company expects to commence decommissioning of both units shortly after cessation of operations at Unit 2 (currently planned for 2026), using a method which removes or decontaminates Unit components promptly at that time. See Note 3 – "Nuclear Plant Decommissioning."

The FASB issued an exposure draft in February 1996 entitled "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets." The scope of the original project was broadened and would include the Company's fossil and hydro plants, as well as nuclear plants. If approved as drafted, a liability will have to be recognized for these assets whenever a legal or constructive obligation exists to perform dismantlement or removal activities. The recognition of the liability would result in an increase to the cost of the related asset and would be reported based upon discounted future cash flows. Additionally, the exposure draft would allow the Company to establish a regulatory asset for the difference between costs of closure and removal obligations recognized and the costs allowable for rate-making purposes, subject to the provisions of SFAS No. 71. As noted above, the Company currently recognizes the liability for nuclear decommissioning over the service life of the plant as an increase to accumulated depreciation based on amounts allowed in rates. The Company does not reflect the closure and removal obligation associated with its fossil and hydro plants in the financial statements. As such, the annual provisions for depreciation could increase. Under traditional cost based regulation such accounting changes would not have an adverse effect on the results of operations of the Company. However, based on the discontinuation of SFAS No. 71 for the fossil and hydro generating assets associated with this obligation and the issuance of SFAS No. 121 (discussed in Note 2), the Company cannot currently predict the impact this exposure draft may have on the Company's future results of operations, particularly the effect it may have on the fossil and hydro plants. However, adoption of the proposed standard is not expected to impact the cash flow from these assets. The FASB had originally indicated it expected to issue a final standard to be effective for the first quarter of 1998. However, since the expanded scope has been subject to great debate, by the FASB and others, it has been indicated by the FASB the next step for this project may be to issue either a final statement or a revised exposure draft. Therefore, the Company cannot predict when it will be required to implement the requirements of this exposure draft.

Amortization of the cost of nuclear fuel is determined on the basis of the quantity of heat produced for the generation of electric energy. The cost of disposal of nuclear fuel, which presently is $.001 per Kwh of net generation available for sale, is based upon a contract with the DOE. These costs are charged to operating expense and recovered from customers through base rates or through the fuel adjustment clause.

Revenues: Revenues are based on cycle billings rendered to certain customers monthly and others bimonthly for energy consumed and not billed at the end of the fiscal year. At December 31, 1996 and 1995, approximately $11.1 million and $5.2 million, respectively, of

unbilled electric revenues remained unrecognized in results of operations, are included in "Other liabilities" and may be used to reduce future revenue requirements. In 1995, the Company used $71.5 million of electric unbilled revenues to reduce the 1995 revenue requirement. At December 31, 1996 and 1995, $38.8 million and $23.2 million, respectively, of unbilled gas revenues remain unrecognized in results of operations and may similarly be used to reduce future gas revenue requirements. The unbilled revenues included in accounts receivable at December 31, 1996 and 1995, were $218.5 million and $202.7 million, respectively.

The Company's tariffs include electric and gas adjustment clauses under which energy and purchased gas costs, respectively, above or below the levels allowed in approved rate schedules, are billed or credited to customers. The Company, as authorized by the PSC, charges operations for energy and purchased gas cost increases in the period of recovery. The PSC has periodically authorized the Company to make changes in the level of allowed energy and purchased gas costs included in approved rate schedules. As a result of such periodic changes, a portion of energy costs deferred at the time of change would not be recovered or may be overrecovered under the normal operation of the electric and gas adjustment clauses. However, the Company has to date been permitted to defer and bill or credit such portions to customers, through the electric and gas adjustment clauses, over a specified period of time from the effective date of each change.

The Company's electric FAC provides for partial pass-through of fuel and purchased power cost fluctuations from amounts forecast, with the Company absorbing a portion of increases or retaining a portion of decreases up to a maximum of $15 million per rate year. Thereafter, 100% of the fluctuation is passed on to ratepayers. The Company also shares with ratepayers fluctuations from amounts forecast for net resale margin and transmission benefits, with the Company retaining/absorbing 40% and passing 60% through to ratepayers. The amounts retained or absorbed in 1994 through 1996 were not material.

However, in December 1996, the Company and the PSC staff reached a three year settlement agreement that was conditionally approved by the PSC. Such an agreement eliminated the gas adjustment clause and established a gas commodity cost adjustment clause (CCAC). The Company's gas CCAC provides for the collection of certain increases or decreases from the base commodity cost of gas. To determine the amount to be recovered from or passed on to customers, a performance target was established against which to measure gas purchases, known as the commodity cost index. The performance target was set at 97% of the typical market price. If actual gas purchases fall between 96% – 98% of the typical market price, then ratepayers will receive all benefits or bear the burdens of costs within this range. If actual gas purchases fall below 96% or are above 98% of the typical market price, then ratepayers and shareholders will share on an equal basis any differences between actual and targeted performance, subject to the limitation that the maximum annual risk or benefit to the Company is $2.25 million. All savings and excess costs beyond that amount will flow to ratepayers. For a discussion of the ratemaking associated with non-commodity gas costs, see Management's Discussion and Analysis of Financial Condition and Results of Operations – Other Federal and State Regulatory Initiatives – "Multi-Year Gas Rate Settlement Agreement."

The Company's *PowerChoice* proposal, which the Company filed in October 1995 as part of its multi-year electric rate proceeding, proposed to eliminate all surcharges, including the FAC and remaining NERAM and MERIT surcharges.

Allowance for Doubtful Accounts: The allowance for doubtful accounts receivable on the consolidated balance sheets amounted to $52.1 million and $20.0 million at December 31, 1996 and 1995, respectively. The net increase in the allowance for doubtful accounts reflects the implementation of the risk assessment methodology that puts more emphasis on past due balances. Previously, the Company's allowance for doubtful accounts followed regulatory practice and consequently focused on final billed accounts only (typically accounts that are no longer active).

Federal Income Taxes: As directed by the PSC, the Company defers any amounts payable pursuant to the alternative minimum tax rules. Deferred investment tax credits are amortized to "Other income and deductions" over the useful life of the underlying property.

Statement of Cash Flows: The Company considers all highly liquid investments, purchased with a remaining maturity of three months or less, to be cash equivalents.

Reclassifications: Certain amounts from prior years have been reclassified on the accompanying Consolidated Financial Statements to conform with the 1996 presentation.

NOTE 2. Rate and Regulatory Issues and Contingencies

The Company's financial statements conform to GAAP, as applied to regulated public utilities and reflect the application of SFAS No. 71, with the exception of the Company's non-nuclear generation business. Substantively, SFAS No. 71 permits a public utility regulated on a cost-of-service basis to defer certain costs when authorized to do so by the regulator which would otherwise be charged to expense. These deferred costs are known as regulatory assets, which in the case of the Company are approximately $949 million, net of approximately $240 million of regulatory liabilities at December 31, 1996. These regulatory assets are probable of recovery. The portion of the $949 million which has been allocated to the nuclear generation and electric transmission and distribution business is approximately $774 million, which are net of approximately $240 million of regulatory liabilities. Regulatory assets allocated to the rate-regulated gas distribution business are $175 million. Generally, regulatory assets and liabilities were allocated to the portion of the

business that incurred the underlying transaction that resulted in the recognition of the regulatory asset or liability. The allocation methods used between electric and gas are consistent with those used in prior regulatory proceedings.

The Company has concluded that the termination or restructuring of IPP contracts and implementation of *PowerChoice*, or a similar proposal, is the probable outcome of negotiations that have taken place over the past 18 months. Under *PowerChoice*, the separated non-nuclear generation business will no longer be rate-regulated on a cost-of-service basis and, accordingly, existing regulatory assets related to the non-nuclear power generation business, amounting to approximately $103.6 million ($67.4 million after tax or 47 cents per share) at December 31, 1996, have been charged against income as an extraordinary non-cash charge.

Of the remaining electric business, under *PowerChoice*, the Company expects that its nuclear generation and electric transmission and distribution business continue to be rate-regulated on a cost-of-service basis and, accordingly, the Company will continue to apply SFAS No. 71 to these businesses.

PowerChoice and the termination or restructuring costs of IPP contracts will result in rates that reflect reduced or stable costs that the Company believes meet the Governor's stated economic objectives as to energy prices in New York State as well as the PSC's objectives (see Management's Discussion and Analysis of Financial Condition and Results of Operations – "PSC Competitive Opportunities Proceeding – Electric"). Therefore, the Company expects the PSC to continue to apply the concept of cost-of-service based rates to the nuclear generation and transmission and distribution business. The Company expects that these cost-of-service based rates can be charged to and collected from customers without unanticipated reduction in demand. The Company proposes, and believes it is probable that the PSC will approve, deferral and recovery of the termination or restructuring costs of IPP contracts over a period not to exceed ten years. To the extent that recovery of the termination or restructuring cost is not approved by the PSC, that amount would be charged to expense, which could have a material adverse effect on the financial condition and results of operations of the Company. Furthermore, the Company does not expect the PSC to provide a return on the regulatory asset associated with IPP termination or restructuring costs. SFAS No. 71 does not require the Company to earn a return on regulatory assets in assessing its applicability. The Company believes that the prices it will charge for electric service, including a non-bypassable transition charge, over the ten-year period will be sufficient to recover the regulatory asset for the termination or restructuring costs of IPP contracts and provide recovery of and a return on the remainder of its regulated assets, as appropriate. The Company expects that the reported amounts of future net income will be adversely affected by a lack of a return on the regulatory asset and expected lower returns of the unregulated non-nuclear generating business.

The Company has been made aware of a recent request of the SEC Chief Accountant to the Public Utilities Committee of the American Institute of Certified Public Accountants to develop guidance on applying SFAS No. 101. It is the Company's understanding that the guidance may include when to discontinue SFAS No. 71, as well as the accounting applicable to recovering strandable costs on the transmission and distribution business that originate from generation assets. The Company cannot predict whether and when such guidance will be issued or the attendant consequences on the Company's financial condition or results of operations.

The Company adopted SFAS No. 121 in 1996. This Statement requires that long-lived assets and certain identifiable intangibles held and used by an entity be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. In performing the review for recoverability, the Company is required to estimate future undiscounted cash flows expected to result from the use of the asset and its eventual disposition.

With the probable implementation of *PowerChoice*, specifically the separation of non-nuclear generation as an entity that will face market prices, the Company is required to assess the carrying amounts of its long-lived assets in accordance with SFAS No. 121. The Company has determined that there is no impairment of its non-nuclear generating assets. In certain instances, the Company has considered opportunities to invest in changes in fuel sources that are technologically available, to improve cash flow. In one instance, the Company has considered the value of relocating a unit to a region where demand is greater. To the extent an impairment loss cannot be otherwise avoided, the Company believes it will be able to recover the loss through a non-bypassable transition fee proposed in *PowerChoice*. In reaching conclusions as to impairment of non-nuclear generating assets, the Company must make significant estimates and judgments as to the future price of electricity, capacity factors and cost of operation of each of its generating units and, where necessary, the fair market value of each unit. As *PowerChoice* is implemented and generation markets become open to competition, these estimates and judgments may change. An update of the SFAS No. 121 assessment must be prepared when conditions occur which in the opinion of management may have impaired the value of these assets.

As described in Management's Discussion and Analysis of Financial Condition and Results of Operations – "Announced Agreement-in-Principle to Terminate or Restructure 44 IPP Contracts," the conclusion of the termination or restructuring of IPP contracts, as well as implementation of *PowerChoice*, is subject to a number of contingencies. In the event the Company is unable to successfully bring these events to conclusion, it would pursue a traditional rate request. However, notwithstanding such a rate request, it is likely that application of SFAS No. 71 would be discontinued. The resulting after-tax charges against income, based on regulatory assets associated with the nuclear generation and transmission and distribution businesses as of December 31, 1996, would be approximately $503.2 million or $3.48 per share. Various requirements under applicable law and regulations and under corporate instruments, including those with respect

to issuance of debt and equity securities, payment of common and preferred dividends, the continued availability of the Company's senior debt facility and certain types of transfers of assets could be adversely impacted by any such write-downs.

The Company has recorded the following regulatory assets on its Consolidated Balance Sheets reflecting the rate actions of its regulators:

Regulatory tax asset represents the expected future recovery from ratepayers of the tax consequences of temporary differences between the recorded book bases and the tax bases of assets and liabilities. This amount is primarily timing differences related to depreciation. These amounts are amortized and recovered as the related temporary differences reverse. In January 1993, the PSC issued a Statement of Interim Policy on Accounting and Ratemaking Procedures that required adoption of SFAS No. 109 on a revenue-neutral basis.

Deferred finance charges represent the deferral of the discontinued portion of AFC related to CWIP at Unit 2 which was included in rate base. In 1985, pursuant to PSC authorization, the Company discontinued accruing AFC on CWIP for which a cash return was being allowed. This amount, which was accumulated in deferred debit and credit accounts up to the commercial operation date of Unit 2, awaits future disposition by the PSC. A portion of the deferred credit could be utilized to reduce future revenue requirements over a period shorter than the life of Unit 2, with a like amount of deferred debit amortized and recovered in rates over the remaining life of Unit 2.

Deferred environmental restoration costs represent the Company's share of the estimated minimum costs to investigate and perform certain remediation activities at both Company-owned sites and non-owned sites with which it may be associated. The Company has recorded a regulatory asset representing the remediation obligations to be recovered from ratepayers. See Note 9 – "Environmental Contingencies."

Unamortized debt expense represents the costs to issue and redeem certain long-term debt securities which were retired prior to maturity. These amounts are amortized as interest expense ratably over the lives of the related issues in accordance with PSC directives.

Postretirement benefits other than pensions represent the excess of such costs recognized in accordance with SFAS No. 106 over the amount received in rates. In accordance with the PSC policy statement, postretirement benefit costs other than pensions are being phased-in to rates over a five-year period and amounts deferred will be amortized and recovered over a period not to exceed 20 years.

Substantially all of the Company's regulatory assets described above are being amortized to expense and recovered in rates over periods approved in the Company's 1995 or 1996 electric and gas rate cases, respectively.

NOTE 3. Nuclear Operations

The Company is the owner and operator of the 613 MW Unit 1 and the operator and a 41% co-owner of the 1,142 MW Unit 2. The remaining ownership interests are Long Island Lighting Company (LILCO) – 18%, New York State Electric and Gas Corporation (NYSEG) – 18%, Rochester Gas and Electric Corporation (RG&E) – 14%, and Central Hudson Gas and Electric Corporation (Central Hudson) – 9%. Unit 1 was placed in commercial operation in 1969 and Unit 2 in 1988.

Unit 1 Status: In 1995, Unit 1 was taken out of service for a 56 day planned refueling and maintenance outage. Using the net design electric rating as a basis, Unit 1's capacity factor for 1996 was approximately 86.8%. Using NRC guidelines, which reflect net maximum dependable capacity during the most restrictive seasonal conditions, Unit 1's capacity factor was approximately 94.2%.

On March 3, 1997, Unit 1 was taken out of service for a 35 day planned refueling and maintenance outage. Owners of older General Electric Co. boiling water reactors, including the Company, have experienced cracking near welds in the plants' core shrouds. In response to industry findings, the Company installed modifications in the Unit 1 core shroud during a 1995 refueling and maintenance outage.

Inspections conducted as part of the March 1997 refueling and maintenance outage detected cracking in areas not directly reinforced by the 1995 repairs, which may require additional core shroud modifications. Preliminary analysis indicates the Company may be able to restart the reactor from the current refueling and maintenance outage without a significant extension of the outage duration. Additional modifications, if required, would be installed during a mid-cycle outage or as part of Unit 1's next refueling and maintenance outage (February, 1999). If modifications are required before the restart of Unit 1 from the current refueling and maintenance outage, a 2-3 month extension of the outage would be anticipated. The Company's action plan on this issue requires consent from the NRC.

Unit 2 Status: In 1995, Unit 2 was taken out of service for a 56 day planned refueling and maintenance outage. On September 28, 1996, Unit 2 was taken out of service for a planned refueling and maintenance outage and returned to service on November 2, 1996. Its next refueling and maintenance outage is scheduled for Spring 1998. Using the net design electric rating as a basis, Unit 2's capacity factor for 1996 was approximately 86.6%. Using NRC guidelines as described above, Unit 2's capacity factor was approximately 89.6%.

Nuclear Plant Decommissioning: The Company's site specific cost estimates for decommissioning Unit 1 and its ownership interest in Unit 2 at December 31, 1996 are as follows:

	Unit 1	Unit 2
Site Study (year)	1995	1995
End of Plant Life (year)	2009	2026
Radioactive Dismantlement to Begin (year)	2026	2028
Method of Decommissioning	Delayed Dismantlement	Immediate Dismantlement
Cost of Decommissioning (in Jan 1997 dollars)	*In millions of dollars*	
Radioactive Components	$474	$194
Non-radioactive Components	117	46
Fuel Dry Storage/Continuing Care	101	41
	$692	$281

The Company estimates that by the time decommissioning is completed, the above costs will ultimately amount to $1.8 billion and $.9 billion for Unit 1 and Unit 2, respectively, using approximately 3.5% as an annual inflation factor.

In addition to the costs mentioned above, the Company expects to incur post-shutdown costs for plant rampdown, insurance and property taxes. In 1997 dollars, these costs are expected to amount to $110 million and $61 million for Unit 1 and the Company's share of Unit 2, respectively. The amounts will escalate to $192 million and $190 million for Unit 1 and the Company's share of Unit 2, respectively.

NRC regulations require owners of nuclear power plants to place funds into an external trust to provide for the cost of decommissioning radioactive portions of nuclear facilities and establish minimum amounts that must be available in such a trust at the time of decommissioning. The annual allowance for Unit 1 and the Company's share of Unit 2 for the years ended December 31, 1996, 1995 and 1994 was approximately $23.7 million, $23.7 million and $18.7 million, respectively. The amounts for 1996 and 1995 were based upon the 1993 NRC minimum decommissioning cost requirements of $422 million and $191 million (in 1997 dollars) for Unit 1 and the Company's share of Unit 2, respectively. The amounts for 1994 were based upon site studies performed in 1989. In the 1995 rate order, the Company was authorized, until the PSC orders otherwise, to continue to fund to the NRC minimum requirements. In the 1997 rate filing, the Company has requested, for both units, rate recovery for all radioactive and non-radioactive components (including post-shutdown costs) based upon the amounts estimated in the 1995 site specific studies described above. There is no assurance that the decommissioning allowance recovered in rates will ultimately aggregate a sufficient amount to decommission the units. The Company believes that if decommissioning costs are higher than currently estimated, the costs would ultimately be included in the rate process under traditional ratemaking or *PowerChoice.*

Decommissioning costs recovered in rates are reflected in "Accumulated depreciation and amortization" on the balance sheet and amount to $217.7 million and $183.4 million at December 31, 1996 and 1995, respectively for both Units. Additionally at December 31, 1996, the fair value of funds accumulated in the Company's external trusts were $136.5 million for Unit 1 and $38.7 million for its share of Unit 2. The trusts are included in "Other property and investments." Earnings on the external trust aggregated $28.8 million through December 31, 1996 and, because the earnings are available to fund decommissioning, have also been included in "Accumulated depreciation and amortization." Amounts recovered for non-radioactive dismantlement are accumulated in an internal reserve fund which has an accumulated balance of $42.5 million at December 31, 1996.

The FASB issued an exposure draft in February 1996 on accounting for closure and removal of long-lived assets. See Note 1 – "Depreciation, Amortization and Nuclear Generating Plant Decommissioning Costs."

NRC Draft Policy Statement: In September 1996, the NRC issued a draft policy statement on the Restructuring and Economic Deregulation of the Electric Utility Industry (Draft Policy Statement). The Draft Policy Statement addresses NRC's concerns about the adequacy of decommissioning funds and about the potential impact on operational safety. Current NRC regulations allow a utility to set aside decommissioning funds annually over the estimated life of a plant.

The policy statement declares the NRC will:

- Continue to conduct reviews of financial qualifications, decommissioning funding and antitrust requirements of nuclear power plants;
- Establish and maintain working relationships with state and federal rate-regulators;
- Evaluate the relative responsibilities of power plant co-owners and co-licensees; and
- Re-evaluate the adequacy of current regulations in light of economic and other changes resulting from rate deregulation.

In addition, the Draft Policy Statement stresses that no license may be transferred without prior written approvals from the NRC. Prior written approvals are also required for mergers, formation of holding companies or the sale of facilities, including a partial sale.

The Company participated in comments filed by the Utility Decommissioning Group in December 1996 in response to the Draft Policy Statement. As noted therein, the Company agrees with the NRC's views that the existing regulatory framework provides reasonable assurance of the financial qualifications of both electric utility and non-electric utility applicants and licensees. However, the Company does not agree with the suggestion in the Draft Policy Statement that a licensee who fails to meet the current definition of "electric utility," which might occur as a result of rate deregulation, must satisfy the more stringent decommissioning funding assurance requirements applicable to non-electric utilities. These requirements prohibit a non-electric utility licensee from funding decommissioning on a "pay-as-you-go" basis using an external trust. In this regard, the Company encouraged the NRC to consider whether the definition of "electric utility" continues

to be the appropriate test of whether a licensee should be exempt from up-front decommissioning or instead, a test that takes into consideration all relevant factors of the licensee.

In addition, the Company stated its concern that the Draft Policy Statement suggested that power reactor licensees are "joint owners," which implies that the NRC may seek to impose joint and several liability on co-owners for decommissioning funding obligations. The Company stressed that co-owners of nuclear power plants are not joint owners, and as such are not jointly and severally liable. The Company is unable to predict the outcome of this matter.

Nuclear Liability Insurance: The Atomic Energy Act of 1954, as amended, requires the purchase of nuclear liability insurance from the Nuclear Insurance Pools in amounts as determined by the NRC. At the present time, the Company maintains the required $200 million of nuclear liability insurance.

In 1993, the statutory limit for the protection of the public under the Price-Anderson Amendments Act of 1988 were further increased. With respect to a nuclear incident at a licensed reactor, the statutory limit, which is in excess of the $200 million of nuclear liability insurance, is currently $8.3 billion without the 5% surcharge discussed below. This limit would be funded by assess-ments of up to $75.5 million for each of the 110 presently licensed nuclear reactors in the United States, payable at a rate not to exceed $10 million per reactor per year. Such assessments are subject to periodic inflation indexing and to a 5% surcharge if funds prove insufficient to pay claims. With the 5% surcharge included, the statutory limit is $8.7 billion.

The Company's interest in Units 1 and 2 could expose it to a maximum potential loss, for each accident, of $111.8 million (with 5% assessment) through assessments of $14.1 million per year in the event of a serious nuclear accident at its own or another licensed U.S. commercial nuclear reactor. The amendments also provide, among other things, that insurance and indemnity will cover precautionary evacuations, whether or not a nuclear incident actually occurs.

Nuclear Property Insurance: The Nine Mile Point Nuclear Site has $500 million primary nuclear property insurance with the Nuclear Insurance Pools (ANI/MRP). In addition, there is $2,250 million in excess of the $500 million primary nuclear insurance with Nuclear Electric Insurance Limited (NEIL). The total nuclear property insurance is $2.75 billion. NEIL also provides insurance coverage against the extra expense incurred in purchasing replacement power during prolonged accidental outages. The insurance provides coverage for outages for 156 weeks, after a 21-week waiting period. NEIL insurance is subject to retrospective premium adjustment under which the Company could be assessed up to approximately $12.7 million per loss.

Low Level Radioactive Waste: The Company currently uses the Barnwell, South Carolina waste disposal facility for low level radioactive waste, however, access to Barnwell was denied by the State of South Carolina to out of region low level waste generators, including New York State from July 1, 1994 to July 1, 1995. The Company also has implemented a low level radioactive waste management program so that Unit 1 and Unit 2 are prepared to properly handle interim on-site storage of low level radioactive waste for at least a 10 year period.

Under the Federal Low Level Waste Policy Amendment Act of 1985, New York State was required, by January 1, 1993 to have arranged for the disposal of all low level radioactive waste within the state or in the alternative, contracted for the disposal at a facility outside the state. New York State has made no funding available currently, to support siting for a disposal facility.

Nuclear Fuel Disposal Cost: In January 1983, the Nuclear Waste Policy Act of 1982 (the Nuclear Waste Act) established a cost of $.001 per Kwh of net generation for current disposal of nuclear fuel and provides for a determination of the Company's liability to the DOE for the disposal of nuclear fuel irradiated prior to 1983. The Nuclear Waste Act also provides three payment options for liquidating such liability and the Company has elected to delay payment, with interest, until the year in which the Company initially plans to ship irradiated fuel to an approved DOE disposal facility. Progress in developing the DOE facility has been slow and it is anticipated that the DOE facility will not be ready to accept deliveries until at least 2010. However, in July 1996, the United States Circuit Court of Appeals for the District of Columbia ruled that the DOE must begin accepting used fuel from the nuclear industry by 1998 even though a permanent storage site will not be ready by then. The DOE did not appeal this decision. The DOE's anticipatory breach of this contract will likely involve further legal proceedings. The Company is unable to determine the outcome of this matter.

The Company does not anticipate that the DOE will accept all of its spent fuel immediately upon opening of the facility, but rather expects a transfer period that will extend to the year 2044. The Company has several alternatives under consideration to provide additional storage facilities, as necessary. Each alternative will likely require NRC approval, may require other regulatory approvals and would likely require incurring additional costs, which the Company has included in its decommissioning estimates for both Unit 1 and its share of Unit 2. The Company does not believe that the possible unavailability of the DOE disposal facility until 2010 will inhibit operation of either Unit.

NOTE 4. Jointly-Owned Generating Facilities

The following table reflects the Company's share of jointly-owned generating facilities at December 31, 1996. The Company is required to provide its respective share of financing for any additions to the facilities. Power output and related expenses are shared based on proportionate ownership. The Company's share of expenses associated with these facilities is included in the appropriate operating expenses in the Consolidated Statements of Income.

		In thousands of dollars		
	Percentage Ownership	Utility Plant	Accumulated Depreciation	Construction Work in Progress
Roseton Steam Station				
Units No. 1 & 2 *(a)*...	25	$ 96,458	$ 51,449	$ 540
Oswego Steam Station				
Unit No. 6 *(b)*.....	76	$ 270,136	$116,648	$ 299
Nine Mile Point Nuclear Station				
Unit No. 2 *(c)*.....	41	$1,508,898	$297,922	$8,825

(a) The remaining ownership interests are Central Hudson, the operator of the plant (35%), and Consolidated Edison Company of New York, Inc. (40%). Output of Roseton Units No. 1 and 2, which have a capability of 1,200,000 Kw., is shared in the same proportions as the cotenants' respective ownership interests.

(b) The Company is the operator. The remaining ownership interest is RG&E (24%). Output of Oswego Unit No. 6, which has a capability of 850,000 Kw., is shared in the same proportions as the cotenants' respective ownership interests.

(c) The Company is the operator. The remaining ownership interests are LILCO (18%), NYSEG (18%), RG&E (14%), and Central Hudson (9%). Output of Unit 2, which has a capability of 1,143,000 Kw., is shared in the same proportions as the cotenants' respective ownership interests. On December 30, 1996, LILCO and Brooklyn Union Gas agreed to a merger that would create a new utility. It would take effect in 12 to 18 months if endorsed by the stockholders of both companies and by state and federal regulatory agencies. The new company would retain its 18% ownership interest in Unit 2.

NOTE 5. Bank Credit Arrangements

During March 1996, the Company completed an $804 million senior debt facility with a bank group for the purposes of consolidating and refinancing certain of the Company's existing working capital lines of credit and letter of credit facilities and providing additional reserves of bank credit. This senior debt facility will enhance the Company's financial flexibility during the period 1996 through June 1999. The senior debt facility consists of a $255 million term loan facility, a $125 million revolving credit facility and $424 million for letters of credit. The letter of credit facility provides credit support for the adjustable rate pollution control revenue bonds issued through the NYSERDA discussed in Note 6. As of December 31, 1996, the amount outstanding under the senior debt facility was $542 million, consisting of $105 million under the term loan facility, a $424 million letter of credit and a $13 million letter of credit under the revolving credit facility, leaving the Company with $262 million of borrowing capability under the facility. The facility expires on June 30, 1999 (subject to earlier termination upon the implementation of the Company's *PowerChoice* proposal or any other significant restructuring plan). The interest rate applicable to the facility is variable based on certain rate options available under the agreement and currently approximates 7.38% (but capped at 15%).

The Company did not have any short-term debt outstanding at December 31, 1996 and December 31, 1995. For the year ended December 31, 1995, the daily average outstanding short-term debt was $179.5 million, the monthly weighted average interest rate was 6.43% and the maximum amount of short-term debt outstanding was $459.7 million. Comparable amounts for 1996 were not material.

NOTE 6. Capitalization

Capital Stock

The Company is authorized to issue 185,000,000 shares of common stock, $1 par value; 3,400,000 shares of preferred stock, $100 par value; 19,600,000 shares of preferred stock, $25 par value; and 8,000,000 shares of preference stock, $25 par value. The table below summarizes changes in the capital stock issued and outstanding and the related capital accounts for 1994, 1995 and 1996:

	Common Stock $1 par value		Preferred Stock						Capital Stock Premium and Expense (Net)*
			$100 par value			$25 par value			
	Shares	Amount*	Shares	Non-Redeemable*	Redeemable*	Shares	Non-Redeemable*	Redeemable*	
December 31, 1993:	142,427,057	$142,427	2,394,000	$210,000	$29,400 *(a)*	8,040,005	$ 80,000	$121,000 *(a)*	$1,762,706
Issued	1,884,409	1,884	—	—	—	6,000,000	150,000	—	27,630
Redemptions			(18,000)	—	(1,800)	(1,266,000)	—	(31,650)	(4,619)
Foreign currency translation adjustment									(6,213)
December 31, 1994:	144,311,466	$144,311	2,376,000	$210,000	$27,600 *(a)*	12,774,005	$230,000	$ 89,350 *(a)*	$1,779,504
Issued	20,657	21	—	—	—	—	—	—	283
Redemptions			(18,000)	—	(1,800)	(366,000)	—	(9,150)	1,319
Foreign currency translation adjustment									3,141
December 31, 1995:	144,332,123	$144,332	2,358,000	$210,000	$25,800 *(a)*	12,408,005	$230,000	$ 80,200 *(a)*	$1,784,247
Issued	33,091	33	—	—	—	—	—	—	214
Redemptions			(18,000)	—	(1,800)	(344,000)	—	(8,600)	(28)
Foreign currency translation adjustment									(708)
December 31, 1996:	144,365,214	$144,365	2,340,000	$210,000	$24,000 *(a)*	12,064,005	$230,000	$ 71,600 *(a)*	$1,783,72[illegible]

* *In thousands of dollars*

(a) Includes sinking fund requirements due within one year.

The cumulative amount of foreign currency translation adjustment at December 31, 1996 was $(10,880).

Non-Redeemable Preferred Stock (Optionally Redeemable)

The Company has certain issues of preferred stock which provide for optional redemption at December 31, as follows:

Series	Shares	*In thousands of dollars* 1996	1995	Redemption price per share *(Before adding accumulated dividends)*
Preferred $100 par value:				
3.40%	200,000	$ 20,000	$ 20,000	$103.50
3.60%	350,000	35,000	35,000	104.85
3.90%	240,000	24,000	24,000	106.00
4.10%	210,000	21,000	21,000	102.00
4.85%	250,000	25,000	25,000	102.00
5.25%	200,000	20,000	20,000	102.00
6.10%	250,000	25,000	25,000	101.00
7.72%	400,000	40,000	40,000	102.36
Preferred $25 par value:				
9.50%	6,000,000	150,000	150,000	25.00 *(a)*
Adjustable Rate —				
Series A	1,200,000	30,000	30,000	25.00
Series C	2,000,000	50,000	50,000	25.00
		$440,000	$440,000	

(a) Not redeemable until 1999.

Mandatorily Redeemable Preferred Stock

At December 31, the Company has certain issues of preferred stock, as detailed below, which provide for mandatory and optional redemption. These series require mandatory sinking funds for annual redemption and provide optional sinking funds through which the Company may redeem, at par, a like amount of additional shares (limited to 120,000 shares of the 7.45% series). The option to redeem additional amounts is not cumulative. The Company's five year mandatory sinking fund redemption requirements for preferred stock, in thousands, for 1997 through 2001 are as follows: $8,870; $10,120; $7,620; $7,620; and $7,620, respectively. The aggregate preference of preferred shares upon involuntary liquidation of the Company is the aggregate par value of such shares, plus an amount equal to the dividends accumulated and unpaid on such shares to the date of payment whether or not earned or declared.

	Shares		*In thousands of dollars*		Redemption price per share *(Before adding accumulated dividends)*	
Series	1996	1995	1996	1995	1996	Eventual minimum
Preferred $100 par value:						
7.45%	240,000	258,000	$ 24,000	$ 25,800	$101.93	$100.00
Preferred $25 par value:						
7.85%	914,005	914,005	22,850	22,850	*(a)*	25.00
8.375%	200,000	300,000	5,000	7,500	25.11	25.00
9.75%	—	144,000	—	3,600	25.00	25.00
Adjustable Rate – Series B	1,750,000	1,850,000	43,750	46,250	25.00	25.00
			95,600	106,000		
Less sinking fund requirements			8,870	9,150		
			$ 86,730	$96,850		

(a) Not redeemable until 1997.

Long-Term Debt

Long-term debt at December 31, consisted of the following:

		In thousands of dollars			*In thousands of dollars*	
Series	Due	1996	1995	Series	1996	1995
First mortgage bonds:				**Promissory notes:**		
5 7/8%	1996	$ —	$ 45,000	*Adjustable Rate Series due		
6 1/4%	1997	40,000	40,000	July 1, 2015	100,000	100,000
6 1/2%	1998	60,000	60,000	December 1, 2023	69,800	69,800
9 1/2%	2000	150,000	150,000	December 1, 2025	75,000	75,000
6 7/8%	2001	210,000	210,000	December 1, 2026	50,000	50,000
9 1/4%	2001	100,000	100,000	March 1, 2027	25,760	25,760
5 7/8%	2002	230,000	230,000	July 1, 2027	93,200	93,200
6 7/8%	2003	85,000	85,000	**Term Loan Agreement**	105,000	—
7 3/8%	2003	220,000	220,000	**Unsecured notes payable:**		
8%	2004	300,000	300,000	Medium Term Notes,		
6 5/8%	2005	110,000	110,000	Various rates, due 1996-2004	20,000	30,000
9 3/4%	2005	150,000	150,000	Revolving Credit Agreement	—	170,000
7 3/4%	2006	275,000	275,000	Other	156,606	159,198
*6 5/8%	2013	45,600	45,600	Unamortized premium (discount)	(10,708)	(11,785)
9 1/2%	2021	150,000	150,000	**TOTAL LONG-TERM DEBT**	3,525,963	3,647,478
8 3/4%	2022	150,000	150,000	Less long-term debt due within one year	48,084	65,064
8 1/2%	2023	165,000	165,000			
7 7/8%	2024	210,000	210,000		$3,477,879	$3,582,414
*8 7/8%	2025	75,000	75,000			
*7.2%	2029	115,705	115,705			
Total First Mortgage Bonds		2,841,305	2,886,305			

**Tax-exempt pollution control related issues*

Several series of First Mortgage Bonds and Notes were issued to secure a like amount of tax-exempt revenue bonds issued by NYSERDA. Approximately $414 million of such securities bear interest at a daily adjustable interest rate (with a Company option to convert to other rates, including a fixed interest rate which would require the Company to issue First Mortgage Bonds to secure the debt) which averaged 3.46% for 1996 and 3.82% for 1995 and are supported by bank direct pay letters of credit. Pursuant to agreements between NYSERDA and the Company, proceeds from such issues were used for the purpose of financing the construction of certain pollution control facilities at the Company's generating facilities or to refund outstanding tax-exempt bonds and notes (see Note 5).

Other long-term debt in 1996 consists of obligations under capital leases of approximately $33.1 million, a liability to the DOE for nuclear fuel disposal of approximately $108.6 million and a liability for IPP contract terminations of approximately $14.9 million.The aggregate maturities of long-term debt for the five years subsequent to December 31, 1996, including capital leases, in millions, are approximately $45, $64, $108, $158 and $310, respectively.

NOTE 7. Federal and Foreign Income Taxes

See Note 9 – "Tax Assessments."

Components of United States and foreign income before income taxes:

	In thousands of dollars		
	1996	1995	1994
United States	$269,128	$400,087	$291,501
Foreign	28,522	17,609	15,475
Consolidating eliminations	(17,402)	(10,267)	(18,523)
Income before extraordinary item and income taxes	$280,248	$407,429	$288,453

Following is a summary of the components of Federal and foreign income tax and a reconciliation between the amount of Federal income tax expense reported in the Consolidated Statements of Income and the computed amount at the statutory tax rate:

	In thousands of dollars		
	1996*	1995	1994
Components of Federal and foreign income taxes:			
Current tax expense: Federal	$103,254	$ 67,563	$117,314
Foreign	3,708	3,900	4,423
	106,962	71,463	121,737
Deferred tax expense: Federal	(2,071)	82,323	(6,931)
Foreign	692	2,222	3,028
	(1,379)	84,545	(3,903)
Income taxes included in Operating Expenses	105,583	156,008	117,834
Current Federal and foreign income tax credits included in Other Income and Deductions	(7,243)	(197)	(11,507)
Deferred Federal and foreign income tax expense included in Other Income and Deductions	4,154	3,582	5,142
Total	$102,494	$159,393	$111,469
Reconciliation between Federal and foreign income taxes and the tax computed at prevailing U.S. statutory rate on income before income taxes:			
Computed tax	$98,087	$142,601	$100,959
Increase (reduction) attributable to flow-through of certain tax adjustments:			
Depreciation	28,103	31,033	33,328
Cost of removal	(8,849)	(9,247)	(8,908)
Deferred investment tax credit amortization	(8,018)	(8,589)	(8,018)
Other	(6,829)	3,595	(5,892)
	4,407	16,792	10,510
Federal and foreign income taxes	$102,494	$159,393	$111,469

At December 31, the deferred tax liabilities (assets) were comprised of the following:

	In thousands of dollars	
	1996	1995
Alternative minimum tax	$ (64,313)	$ (82,869)
Unbilled revenue	(83,577)	(77,675)
Other	(237,850)	(248,275)
Total deferred tax assets	(385,740)	(408,819)
Depreciation related	1,433,907	1,456,949
Investment tax credit related	84,294	91,458
Other	199,452	249,211
Total deferred tax liabilities	1,717,653	1,797,618
Accumulated deferred income taxes	$1,331,913	$1,388,799

* Does not include the deferred tax benefit of $36,273 associated with the extraordinary item for the discontinuance of regulatory accounting principles.

NOTE 8. Pension and Other Retirement Plans

The Company and certain of its subsidiaries have non-contributory, defined-benefit pension plans covering substantially their employees. Benefits are based on the employee's years of service and compensation level. The Company's general policy is to fund the pension costs accrued with consideration given to the maximum amount that can be deducted for Federal income tax purposes.

During 1994, the Company offered an early retirement program and a voluntary separation program (together the VERP) to reduce the Company's staffing levels and streamline operations. The VERP, which included both represented and non-represented employees, was accepted by approximately 1,400 employees. The program cost the Company approximately $208 million of which $11.4 million, related to the gas business, was deferred with recovery anticipated to occur over a five year period, beginning in 1995.

Net pension cost for 1996, 1995 and 1994 included the following components:

	In thousands of dollars		
	1996	1995	1994
Service cost — benefits earned during the period	$ 25,000	$ 22,500	$ 30,400
Interest cost on projected benefit obligation	71,700	73,000	62,700
Actual return on plan assets	(134,100)	(215,600)	7,700
Net amortization and deferral	55,700	140,300	(63,600)
Net pension cost	18,300	20,200	37,200
VERP costs	—	—	114,000
Regulatory asset	—	—	(6,200)
Total pension cost *(1)*	$ 18,300	$ 20,200	$145,000

(1) $3.8 million for 1996, $4.1 million for 1995 and $5.9 million for 1994 was related to construction labor and, accordingly, was charged to construction projects.

The following table sets forth the plan's funded status and amounts recognized in the Company's Consolidated Balance Sheets:

	In thousands of dollars	
December 31,	1996	1995
Actuarial present value of accumulated benefit obligations:		
Vested benefits	$ 803,202	$ 777,584
Non-vested benefits	83,107	64,383
Accumulated benefit obligations	886,309	841,967
Additional amounts related to projected pay increases	141,472	135,115
Projected benefits obligation for service rendered to date	1,027,781	977,082
Plan assets at fair value, consisting primarily of listed stocks, bonds, other fixed income obligations and insurance contracts	(1,159,822)	(1,074,333)
Plan assets in excess of projected benefit obligations	(132,041)	(97,251)
Unrecognized net obligation at January 1, 1987 being recognized over approximately 19 years	(22,005)	(21,500)
Unrecognized net gain from actual return on plan assets different from that assumed	219,680	198,035
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions amortized over 10 years	66,129	46,982
Prior service cost not yet recognized in net periodic pension cost	(49,651)	(41,291)
Pension liability included in the consolidated balance sheets	$ 82,112	$ 84,975
Principle Actuarial Assumptions (%):		
Discount Rate	7.50	7.50
Rate of increase in future compensation levels (plus merit increases)	2.50	2.50
Long-term rate of return on plan assets	9.25	9.25

In addition to providing pension benefits, the Company and its subsidiaries provide certain health care and life insurance benefits for active and retired employees and dependents. Under current policies, substantially all of the Company's employees may be eligible for continuation of some of these benefits upon normal or early retirement.

The Company accounts for the cost of these benefits in accordance with PSC policy requirements which generally comply with SFAS No. 106. The Company has established various trusts to fund its future postretirement benefit obligation. In 1996, 1995 and 1994, the Company made contributions to such trusts of approximately $28.5 million, $53.1 million and $24 million, respectively. Contributions made in 1996 and 1994 represented the amount received in rates, while the amount contributed in 1995 represented the amount received in rates, certain capital portions of the postretirement benefit obligation and amounts received from cotenants.

Net postretirement benefit cost for 1996, 1995 and 1994 included the following components:

	In thousands of dollars		
	1996	1995	1994
Service cost — benefits attributed to service during the period	$12,900	$12,600	$ 15,000
Interest cost on accumulated benefit obligation	37,500	45,400	40,200
Actual return on plan assets	(12,900)	(11,200)	(900)
Amortization of the transition obligation over 20 years	13,500	18,800	20,200
Net amortization	6,000	14,600	8,900
Net postretirement benefit cost	57,000	80,200	83,400
VERP costs	—	—	80,200
Regulatory asset	—	—	(4,300)
Total postretirement benefit cost	$57,000	$80,200	$159,300

The following table sets forth the plan's funded status and amounts recognized in the Company's Consolidated Balance Sheets:

	In thousands of dollars	
At December 31,	1996	1995
Actuarial present value of accumulated benefit obligations:		
Retired and surviving spouses	$370,259	$397,547
Active eligible	31,030	24,374
Active ineligible	69,441	214,367
Accumulated benefit obligation	470,730	636,288
Plan assets at fair value, consisting primarily of listed stocks, bonds and other fixed obligations	(143,071)	(101,721)
Accumulated postretirement benefit obligation in excess of plan assets	327,659	534,567
Unrecognized net loss from past experience different from that assumed and effects of changes in assumptions	(36,048)	(55,899)
Prior service cost not yet recognized in postretirement benefit cost	39,205	—
Unrecognized transition obligation to be amortized over 20 years	(174,240)	(318,596)
Accrued postretirement benefit liability included in the consolidated balance sheet	$156,576	$160,072
Principle actuarial assumptions (%):		
Discount rate	7.50	7.50
Long-term rate of return on plan assets	8.00	9.25
Health care cost trend rate:		
Pre-65	8.00	8.25
Post-65	6.50	5.25

During 1996, the Company changed the eligibility requirements for plan benefits for employees who will retire after May 1, 1996. Generally, plan benefits are now accrued for eligible participants beginning after age 45. Previous to this change, the Company accrued these benefits over the employees' service life. The effect of this change resulted in a decrease in the accumulated benefit obligation for active ineligible employees, as shown in the table above.

At December 31, 1996, the assumed health cost trend rates gradually decline to 5.0% in 2000. If the health care cost trend rate was increased by one percent, the accumulated postretirement benefit obligation as of December 31, 1996 would increase by approximately 8.6% and the aggregate of the service and interest cost component of net periodic postretirement benefit cost for the year would increase by approximately 10.3%.

The Company recognizes the obligation to provide postemployment benefits if the obligation is attributable to employees' past services, rights to those benefits are vested, payment is probable and the amount of the benefits can be reasonably estimated. At December 31, 1996 and 1995, the Company's postemployment benefit obligation is approximately $13 million and $12.5 million, respectively, including the portion of the obligation related to the VERP.

NOTE 9. Commitments and Contingencies

See Note 2 and Note 5.

Long-term Contracts for the Purchase of Electric Power: At January 1, 1997, the Company had long-term contracts to purchase electric power from the following generating facilities owned by NYPA:

Facility	Expiration Date of Contract	Purchased Capacity in Kw.	Estimated Annual Capacity Cost
Niagara hydroelectric project.....	2007	936,000	$26,176,000
St. Lawrence hydroelectric project.....	2007	104,000	1,300,000
Blenheim-Gilboa pumped storage generating station	2002	270,000	7,500,000
Fitzpatrick nuclear plant	2014	110,000 *(a)*	4,785,000
		1,420,000	$39,761,000

(a) 110,000 Kw through May 1997; 26,000 Kw thereafter

The purchase capacities shown above are based on the contracts currently in effect. The estimated annual capacity costs are subject to price escalation and are exclusive of applicable energy charges. The total cost of purchases under these contracts was approximately, in millions, $93.3, $92.5 and $85.1 for the years 1996, 1995 and 1994, respectively.

Under the requirements of the Federal Public Utility Regulatory Policies Act of 1978, the Company is required to purchase power generated by IPPs, as defined therein. The Company has 157 IPP contracts, of which 148 are on line, amounting to approximately 2,710 MW of capacity at December 31, 1996. Of this amount 2,406 MW is considered firm. The following table shows the payments for fixed and other capacity costs, and energy and related taxes the Company estimates it will be obligated to make under these contracts without giving effect to the IPP agreement-in-principle. The payments are subject to the tested capacity and availability of the facilities, scheduling and price escalation.

	In thousands of dollars			
	Schedulable Fixed Costs			
Year	Capacity	Other	Energy and Taxes	Total
1997	$223,880	$40,510	$ 873,030	$1,137,420
1998	247,740	41,420	906,590	1,195,750
1999	252,130	42,450	943,720	1,238,300
2000	242,030	44,080	974,080	1,260,190
2001	244,620	45,650	1,042,380	1,332,650

The capacity and other fixed costs relate to contracts with 11 facilities where the Company is required to make capacity and other fixed payments, including payments when a facility is not operating but available for service. These 11 facilities account for approximately 774 MW of capacity, with contract lengths ranging from 20 to 35 years. The terms of these existing contracts allow the Company to schedule energy deliveries from the facilities and then pay for the energy delivered. The Company estimates the fixed payments under these contracts will aggregate to approximately $8 billion dollars over their terms, using escalated contract rates. Contracts relating to the remaining facilities in service at December 31, 1996, require the Company to pay only when energy is delivered, except when the Company decides that it would be better to pay a particular project a reduced energy payment to have the project reduce its high priced energy deliveries as described below. The Company currently recovers schedulable capacity through base rates and energy payments, taxes and other schedulable fixed costs through the FAC. The Company paid approximately $1,088 million, $980 million and $960 million in 1996, 1995 and 1994 for 13,800,000 MWh, 14,000,000 MWh and 14,800,000 MWh, respectively, of electric power under all IPP contracts.

On March 10, 1997, the Company and 19 developers of IPP projects jointly announced an agreement-in-principle to terminate or restructure 44 power purchase contracts. These contracts represent more than 90% of the Company's above-market power costs under all existing IPP contracts. The agreement contemplates that the Company would terminate or restructure the 44 power contracts in exchange for approximately $3.6 billion in cash and/or marketable debt securities, and 46 million shares of the Company's common stock, representing approximately 25% of the anticipated fully diluted outstanding common shares. The new debt will be subordinate to existing first mortgage bonds. The value of the common equity will vary depending on the market value of the shares at closing. In addition, the Company and several IPPs would enter into new agreements that would further compensate the IPPs and hedge prices for specific amounts of power. (As noted in Management's Discussion and Analysis of Financial Condition and Results of Operations – "Announced Agreement-in-Principle to Terminate or Restructure 44 IPP Contracts," implementation of these arrangements are subject to a number of contingencies.)

Separate from the agreement-in-principle, the Company has negotiated three long term and sixteen limited term contract amendments whereby the Company can reduce the energy deliveries from the facilities. These reduced energy agreements resulted in a reduction of IPP deliveries of approximately 984,000 Mwh during 1996. The Company expects to continue efforts of these types into the future, to control its power supply and related costs, but at this time cannot predict the outcome of such efforts.

Sale of Customer Receivables: The parent Company has established a single-purpose wholly-owned financing subsidiary, NM Receivables Corp., whose business consists of the purchase and resale of an undivided interest in a designated pool of customer receivables, including accrued unbilled revenues. For receivables sold, the Company has retained collection and administrative responsibilities as agent for the purchaser. As collections reduce previously sold undivided interests, new receivables are customarily sold. NM Receivables Corp. has its own separate creditors which, upon liquidation of NM Receivables Corp., will be entitled to be satisfied out of its assets prior to any value becoming available to its equity holders. The sale of receivables are in fee simple for a reasonably equivalent value and are not secured loans. Some receivables have been contributed in the form of a capital contribution to NM Receivables Corp. in fee simple for reasonably equivalent value, and all receivables transferred to NM Receivables Corp. are assets owned by NM Receivables Corp. in fee simple and are not available to pay the parent Company's creditors.

At December 31, 1996 and 1995, $250 million of receivables had been sold by NM Receivables Corp. to a third party. The undivided interest in the designated pool of receivables was sold with limited recourse. The agreement provides for a formula based loss reserve pursuant to which additional customer receivables are assigned to the purchaser to protect against bad debts. At December 31, 1996, the amount of additional receivables assigned to the purchaser, as a loss reserve, was approximately $85.8 million. Although this represents the formula-based amount of credit exposure at December 31, 1996 under the agreement, historical losses have been substantially less.

To the extent actual loss experience of the pool receivables exceeds the loss reserve, the purchaser absorbs the excess. Concentrations of credit risk to the purchaser with respect to accounts receivable are limited due to the Company's large, diverse customer base within its service territory. The Company generally does not require collateral, i.e., customer deposits.

Tax assessments: The Internal Revenue Service (IRS) has conducted an examination of the Company's Federal income tax returns for the years 1987 and 1988 and has submitted a Revenue Agents' Report to the Company. The IRS has proposed various adjustments to the Company's Federal income tax liability for these years which could increase the Company's Federal income tax liability by approximately $80 million, before assessment of penalties and interest. Included in these proposed adjustments are several significant issues involving Unit 2. The Company is vigorously defending its position on each of the issues, and submitted a protest to the IRS in 1993. Pursuant to the Unit 2 settlement entered into with the PSC in 1990, to the extent the IRS is able to sustain adjustments, the Company will be required to absorb a portion of any assessment. The Company believes any such disallowance will not have a material impact on its financial position or results of operations under traditional cost-of-service based ratemaking. The Company is currently attempting to finalize a settlement of these issues with the Appeals Division of the IRS.

In addition, the IRS has conducted an examination of the Company's federal income tax returns for the years 1989 and 1990 and issued a Revenue Agents' Report. The IRS has raised the issue concerning the deductibility of payments made to IPPs in accordance with certain contracts that include a provision for a tracking account. A tracking account represents amounts that these mandated contracts required the Company to pay IPPs in excess of the Company's avoided costs, including a carrying charge. The IRS proposes to disallow a current deduction for amounts paid in excess of the avoided costs of the Company. Although the Company believes that any such disallowances for the years 1989 and 1990 will not have a material impact on its financial position or results of operations, it believes that a disallowance for these above-market payments for the years subsequent to 1990 could have a material adverse affect on its cash flows. To the extent that contracts involving tracking accounts are terminated or restructured under the agreement-in-principle with IPPs as described in Note 2, then it is possible that the effects of any proposed disallowance would be mitigated. The Company is vigorously defending its position on this issue. The IRS has commenced its examination of the Company's Federal income tax returns for the years 1991 through 1993.

Litigation: In March 1993, Inter-Power of New York, Inc. (Inter-Power), filed a complaint against the Company and certain of its officers and employees in the NYS Supreme Court. Inter-Power alleged, among other matters, fraud, negligent misrepresentation and breach of contract in connection with the Company's alleged termination of a PPA in January 1993. The plaintiff sought enforcement of the original contract or compensatory and punitive damages in an aggregate amount that would not exceed $1 billion, excluding pre-judgment interest.

In early 1994, the NYS Supreme Court dismissed two of the plaintiff's claims; this dismissal was upheld by the Appellate Division, Third Department of the NYS Supreme Court. Subsequently, the NYS Supreme Court granted the Company's motion for summary judgment on the remaining causes of action in Inter-Power's complaint. In August 1994, Inter-Power appealed this decision and on July 27, 1995, the Appellate Division, Third Department affirmed the granting of summary judgment as to all counts, except for one dealing with an alleged breach of the PPA relating to the Company's having declared the agreement null and void on the grounds that Inter-Power had failed to provide it with information regarding its fuel supply in a timely fashion. This one breach of contract claim was remanded to the NYS Supreme Court for further consideration. Discovery on this one breach of contract claim is currently in progress.

The Company is unable to predict the ultimate disposition of this lawsuit. However, the Company believes it has meritorious defenses and intends to defend this lawsuit vigorously, but can neither provide any judgment regarding the likely outcome nor provide any estimate or range of possible loss. Accordingly, no provision for liability, if any, that may result from this lawsuit has been made in the Company's financial statements.

Environmental Contingencies: The public utility industry typically utilizes and/or generates in its operations a broad range of potentially hazardous wastes and by-products. The Company believes it is handling identified wastes and by-products in a manner consistent with Federal, state and local requirements and has implemented an environmental audit program to identify any potential areas of concern and assure compliance with such requirements. The Company is also currently conducting a program to investigate and restore, as necessary to meet current environmental standards, certain properties associated with its former gas manufacturing process and other properties which the Company has learned may be contaminated with industrial waste, as well as investigating identified industrial waste sites as to which it may be determined that the Company contributed. The Company has also been advised that various Federal, state or local agencies believe certain properties require investigation and has prioritized the sites based on available information in order to enhance the management of investigation and remediation, if necessary.

The Company is currently aware of 85 sites with which it has been or may be associated, including 42 which are Company-owned. With respect to non-owned sites, the Company may be required to contribute some proportionate share of remedial costs.

Investigations at each of the Company-owned sites are designed to (1) determine if environmental contamination problems exist, (2) if necessary, determine the appropriate remedial actions required for site restoration and (3) where appropriate, identify other parties who should pay some or all of the cost of remediation. Legal action against such other parties will be initiated where appropriate. After site investigations are completed, the Company expects to determine site-specific remedial actions and to estimate the attendant costs for restoration. However, since technologies are still developing the ultimate cost of remedial actions may change substantially.

Estimates of the cost of remediation and post-remedial monitoring are based upon a variety of factors, including identified or potential contaminants, location, size and use of the site, proximity to sensitive resources, status of regulatory investigation and knowledge of activities at similarly situated sites, and the EPA figure for average cost to remediate a site. Actual Company expenditures are dependent upon the total cost of investigation and remediation and the ultimate determination of the Company's share of responsibility for such costs, as well as the financial viability of other identified responsible parties since clean-up obligations are joint and several. The Company has denied any responsibility in certain of these PRP sites and is contesting liability accordingly.

As a consequence of site characterizations and assessments completed to date and negotiations with PRP's, the Company has accrued a liability in the amount of $225 million, which is reflected in the Company's Consolidated Balance Sheets at both December 31, 1996 and 1995. This represents the low end of the range of its share of the estimated cost for investigation and remediation. The potential high end of the range is presently estimated at approximately $850 million, including approximately $340 million in the unlikely event the Company is required to assume 100% responsibility at non-owned sites. In addition, the Company has recorded a regulatory asset representing the remediation obligations to be recovered from ratepayers. The Company expects under *PowerChoice* that the regulatory asset will be recovered in rates charged to customers.

Where appropriate, the Company has provided notices of insurance claims to carriers with respect to the investigation and remediation costs for manufactured gas plant, industrial waste sites and sites for which the Company has been identified as a PRP. The Company has settled some of these claims and continues to pursue others, but is unable to predict what the ratemaking disposition of the proceeds will be.

Construction Program: The Company is committed to an ongoing construction program to assure delivery of its electric and gas services. The Company presently estimates that the construction program for the years 1997 through 2001 will require approximately $1.4 billion, excluding AFC and nuclear fuel. For the years 1997 through 2001, the estimates, in millions, are $293, $298, $269, $264 and $265, respectively, which includes $24, $30, $25, $23 and $21, respectively, related to non-nuclear generation. These amounts are reviewed by management as circumstances dictate.

Under the Company's *PowerChoice* proposal, the Company proposes to separate the Company's non-nuclear power generation business from the remainder of the business.

NOTE 10. Disclosures about Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

Cash and short-term investments: The carrying amount approximates fair value because of the short maturity of the financial instruments.

Long-term debt and mandatorily redeemable preferred stock: The fair value of fixed rate long-term debt and redeemable preferred stock is estimated using quoted market prices where available or discounting remaining cash flows at the Company's incremental borrowing rate. The carrying value of NYSERDA bonds and other long-term debt are considered to approximate fair value.

The financial instruments held or issued by the Company are for purposes other than trading. The estimated fair values of the Company's financial instruments are as follows:

At December 31,	1996 Carrying Amount	1996 Fair Value	1995 Carrying Amount	1995 Fair Value
	In thousands of dollars			
Cash and short-term investments	$ 325,398	$ 325,398	$ 153,475	$ 153,47[illegible]
Mandatorily redeemable preferred stock	95,600	86,516	106,000	92,6[illegible]
Long-term debt: First Mortgage bonds	2,841,305	2,690,707	2,866,305	2,815,20[illegible]
Medium-term notes	20,000	21,994	30,000	31,826
Promissory notes	413,760	413,760	413,760	413,760
Other	228,461	228,461	292,436	292,436

The Company's investments in debt and equity securities consist of trust funds for the purpose of funding the nuclear decommissioning of Unit 1 and its share of Unit 2 (See Note 3 – "Nuclear Plant Decommissioning"), short-term investments held by Opinac Energy Corporation (a subsidiary) and a trust fund for certain pension benefits. The Company has classified all investments in debt and equity securities as available for sale and has recorded all such investments at their fair market value at December 31, 1996. The proceeds from the sale of investments were $99.4 million, $70.3 million and $104.6 million in 1996, 1995 and 1994, respectively. Net realized and unrealized gains and losses related to the nuclear decommissioning trust are reflected in "Accumulated depreciation and amortization" on the Consolidated Balance Sheets, which is consistent with the method used by the Company to account for the decommissioning costs recovered in rates. The unrealized gains and losses related to the investments held by Opinac Energy Corporation and the pension trust are included, net of tax, in "Common stockholders' equity" on the Consolidated Balance Sheets, while the realized gains and losses are included in "Other items (net)" on the Consolidated Income Statements. The recorded fair values and cost basis of the Company's investments in debt and equity securities is as follows:

At December 31,	1996				1995			
Security Type	Cost	Gross Unrealized Gain	Gross Unrealized (Loss)	Fair Value	Cost	Gross Unrealized Gain	Gross Unrealized (Loss)	Fair Value
	In thousands of dollars							
U.S. Government Obligations	$ 24,782	$ 1,530	$ (33)	$ 26,279	$ 16,271	$ 3,009	$ —	$ 19,280
Commercial Paper	90,495	739	—	91,234	47,105	1,019	—	48,124
Tax Exempt Obligations	75,590	3,209	(147)	78,652	66,155	3,830	(72)	69,91[illegible]
Corporate Obligations	62,723	8,524	(422)	70,825	45,279	5,399	(344)	50,3[illegible]
Other	2,586	—	—	2,586	10,022	945	—	10,9[illegible]
	$256,176	$14,002	$(602)	$269,576	$184,832	$14,202	$(416)	$198,618

Using the specific identification method to determine cost, the gross realized gains and gross realized losses were:

Year Ended December 31	1996	1995	1994
	In thousands of dollars		
Realized gains	$2,121	$2,523	$1,123
Realized losses	806	328	1,637

The contractual maturities of the Company's investments in debt securities is as follows:

At December 31, 1996:	Fair Value	Cost
	In thousands of dollars	
Less than 1 year	$93,485	$92,523
1 year to 5 years	10,494	10,201
5 years to 10 years	38,543	36,969
Due after 10 years	97,378	92,787

NOTE 11. Information Regarding the Electric and Gas Businesses

The Company is engaged principally in the business of production, purchase, transmission, distribution and sale of electricity and the purchase, distribution, sale and transportation of gas in New York State. The Company provides electric service to the public in an area of New York State having a total population of about 3,500,000, including among others, the cities of Buffalo, Syracuse, Albany, Utica, Schenectady, Niagara Falls, Watertown and Troy. The Company distributes or transports natural gas in areas of central, northern and eastern New York having a total population of about 1,700,000 nearly all within the Company's electric service area. Certain information regarding the Company's electric and natural gas segments is set forth in the following table. General corporate expenses, property common to both segments and depreciation of such common property have been allocated to the segments in accordance with the practice established for regulatory purposes. Identifiable assets include net utility plant, materials and supplies, deferred finance charges, deferred recoverable energy costs and certain other regulatory and other assets. Corporate assets consist of other property and investments, cash, accounts receivable, prepayments, unamortized debt expense and certain other regulatory and other assets. At December 31, 1996, total plant assets consisted of approximately 24% Nuclear, 20% Fossil/Hydro, 42% Transmission and Distribution, 11% Gas and 3% Common.

	In thousands of dollars		
	1996	1995	1994
Operating revenues:			
Electric	$ 3,308,979	$ 3,335,548	$3,528,987
Gas	681,674	581,790	623,191
Total	$ 3,990,653	$ 3,917,338	$4,152,178
Operating income before taxes:			
Electric	$ 438,590	$ 587,282	$ 469,371*
Gas	83,748	96,752	80,836
Total	$ 522,338	$ 684,034	$ 550,207
Pretax operating income, including AFC:			
Electric	$ 445,651	$ 595,970	$ 478,087
Gas	84,042	97,114	81,199
Total	529,693	693,084	559,286
Income taxes, included in operating expenses:			
Electric	82,663	129,556	92,469
Gas	22,920	26,452	25,365
Total	105,583	156,008	117,834
Other (income) and deductions	(35,367)	1,379	(21,410)
Interest charges	281,723	287,661	285,878
Income before extraordinary item	$ 177,754	$ 248,036	$ 176,984
Depreciation and amortization:			
Electric	$ 302,825	$ 292,995	$ 281,301
Gas	27,002	24,836	27,050
Total	$ 329,827	$ 317,831	$ 308,351
Construction expenditures (including nuclear fuel):			
Electric	$ 277,505	$ 285,722	$ 376,159
Gas	74,544	60,082	113,965
Total	$ 352,049	$ 345,804	$ 490,124
Identifiable assets:			
Electric	$ 7,346,765	$ 7,592,287	$7,759,549
Gas	1,203,184	1,123,045	1,093,812
Total	8,549,949	8,715,332	8,853,361
Corporate assets	852,081	762,537	796,455
Total assets	$ 9,402,030	$ 9,477,869	$9,649,816

*Includes $196,625 of VERP expenses.

NOTE 12. Quarterly Financial Data (Unaudited)

Operating revenues, operating income, net income and earnings per common share by quarters from 1996, 1995 and 1994, respectively, are shown in the following table. The Company, in its opinion, has included all adjustments necessary for a fair presentation of the results of operations for the quarters. Due to the seasonal nature of the utility business, the annual amounts are not generated evenly by quarter during the year. The Company's quarterly results of operations reflect the seasonal nature of its business, with peak electric loads in summer and winter periods. Gas sales peak in the winter.

	In thousands of dollars			
Quarter Ended	Operating revenues	Operating income (loss)	Net income (loss)	Earnings (loss) per common share
December 31, 1996	$ 971,106	$ 91,977	$ (25,808)	$(.24)
1995	966,478	113,510	27,874	.13
1994	1,018,110	(10,536)	(77,422)	(.61)
September 30, 1996	$ 895,713	$ 53,406	$ (12,916)	$(.16)
1995	887,231	114,126	46,941	.26
1994	918,810	108,937	48,383	.27
June 30, 1996	$ 960,771	$ 113,363	$ 52,992	$ .30
1995	938,816	121,985	54,485	.31
1994	979,700	130,624	67,559	.42
March 31, 1996	$1,163,063	$158,009	$ 96,122	$ .60
1995	1,124,813	178,405	118,736	.75
1994	1,235,558	203,348	138,464	.92

In the fourth quarter of 1996 the Company recorded an extraordinary item for the discontinuance of regulatory accounting principles of $103.6 million (47 cents per common share).

In the third quarter of 1996 the Company increased the allowance for doubtful accounts by $68.5 million (31 cents per common share).

In the fourth quarter of 1994 the Company recorded $196.6 million (89 cents per common share) for the electric expense allocation of the VERP. In the fourth quarters of 1994 and 1995, the Company recorded, $12.3 million (6 cents per common share) and $16.9 million (8 cents per common share), respectively, for MERIT earned in accordance with the 1991 Agreement.

Market Price of Common Stock and Related Stockholder Matters

The Company's common stock and certain of its preferred series are listed on the New York Stock Exchange (NYSE). The common stock is also traded on the Boston, Cincinnati, Midwest, Pacific and Philadelphia stock exchanges. Common stock options are traded on the American Stock Exchange. The ticker symbol is "NMK".

Preferred dividends were paid on March 31, June 30, September 30 and December 31. The Company estimates that none of the 1996 preferred stock dividends will constitute a return of capital and therefore all of such dividends are subject to Federal tax as ordinary income.

The table below shows quoted market prices (NYSE) for the Company's common stock:

1996	Price Range High	Price Range Low
1st Quarter	$10⅛	$6½
2nd Quarter	8¾	6½
3rd Quarter	8¾	6¾
4th Quarter	10	7⅝
1995		
1st Quarter	$15⅝	$13⅜
2nd Quarter	15⅛	13⅜
3rd Quarter	14¾	11¼
4th Quarter	13⅜	9½

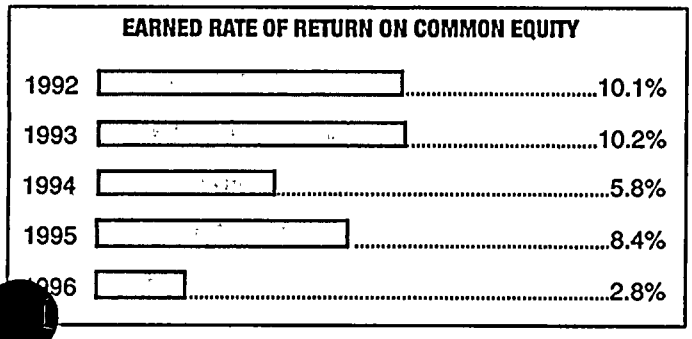
The Company paid dividends of 28 cents per common share in each of the four quarters of 1995. The board of directors omitted the common stock dividend for all of 1996 and the first quarter of 1997. This action was taken to help stabilize the Company's financial condition and provide flexibility as the Company addresses growing pressure from mandated power purchases and weaker sales and is the primary reason for the increase in the cash balance. See Management's Discussion and Analysis of Financial Condition and Results of Operations – "Financial Position, Liquidity and Capital Resources – Common Stock Dividend" below. In making future dividend decisions, the board will evaluate, along with standard business considerations, the financial condition and contractual obligations of the Company, the progress on concluding negotiations and implementing the termination or restructuring of IPP contracts and *PowerChoice*, or the failure to implement such actions, the degree of competitive pressure on its prices, the level of available cash flow and retained earnings and other strategic considerations.

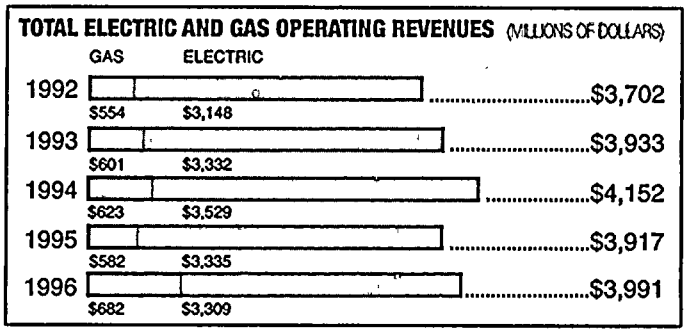
Other Stockholder Matters. The holders of common stock are entitled to one vote per share and may not cumulate their votes for the election of Directors. Whenever dividends on preferred stock are in default in an amount equivalent to four full quarterly dividends and thereafter until all dividends thereon are paid or declared and set aside for payment, the holders of such preferred stock can elect a majority of the board of directors. Whenever dividends on any preference stock are in default in an amount equivalent to six full quarterly dividends and thereafter until all dividends thereon are paid or declared and set aside for payment, the holders of such stock can elect two members to the board of directors. No dividends on preferred stock are now in arrears and no preference stock is now outstanding. Upon any dissolution, liquidation or winding up of the Company's business, the holders of common stock are entitled to receive a pro rate share of all of the Company's assets remaining and available for distribution after the full amounts to which holders of preferred and preference stock are entitled have been satisfied.

The indenture securing the Company's mortgage debt provides that retained earnings shall be reserved and held unavailable for the payment of dividends on common stock to the extent that expenditures for maintenance and repairs plus provisions for depreciation do not exceed 2.25% of depreciable property as defined therein. Such provisions have never resulted in a restriction of the Company's retained earnings.

As of March 18, 1997, there were approximately 75,100 holders of record of common stock of the Company and about 5,400 holders of record of preferred stock. The chart below summarizes common stockholder ownership by size of holding:

Size of Holding (Shares)	Total Stockholders	Total Shares Held
1 to 99	33,201	889,029
100 to 999	37,787	9,313,655
1,000 or more	4,144	134,187,935
	75,132	144,390,619



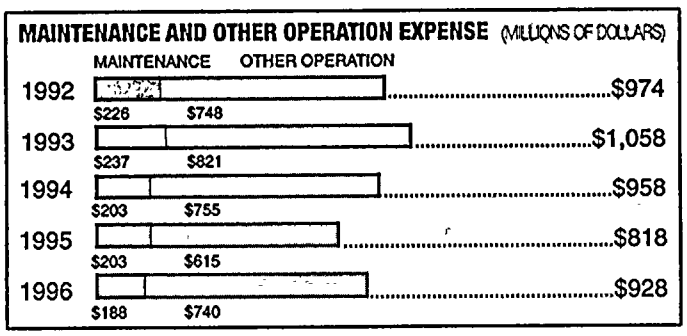


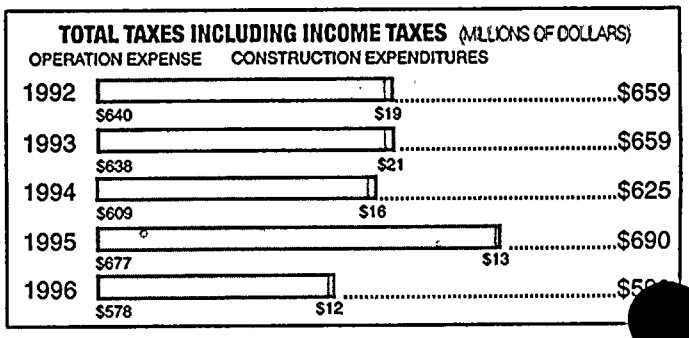
Selected Consolidated Financial Data

The following table sets forth selected financial information of the Company for each of the five years during the period ended December 31, 1996, which has been derived from the audited financial statements of the Company, and should be read in connection therewith. As discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Notes to Consolidated Financial Statements," the following selected financial data may not be indicative of the Company's future financial condition or results of operations.

	1996*	1995	1994	1993	1992
Operations: (000's)					
Operating revenues	$3,990,653	$3,917,338	$4,152,178	$3,933,431	$3,701,527
Net income	110,390	248,036	176,984	271,831	256,432
Common stock data:					
Book value per share at year end	$17.91	$17.42	$17.06	$17.25	$16.33
Market price at year end	9 7/8	9 1/2	14 1/4	20 1/4	19 1/8
Ratio of market price to book value at year end	55.1%	54.5%	83.5%	117.4%	117.1%
Dividend yield at year end	—	11.8%	7.9%	4.9%	4.2%
Earnings per average common share	$ .50	$ 1.44	$ 1.00	$ 1.71	$ 1.61
Rate of return on common equity	2.8%	8.4%	5.8%	10.2%	10.1%
Dividends paid per common share	$ —	$ 1.12	$ 1.09	$ .95	$ .76
Dividend payout ratio	—	77.8%	109.0%	55.6%	47.2%
Capitalization: (000's)					
Common equity	$2,585,572	$2,513,952	$2,462,398	$2,456,465	$2,240,441
Non-redeemable preferred stock	440,000	440,000	440,000	290,000	290,000
Mandatorily redeemable preferred stock	86,730	96,850	106,000	123,200	170,400
Long-term debt	3,477,879	3,582,414	3,297,874	3,258,612	3,491,059
Total	6,590,181	6,633,216	6,306,272	6,128,277	6,191,900
Long-term debt maturing within one year	48,084	65,064	77,971	216,185	57,722
Total	$6,638,265	$6,698,280	$6,384,243	$6,344,462	$6,249,622
Capitalization ratios: *(including long-term debt maturing within one year)*					
Common stock equity	39.0%	37.5%	38.6%	38.7%	35.8%
Preferred stock	7.9	8.0	8.5	6.5	7.4
Long-term debt	53.1	54.5	52.9	54.8	56.8
Financial ratios:					
Ratio of earnings to fixed charges	1.57	2.29	1.91	2.31	2.24
Ratio of earnings to fixed charges without AFC	1.55	2.26	1.89	2.26	2.17
Ratio of AFC to balance available for common stock	10.2%	4.3%	6.3%	6.8%	9.7%
Ratio of earnings to fixed charges and preferred stock dividends	1.31	1.90	1.63	2.00	1.90
Other ratios – % of operating revenues:					
Fuel, purchased power and purchased gas	43.5%	40.3%	39.6%	36.1%	34.1%
Other operation expenses and maintenance	23.3	20.9	23.1	26.9	26.3
Depreciation and amortization	8.3	8.1	7.4	7.0	7.4
Total taxes, incl. real property, income and revenue taxes	13.6	17.3	14.7	16.2	17.3
Operating income	10.4	13.5	10.4	13.3	14.2
Balance available for common stock	1.8	5.3	3.5	6.1	5.9
Miscellaneous: (000's)					
Gross additions to utility plant	$ 352,049	$ 345,804	$ 490,124	$ 519,612	$ 502,244
Total utility plant	10,839,341	10,649,301	10,485,339	10,108,529	9,642,262
Accumulated depreciation and amortization	3,881,726	3,641,448	3,449,696	3,231,237	2,975,977
Total assets	9,402,030	9,477,869	9,649,816	9,471,327	8,590,535

* Amounts include extraordinary item, see Note 2. Rate and Regulatory Issues and Contingencies.





Electric and Gas Statistics

ELECTRIC CAPABILITY

ember 31,	Thousands of kilowatts 1996	%	1995	1994
Owned:				
Coal	1,333	16.3	1,316	1,285
Oil	636	7.8	636	646
Dual Fuel — Oil/Gas	700	8.5	700	700
Nuclear	1,082	13.2	1,082	1,048
Hydro	617	7.5	665	700
	4,368	53.3	4,399	4,379
Purchased:				
New York Power Authority				
— Hydro	1,310	16.0	1,325	1,300
— Nuclear	110	1.3	110	74
IPPs	2,406	29.4	2,390	2,273
	3,826	46.7	3,825	3,647
Total capability *	8,194	100.0	8,224	8,026
Electric peak load	6,021		6,211	6,458

*Available capability can be increased during heavy load periods by purchases from neighboring interconnected systems. Hydro station capability is based on average December stream-flow conditions.

ELECTRIC STATISTICS

	1996	1995	1994
Electric sales *(Millions of Kwh)*:			
Residential	10,109	10,055	10,316
Commercial	11,564	11,613	11,739
Industrial	7,148	7,061	7,382
Industrial – Special	4,326	4,053	4,118
cipal service	246	229	227
electric systems	5,431	4,305	7,441
diary	303	368	376
	39,127	37,684	41,599
Electric revenues *(Thousands of dollars)*:			
Residential	$1,252,165	$1,214,848	$1,226,490
Commercial	1,237,385	1,237,502	1,268,083
Industrial	524,858	523,996	574,251
Industrial – Special	58,444	56,250	49,217
Municipal service	53,795	50,860	51,401
Other electric systems	113,391	88,936	157,826
Miscellaneous	53,698	143,625	179,529
Subsidiary	15,243	19,531	22,190
	$3,308,979	$3,335,548	$3,528,987
Electric customers *(Average)*:			
Residential	1,405,083	1,399,725	1,393,273
Commercial	145,149	144,731	143,017
Industrial	2,045	2,122	2,069
Industrial – Special	99	83	82
Other	1,302	1,488	2,312
Subsidiary	13,557	13,508	13,344
	1,567,235	1,561,657	1,554,097
Residential *(Average)*:			
Annual Kwh use per customer	7,195	7,184	7,404
Cost to customer per Kwh	12.39¢	12.08¢	11.89¢
Annual revenue per customer	$891.17	$867.92	$880.29

GAS STATISTICS

	1996	1995	1994
Gas sales *(Thousands of Dth)*:			
Residential	56,728	51,842	56,491
Commercial	25,353	23,818	25,783
Industrial	2,770	2,660	3,097
Other gas systems	30	161	244
Total sales	84,881	78,481	85,615
Spot market	10,459	1,723	1,572
Transportation of customer-owned gas	134,671	144,613	85,910
Total gas delivered	230,011	224,817	173,097
Gas revenues *(Thousands of dollars)*:			
Residential	$417,348	$368,391	$398,257
Commercial	162,275	143,643	159,157
Industrial	13,325	11,530	14,602
Other gas systems	138	762	1,159
Spot market	37,124	3,096	4,370
Transportation of customer-owned gas	50,381	48,290	38,346
Miscellaneous	1,083	6,078	7,300
	$681,674	$581,790	$623,191
Gas customers *(Average)*:			
Residential	477,786	471,948	463,933
Commercial	41,266	40,945	40,256
Industrial	206	225	256
Other	6	1	1
Transportation	713	652	661
	519,977	513,771	505,107
Residential *(Average)*:			
Annual dekatherm use per customer	118.7	109.8	121.8
Cost to customer per Dth	$7.36	$7.11	$7.05
Annual revenue per customer	$873.50	$780.58	$858.44
Maximum day gas sendout (Dth)	1,152,996	1,211,252	995,801

Glossary of Terms

Term	Definition
AFC	Allowance for Funds Used During Construction
Clean Air Act	Clean Air Act Amendments of 1990
CNP	Canadian Niagara Power Company, Limited
COPS	Competitive Opportunities Proceeding
CWIP	Construction Work in Progress
DOE	U.S. Department of Energy
DSM	Demand-Side Management
Dth	Dekatherms
EPA	U.S. Environmental Protection Agency
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Investors Services, Inc.
GAC	Gas Adjustment Clause
GAAP	Generally Accepted Accounting Principles
GRT	Gross Receipts Tax
GwHrs	Gigawatt-hours
HYDRA-CO	HYDRA-CO Enterprises, Inc. (former subsidiary)
IPP	Independent Power Producer
ISO	Independent System Operator
Kw	Kilowatt
Kwh	Kilowatt-hour
MERIT	Measured Equity Return Incentive Term
Moody's	Moody's Investors Service
MW	Megawatt
Mwh	Megawatt-hour
NERAM	Niagara Mohawk Electric Revenue Adjustment Mechanism
NYS Supreme Court	Supreme Court of the State of New York, Albany County
NOx	Nitrogen Oxide
NRC	U.S. Nuclear Regulatory Commission
NYPA	New York Power Authority
NYPP	New York Power Pool
NYSERDA	New York State Energy Research and Development Authority
PPA	Power Purchase Agreements
PRP	Potentially Responsible Party
PSC	New York State Public Service Commission
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility
ROE	Return on Common Stock Equity
SFAS No. 71	Statement of Financial Accounting Standards No. 71 "Accounting for the Effects of Certain Types of Regulation"
SFAS No. 101	Statement of Financial Accounting Standards No. 101 "Regulated Enterprises – Accounting for the Discontinuance of Application of FASB Statement No. 71"
SFAS No. 106	Statement of Financial Accounting Standards No. 106 "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS No. 109	Statement of Financial Accounting Standards No. 109 "Accounting for Income Taxes"
SFAS No. 121	Statement of Financial Accounting Standards No. 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of"
SO_2	Sulfur Dioxide
S&P	Standard & Poor's
Unit 1	Nine Mile Point Nuclear Station Unit No. 1
Unit 2	Nine Mile Point Nuclear Station Unit No. 2
VERP	Voluntary Employee Reduction Program

Notice of 1997 Annual Meeting & Proxy Statement

(Please sign and return your proxy promptly)

Contents

NIAGARA MOHAWK

300 ERIE BOULEVARD WEST, SYRACUSE, NEW YORK 13202

NOTICE OF ANNUAL MEETING
NIAGARA MOHAWK POWER CORPORATION

Please take notice that the Annual Meeting of Shareholders of Niagara Mohawk Power Corporation will be held at **The Onondaga County Convention Center, 800 South State Street, Syracuse, New York 13202-3017** on Tuesday, May 6, 1997, at 10:30 a.m. for the following purposes:

(1) To elect four directors to serve in Class III for a term expiring at the 2000 Annual Meeting;

(2) To consider and act upon a shareholder proposal relating to an endorsement by the Company of the CERES Principles;

(3) To consider and act upon a shareholder proposal relating to executive compensation; and

(4) To transact such other business as may be properly brought before the meeting or any adjournment thereof.

Shareholders entitled to vote at the meeting are the holders of Common Stock of record at the close of business on March 18, 1997.

By Order of the Board of Directors

Kapua Rice

Kapua A. Rice

Secretary

Dated: April 7, 1997

Proxy Statement

The enclosed proxy is solicited by the Board of Directors (the "Board of Directors" or the "Board") of Niagara Mohawk Power Corporation (the "Corporation") for use at the Annual Meeting of Shareholders to be held on May 6, 1997, and at any adjournment thereof. This proxy statement and the form of proxy, together with the 1996 Annual Report, are first being mailed to shareholders on or about April 7, 1997.

Voting Rights and Vote Required

The close of business on March 18, 1997, has been fixed as the record date for determining the holders of Common Stock entitled to vote at the meeting. Only shareholders of Common Stock whose names appeared of record on the books of the Corporation on the record date will be entitled to notice of and to vote at the meeting and at any adjournment thereof. On the record date there were 144,390,619 shares of Common Stock outstanding and entitled to vote. Each share of Common Stock is entitled to one vote.

Shareholders are urged to sign the accompanying form of proxy and return it promptly in the envelope provided for that purpose. The proxy does not affect the right to vote in person at the meeting and, if voted, may be revoked at any time prior to the vote being taken at the meeting. Proxies will be voted in accordance with the shareholders' directions. If no directions are given, proxies will be voted for the election of the nominees for directors set forth in this Proxy Statement. In the event any nominee withdraws or is for any reason unable to serve, a contingency not presently anticipated, proxies will be voted for any nominee that may be designated by the Board of Directors as a substitute nominee.

A majority of the shares entitled to vote at the meeting shall constitute a quorum. A plurality of the votes cast at the meeting is required for the election of directors. Except where otherwise provided by law, an affirmative vote of a majority of the votes cast at the meeting is required for approval of any other matter. Abstentions and broker non-votes will not be considered as votes cast with respect to a particular matter, but will be counted in the number of shares present in person or represented by proxy for purposes of determining whether a quorum is present.

Voting is confidential, in accordance with the provisions of Sections 8 and 9 of Article II of the By-Laws of the Corporation. Tabulation of proxies and the votes cast at the meeting is conducted by an independent agent and certified by independent inspectors of election. Any information which would identify the vote of any shareholder is held permanently confidential and will not be disclosed to the Corporation, except in limited circumstances set forth in such Sections of the By-Laws.

Proposal 1: Nomination and Election of Directors

At the meeting, four directors will be elected to Class III of the Board of Directors for three-year terms expiring at the 2000 Annual Meeting or until their respective successors are duly elected and qualified. All nominees are members of the present Board of Directors. Directors will be elected by a plurality of the votes cast at the meeting.

In accordance with the Corporation's Certificate of Incorporation, the Board of Directors is divided into three classes, composed of as nearly equal a number of directors as is possible, with staggered terms of office so that one class of the directors must be elected at each annual meeting.

The Board of Directors currently consists of fifteen directors. Mr. John G. Wick, who has served as director for 21 years, will retire from the Board of Directors at the 1997 Annual Meeting due to the mandatory retirement age. In addition, Mr. H. Eugene Lockhart, who has served on the Board since June 1996, was recently selected for and has accepted the position of President, Bank of America and accordingly, has tendered his resignation, effective May 6, 1997. As a result, the Corporation will have thirteen directors as of the 1997 Annual Meeting. The Board of Directors is deeply appreciative of the contributions made by Mr. Wick and Mr. Lockhart.

As applicable to each nominee and continuing director, the name, age as of March 1, 1997, principal occupation, business experience for the last five years or more, other directorships and the year in which first elected a director, are set forth below.

Business Background of Nominees and Directors

NOMINEES FOR CLASS III DIRECTORS — TERMS EXPIRING IN 2000

LAWRENCE BURKHARDT, III

- *Nuclear Consultant*
- *Director since 1988*
- *Chairperson of Nuclear Oversight Committee of the Board*

Mr. Burkhardt, Age 64, independent consultant to the nuclear industry since 1990. Prior to his retirement in 1990, Mr. Burkhardt was employed by the Corporation and served as Executive Vice President of Nuclear Operations. Director of Management Analysis Company.

DOUGLAS M. COSTLE

- *Distinguished Senior Fellow and Chairman of the Board of the Institute for Sustainable Communities*
- *Director since 1991*
- *Member of Executive, Corporate Public Policy & Environmental Affairs, and Nuclear Oversight Committees of the Board*

Mr. Costle, Age 57, Distinguished Senior Fellow and Chairman of the Board of the Institute for Sustainable Communities, a non-profit organization located in Montpelier, VT. Mr. Costle served as Dean of the Vermont Law School in South Royalton, Vermont from 1987-1992. Former Administrator of the U.S. Environmental Protection Agency. Independent Trustee of John Hancock Mutual Funds.

DONALD B. RIEFLER

- *Financial Market Consultant*
- *Director since 1978*
- *Member of Executive, Audit, Finance (Chairperson), and Nuclear Oversight Committees of the Board*

Mr. Riefler, Age 69, financial market consultant and advisor to J. P. Morgan, Florida FSB, Palm Beach, FL, a private banking concern affiliated with J. P. Morgan & Co., Inc. Prior to his retirement in 1991, Mr. Riefler was Chairman of the Market Risk Committee for J. P. Morgan & Co. Incorporated and Morgan Guaranty Trust Company of New York. Director of Bank of Tokyo Mitsubishi Trust Company.

STEPHEN B. SCHWARTZ

- *Retired Senior Vice President, International Business Machines Corporation*
- *Director since 1992*
- *Member of Executive, Compensation & Succession (Chairperson) and Finance Committees of the Board*

Mr. Schwartz, Age 62, retired as Senior Vice President, of International Business Machines Corporation in 1992. Mr. Schwartz joined IBM in 1957 and was elected Senior Vice President in 1990. Director of MFRI, Inc.

CONTINUING CLASS II DIRECTORS — TERMS EXPIRING IN 1999

WILLIAM F. ALLYN

- *President and Chief Executive Officer of Welch Allyn, Inc.*
- *Director since 1988*
- *Member of Audit, Compensation & Succession, and Nuclear Oversight Committees of the Board*

Mr. Allyn, Age 61, President and Chief Executive Officer of Welch Allyn, Inc., Skaneateles Falls, NY, a manufacturer of medical equipment. Mr. Allyn joined Welch Allyn, Inc. in 1962 and was elected to his present position in 1980. Director of ONBANCorp., Inc.; Oneida Limited; and Perfex Corporation.

WILLIAM E. DAVIS

- *Chairman of the Board and Chief Executive Officer, Niagara Mohawk Power Corporation*
- *Director since 1992*
- *Chairperson of Executive Committee of the Board*

Mr. Davis, Age 54, was elected Chairman of the Board and Chief Executive Officer of the Corporation in 1993. Mr. Davis joined the Corporation in 1990 and was elected Senior Vice President in April 1992, serving in that capacity until elected Vice-Chairman of the Board of the Corporation in November 1992. Director of Opinac Energy Corporation ("Opinac"), a wholly-owned subsidiary of the Corporation, and of its subsidiaries, Canadian Niagara Power Company, Limited, in which Opinac has a 50 percent interest, and Plum Street Enterprises, Inc.; and Utilities Mutual Insurance Company. Mr. Davis also holds the position of Chief Executive Officer, Plum Street Enterprises, Inc.

WILLIAM J. DONLON

- *Former Chairman of the Board and Chief Executive Officer, Niagara Mohawk Power Corporation*
- *Director since 1980*

Mr. Donlon, Age 67, retired in 1993 as Chairman of the Board and Chief Executive Officer of the Corporation with 45 years service as an active employee. Director of Opinac Energy Corporation, a wholly-owned subsidiary of the Corporation, and ONBANCorp., Inc.

ANTHONY H. GIOIA

- *Chairman and Chief Executive Officer of Gioia Management, Inc.*
- *Director since 1996*
- *Member of Compensation & Succession and Nuclear Oversight Committees of the Board*

Mr. Gioia, Age 55, Chairman and Chief Executive Officer of Gioia Management, Inc., a holding company for several companies, including three packaging companies located in Buffalo and Lockport, NY. Mr. Gioia has held his present position since 1987.

DR. PATTI McGILL PETERSON

- *Senior Fellow of the Cornell Institute for Public Affairs*
- *Director since 1988*
- *Member of Audit and Corporate Public Policy & Environmental Affairs Committees of the Board*

Dr. Peterson, Age 53, Senior Fellow of the Cornell Institute for Public Affairs, Cornell University, Ithaca, NY. Dr. Peterson served as President of St. Lawrence University from 1987-1996. Prior to that, she was President of Wells College. She holds the title President Emerita at both institutions. Director of Security Mutual Life Insurance Company. Independent Trustee of John Hancock Mutual Funds.

CONTINUING CLASS I DIRECTORS — TERMS EXPIRING IN 1998

ALBERT J. BUDNEY, JR.

- *President, Niagara Mohawk Power Corporation*
- *Director since 1995*

Mr. Budney, Age 49, was elected President of the Corporation in 1995. Mr. Budney was previously employed by UtiliCorp United, Inc., an energy services company, as Managing Vice President of the UtiliCorp Power Services Group and as President of the Missouri Public Service Division. From 1990-1992, he held the position of Vice President with Stone & Webster Inc., an engineering firm. Director and President of Opinac Energy Corporation, a wholly-owned subsidiary of the Corporation, and Director of its subsidiaries, Canadian Niagara Power Company, Limited, in which Opinac has a 50 percent interest, and Plum Street Enterprises, Inc.; and Director of Utilities Mutual Insurance Company.

EDMUND M. DAVIS

- *Attorney*
- *Director since 1970*
- *Member of Executive, Compensation & Succession, Corporate Public Policy & Environmental Affairs (Chairperson), and Finance Committees of the Board*

Mr. Davis, Age 67, retired in 1995 as of counsel to Hiscock & Barclay, LLP, Syracuse, NY, Attorneys-at-Law. Mr. Davis was a partner and had been associated with the law firm since 1957.

DR. BONNIE GUITON HILL

- *President and Chief Executive Officer of Times Mirror Foundation and Vice President of Times Mirror*
- *Director since 1991*
- *Member of Executive, Audit and Corporate Public Policy & Environmental Affairs Committees of the Board*

Dr. Hill, Age 55, President and Chief Executive Officer of the Times Mirror Foundation, a non-profit institution, and Vice President of Times Mirror, a news and information company, located in Los Angeles, CA. Dr. Hill served as Dean and Professor of Commerce of the McIntire School of Commerce at the University of Virginia from 1992-1996. Prior to that, she served as the Secretary of State and Consumer Services Agency for the State of California. Director of AK Steel Corporation; Crestar Financial Corporation; Hershey Foods Corporation; Louisiana-Pacific Corporation; and RREEF America, Inc.

HENRY A. PANASCI, JR.

- *Chairman, Cygnus Management Group, LLC*
- *Director since 1988*
- *Member of Compensation & Succession and Finance Committees of the Board*

Mr. Panasci, Age 68, Chairman of Cygnus Management Group, LLC, a consulting firm specializing in venture capital and private investments located in Syracuse, NY. Mr. Panasci retired in 1996 as Chairman of the

Board and Chief Executive Officer of Fay's Incorporated, a drug store chain. Mr. Panasci co-founded Fay's Drug Co., Inc. with his father in 1958. Director of National Association of Chain Drug Stores.

Board of Directors and Committees

Meetings and Attendance

During 1996, sixteen meetings of the Corporation's Board of Directors were held. Each director, except for Mr. H. Eugene Lockhart, attended more than 75 percent of the combined total of meetings of the Board of Directors and the Committees on which he or she served.

There are six standing Committees of the Board: the Executive Committee, the Audit Committee, the Compensation and Succession Committee, the Committee on Corporate Public Policy and Environmental Affairs, the Finance Committee and the Nuclear Oversight Committee. The Board does not have a standing Nominating Committee to nominate candidates for Board membership, but functions as a committee of the whole. Any nomination may be made from the floor by any shareholder who has made a written request to the Corporation to have such nomination considered at the annual meeting in accordance with the requirements of the Corporation's By-Laws. Information with respect to the Audit Committee and the Compensation and Succession Committee is set forth below.

Audit Committee

The Audit Committee, consisting of John G. Wick, Chairperson, William F. Allyn, Bonnie Guiton Hill, H. Eugene Lockhart, Patti McGill Peterson and Donald B. Riefler, all of whom are non-employee directors, met eleven times in 1996. Duties performed by the Audit Committee include meeting with the independent accountants, chief internal auditors and certain personnel of the Corporation to discuss the planned scope of auditing examinations and the adequacy of internal controls and interim and annual financial reporting; reviewing the results of the annual examination of the consolidated financial statements and periodic internal audit examinations; reviewing the services and fees of the Corporation's independent accountants; overseeing matters involving compliance with corporate business ethics policies; reviewing management's assessment of financial risks; authorizing and participating in special projects and studies; and performing any duties or functions deemed appropriate by the Board.

Compensation and Succession Committee

The Compensation and Succession Committee, consisting of Stephen B. Schwartz, Chairperson, William F. Allyn, Edmund M. Davis, Anthony H. Gioia and Henry A. Panasci, Jr., all of whom are non-employee directors, met nine times during 1996. The Committee evaluates the performance of the Corporation's Chief Executive Officer and the other senior officers of the Corporation; reviews the annual and incentive compensation of the elected officers of the Corporation, the Corporation's compensation programs and benefit plans, and officer development and succession plans; makes recommendations to the Board of Directors with respect to these matters; and meets with the Corporation's actuarial advisors to review the advisor's annual reports and progress toward funding the pension, post-retirement health plans, and supplemental executive retirement plan.

Compensation and Succession Commitee Interlocks and Insider Participation

Directors Allyn, Edmund Davis, Gioia, Panasci and Schwartz, all of whom are non-employee directors, are members of the Compensation and Succession Committee.

No person serving during 1996 as a member of the Compensation and Succession Committee of the Board served as an officer or employee of the Corporation or any of its subsidiaries during or prior to 1996.

No person serving during 1996 as an executive officer of the Corporation serves or has served as a director or a member of the compensation committee of any other entity that has an executive officer who serves or has served either as a member of the Compensation and Succession Committee or as a member of the Board of Directors of Niagara Mohawk Power Corporation.

Security Ownership of Certain Beneficial Owners and Management

The following table shows the persons (as the term is used in Section 13(d)(3) of the Securities Exchange Act of 1934) known to the Corporation to beneficially own more than five percent (5%) of the Corporation's Common Stock as of March 6, 1997. It also shows the same information for all directors of the Corporation, the executive officers named in the Summary Compensation Table below and the directors and executive officers of the Corporation as a group. The table also lists the number of stock units credited to directors, named executive officers and the directors and executive officers of the Corporation as a group as of March 6, 1997, pursuant to the Corporation's compensation and benefit programs. No voting rights are associated with stock units.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership**	Percent of Class	Number of Stock Units Held
Common Stock	Fidelity Management Trust Co. 82 Devonshire Street Boston, Massachusetts 02109	12,230,956(1)	8.47%	
	Directors:			
	William F. Allyn	1,000	*	7,990(8)
	Albert J. Budney, Jr.	500	*	55,000(9)
	Lawrence Burkhardt, III	452	*	1,371(8)
	Douglas M. Costle	500	*	8,149(8)
	Edmund M. Davis	2,274	*	25,218(8)
	William E. Davis	24,754(2)	*	105,000(9)
	William J. Donlon	15,343(3)	*	0
	Anthony H. Gioia	500	*	1,143(8)
	Bonnie Guiton Hill	700	*	6,909(8)
	H. Eugene Lockhart	375	*	1,143(8)
	Henry A. Panasci, Jr.	2,500	*	1,143(8)
	Patti McGill Peterson	500	*	9,797(8)
	Donald B. Riefler	1,000	*	24,475(8)
	Stephen B. Schwartz	500	*	9,802(8)
	John G. Wick	1,320	*	1,371(8)
	Named Executives:			
	B. Ralph Sylvia	17,285(4)	*	35,350(9)
	John W. Powers	23,220(5)	*	25,750(9)
	Darlene D. Kerr	12,228(6)	*	25,750(9)
	All Directors and Executive Officers (23) as a group	141,305(7)	*	430,961

* Less than one percent.

** Based on information furnished to the Corporation by the Directors and Executive Officers. Includes shares of Common Stock credited under the Employees' Savings Fund Plan as of March 6, 1997.

(1) Fidelity Management Trust Company serves as Trustee. The above represents shares in the Corporation's Non-Represented and Represented Employees' Savings Fund Plans. The Trustee will vote all shares of Common Stock held in the Trusts established for the Plans in accordance with the directions received from the employees participating in the Plans. The Trustee will vote shares for which it receives no instructions in the same proportion as it votes shares for which it receives instructions.

(2) Includes presently exercisable options for 22,625 shares of Common Stock.

(3) Includes presently exercisable options for 13,333 shares of Common Stock.

(4) Includes presently exercisable options for 13,000 shares of Common Stock.

(5) Includes presently exercisable options for 9,000 shares of Common Stock.

(6) Includes presently exercisable options for 6,000 shares of Common Stock.

(7) Includes presently exercisable options for 89,083 shares of Common Stock.

(8) Represents deferred stock units granted pursuant to the Outside Director Deferred Stock Unit Plan. No voting rights are associated with deferred stock units. For additional information regarding deferred stock units, refer to page II-16 ("Compensation of Directors").

(9) Represents stock units granted in 1995 pursuant to the 1995 Stock Incentive Plan and in 1996 and 1997 pursuant to the Officer Long-Term Incentive Plan. No voting rights are associated with stock units. For additional information regarding stock units granted to named executives, refer to pages II-8–II-9 ("1995 Stock Incentive Plan" and "Officer Long-Term Incentive Plan").

Section 16(a) Compliance

Section 16(a) of the Securities and Exchange Act of 1934 requires the Corporation's directors and executive officers to file initial reports of ownership and reports of changes in ownership of the Corporation's equity securities with the Securities and Exchange Commission ("SEC") and the New York Stock Exchange. Based solely on a review of the copies of such forms and written representations from the Corporation's directors and executive officers, the Company believes that during the preceding year the Corporation's directors and executive officers have complied with all Section 16(a) filing requirements.

Board of Directors' Compensation and Succession Committee Report On Executive Compensation

The Compensation and Succession Committee of the Board of Directors (the "Committee") is composed entirely of non-employee directors. The Committee has responsibility for recommending officer salaries and for the administration of the Corporation's officer incentive compensation plans as described in this report. The Committee makes recommendations to the Board of Directors which makes final officer compensation determinations.

This Committee report describes the Corporation's executive officer compensation policies, the components of the compensation program, and the manner in which 1996 compensation determinations were made for the Corporation's Chairman of the Board and Chief Executive Officer, Mr. William E. Davis.

The 1996 Executive Officer Compensation Program was composed entirely of base salary, frozen at 1995 levels, and 1996 grants of stock units and stock appreciation rights ("SARs") made pursuant to the new Officer Long-Term Incentive Plan ("LTIP") adopted by the Board of Directors on September 25, 1996, as described later in this report.

Base Salary

The Committee seeks to ensure that salaries of the Corporation's officers, including executive officers, remain competitive with levels paid to comparable positions among 23 Eastern Region investor-owned electric and gas utilities (the same companies included in the peer group shown on the performance graph - the "Peer Group") together with other U.S. electric and gas utilities with comparable revenues (collectively referred to as the "Comparator Utilities"). The Committee believes that competitive salaries provide the foundation of the Corporation's officer compensation program and are essential for the Corporation to attract and retain qualified officers, especially in light of the increasing competition within the industry. Each officer position has been assigned to a competitive salary range. The Committee intends to administer salaries within the 25th to 75th percentiles of practice with respect to those Comparator Utilities. The 1996 salary of the Chief Executive Officer and the average salary of the other four named executive officers fall below median (50th percentile) competitive levels. Since executive officer salaries were frozen at 1995 levels, as a condition for receipt of 1995 stock incentive grants, the competitiveness of 1996 executive officer compensation is based entirely on stock-related incentives in the form of stock units and stock appreciation rights granted under the 1995 Stock Incentive Plan ("SIP") and the Officer Long-Term Incentive Plan adopted by the Board of Directors on September 25, 1996.

1995 Stock Incentive Plan

On December 14, 1995, the Board of Directors approved the SIP to promote the success and enhance the value of the Corporation through the retention and continued motivation of the Corporation's officers and to focus their efforts toward the execution of business strategies directed toward improving financial returns to shareholders. Awards under the SIP consisted of stock units and SARs. The stock unit grants will be paid in cash in early 1998 based on the average closing price of the Corporation's common stock during the last twelve consecutive trading days in 1997. Dividends are credited (in an amount equivalent to dividends paid, if any, on the Corporation's common stock) with respect to all stock units granted. These credits are reinvested at the prevailing stock price, thereby increasing the number of stock units payable at the end of the period. The SARs first become exercisable on January 2, 1998 and may be exercised until they expire on December 31, 2002.

The SIP was structured so that any compensation earned by officers during the two-year period 1996 and 1997, other than base salary, will be based on the Corporation's year-end 1997 stock price and total returns realized by shareholders during this period. Accordingly, participants (including the exe

officers listed in the Summary Compensation Table) will not receive any salary increases (except to reflect promotions), annual bonus payments or stock option g[illegible] during 1996 and 1997. Participants have also sur-r[illegible]ed their rights to payment with respect to Performance Share Units (a performance-based incentive plan first adopted in 1992) granted in 1995 for the 1995-1997 period as a condition of participation in the SIP. Generally speaking, SIP grants were structured so that the Corporation's stock price would have to more than double during this two-year period in order for the total compensation of the participants to approximate median competitive levels.

The Committee does not intend to make further SIP grants other than the 1995 stock unit grants which become payable in early 1998 and the 1995 stock appreciation rights grants which become exercisable on January 1, 1998 and expire on December 31, 2002. Long-term incentive grants were made in 1996 and 1997 under the LTIP described below.

Officer Long-Term Incentive Plan

Since SIP stock unit grants will be paid in early 1998, when SIP SAR grants will also first become exercisable, and the Committee seeks to provide a continuous program of long-term stock incentives thereafter, on Sep-t[illegible] 25, 1996 the Board of Directors adopted the L[illegible]nd approved stock unit and SAR grants for the 1996-1998 period. These stock unit grants will be paid in cash in early 1999, one year after SIP stock unit grants have been paid. Dividends are credited (in an amount equivalent to dividends paid, if any, on the Corporation's common stock) with respect to the 1996-1998 stock unit grants, which are reinvested at the prevailing stock price, thereby increasing the number of stock units payable in early 1999. The payment value of the stock units will be based on the average closing price of the Corporation's common stock during the last twelve consecutive trading days in 1998. The 1996 LTIP SAR grants first become exercisable on January 2, 1999, and may be exercised until they expire on December 31, 2005.

On January 29, 1997, the Board of Directors approved the grant of LTIP stock units and SARs for the 1997-1999 performance period. These stock units, and accumulated dividend stock units, will be paid in early 2000 based on the average closing price of the Corporation's common stock during the last twelve consecutive trading days in 1999. The SARs first become exercisable on January 2, 2000, and can be exercised u[illegible]ey expire on December 31, 2006.

The size of both the 1996-1998 and 1997-1999 LTIP stock unit and SAR grants were determined, based on the price of the Corporation's common stock at the time these grants were made, so that the combination of the officers' current salaries plus the grant date present value of SIP, and LTIP grants for the 1996-1998 and 1997-1999 performance periods, would approximate the 50th percentile of comparator utility total compensation practice for the three-year period 1995 through 1997. The competitiveness of the actual compensation realized from SIP and the 1996-1998 and 1997-1999 LTIP grants will depend on the market value of the Corporation's common stock at the end of 1997, 1998, and 1999.

Compensation of William E. Davis, Chairman of the Board and Chief Executive Officer

Mr. Davis became CEO on May 1, 1993. In April 1996, Mr. Davis voluntarily reduced his annual salary from a level of $490,000 to the current level of $450,500. The Committee has been advised by its consultant that Mr. Davis' 1996 salary falls below the median relative to the CEOs of the Comparator Utilities. On December 13, 1995, the Board granted Mr. Davis 25,000 stock units and 142,500 SARs, with an exercise price of $10.75, under the 1995 Stock Incentive Plan. Mr. Davis' SIP stock unit and SAR grants were intended to maintain the competitiveness of his total compensation during the 1996 and 1997 period, based on the Corporation's year-end 1997 stock price, considering that his salary would not be increased and that he would receive no annual bonuses and no stock options during this two-year period.

As previously indicated, the Committee and the Board of Directors seek to provide a continuous program of long-term stock incentives beyond 1997 when SIP stock unit grants are paid and SIP SAR grants become exercisable. Accordingly, on September 25, 1996 the Board of Directors approved a grant of 45,000 stock units and 90,000 SARs, with an exercise price of $8.00, for Mr. Davis for the 1996-1998 performance period. On January 29, 1997 the Board of Directors approved a grant of 35,000 stock units and 70,000 SARs, with an exercise price of $10.30, for the 1997-1999 performance period. Both the 1996-1998 and 1997-1999 grants were made under the terms of the LTIP. The size of the 1996-1998 and 1997-1999 LTIP grants for Mr. Davis was determined so that the grant date present value of both grants, in combination with his current salary and his SIP grants, would approximate the 50th percentile for comparator utility chief executive officers during the 1995-1997 period. The competitiveness of the compensation Mr. Davis actually

realizes from the SIP and LTIP grants will depend on the market value of the Corporation's common stock at the end of 1997, 1998, and 1999.

The Committee is aware of the limitations that tax legislation has placed on the tax deductibility of compensation in excess of $1 million which is paid in any year to an executive officer. Currently none of the executive officers has received compensation subject to such limitations. The Committee will continue to monitor developments in this area and take appropriate actions to preserve the tax deductibility of compensation paid to executive officers, should this become necessary.

Through the combination of base salary, and during 1996 and 1997, the combination of stock unit and stock appreciation right grants, the Committee seeks to focus the efforts of officers toward improving, [illegible] ally and over the longer-term, the financial retu[illegible] its shareholders.

Submitted by the Compensation and Succession Committee of the Board of Directors:

Stephen B. Schwartz, Chairperson
William F. Allyn
Edmund M. Davis
Anthony H. Gioia
Henry A. Panasci, Jr.

Executive Compensation

The table below sets forth all compensation paid by the Corporation and its wholly-owned subsidiaries for services [illegible]red in all capacities during the fiscal years ended December 31, 1996, December 31, 1995 and December 31, 1[illegible] to the Chairman of the Board and Chief Executive Officer and to each of the other four most highly compensated Executive Officers of the Corporation for the fiscal year ended December 31, 1996.

Summary Compensation Table

Fiscal Years 1996, 1995 and 1994

			Annual Compensation			Long-Term Compensation		
Name	Position	Year	Salary(A)	Bonus	Other Annual Compensation	Restricted Stock Awards($)(D)	Securities Underlying Options/SARs(#)	All Other Compensation (E)
W. E. Davis	Chairman of the	1996	$462,351	$ 0	$ 0	$360,000	90,000	$43,365
	Board and Chief	1995	473,542	0	0	246,875	152,500	35,729
	Executive Officer	1994	441,542	0	0	—	20,000	44,916
A. J. Budney, Jr.	President and	1996	315,002	0	2,956(C)	$180,000	45,000	24,975
	Chief Operating	1995	236,251	50,000(B)	32,727	148,125	76,000	48,541
	Officer	1994	—	—	—	—	—	—
B. R. Sylvia	Executive Vice	1996	295,001	0	0	$114,000	28,500	10,174
	President	1995	295,001	0	0	98,750	49,000	24,832
		1994	290,834	0	0	—	5,000	8,061
J. W. Powers	Senior Vice	1996	211,002	0	0	$142,000	30,000	30,541
	President	1995	209,251	0	0	0	22,000	58,466
		1994	187,301	0	0	—	3,000	27,836
D. [illegible]rr	Senior Vice	1996	210,001	0	0	$82,000	20,500	9,415
	President	1995	191,085	0	0	74,063	31,500	7,338
		1994	183,968	—	—	—	3,000	6,829

(A) Includes all employee contributions to the Employees' Savings Fund Plan.

(B) 1995 bonus for Mr. Budney represents a bonus for 1995 guaranteed at the time he was hired if earnings per share thresholds were not met under the Officer Incentive Compensation Plan (an annual incentive compensation plan adopted by the Board of Directors on December 13, 1990, and suspended for 1996 and 1997 as a condition of participation in the SIP).

(C) 1996 and 1995 Other Annual Compensation for Mr. Budney represents amounts reimbursed for payment of taxes associated with relocation expenses.

(D) In 1995, stock units were granted pursuant to the SIP adopted by the Board of Directors on December 14, 1995. These stock units vest and become payable on December 31, 1997. Dividend equivalents, if any, will be credited on all stock units and will be paid in cash when the related stock units are paid. The 1995 values listed in the table were calculated by multiplying the stock units granted by the closing market price of the company's stock ($9.875) on the date of the grant (December 31, 1995).

In 1996, stock units were granted pursuant to the LTIP adopted by the Board of Directors on September 25, 1996. These grants were made for the three-year period January 1, 1996, through December 31, 1998, and vest and become payable on January 2, 1999. The 1996 values listed in the table were calculated by multiplying the stock units granted by $8.00, the price at the time these stock unit grants were determined. Dividend equivalents, if any, will be credited on these grants and will be paid when the related stock units are paid. For Mr. Powers, the value also includes the value of stock units granted in 1996 under the 1995 SIP.

As of the end of the 1996 fiscal year, based on a closing market price of $9.875, Mr. Davis held 70,000 stock units having a market value of $691,250; Mr. Budney held 37,500 stock units having a market value of $370,313; Mr. Sylvia held 24,250 stock units having a market value of $239,469; Mr. Powers held 17,750 stock units having a market value of $175,281; and Ms. Kerr held 17,750 stock units having a market value of $175,281.

(E) All Other Compensation for 1996 includes: Employer contributions to the Corporation's Employees' Savings Fund Plan: Mr. Davis ($4,500), Mr. Sylvia ($4,500), Mr. Powers ($4,500), and Ms. Kerr ($4,500); Taxable portion of life insurance premiums: Mr. Davis ($8,994), Mr. Budney ($1,472), Mr. Sylvia ($3,537), Mr. Powers ($3,528), and Ms. Kerr ($3,115); Employer contributions to the Corporation's Excess Benefit Plan: Mr. Davis ($9,371), Mr. Sylvia ($2,137), Mr. Powers ($1,513), and Ms. Kerr ($1,800); Payments under the Corporation's [illegible]location Policy: Mr. Budney ($3,503). All Other Compensation for the three years shown now include directors fees received from [illegible]nac Energy Corporation, which in prior proxy statements were reflected under Salary. In 1996, those fees were: Mr. Davis ($20,500), [illegible]. Budney ($20,000), and Mr. Powers ($21,000).

The following table discloses, for the Chairman of the Board and Chief Executive Officer, Mr. William E. Davis and the other named executives, the number and terms of SARs granted during the fiscal year ended December 31, 1996.

Option/SAR Grants in Last Fiscal Year

	Individual Grants				
Name	Number of Securities Underlying Options/SARs Granted (#) (A)	% of Total Options/SARs Granted to Employees In Fiscal Year	Exercise or Base Price Per Share	Expiration Date (B)	Grant Date Present Value (C)
W. E. Davis	90,000	23.90%	8.00	12/31/2005	$174,600
A. J. Budney, Jr.	45,000	11.95%	8.00	12/31/2005	87,300
B. R. Sylvia	28,500	7.57%	8.00	12/31/2005	55,290
J. W. Powers	9,500	2.52%	8.00	12/31/2002	17,480
J. W. Powers	20,500	5.44%	8.00	12/31/2005	39,770
D. D. Kerr	20,500	5.44%	8.00	12/31/2005	39,770

(A) The first grant listed for Mr. Powers represents a grant of SARs made under the SIP, while the second grant for Mr. Powers and the grant to the other four named executive officers represents SARs granted in 1996 under the LTIP.

(B) SARs granted in 1996 under the LTIP become exercisable January 2, 1999, and those granted to Mr. Powers under the 1995 SIP become exercisable January 2, 1998. All SARs become exercisable upon a change in control.

(C) The grant date present value of SARs is calculated using the Black-Scholes Option Pricing Model with the following assumptions: market price of the stock at the September 25, 1996 grant date ($8.00); exercise price of rights that expire on December 31, 2005 ($8.00); stock volatility (0.2867); dividend yield (5.02%); risk free rate (6.50%); exercise term (10 years); Black-Scholes ratio (0.2425); and Black-Scholes value ($1.94) for rights that expire on December 31, 2005. Stock volatility and dividend yield assumptions are based on 36 months of results for the period ending December 31, 1996. The Black-Scholes assumptions used to calculate the grant date present value for the rights provided to Mr. Powers [illegible] n expiration date of December 31, 2002 were the same as noted above, except for risk free rate (6.25%); exercise [illegible] 7 years); Black-Scholes ratio (0.2303); and Black-Scholes value ($1.84).

The following table summarizes exercises of options by the Chairman of the Board and Chief Executive Officer, Mr. William E. Davis, and the other named executives, the number of unexercised options held by them and the spread (the difference between the current market price of the stock and the exercise price of the option, to the extent that market price at the end of the year exceeds exercise price) on those unexercised options for fiscal year ended December 31, 1996.

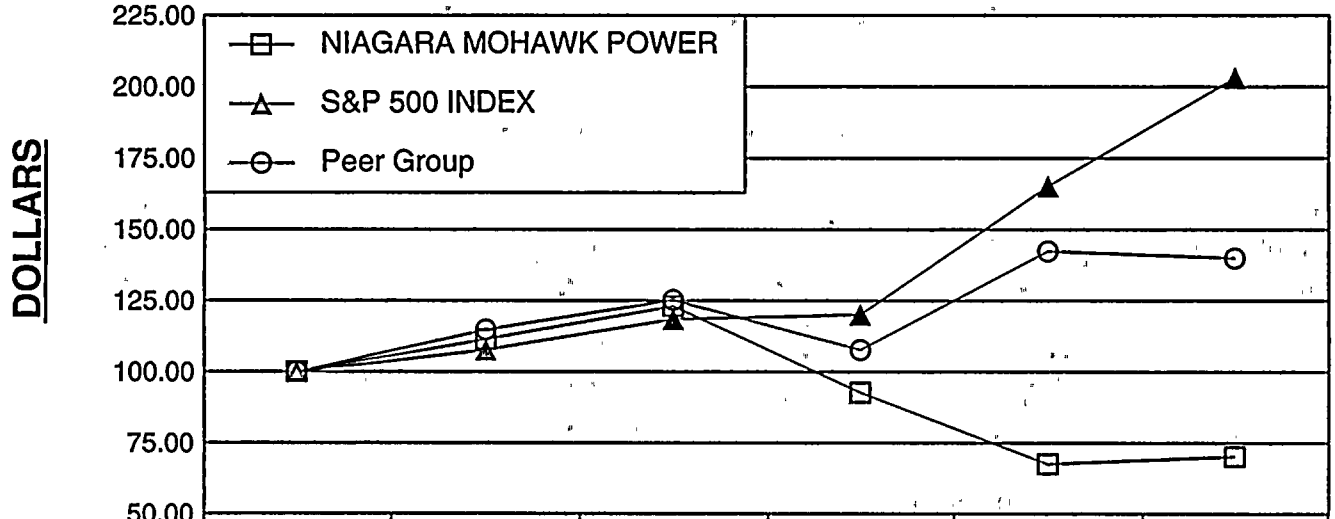
Aggregated Option/SAR Exercises in Last Fiscal Year and Fiscal Year-End Option Values

			Number of Securities Underlying Unexercised Options/SARs At Fiscal Year End (#)		Value of Unexercised Options/SARs At Fiscal Year-End ($) (A)	
Name	Shares Acquired on Exercise (#)	Value Realized ($)	Exercisable	Unexercisable	Exercisable	Unexercisable
W. E. Davis	0	$0	12,625	262,500	$0	$168,750
A. J. Budney, Jr.	0	0	0	121,000	0	84,375
B. R. Sylvia	0	0	8,000	82,500	0	53,438
J. W. Powers	0	0	6,000	55,000	0	56,251
D. D. Kerr	0	0	3,000	55,000	0	38,438

(A) Calculated based on the closing market price of the Corporation's common stock on December 31, 1996 ($9.875

NIAGARA MOHAWK POWER CORPORATION
Comparison of Five-Year Cumulative Total Return(1)
vs. S&P 500 and Peer Group of Eastern Region Utilities

TOTAL SHAREHOLDERS RETURNS



	Dec 91	Dec 92	Dec 93	Dec 94	Dec 95	Dec 96
NMPC	100.00	111.36	123.01	92.73	67.57	70.23
S&P 500	100.00	107.62	118.46	120.03	165.13	203.05
Peer Group	100.00	114.70	125.19	107.67	142.42	139.96

Assumes $100 invested on 12-31-91 in Niagara Mohawk stock, S&P 500 and Eastern Region utilities. All dividends assumed to be reinvested over the five-year period.

PEER GROUP OF EASTERN REGION UTILITIES:

Allegheny Power System Inc.
Atlantic Energy, Inc.
Baltimore Gas & Electric Company
Boston Edison Company
Brooklyn Union Gas Company
Central Hudson Gas & Electric Corp.
Central Maine Power Co.
Consolidated Edison Co. of New York, Inc.
DQE, Inc.
Delmarva Power & Light Co.
Eastern Utilities Associates
General Public Utilities Corp.
Long Island Lighting Co.
National Fuel Gas Company
New England Electric System
New York State Electric & Gas Corp.
Northeast Utilities
Orange & Rockland Utilities Inc.
Pennsylvania Power & Light Co.
PECO Energy Company
Public Service Enterprise Group Inc.
Rochester Gas & Electric Corp.
The United Illuminating Company

(1) Total returns for each Eastern Region Utility were determined in accordance with the Securities and Exchange Commission's regulations, i.e., weighted according to each issuer's stock market capitalization.

Retirement Benefits

The following table illustrates the maximum aggregate pension benefit, with certain deductions for Social Security, payable by the Corporation under both the Niagara Mohawk Pension Plan ("Basic Plan") and the Corporation's Supplemental Executive Retirement Plan ("SERP") to an officer in specified average salary and years-of-service classifications. Such benefit amounts have been calculated as though each officer selected a straight life annuity and retired on December 31, 1996 at age 65. The amount of compensation taken into account under a tax-qualified plan is subject to certain annual limits (adjusted for increases in the cost of living, $150,000 in 1995 and $150,000 in 1996). This limitation may reduce benefits payable to highly compensated individuals.

Annual Retirement Allowance

3-Year Average Annual Salary	10 Years Service*	20 Years Service	30 Years Service	40 Years Service	45 Years Service
$150,000	$21,090	$ 82,134	$ 82,134	$ 82,134	$ 94,770
225,000	25,440	127,134	127,134	127,134	127,134
300,000	25,866	172,134	172,134	172,134	172,134
375,000	25,866	217,134	217,134	217,134	217,134
450,000	25,866	262,134	262,134	262,134	262,134
525,000	25,866	307,134	307,134	307,134	307,134

*Subject to five-year average annual salary.

The credited years of service under the Basic Plan and the SERP for the individuals listed in the Summary Compensation Table are Mr. Davis, 7 years; Mr. Budney, 2 years; Mr. Sylvia, 6 years; Mr. Powers, 33 years; Ms. Kerr, 23 years.

The Basic Plan, a noncontributory, tax-qualified defined benefit plan, provides all employees of the Corporation with a minimum retirement benefit related to the highest consecutive five-year average compensation. Compensation covered by the Basic Plan includes only the participant's base salary or pay, subject to the maximum annual limit noted above. Directors who are not employees are not eligible to participate.

The SERP is a nonqualified, noncontributory defined benefit plan providing additional benefits to certain officers of the Corporation upon retirement after age 55 who have 20 or more years of employment. The Committee may grant exceptions to these requirements. The SERP provides for payment monthly of an amount equal to the greater of (i) 60% of monthly base salary averaged over the final 36 months of employment, less benefits payable under the Basic Plan, retirement benefits accrued during previous employment and one-half of the maximum Social Security benefit to which the participant may be entitled at the time of retirement, or (ii) benefits payable under the Basic Plan without regard to the annual benefit limitations imposed by the Internal Revenue Code. Participants in the SERP may elect to receive their benefit in a lump sum payment provided certain established criteria are met.

Employee Agreements

The Corporation entered into employment agreements with Messrs. Davis, Budney, Sylvia and Powers and Ms. Kerr, effective as of December 20, 1996, which superseded their prior agreements with the Corporation. The agreements have a three-year term, and, unless either party gives 60 days prior notice to the contrary, the agreements are extended at the end of each year for an additional year. In the event of a change in control (as defined in the agreement), the agreement will remain in effect for a period of at least 36 months thereafter unless a notice not to extend the term of the agreement was given at least 18 months prior to the change in control. The agreements provide that the executive will receive a base salary at the executive's current annual salary or such greater amount determined by the Corporation and that the executive will be able to participate in the Corporation's incentive compensation plans according to their terms. In addition, the executive is entitled to business expense reimbursement, vacation, sick leave, perquisites, fringe benefits, insurance coverage and other terms and conditions of the agreement as are provided to employees of the Corporation with comparable rank and seniority.

The employment agreements also provide that the executive's benefits under the SERP will be based on the executive's salary, annual incentive awards and SIP a[illegible], as applicable. Further, if the executive's employm[illegible]s terminated by the Corporation without cause (whether prior to or after a change in control), or by the executive for good reason after a change in control, or after completing eight years of service, the agreements provide that the executive will be deemed fully vested under such plan without reduction for early commencement. If the executive is under age 55 at the time of such termination, the executive will be entitled to a fully vested benefit under the SERP upon attaining age 55, without reduction for early commencement.

The agreements restrict under certain circumstances prior to a change in control the executive's ability to compete with the Corporation and to use confidential information concerning the Corporation. In the event of a dispute over an executive's rights under the executive's agreement following a change in control of the Corporation, the Corporation will pay the executive's reasonable legal fees with respect to the dispute unless the executive's claims are found to be frivolous.

If the executive's employment is terminated by the Corporation without cause prior to a change in control (a[illegible]fined in the agreement), the executive will be e[illegible]d to a lump sum severance benefit in an amount equal to two times the executive's base salary plus an amount equal to two times the greater of the executive's (i) most recent annual incentive award or (ii) average annual incentive award paid over the previous three years (a portion of the value of the SIP awards to the executive will be treated as incentive awards for 1996 and 1997 for this purpose). In addition, the executive will receive a pro rata portion of the incentive award which would have been payable to the executive for the fiscal year in which termination of employment occurs provided that the executive has been employed for 180 days in such fiscal year. In the event of such termination of employment, the executive will also be entitled to continued participation in the Corporation's employee benefit plans for two years, coverage for the balance of the executive's life under a life insurance policy providing a death benefit equal to 2.5 times the executive's base salary at termination and payment by the Corporation of fees and expenses or any executive recruiting or placement firm in seeking new employment.

If, following a change in control, the executive's employment is terminated by the Corporation without ca[illegible]or by the executive for good reason (as defined i[illegible]agreement), the executive will be entitled to a lump sum severance benefit equal to four times the executive's base salary. The executive will also be entitled to the additional benefits referred to in the last sentence of the preceding paragraph, except that employee benefit plan coverage for medical, prescription drug, dental and hospitalization benefits will continue for the remainder of the executive's life with all premiums therefor paid by the Corporation and coverage under other employee benefit plans will continue for four years. In the event that the payments to the executive upon termination of employment following a change in control would subject the executive to the excise tax on excess parachute payments under the Internal Revenue Code, the Corporation will reimburse the executive for such excise tax (and the income tax and excise tax on such reimbursement).

In November 1994, the Corporation entered into a supplemental agreement with Mr. Powers in exchange for his foregoing retirement under the Corporation's Voluntary Employee Reduction Program and continuing employment with the Corporation until December 31, 1996. This agreement was modified by an agreement between Mr. Powers and the Corporation entered into in October 1996 in exchange for his foregoing retirement on December 31, 1996, and continuing employment with the Corporation for up to twelve additional months. Under the agreements, Mr. Powers became entitled to a lump sum payment following the successful closing of the sale of HYDRA CO Enterprises, Inc., and to a severance allowance equal to one-half of his annual salary in effect on December 31, 1996, which was paid to him in January 1997. The agreements also provide that Mr. Powers would be entitled to (i) a SIP award of 7,500 stock units and 9,500 SARs, which would be fully vested (assuming retirement during 1997) and payable (in the case of stock units) or exercisable (in the case of SARs) on December 31, 1997, (ii) long-term incentive grants equivalent to those provided to other senior vice presidents for the 1996-1998 and 1997-1999 cycles (prorated for his period of service during those cycles), (iii) a lump sum payment for unused vacation for 1995, 1996 and 1997 upon retirement and (iv) "grandfathered" retiree medical coverages in effect on December 31, 1996. Under the agreements Mr. Powers also is entitled to a benefit under the Corporation's SERP no less than his benefit calculated as of November 1994, and to have the fees he received as a member of the board of directors of Opinac Energy Corporation (or would have received in the event that such fees are eliminated) taken into account in calculating his benefit under this plan period. In January 1997, the Committee agreed that if

Mr. Powers elected to receive a lump sum payment of his benefit under the SERP, it would be based on a discount rate no higher than the applicable discount rate in effect under the plan on December 31, 1996.

Compensation of Directors

Directors who are not employees of the Corporation receive an annual retainer of $20,000 and $1,000 per Board meeting attended. Directors who are not employees and who chair any of the standing Board Committees receive an additional annual fee of $3,000 and those who serve on any of the standing Board Committees, including the chair, receive $850 per Committee meeting attended. The Corporation also reimburses its directors for travel, lodging and related expenses they incur in attending Board and Committee meetings.

The Corporation had an unfunded, nonqualified retirement plan for directors who have not been employees of the Corporation. Under the plan, a director retiring at age 65 or older after ten years of service as a director was entitled to an annual benefit equal to such director's annual retainer, including Chairperson's fee if applicable, at the time of retirement. If a director of such age retired after serving less than ten years, but more than five years, such director would receive a pro-rated benefit based on years of service. If a director served on the Board less than five years or left before reaching age 65, no benefit was available.

On December 2, 1996, the retirement plan for outside directors was terminated by the Board of Directors, effective December 31, 1995. In its place, the Board of Directors adopted the Outside Director Deferred Stock Unit Plan, under which outside directors age 60 and older were given the alternative to: (1) continue to receive plan benefits, based on the current retainer of $20,000 ($23,000 for Committee Chairs), upon their retirement in accordance with the terms of the plan as described above; (2) have the present value of their accrued plan benefits, as of December 31, 1995, converted into deferred stock units based on the Corporation's closing stock price of $8.75 on December 2, 1996; or (3) receive payment of half their current retirement plan benefit and to have half the present value of their accrued retirement benefit as of December 31, 1995, converted into deferred stock units at a price of $8.75/share. The present value of accrued retirement benefits as of December 31, 1995, was converted into deferred stock units at a price of $8.[illegible]r outside directors who were under age 60.

Deferred Stock Units ("DSUs"), administered in accordance with the terms of the Outside Director Deferred Stock Unit Plan adopted by the Board of Directors on December 2, 1996, would be paid when a person ceases to be an outside director, either in a lump sum or in five equal annual installments. The first DSU installment payment would be made shortly after the director's service ends and the other installments would be paid on the first through fourth anniversaries of such date, based on the prevailing stock price at that time.

DSUs will be credited with respect to any dividends paid during the term of their deferral. Such dividend credits would be reinvested into DSUs of equivalent current value based on the prevailing price of the Corporation's common stock at that time.

Commencing in 1996, and annually thereafter, each outside director will be credited with DSUs equal in value to 50% of the prevailing year's annual retainer (60% for Committee Chairs). Accordingly, all outside directors were credited with 1,143 DSUs (1,371 for Committee Chairs) based on a closing stock pr[illegible] of $8.75 on December 2, 1996, the date the Board a[illegible]d the Outside Director Deferred Stock Unit Plan. The beneficial stock ownership table on page II-7, shows the DSUs which have been credited to each of the outside directors under this plan as of March 6, 1997.

The Corporation provides certain health and life insurance benefits to directors who are not employees of the Corporation. During 1996, the following directors received the indicated benefits under the foregoing arrangements: Mr. Allyn ($6,043), Mr. Burkhardt ($3,887), Mr. Costle ($3,684), Mr. Edmund Davis ($5,568), Mr. Donlon ($250), Dr. Hill ($432), Mr. Panasci ($182), Dr. Peterson ($3,305), Mr. Riefler ($6,313) and Mr. Wick ($5,848). Mr. Burkhardt received a consulting fee of $18,000 during 1996. Effective January 1997, each outside director covered under the Corporation's health care plans will contribute 20 percent of the monthly costs associated with these plans.

PROPOSAL 2

The Benedictine Sisters, 3120 W. Ashby, San Antonio, Texas 78228, who own 205 shares of the Corporation's common stock have advised the Corporation that they intend to present the following proposal at the 1997 Annual Meeting of Shareholders. The proposed resolution and supporting statement are as follows:

"WHEREAS WE BELIEVE: Responsible implementation of a sound, credible environmental policy increases long-term shareholder value by raising efficiency, decreasing clean-up costs, reducing litigation, and enhancing public image and product attractiveness;

Adherence to public standards for environmental performance gives a company greater public credibility than standards created by industry alone. For maximum credibility and usefulness, such standards should specifically meet the concerns of investors and other stakeholders;

Companies are increasingly being expected by investors to do meaningful, regular, comprehensive and impartial environmental reports. Standardized environmental reports enable investors to compare performance over time. They also attract investment from investors seeking companies which are environmentally responsible and which minimize risk of environmental liability.

WHEREAS: The Coalition for Environmentally Responsible Economies (CERES) - which includes shareholders of this Company; public interest representatives, and environmental experts - consulted with corporations to produce the CERES Principles as comprehensive public standards for both environmental performance and reporting. Fifty-four companies, including Sun (Sunoco), General Motors, H.B. Fuller, Polaroid, and Bethlehem Steel, have endorsed these principles to demonstrate their commitment to public environmental accountability. Fortune-500 endorsers say that benefits of working with CERES are public credibility; 'value-added' for the company's environmental initiatives;

In endorsing the CERES Principles, a company commits to work toward:

1. Protection of the biosphere
2. Sustainable natural resource use
3. Waste reduction and disposal
4. Energy conservation
5. Risk reduction
6. Safe products & services
7. Environmental restoration
8. Informing the public
9. Management commitment
10. Audits and reports

(Full text of the CERES Principles and accompanying CERES Report Form obtainable from CERES, 711 Atlantic Avenue, Boston MA 02110, tel: 617/451-0927).

CERES is distinguished from other initiatives for corporate environmental responsibility, in being (1) a successful model of shareholder relations; (2) a leader in public accountability through standardized environmental reporting; and (3) a catalyst for significant and measurable environmental improvement within firms.

RESOLVED: Shareholders request the Company to endorse the CERES Principles as a part of its commitment to be publicly accountable for its environmental impact."

Statement of Shareholders

"Many investors support this resolution. Those sponsoring similar resolutions at various companies have portfolios totaling $75 billion. The number of public pension funds and foundations supporting this resolution increases every year. The objectives are: standards for environmental performance and disclosure; methods for measuring progress toward these goals; and a format for public reporting of progress. We believe this is comparable to the European Community regulation for voluntary participation in verified and publicly-reported eco-management and auditing, and fully compatible with ISO 14000 certification.

Your vote FOR this resolution will encourage scrutiny of our Company's environmental policies and reports and adherence to standards upheld by management and stakeholders alike."

Board of Directors' Response to the Shareholder Proposal

In 1991, the Corporation adopted a Corporate Policy on Protection of the Environment which articulates the Corporation's proactive approach toward environmental issues. The environmental policy takes the Corporation beyond mere compliance with the law. In addition, its comprehensive environmental management system has helped the Corporation stay in the forefront of progress toward an environmentally sustainable energy future.

The Corporation carefully reviewed the CERES Principles and does not believe that endorsement of a set of broad-based principles, in addition to the Corporation's environmental policy and programs, would help the Corporation better fulfill its continuing commitment to environmental excellence. The Corporation believes that its environmental program provides the most specific and focused approach to ensure that the Corporation is in compliance with all applicable environmental regulations and to position itself as a recognized leader for its environmental achievements.

Therefore, the Board of Directors recommends that you vote AGAINST this proposal.

PROPOSAL 3

Edward S. George, 89 Corning Hill, Glenmont, New York 12077, who owns 5,000 shares of the Corporation's Common Stock, has advised the Corporation that he intends to present the following proposal at the 1997 Annual Meeting of Shareholders:

"Whereas the dividend is the first casualty in any economic downturn and the stockholder is the first casualty and the last to benefit from an upturn, be it

Resolved: That when a dividend is cut, it is recommended that, with respect to future contract obligations, no salaries will be increased or any stock options allowed to executives or directors until the dividend is restored to its original amount before the cut."

Statement of Shareholder

"The bullet must be large enough to enable the executives and directors as well as the stockholders to get their teeth on it.'

The administration will maintain that the increases in salary and stock options are necessary to attract and hold good people. This cliche' belongs with the one 'The check is in the mail', the New York State Legislature and certain elected officials to justify an increase in their salaries, and 'I'm from the government and I'm here to help.'"

Board of Directors' Response to the Shareholder Proposal

The suspension of dividend payments on the common stock was taken to help stabilize the Corporation's financial condition and provide flexibility as the Corporation addresses growing pressure from mandated power purchases and weaker sales. While we recognize the unfavorable effect it has had on our shareholders, the Corporation believes that the shareholders' long-term financial interests would not be served by basing compensation decisions on dividend payment levels.

The Corporation and the Compensation and Succession Committee of the Board of Directors have made decisions regarding the compensation of officers and other employees which we believe are appropriate to the circumstances the Corporation faces. The Compensation and Succession Committee's Report on Executive Compensation, which appears earlier in this Proxy Statement, describes the decisions that have been made regarding the structure and administration of the officer compensation program, including a freeze on salary increases during 1996 and 1997. These decisions will ensure the Corporation's ability to maintain a group of qualified officers, in an increasingly competitive industry, and will directly relate the payment of a significant component of their total compensation to the future value of our stock and our shareholders' investment. Adopting a rigid, inflexible rule like that proposed by Dr. George could harm the stockholders by making retention of qualified executives difficult, if not impossible.

Therefore, the Board of Directors recommends that you vote AGAINST this proposal.

Additional Information

The directors and officers of the Corporation and its subsidiaries are insured against obligations which may be incurred as a result of the Corporation's indemnification of its directors and officers. The coverage also insures the directors and officers against liabilities for which they may not be indemnified by the Corporation or its subsidiaries, except a dishonest act or breach of trust. The insurance was purchased from the National Union Fire Insurance Company, Associated Electric & Gas Insurance Services, Ltd., Aetna Casualty and Surety Company, Federal Insurance Company, CNA Insurance Company and ACE Insurance Company, Ltd. for the term from January 31, 1997 to January 30, 1998 for an aggregate premium of $1,829,451.

Independent Accountants

The Corporation has selected the independent accounting firm of Price Waterhouse LLP to examine the financial statements of the Corporation and its subsidiaries for the year ended December 31, 1997. Representatives of Price Waterhouse LLP will be present at the meeting with the opportunity to make a statement if they desire to do so and will be available to respond to appropriate questions.

Quarterly Reports

Shareholders who are *not receiving* quarterly reports *directly from the Corporation* and who would like to receive the Corporation's quarterly reports may write to Investor Relations, Niagara Mohawk Power Corporation, 300 Erie Boulevard West, Building C 3, Syracuse, New York 13202-7904 to be included on the Corporation's mailing list.

Other Business

Management does not know of any matters of business other than the foregoing to be presented at the Annual Meeting. However, if other matters are properly brought before the meeting or any adjournment thereof, the proxies will be voted accordingly to the best judgment of the persons authorized thereby.

Expenses incurred in connection with this solicitation will be borne by the Corporation. The firm of D. F. King & Co., Inc. has been engaged to aid in the solicitation of proxies for a fee of $10,500. Directors, officers or employees of the Corporation may solicit proxies in person, by telephone, or by mail, but without extra compensation. Upon request, brokerage houses or other nominees or fiduciaries will be reimbursed by the Corporation for the expense of forwarding proxy material to beneficial owners of stock.

Shareholder Proposals For 1998 Annual Meeting

Proposals of shareholders intended to be presented at the 1998 Annual Meeting must be received by the Corporation on or before December 2, 1997, to be considered for inclusion in the Corporation's Proxy Statement and Form of Proxy relating to that meeting.

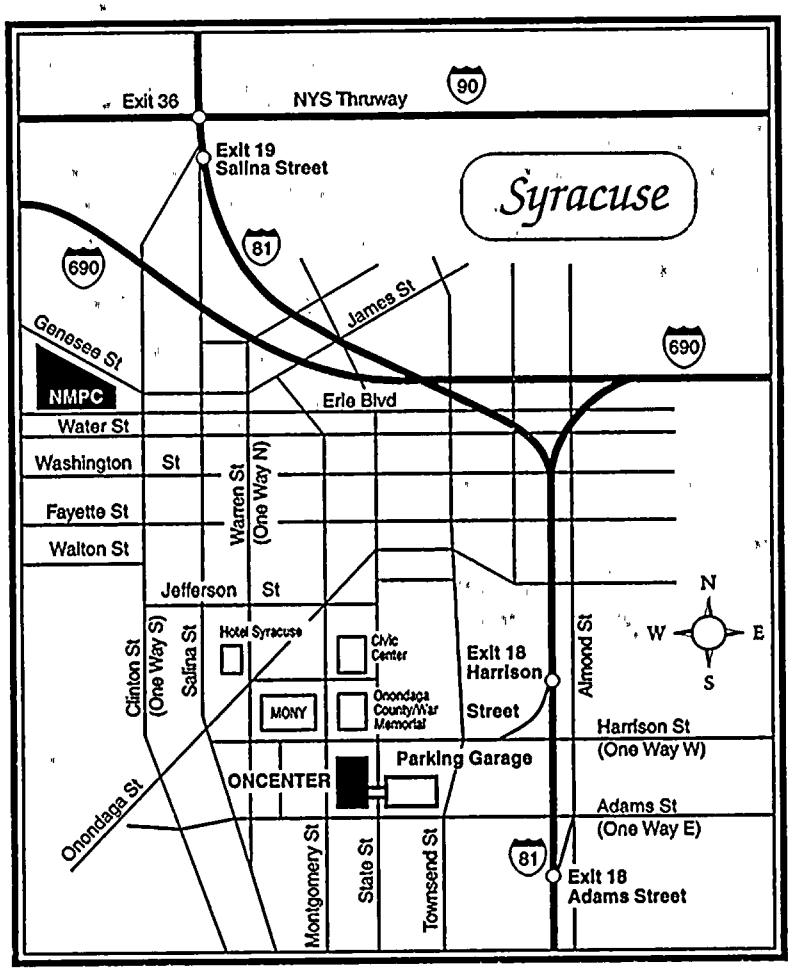
By Order of the Board of Directors

Kapria Rice

Kapria A. Rice
Secretary

Dated: April 7, 1997

ONCENTER Directions



From the NYS Thruway (I90):
Take Exit 36, Rt. 81 South to Syracuse. Harrison Street Exit #18, right on Harrison two blocks, turn left onto State Street, left into parking garage.

From the North:
Rt. 81 South to Harrison Street Exit #18, right on Harrison two blocks, turn left onto State Street, left into parking garage.

From the South:
Rt. 81 North to Adams Street Exit #18, straight one block, left onto Harrison two blocks, turn left onto State Street, left into parking garage.

Directors

William F. Allyn (A, C, F)
[illegible]ent and Chief Executive Officer
[illegible] Allyn, Inc., Skaneateles Falls, NY

Albert J. Budney, Jr.
President

Lawrence Burkhardt, III (F)
Former Executive Vice President
Nuclear Operations, San Diego, CA

Douglas M. Costle (B, D, F)
Distinguished Senior Fellow and
Chairman of the Board
Institute for Sustainable Communities
Montpelier, VT

Edmund M. Davis (B, C, D, E)
Attorney, Syracuse, NY

William E. Davis (D)
Chairman of the Board and
Chief Executive Officer

William J. Donlon
Former Chairman of the Board and
Chief Executive Officer, Syracuse, NY

Edward W. Duffy (C, D, F)
Former Chairman of the Board and
Chief Executive Officer
Marine Midland Banks, Inc.
Sarasota, FL
(Retired May 7, 1996)

Anthony H. Gioia (C, F)
Chairman of the Board and
Chief Executive Officer
Gioia Management, Inc.
Buffalo, NY
(Effective April 1, 1996)

Dr. Bonnie Guiton Hill (A, B, D)
President and Chief Executive Officer
Times Mirror Foundation
Los Angeles, CA

H. Eugene Lockhart (A, E)
Chief Executive Officer
MasterCard International
Purchase, NY
(Effective June 11, 1996)

Henry A. Panasci, Jr. (C, E)
Chairman
Cygnus Management Group, LLC
Syracuse, NY

Dr. Patti McGill Peterson (A, B)
Senior Fellow of the
Cornell Institute for Public Affairs
Cornell University, Ithaca, NY

Donald B. Riefler (A, D, E, F)
Financial Market Consultant
Vero Beach, FL

Stephen B. Schwartz (C, D, E)
Former IBM Senior Vice President
Palm Beach Gardens, FL

John G. Wick (A, B, E)
Attorney, East Amherst, NY

A. Audit Committee
B. Committee on Corporate Public Policy and Environmental Affairs
C. Compensation and Succession Committee
D. Executive Committee
E. Finance Committee
F. Nuclear Oversight Committee

Officers

William E. Davis
Chairman of the Board and
Chief Executive Officer

Albert J. Budney, Jr.
President

B. Ralph Sylvia
Executive Vice President
Electric Generation and
Chief Nuclear Officer

David J. Arrington
Senior Vice President
Human Resources

Darlene D. Kerr
Senior Vice President
Energy Distribution

Gary J. Lavine
Senior Vice President
Legal and Corporate Relations

John W. Powers
Senior Vice President
and Chief Financial Officer
(Effective January 25, 1996)

Richard B. Abbott
Vice President and
General Manager-Nuclear

Joseph T. Ash
[illegible]sident
[illegible]ng and Support Services
([illegible]ve January 25, 1996)

Nicholas J. Ashooh
Vice President
Public Affairs and Corporate Communications

Thomas H. Baron
Vice President
Fossil and Hydro Generation

Edward J. Dienst
Vice President
Electric Delivery
(Effective May 7, 1996)

William F. Edwards
Vice President
Financial Planning

Thomas R. Fair
Vice President
Environmental Affairs

Theresa A. Flaim
Vice President
Corporate Strategic Planning

Paul J. Kaleta
Vice President
Law and General Counsel

Martin J. McCormick, Jr.
Vice President
Nuclear Engineering
(Effective December 1, 1996)

Douglas R. McCuen
Vice President
Government and Regulatory Relations

Clement E. Nadeau
Vice President
Marketing and Planning
(Effective August 16, 1996)

Kapua A. Rice
Corporate Secretary

Arthur W. Roos
Vice President-Treasurer

Richard H. Ryczek
Vice President
Gas Operations

William J. Synwoldt
Vice President
Information Technology and
Chief Information Officer
(Effective May 7, 1996)

Steven W. Tasker
Vice President-Controller

Carl D. Terry
Vice President
Nuclear Safety Assessment and Support
(Effective December 1, 1996)

Andrew M. Vesey
Vice President
Power Delivery
(Resigned May 1, 1996)

Stanley W. Wilczek, Jr.
Vice President
Customer Service

Niagara Mohawk Power Corporation
300 Erie Boulevard West
Syracuse, New York 13202