Leading the Change

Contents

This report was designed, photographed, written and produced by Niagara Mohawk employees. Employees shown in photo on page 1 (from left): Beverly Rogers, Barry Thornton, Kenneth Stack, Sharon DeLee, David Dillenbeck, Bob Kimber, Dan Williams, John Napolitano, Barbara Smith, Gina Jones, Michele DeCaire, and Bill Davis (center).

Niagara Mohawk has major strengths on which to build, such as our industry expertise, a skilled and dedicated work force and our strategic location.... Our success will be determined by how well we capitalize on those strengths and minimize our weaknesses, and by how well we fare in changing the regulatory paradigms to allow competition on a fair and equal footing.

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

Dear shareholder:

Niagara Mohawk is a changing company in a changing industry. The pace of competition is quickening, and all utilities, including Niagara Mohawk, must become more competitive if they are to grow and prosper in the electricity and natural gas marketplaces of the future.

Niagara Mohawk faces profound challenges during this transitional period. Responding to those challenges requires us to bring down our costs, so that we can offer our customers competitive prices, and to gain the necessary regulatory flexibility to perform well in the faster-moving competitive marketplace.

We recognize that the specter of increasing competition is changing traditional views of utility investments. The heightened level of concern expressed by bond rating agencies and the end-of-year slippage of our common stock price, after strong performance during the first three quarters, clearly indicate the perception of increased risk in the industry. This higher level of risk will necessitate further strengthening of our capital structure by additional common and preferred stock issuances in 1994.

NIAGARA MOHAWK ALSO HAS MAJOR STRENGTHS ON WHICH TO BUILD

Circumstances unique to Niagara Mohawk, as well as burdens placed on all utilities during decades of regulation, now loom as obstacles to fair competition with new, unregulated market entrants.

As we confront these challenges and address these obstacles, Niagara Mohawk also has major strengths on which to build, such as our industry expertise, a skilled and dedicated work force and our strategic location in major electricity and natural gas markets. Our success will be determined by how well we can capitalize on those strengths and minimize our weaknesses, and by how well we fare in changing the regulatory paradigms to allow competition on a fair and equal footing.

Neither Niagara Mohawk nor anyone else in the electricity business has definitive answers regarding the final shape of the evolving competitive marketplace. However, we are pursuing responses based on a coordinated strategic planning process that we are confident will position Niagara Mohawk to be competitive in any environment.

Many of the responses are already well under way. We began four years ago with the company's self-assessment and the development of our Vision to become the most responsive and efficient energy services company in the Northeast. Since then, we have been streamlining the company and emphasizing customer service excellence.

Our commitment to the Vision remains, and as competition grows, its importance increases and our efforts to reach it continue to intensify.

Part of that Vision was, and is, to attain high standards of environmental quality in all the company's operations. We do not intend, in the midst of all our competitive challenges, to neglect our responsibilities in this important area. Environmental stewardship makes sense not only from a societal perspective, but also from a business perspective.

OUR COMMITMENT TO THE VISION REMAINS

In addressing our competitive challenges during 1993, we made notable progress in our efforts to cut costs. Our downsizing program, which focused on managed attrition, resulted in a net reduction of almost 650 employees during 1993. Internal spending levels were five percent below challenging targets, justifying a full award for cost management in our MERIT incentive regulation program. Through a continuation of the debt refinancing program initiated in 1992, interest on long-term debt was reduced by about $10 million.

Supported by our continuing self-assessment efforts, spending targets have allowed for no increase in base electricity rates this year, despite continued growth in payments to unregulated generators, and only a 1.7 percent increase in natural gas rates.

Looking to the future, it became clear in late 1993 that our downsizing efforts must be significantly more aggressive to address the pace of increasing competition. In early 1994,

We both accelerated and deepened our staffing cuts by announcing layoffs of almost 900 employees. The layoffs, though by far the most painful action we must take, are only part of our efforts to reshape Niagara Mohawk into a more competitive, customer-focused company. However, internal changes by themselves are not enough. It also is increasingly clear that traditional regulation is inadequate to advance the interests of our shareholders and our customers in the competitive era.

Niagara Mohawk President John M. Endries (standing) meets with senior officers including, from left, Michael P. Ranalli, John W. Powers, B. Ralph Sylvia, Darlene D. Kerr, Robert J. Patrylo, and David J. Arrington. Not shown, Gary J. Lavine.

Accordingly, we continue our pursuit of new regulatory approaches that will allow us more flexibility and provide us with broader-based incentives to operate efficiently and profit accordingly.

In February 1994, we submitted to the New York State Public Service Commission a rate filing that proposes setting 1995 rates at a level somewhat higher than inflation and subsequently, from 1996 to 1999, utilizing an indexing mechanism that ties our electricity price increases to the rate of inflation. Our price increases will be limited to the level of the cap, and our profitability will depend heavily on our ability to improve efficiency and control costs.

We also are seeking to reduce the competitive disadvantage caused by costs unfairly imposed on utilities that our unregulated competitors do not bear, such as high taxes. More than 16 cents of every dollar our customers pay for their electricity and natural gas goes to the government in some form of tax, including both state Gross Receipts Taxes and local property taxes that are much higher than comparable taxes paid by unregulated competitors.

OUR SERVICE TERRITORY HAS SUFFERED SIGNIFICANT JOB LOSSES

Niagara Mohawk's greatest burden, however, is the requirement that we buy electricity from unregulated generators at above-market prices. The high cost of this unneeded power is the largest single reason for the recent increases in our customers' electric bills. In 1993, payments to unregulated generators represented 67 percent of our energy costs, but accounted for only 28 percent of our energy supply.

We have taken assertive action to bring those excess payments under control, a have been successful to a degree, despite being constrained by long-term contracts.

It is imperative that we continue all efforts directed at both controlling customer b increases and attaining greater pricing flexibility, since our financial future will remai closely tied to the economic viability of our service territory.

It is no secret that New York state suffered a deeper recession than many parts of the country during the 1990-1992 period, and is lagging behind the general economic recovery that began last year. Our service territory has suffered significant job losses, and many of our industrial customers are in intensely competitive businesses.

Beyond our actions to control bill increases, we are engaged directly in efforts to increase economic activity in our service territory and in New York state.

PROJECTED EARNINGS GROWTH MAKES ATTAINABLE OUR PRINCIPAL FINANCIAL OBJECTIVE

A major new venture is the Alliance for a New, New York. In partnership with state government, all of the state's major utilities launched a new marketing and advertising effort early in 1994 promoting New York state as a center of high-technology resources with a skilled work force.

The combination of tight cost controls, regulatory changes and exceptional customer service will enable Niagara Mohawk to augment economic development efforts by once again offering competitive rates to attract and retain industry in Upstate New York.

The same combination encourages us to believe that your company can sustain profitability during the transition to the competitive market. Our financial performance showed improvement in 1993, with earnings of $1.71 per share, up 10 cents from $1.61 in 1992. Despite the very difficult challenges ahead, we will strive to continue earnings growth through cost-cutting efforts, achieving our MERIT and other incentive goals and increasing profitability in our gas business.

The restructuring of the natural gas industry began in the late 1970s and wa essentially completed when the Federal Energy Regulatory Commission's Order 6 took full effect in late 1993. During the restructuring, Niagara Mohawk took the necessary actions to position the company well to compete.

Projected earnings growth makes attainable our principal financial objective: total shareholder returns that continue to outperform utility industry averages. An important reason for this stems from our relatively low dividend payout ratio, which affords considerable flexibility to increase our dividend over the next couple of years at a rate higher than the industry average.

Niagara Mohawk has been a pioneer in the electric utility industry since harnessing Niagara Falls 100 years ago. We helped lead the change that electrified this country and turned New York state into its initial industrial hub.

In this new competitive electric utility industry Niagara Mohawk is again mapping a path to lead the change.

Bill Davis

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

Niagara Mohawk continued to build financial strength in 1993, posting earnings of $240 million, or $1.71 per share, up from earnings of $219.9 million, or $1.61 per share in 1992.

The earnings increase, which is attributable in part to the company's success in cutting operating costs, came despite continuing economic difficulty across Niagara Mohawk's service territory.

Niagara Mohawk's 1993 earnings included $20.3 million in special performance incentive awards known as MERIT. The company has recorded $77.1 million of MERIT awards since the start of the program in 1991. MERIT will continue through 1995.

The company continued its commitment to dividend growth, raising the quarterly dividend by 25 percent, from 20 cents per share to 25 cents per share in March 1993.

Concerns in the financial community over the utility industry's ability to adapt to the growth of competition led to general weakness among utility stocks toward the end of 1993. Niagara Mohawk's common stock ended the year at $20.25 per share, after hitting a yearly high of $25.25 per share in September. That still topped the 1992 year-end stock price of $19.125, marking the third straight year of year-to-year stock price increases. Niagara Mohawk's 5.9 percent share price increase in 1993 beat the Dow Jones Utilities Average increase of 3.75 percent for 1993.

Niagara Mohawk continued its move to strengthen capitalization ratios in response to the perceived increase of risk in the utility business. The company issued 4.5 million shares of common stock in April 1993 and plans a similar offering in 1994. Further sales of common stock are planned, based on market conditions.

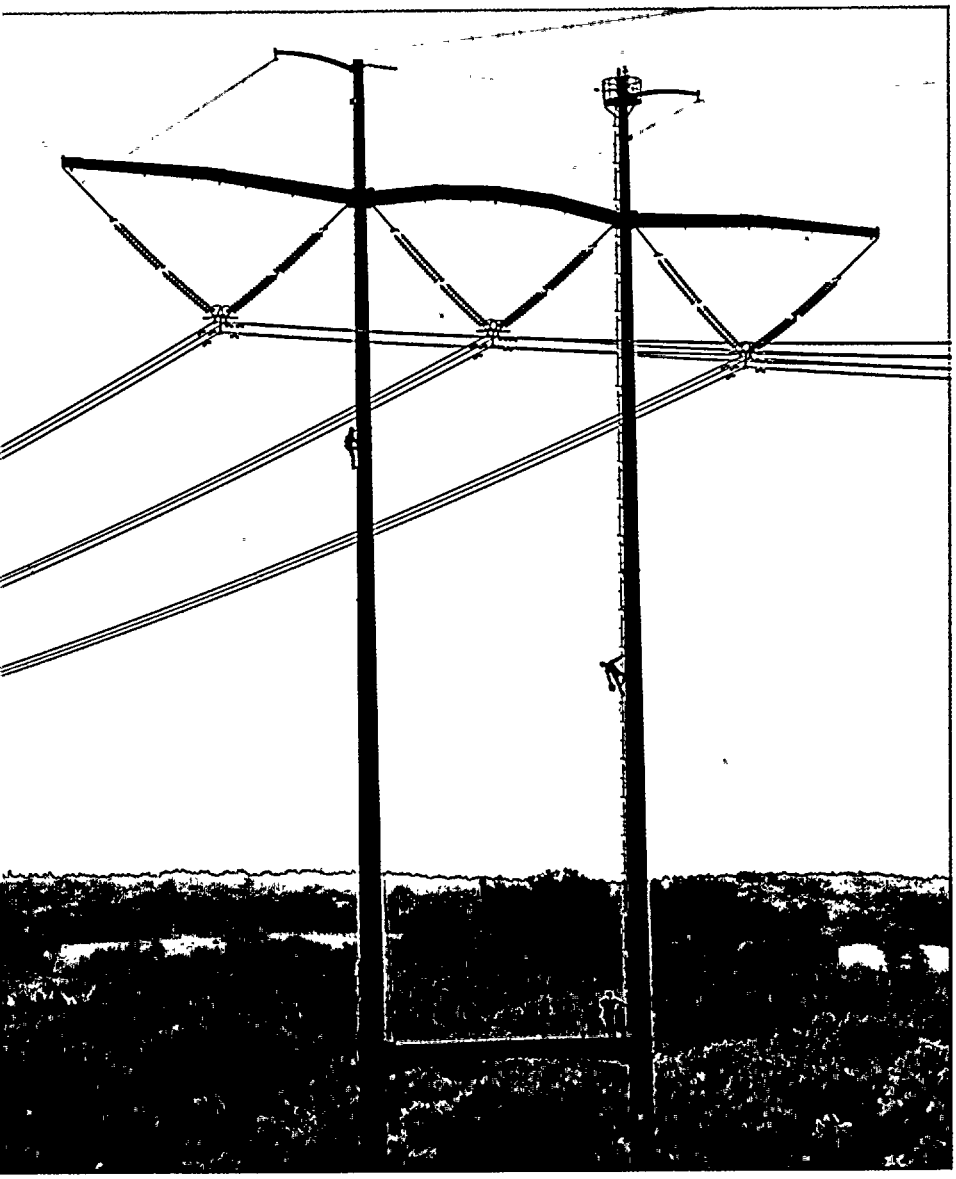
The company also continued its aggressive debt refinancing program, retiring more than $600 million in higher-cost debt. The refinancing reduced the company's average annual interest expense by approximately $7.8 million.

In May the company reached an agreement in principle for the sale of all petroleum and natural gas assets of its Canadian subsidiary Opinac Exploration Ltd. to Tarragon Oil and Gas Ltd. of Calgary, Alberta. The sale, which was effective July 1, called for a cash consideration of $122 million Canadian. Niagara Mohawk retains its interest in Canadian Niagara Power Ltd., Opinac's electric division.

Highlights

	1993	1992	%Change
Total operating revenues	$ 3,933,431,000	$ 3,701,527,000	6.3
Income available for common stockholders	$ 239,974,000	$ 219,920,000	9.1
Earnings per common share	$1.71	$1.61	6.2
Dividends per common share	$0.95	$0.76	25.0
Common shares outstanding (*average*)	140,417,000	136,570,000	2.8
Utility plant (*gross*)	$10,108,529,000	$ 9,642,262,000	4.8
Construction work in progress	$ 569,404,000	$ 587,437,000	(3.1)
Gross additions to utility plant	$ 519,612,000	$ 502,244,000	3.5
Public kilowatt-hour sales	33,750,000,000	33,581,000,000	0.5
Total kilowatt-hour sales	37,724,000,000	36,611,000,000	3.0
Electric customers at end of year	1,552,000	1,543,000	0.6
Electric peak load (*kilowatts*)	6,191,000*	6,205,000	(0.2)
Natural gas sales (*dekatherms*)	83,201,000	79,195,000	5.1
Natural gas transported (*dekatherms*)	67,741,000	65,845,000	2.9
Gas customers at end of year	501,000	493,000	1.6
Maximum day gas deliveries (*dekatherms*)	929,285**	905,872	2.6

* The company set an all-time electric peak load on January 19, 1994, sending out 6,458,000 kilowatts.
**The company set an all-time maximum day gas deliveries on January 26, 1994, of 995,801 dekatherms.



Above, Workers paint transmission towers in Selkirk, N.Y., as part of Niagara Mohawk's maintenance program. The company's transmission and distribution system spans 129,000 miles of Upstate New York.

Right, An economic development rate from Niagara Mohawk allowed the F.X. Matt Brewery of Utica N.Y. to expand its award-winning Saranac product line to include Saranac Black & Tan and Saranac Golden.

Electric and natural gas utilities are follow the airline, telephone, trucking and oth industries into a more competitive futu The rapid change demands swift, decisive action on a scale unprecedented in the utility industry, and a commitment to making difficult choices.

Preparing for and carrying out fundamental organizational restructuring has been the focus of our efforts for several years. The pace of change will accelerate still further in 1994 and beyond.

The passage by the U.S. Congress of the 1992 Energy Policy Act will, as the Act is implemented, accelerate the trends toward competition and deregulation in the electric utility industry that began in the 1980s.

Two major features of the Act are increasing competition:

- The creation of a class of competitors called Exempt Wholesale Generators (EWGs), that can sell electricity at wholesale without the meaningful regulatory restrictions placed on other unregulated generators (retail sales by EWGs and unregulated generators remain against federal law, states can allow them).
- Open access to utility transmissi systems that will make it easier for EWGs and other unregulated generators to reach wholesale customers.

As the Energy Policy Act is implemented and new competitors emerge, traditional utilities must reposition themselves to prosper in the new business environment. Niagara Mohawk already has most of the major components of a competitive, customer-focused organization either in place or in the works. The company has followed up its 1991-1992 reorganization into Business Units with core process redesign efforts in each unit–continually finding new, more efficient ways of doing business.

To measure its progress, Niagara Mohawk began benchmarking its performance in seven key financial, operating and safety areas against peer utilities, starting with 1991 baseline data.

At the same time, the company continued to refine its strategic planning process. The 1994-1996 Corporate Strategic Plan has been revised to reflect developments in the industry and at Niagara Mohawk. It provides guidance for the Business Units and Corporate Support Units to coordinate their business planning and budgeting. The plan makes use of the information provided by the company's CIRCA 2000 stu (Comprehensive Industry Restructuring and Competitive Assessment for the Ye 2000), the first phase of which was completed in 1993.

Innovative Ratemaking

One of the first major initiatives resulting from CIRCA 2000 is an innovative regulatory proposal sent to the state Public Service Commission in February 1994.

The proposal would set Niagara Mohawk's electricity prices for 1995 through 1999. It is a significant departure from traditional utility ratemaking and, if approved, will make Niagara Mohawk one of the first utilities in the country to substantially reduce regulatory barriers, and allow the company to respond more effectively to competition.

The proposal would provide Niagara Mohawk with the flexibility to be able to offer competitive electricity prices to industrial and commercial customers quickly. Speed is needed because large industrial and commercial customers can increasingly choose alternate sources of supply, either through moving out of Niagara Mohawk's service territory, generating their own electricity or even, under certain circumstances, buying power from an unregulated generator.

The proposal also would assure the PSC that residential and commercial customers who do not have supply alternatives will be protected from excessive rate increases from 1996 to 1999.

The rate proposal essentially puts a cap on increases in the company's prices. Below the limit of the cap, Niagara Mohawk would have greater flexibility to price aggressively to retain current business and to draw new business into the state.

Niagara Mohawk also will begin offering a range of options to residential and small commercial customers, based on the cost of serving them and their needs. Examples include lower costs for off-peak electricity use and separation of charges for various services.

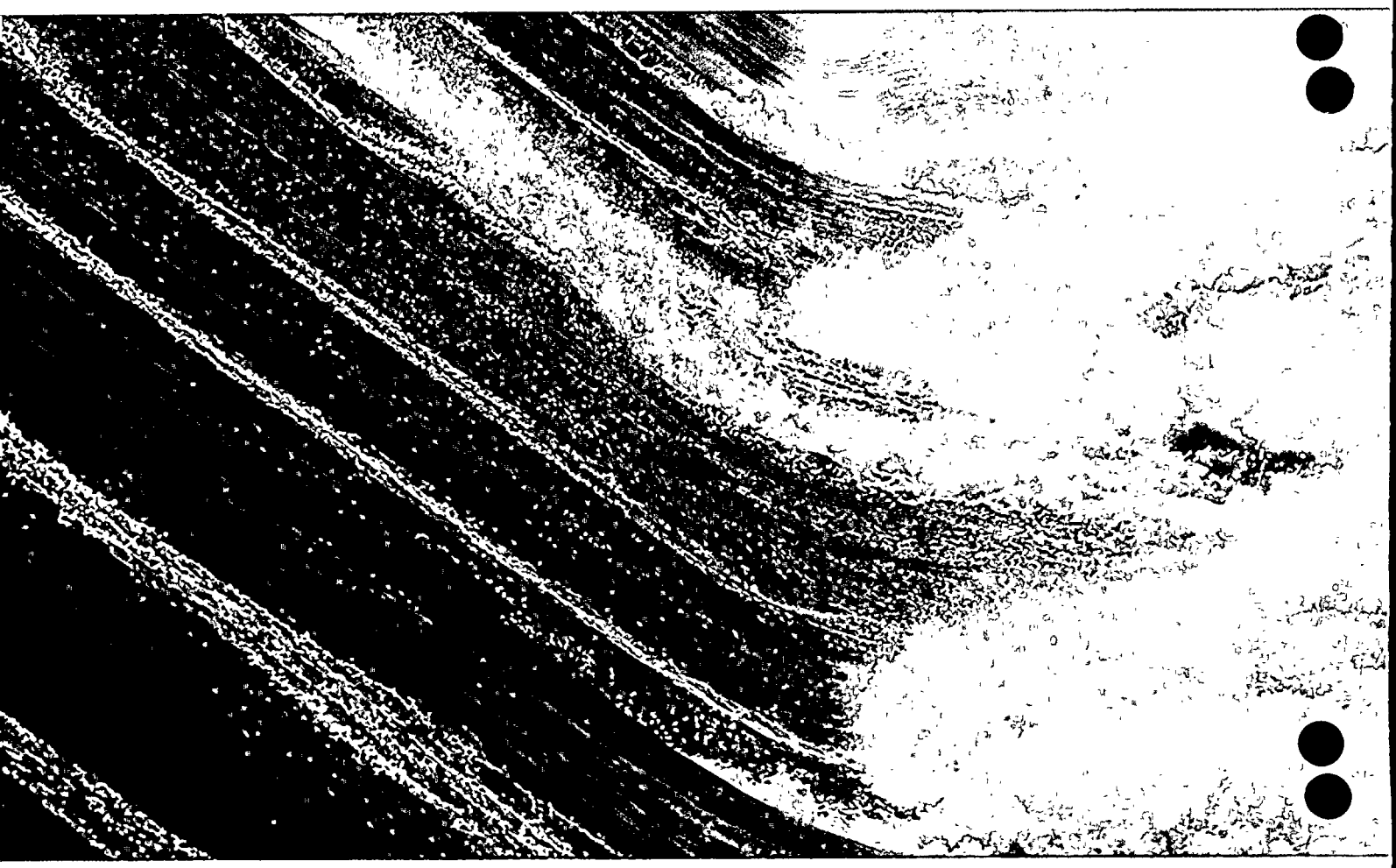
A prototype of the ratemaking package, Niagara Mohawk's SC-10 rate, was approved by the PSC in mid-1993. The rate allows the company to offer competitive electricity prices to large commercial and industrial customers who can show that self-generation is a viable option for their businesses. The SC-10 rate will keep Niagara Mohawk's largest customers on the utility system, helping to hold down rates for other customers. Thus far, 16 of an estimated 75 eligible customers have been offered the SC-10 option, and six have accepted. More acceptances are expected.

Unregulated Generators

The largest single barrier to moderating rates is the level of payments Niagara Mohawk must make to unregulated generators. Because federal law requires utilities to buy power output from these producers, unregulated generators have proliferated throughout the country. New York has drawn an oversupply, largely because of a state law that required utilities to pay above-market prices for power from unregulated generators. That law was repealed in 1992, but not before Niagara Mohawk's service territory attracted more unregulated generators than that of any other utility in the state (see chart, pg. 50).

Niagara Mohawk's payments to unregulated generators were equivalent to 22 cents of every electric customer dollar in 1993, and that is expected to increase to 27 cents, or nearly $1 billion, in 1994.

That amount would be much higher if Niagara Mohawk had not continued in 1993 to take a range of strong actions, including unregulated generator buy-outs and contract renegotiations, to reduce the impact on customers by more than $1 billion over the next decade. The company now is obligated to buy about 2,400 megawatts of unregulated generator capacity, down from about 6,600 megawatts of potential obligations at the start of 1992. All the capacity is expected in service by 1995.



HYDRA-CO Active

In many states, where economic factors have been allowed to determine sources of new generating capacity, unregulated generators are a welcome supply option. Niagara Mohawk has been an active participant in that marketplace for 12 years through its unregulated subsidiary, HYDRA-CO Enterprises Inc. Niagara Mohawk recently obtained state PSC approval to invest another $85 million in HYDRA-CO.

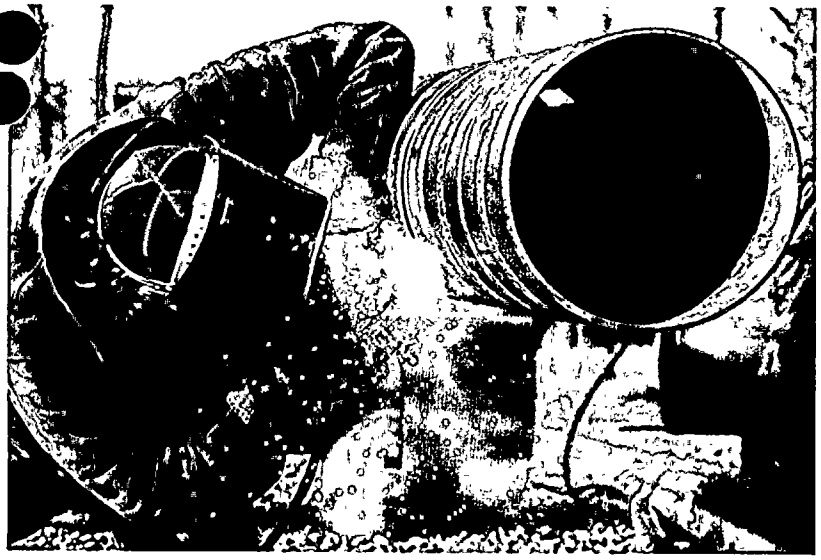
HYDRA-CO has equity ownership in 25 projects with a capacity of about 820 megawatts in operation or under construction in eight states, Canada and Jamaica. Construction will be completed in 1994 on the largest, a 236-megawatt natural-gas-fired facility in Lakewood, N.J. In 1993, a HYDRA-CO project became the first existing project to be approved for Exempt Wholesale Generator status under the Energy Policy Act.

HYDRA-CO will begin construction in 1994 of a 60-megawatt generating station in Kingston, Jamaica, sponsored by the World Bank. The company also is actively pursuing opportunities in other countries, focusing on Latin America and Canada.

Natural Gas Unit Well Positioned

The process of restructuring the natural gas industry, which began in the late 1970s, was essentially completed by the full implementation of Federal Energy Regulatory Commission Order 636, which took effect in November 1993.

Order 636, known as the Restructuring Rule, makes a number of changes in the structure of service provided by interstate natural-gas pipelines. The rule allows local gas distribution companies such as Niagara Mohawk to buy natural gas directly from producers, and arrange to have it transported by interstate pipelines. Historically, interstate pipelines bought all natural gas from producers and sold it to local distribution companies as a bundled service.



NMGas welding safety training program in Syracuse, N.Y.

The restructuring means that Niagara Mohawk will take over many buying, transporting, storing and delivery functions from the pipelines that now mainly serve as common carriers.

NMGas, Niagara Mohawk's natural gas business unit, is well prepared for these new business challenges. For the past several years NMGas has aggressively negotiated directly with producers, and has ample gas for the 1993-1994 heating season and beyond.

NMGas also is offering new services made possible by changes in the industry. The company has been successful in reselling excess pipeline capacity and making sales of gas in the off-system sale-for-resale market. Through its Target Account Program, the unit also has been working with customers to lower their energy costs and improve sales.

NMGas also has a growing natural-gas vehicle marketing program, and expects to have six natural gas refueling stations in operation by the end of 1994.

In another effort to address competition, NMGas has proposed to the state PSC a flexible sales rate that would allow the company to compete with unregulated gas marketing firms for sales to large customers to whom Niagara Mohawk now provides transportation service. The request is being considered as part of a larger PSC proceeding on the restructured natural gas market which is expected to be decided during 1994.

The aggressive NMGas marketing program, which includes both traditional and non-traditional markets, is beginning to have a measurable impact on sales growth. It resulted in 8,000 new customer hook-ups in 1993, while the company's total natural gas throughput to service territory customers increased by approximately 6 million dekatherms, or 4 percent.

Economic Development

Niagara Mohawk joined forces with the state's other electric, gas and telephone utilities during 1993 in a major economic development effort, the Alliance for a New, New York. The Alliance is a partnership with state government through the New York State Department of Economic Development.

An economic development incentive and a large energy efficiency rebate helps Revere Copper Products of Rome remain competitive and develop new product lines, like copper shingle roofing that was brought to market in 1993.

The utilities have committed $4.5 million a year for five years, starting in 1994, and the state will add $500,000 per year. The Alliance is starting an advertising and marketing program directed at retaining existing New York state companies and attracting both domestic and international business. The program will focus on New York's high-tech resources and skilled work force, and also will provide information on the existing government and private economic development efforts in the state.

In addition to helping form the Alliance, Niagara Mohawk spent more than $300,000 during 1993 on its own marketing efforts promoting Upstate New York. The company's efforts resulted in nine companies locating in the state.

As of the end of 1993, Niagara Mohawk is working with 400 U.S. and 250 Canadian firms that have shown interest in Upstate New York.

You've spent considerable time during your first year as Chairman traveling around Niagara Mohawk's service territory, visiting customers and employees. Why did you think it was important to do that?

As the new chairman of this great company, I felt that nothing was more important in my first year than hearing directly, one on one, from our employees and our customers, their views on what we're doing well and what we can do better. I have picked up some advice and insights that will be invaluable as I address some of the tough issues facing Niagara Mohawk.

What have you learned from your visits with customers?

They've made very clear to me the depth of their concern about rising energy costs. Virtually all of our industrial customers are facing their own forms of increasing global competition. Most are engaged in efforts to become more productive and competitive. If a significant component of their cost structure, their energy cost, is increasing, that's not helpful.

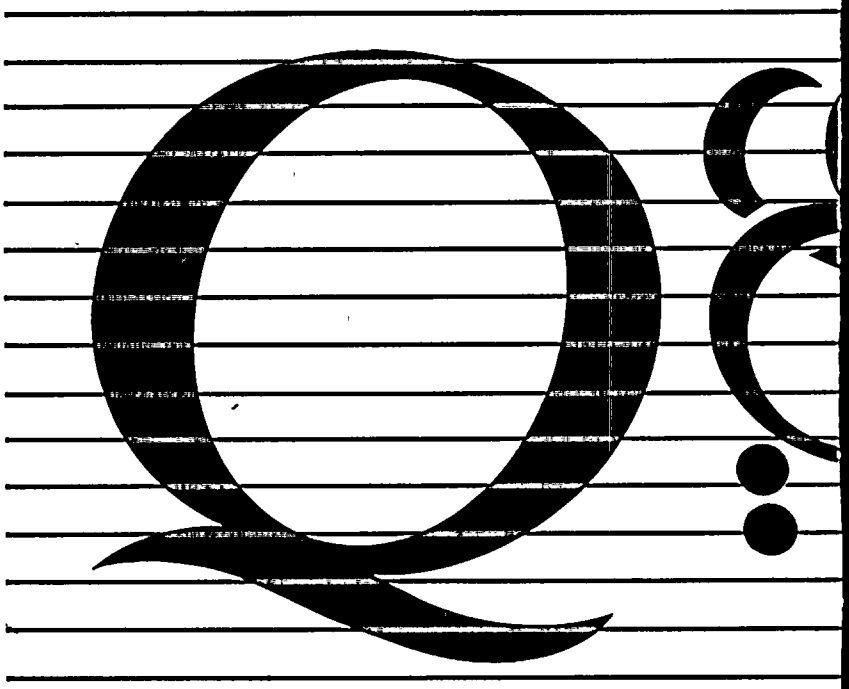
I've also learned that our customers, in general, have little understanding of the factors, such as high utility taxes and unregulated generator payments, that are driving their utility costs up. They know that if they want to remain competitive, they can't raise their prices. They want to see the same from us, particularly because some now have, or may have in the near future, alternatives to Niagara Mohawk service.

What are you doing to address those concerns?

We have a comprehensive strategic plan that is positioning Niagara Mohawk for the competitive marketplace. We're streamlining internally and pushing hard for competitive equity with our unregulated competitors. The keys to success are lower costs and higher standards of service. We also need to turn Niagara Mohawk into a continuously learning, continuously improving organization, to keep pace with the rate of change that is coming.

What did customers have to say about Niagara Mohawk's service?

On the whole, their reaction was positive. I heard a significant number of positive comments about Niagara Mohawk's performance in storm restoration situations and other emergencies. And I also heard many compliments directed toward Niagara Mohawk employees and the constructive role they play in civic and charitable activities in their communities.



But there were enough concerns raised about service reliability and service quality to underscore the importance of making improvement in that area a top priority. In the competitive marketplace, excellent customer service is a survival skill.

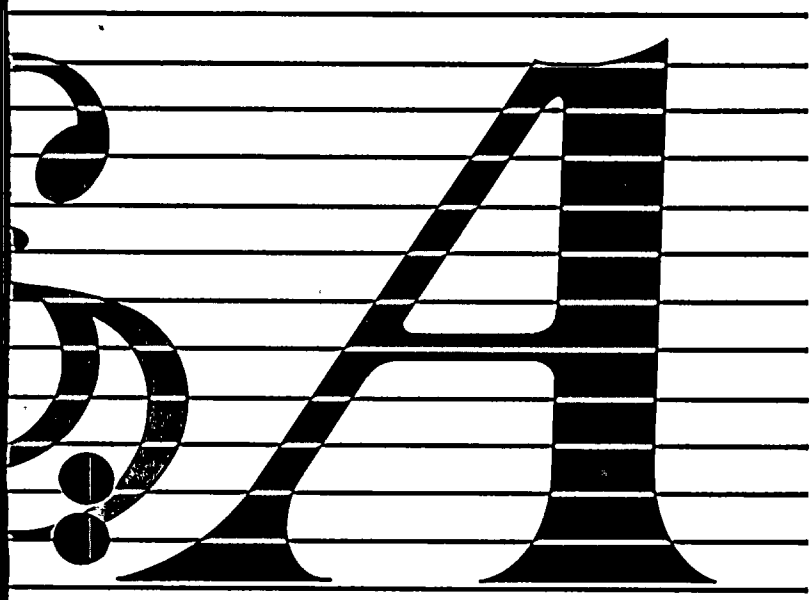
What will it take to improve service?

The key to service improvement is the enthusiastic participation of Niagara Mohawk's employees. I came away from my meetings with employees very impressed with the caliber of the Niagara Mohawk work force. The pride our employees have in their company and their work is very clear. They are concerned about the changes going on in the industry. But the vast majority understand and appreciate the need for change, even though it will involve some

ficult and painful decisions. I am convinced that ith the right leadership and support, Niagara ohawk employees have the skills and capabilities to provide exceptional customer service.

What else can be done to make the work force more competitive?

Union and management have begun using an innovative program called Mutual Gains Bargaining, which



A discussion with Chairman Bill Davis

emphasizes trust, partnership and joint problem-solving. It aided both parties in reaching a new labor agreement last June. As we all become more comfortable with Mutual Gains, it will enable us to become more competitive. Other competitive initiatives include a revitalized safety culture, and placing added emphasis on education and training among all employees to enhance their skills and sharpen their competitive instincts.

What impressions did you get about the state of the economy of Upstate New York?

I heard some disquieting things about the general business climate–high taxes, labor costs, medical care costs, worker's compensation costs–that certainly are contributing factors to the loss of industry and jobs in the region. At the same time, I saw companies that are expanding and prospering, and some examples of new companies coming into the state. They're attracted by New York's high-technology resources and skilled work force, among other attributes.

The clear message is that Niagara Mohawk has to do everything we can to control costs and therefore contribute positively to the business climate. And we must do even more. We have to continue expanding our joint efforts with the state of New York and local economic development efforts to attract new business. We must become much more active on issues of importance to our customers, such as taxes and worker's compensation, that will help to make New York a more attractive place to do business.

We also can help our customers in other ways unconnected to the supply of electricity and gas. We have tremendous technical skills and resources in the company, that can be tapped to assist our customers in addressing environmental, engineering or other technical problems.

We have to be as concerned about our customers' prosperity as our own, because the economic health of Niagara Mohawk is inextricably tied to the economic health of our service territory. My travels and observations lead me to conclude that Upstate New York has some economic problems, but it also has vast untapped potential in the form of a skilled work force, world-class research and educational institutions and a strategic location. There are clearly reasons to be optimistic about the economic future of our service territory if the substantial resources of the public and private sectors can be mobilized to work together cooperatively. Niagara Mohawk is prepared to do its part.

NUCLEAR

Niagara Mohawk's two Nine Mile Point nuclear facilities had a record-setting year in 1993, greatly exceeding goals for electricity generation and completing the year under budget.

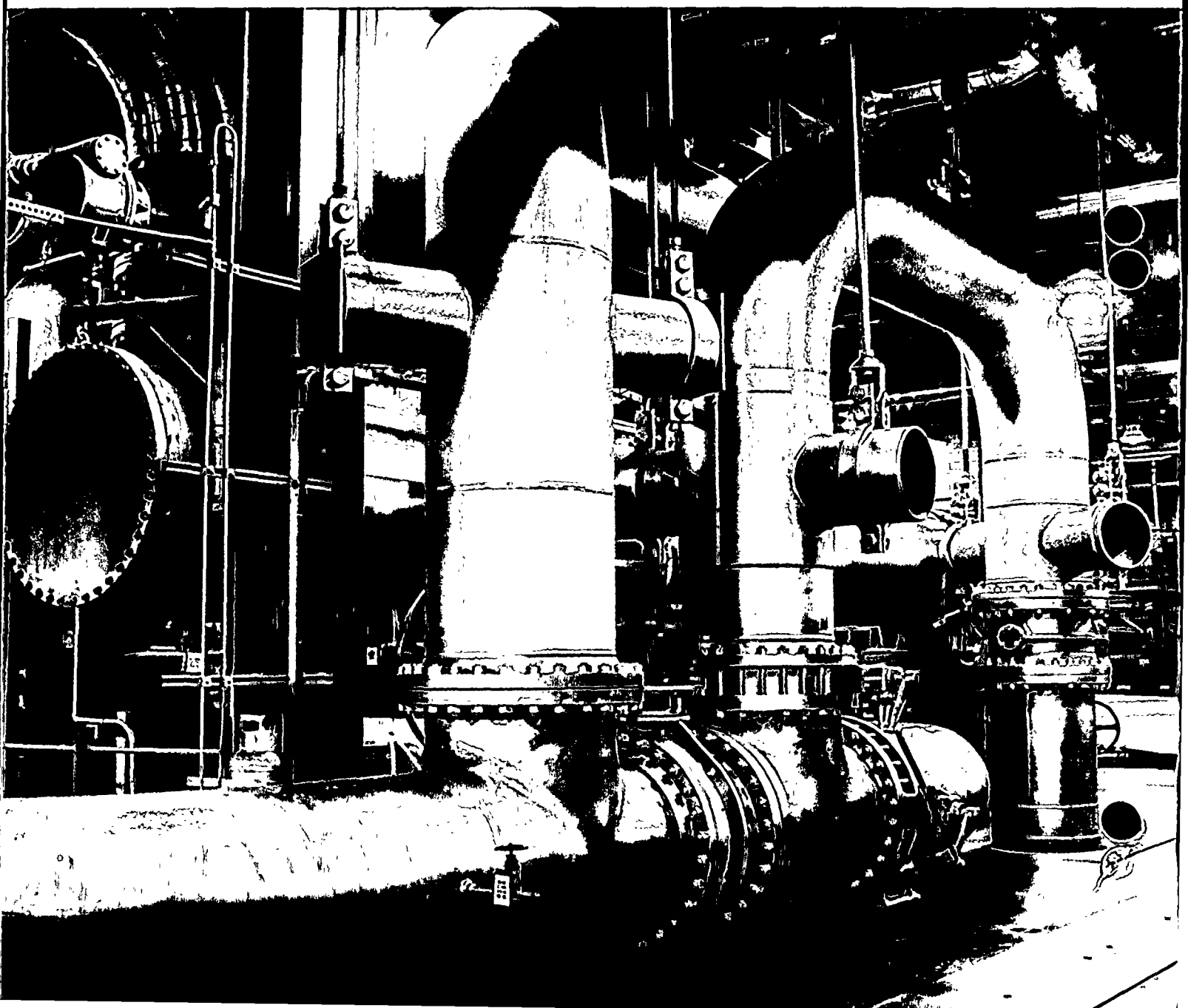
Nine Mile One, a 613-megawatt plant, generated electricity for 309 out of the 310 days it was scheduled for production. The plant also completed a refueling and maintenance outage in 55 days, the shortest full-scale outage in its 24-year history and more than five weeks shorter than the average of previous outages.

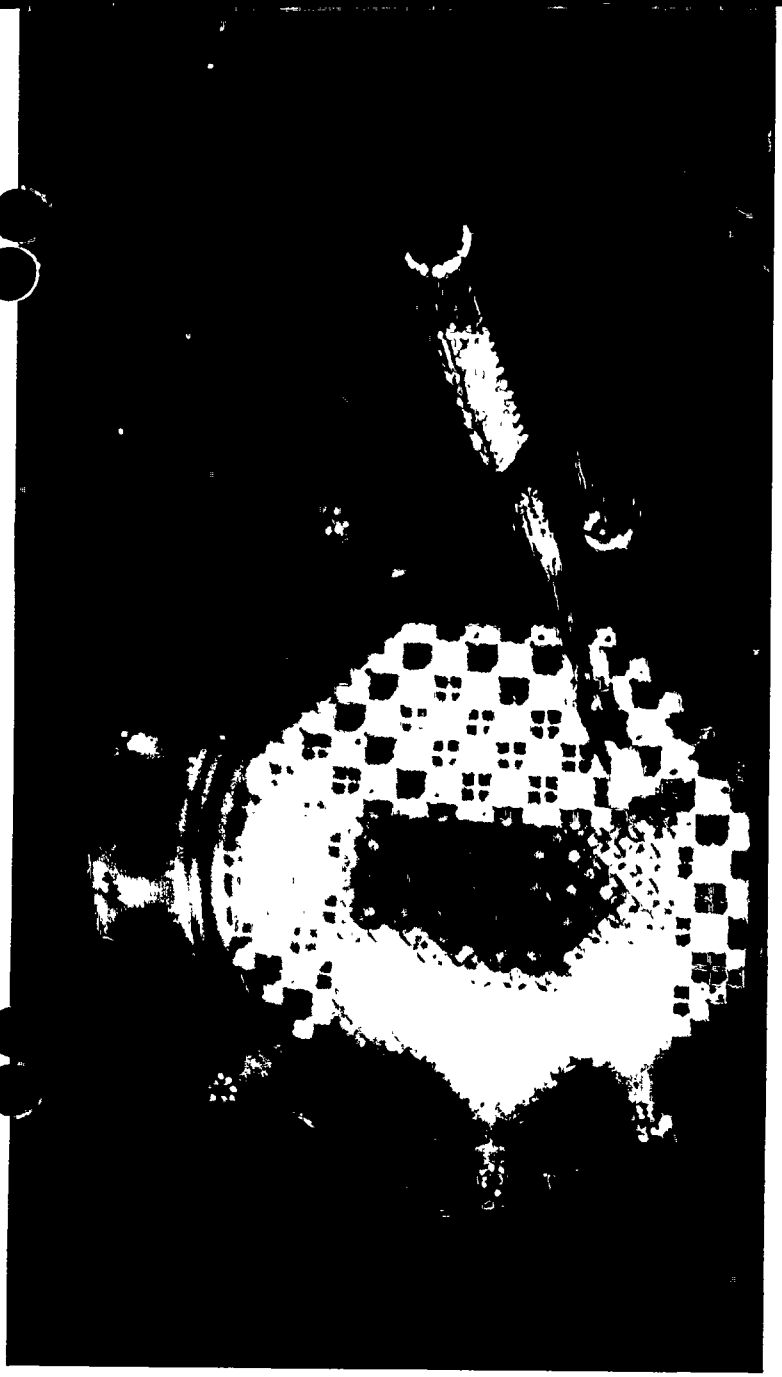
Niagara Mohawk operates and owns 41 percent of Nine Mile Two, a 1,062-megawatt plant. The plant ran for 327 consecutive days heading into an autumn refueling and maintenance outage. The 58-day outage was completed ahead of schedule and in less than half the time of previous outages.

Nine Mile One compiled an 81 percent capacity factor for the year, and Nine Mile Two reached 78 percent, both well above the average for U.S. nuclear plants.

Another highlight of the year was the grades of good or excellent in all categories on a U.S. Nuclear Regulatory Commission inspection.

A look at the closed loop cooling system inside Nine Mile Point Unit Two.





Fuel bundles are being moved from Nine Mile Point Unit Two's reactor core as part of a refueling outage. Both nuclear plants experienced a record-setting 1993.

The excellent results of 1993 come from deep-rooted changes within nuclear operations brought about by an extensive focus on developing teamwork, employee knowledge and leadership ability.

"We needed to demonstrate that we could operate safely and economically, and we did it," said B. Ralph Sylvia, executive vice president-nuclear. "I'm very proud of our nuclear employees, and what they accomplished.

Sylvia said he is "very optimistic" about 1994, when no refueling outages are scheduled.

"We are placing emphasis on continuous improvement," he continued, "and believe we have the key components in place for sustained strong performance."

Electric Supply and Delivery

Niagara Mohawk's drive to establish competitive advantage is evident in its Electric Supply & Delivery Unit (ES&D), which manages the corporation's fossil and hydro generating and power delivery assets, while serving as the company's agent in power transactions. The unit is adopting process-driven business planning, budgeting and performance management systems, to allow it to allocate resources more effectively and to monitor process results with greater precision.

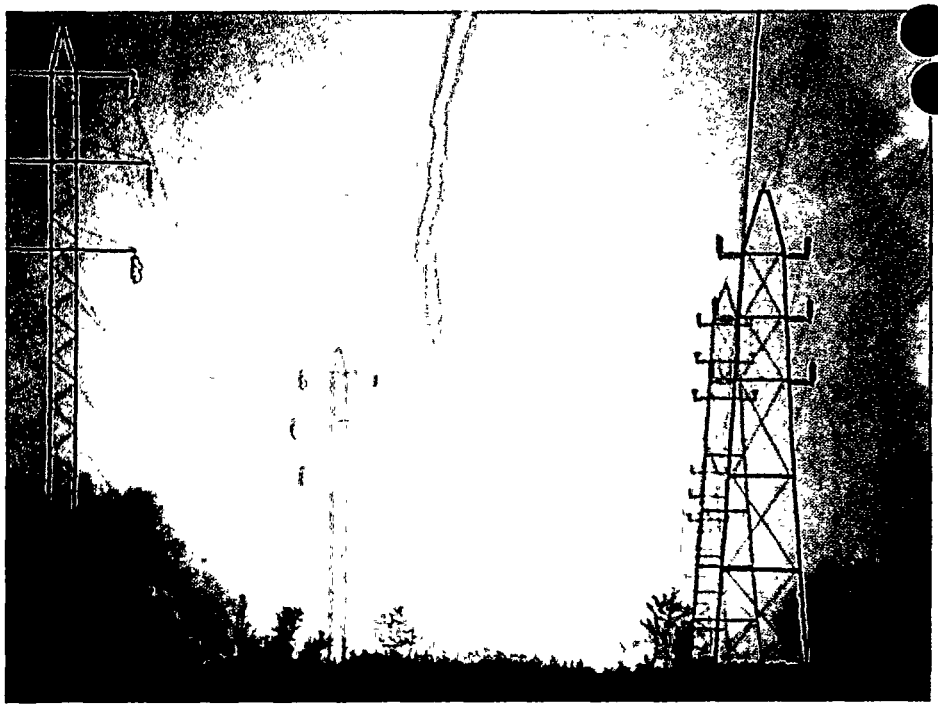
In April 1993, the company announced plans to place an 850-megawatt oil-fired unit at Oswego Steam station in long-term cold standby in 1994 and to retire, by the end of the decade, four older coal-fired units at Huntley Steam Station with a combined capacity of 340 megawatts. Driven by the need to produce value at each remaining unit, an aggressive reengineering effort resulted in plans to streamline engineering, maintenance and operations processes at all four steam stations and their support organizations.

A similar reengineering effort addressing the 72 hydro stations operated by the company is nearing completion, and efforts to renew Federal Energy Regulatory Commission licenses at 30 of the hydro projects are moving forward.

The ES&D business plan anticipates that every generating asset will be subject to value-added economic analysis by the end of 1994.

ES&D's Power Delivery, and Power Transactions and Planning departments also made significant strides in 1993. Power Delivery continued an aggressive substation preventive maintenance program, while implementing reengineering plans that will allow significant capital and expense budget reductions. The Power Transactions and Planning group was a key player in the company's efforts to protect customers from excess costs due to unregulated generation.

The company's total electricity sales were 37.7 billion kilowatt-hours in 1993, up three percent from 1992. The stagnant economy in New York was a major contributing factor to the limited sales growth last year.



Niagara Mohawk met its commitment to its "beyond compliance" environmental policy during 1993 through a number of actions that maintain the company's status as a leader in corporate environmentalism.

"Environmental excellence is not just philosophical altruism," said Chairman and CEO William E. Davis. "It makes good business sense and it's the right thing to do to achieve overall business excellence.

"For example, we are dedicated to courses of action that are environmentally sustainable, because over the long run these directions also are good for the economic health of the communities we serve."

One area where Niagara Mohawk has focused its efforts to help create a more environmentally-sustainable energy future is global climate change. Vice President Albert Gore recognized the company at a White House ceremony in October 1993 for leadership in curbing global warming. Niagara Mohawk was among the first utilities to develop a plan to reduce greenhouse gas emissions, more than a year before the Clinton Administration unveiled its national Climate Change Action Plan. Niagara Mohawk's own Greenhouse Warming Action Program will limit the company's carbon dioxide emissions to 1990 levels or below by the year 2000.

The following month, Chairman Davis testified before the House of Representatives Subcommittee on Energy and Power that voluntary action such as the Niagara Mohawk plan is preferable to a government-mandated program.

The company also has developed an Environmental Performance Index, a quantitative measure of its environmental effectiveness in three categories: level of emissions, compliance with regulations and investment in environmental enhancements. The company is targeting continuous improvement of its environmental performance through 1995, as measured by the Environmental Performance Index.

The state Public Service Commission approved the index as a component of the MERIT performance incentive awards, starting in 1992. Because of the success of its own internal index, the company currently is working with peer group utilities to establish an external benchmarking program.

The company's recycling program also continued to expand in 1993, recycling more than a thousand tons of paper, 2,750 tons of aluminum, steel and copper wire and countless nuts, bolts and batteries.

In addition, Niagara Mohawk has become a front-runner in the reutilization of the ash produced by coal combustion. Instead of sending the ash to a landfill, Niagara Mohawk's innovative program combines fly ash, portland cement and water to make a unique new product called EZ-FILL, an environmentally safe backfill material. EZ-FILL has many applications in construction, engineering and structural projects. Niagara Mohawk used 91,000 tons of ash in this process in 1993, 40 percent above its goal, and expects to increase production still further in the future.

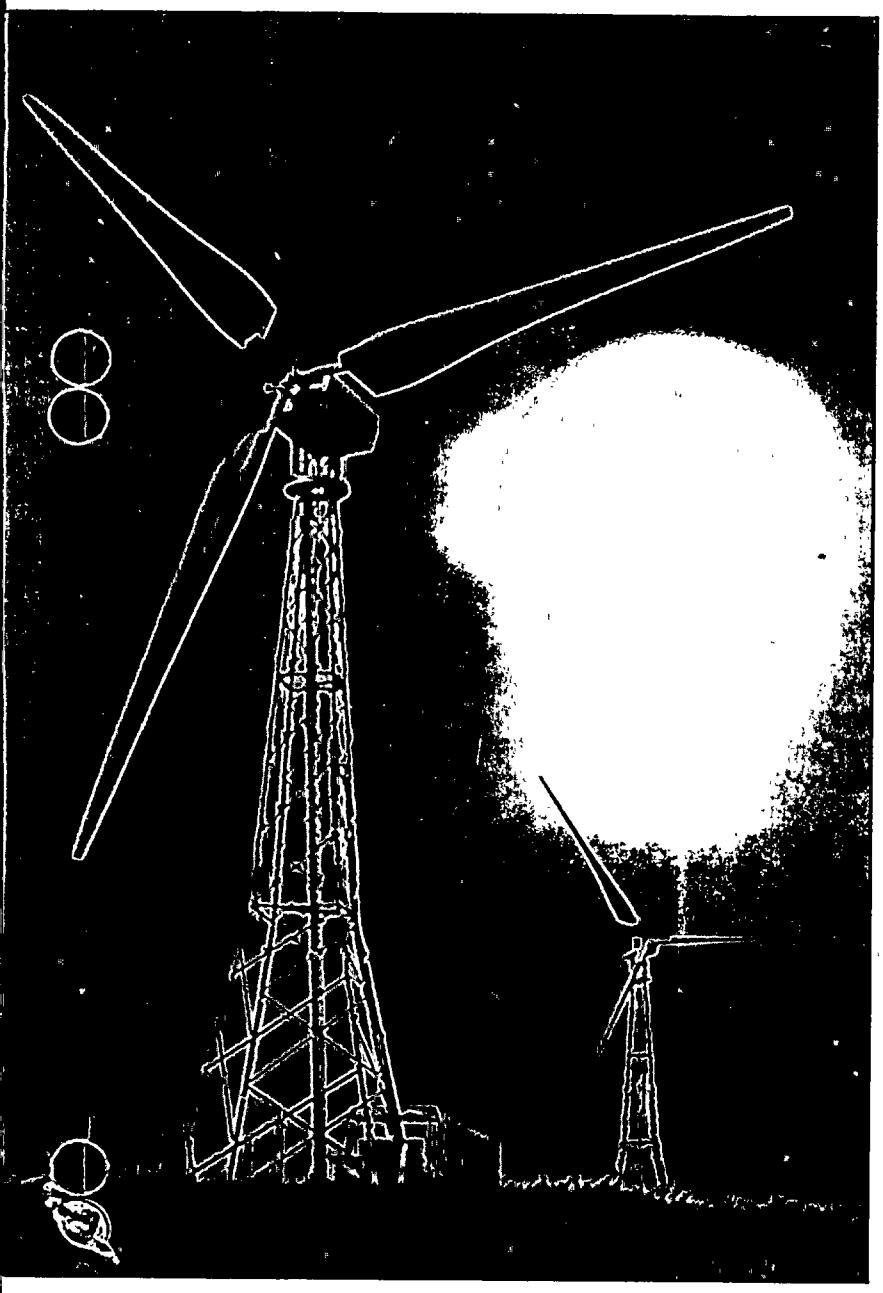
RESEARCH & DEVELOPMENT

Niagara Mohawk maintains a research and development organization that focuses on technologies that enhance the company's competitiveness while maximizing the value of energy for the customer. Research efforts range from reducing the environmental impact of power generation by using renewable fuels such as the wind, the sun and biomass; to developing electrotechnologies that enhance the value of electricity for the customer.

Customer service research programs include a computer-based system that automates the processing of customer electric service trouble calls and crew dispatching during storm emergencies. During 1993, testing on the system was completed and installation began for all offices in the Albany area. Other advanced computer systems in development will improve electric service planning, installation and repair.

Lightning is the major cause of electric service interruptions to Niagara Mohawk customers. In 1993, Niagara Mohawk developed a unique lightning locating system that can pinpoint lightning strikes, on a 2,500-square-mile grid, to within an area the size of a football field. In the future, crews using this system will reduce the time spent searching for downed wires or damaged equipment.

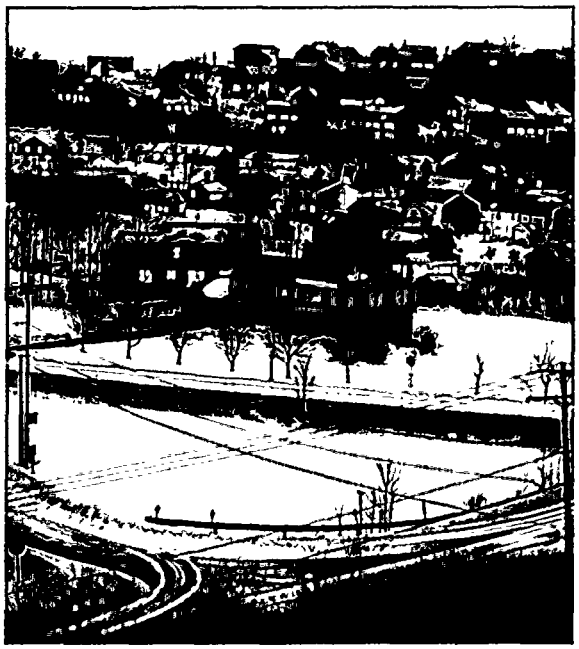
Another research program is converting to a computer system the 75,000 paper maps that show the location of every pole, line transformer and circuit breaker in the Niagara Mohawk service territory. The program uses advanced pattern recognition concepts and neural networks to make the conversion to computer in less than 10 percent of the time conventional computer conversion methods would take.



Niagara Mohawk's research and development projects range from developing a unique system to pinpoint lightning strikes that could interrupt electrical service (far left), to operating the first wind turbines in the Northeast.

Excellent customer service is the hallmark of a successful competitor. As competition in the electricity marketplace has grown, Niagara Mohawk has made customer service improvement a top priority.

Uniting all electric customer-related functions into one business unit in 1991 was an important step. The Electric Customer Service (ECS) business unit is the direct contact point for 1.5 million residential, commercial and industrial electric customers.



Late last year, the business unit began a further reorganization with two goals: to become more cost-effective by streamlining operations and to improve customer service.

The reorganization will proceed under the direction of Darlene D. Kerr, senior vice president-Electric Customer Service and a 20-year veteran of the company. On Jan. 1, 1994, she succeeded John P. Hennessey, who retired after nearly 35 years with Niagara Mohawk.

The first major step, announced in November 1993, is consolidation of the eight ECS regional customer service telephone operations into one state-of-the-art Center for Customer Service Excellence, to be located in Syracuse. The center is expected to be in operation by late 1994.

"We're not just going to be consolidating current practices," explained Kerr. "This gives us the opportunity to design an exceptional customer service operation from scratch, incorporating all the services our customers have told us they want."

The new center will be "a one-stop shop" that will resolve as many customer inquiries as possible in one phone call, she continued. It will operate 24 hours a day, seven days a week.

The center also will provide a focal point for compiling feedback from customers, as part of a further expansion of the company's capability of surveying customer satisfaction levels, and its customer outreach and education programs.

By early 1995, ECS will be scheduling dates and times for all service appointments, and guaranteeing that each appointment will be on time. A pilot program already is under way in Syracuse. Other service guarantees will cover billing accuracy and connection of new service. Customers will receive rebates if service falls short of promised levels.

Also under way are many technological upgrades, such as advanced preventive maintenance, planning and communication systems to end power outages more quickly; and new residential, commercial and industrial billing systems. The company also will be replacing underutilized and inconvenient services currently handled at local offices with more accessible and convenient service locations, such as banks and supermarkets.

"ECS will have to improve customer service with fewer employees and a tighter budget," said Kerr, "because, like the rest of Niagara Mohawk, we're cutting operating costs to keep down customer bills. We're placing great emphasis on use of more advanced technologies, intensive training and empowerment of employees, and improved communications.

"Regardless of technological or management improvements," she added, "the key to our future success will remain the people of Niagara Mohawk. Every change we are making is aimed at helping them to do their jobs better so that they can, in turn, provide excellent service to customers."

The company's industrial customer service operation also is being reorganized. Starting in 1994, each large customer will have an account manager to handle every aspect of the customer's electricity needs.

Niagara Mohawk already offers specialized services to industrial and commercial customers, such as assisting them in increasing their energy efficiency through its Demand-Side Management program.

In addition, the company is working to attract industry and jobs through an economic development rate for companies locating in Upstate New York or expanding. Another rate, the Economic Revitalization Incentive Rider (ERIR), helps to see companies through hard times. The ERIR is offered to companies that might otherwise shut down or curtail operations. When companies return to financial health, they resume paying regular rates.

Niagara Mohawk has helped 16 businesses, representing about 8,000 jobs through the ERIR rate.

Market Price of Common Stock and Related Stockholder Matters

Company's common stock and certain of its preferred series are listed on the New York Stock Exchange. 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. Common stock dividends were paid on February 28, May 31, August 31 and November 30. The Company presently estimates that none of the 1993 common or 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 and dividends per share for the Company's common stock:

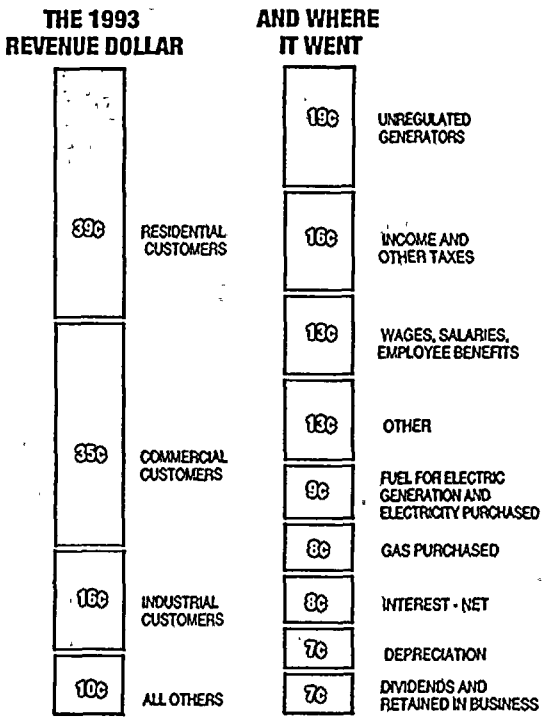
1993	Dividends Paid Per Share	Price Range High	Price Range Low
1st Quarter	$.20	$22¾	$18⅞
2nd Quarter	.25	24¼	21⅝
3rd Quarter	.25	25¼	23¾
4th Quarter	.25	23⅞	19¼
1992			
1st Quarter	$.16	$19	$17⅝
2nd Quarter	.20	19¼	17½
3rd Quarter	.20	20½	18⅞
4th Quarter	.20	19⅞	18⅜

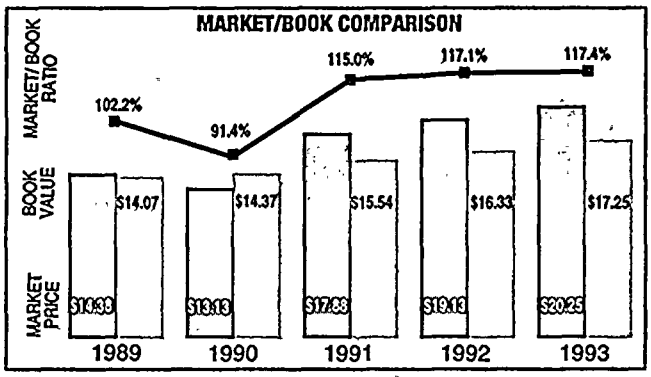
Other Stockholder Matters: The holders of common stock are entitled to one vote per share and may not cumulate their votes for the election of Directors. Whenever dividends on preferred stock are in default in an amount equivalent to four full quarterly dividends and thereafter until all dividends thereon are paid or declared and set aside for payment, the holders of such 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 rata 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.

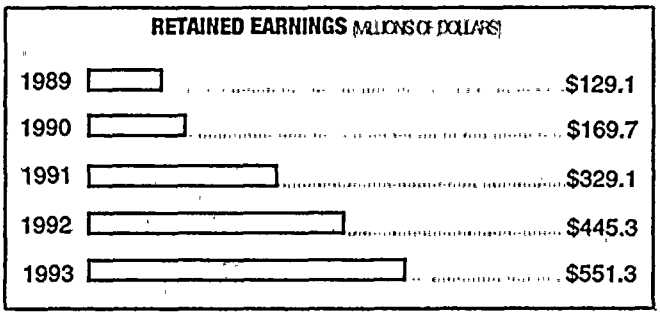
The indenture securing the Company's mortgage debt provides that surplus shall be reserved and held unavailable for the payment of dividends on Common Stock to the extent that expenditures for maintenance and repairs plus provisions for depreciation do not exceed 2.25% of depreciable property as defined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

At year end, about 109,000 stockholders owned common shares of the Company and about 5,000 held 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	43,269	1,401,921
100 to 999	59,329	16,476,333
1,000 or more	6,742	124,548,803
	109,340	142,427,057







Overview of 1993

Earnings improved to $240.0 million or $1.71 per share as compared to $219.9 million or $1.61 per share in 1992, principally as a result of rate increases to electric and gas customers. Although earnings improved, the Company's earned return on equity of 10.2% was below the allowed return on utility operations of 11.4%. Expectations for 1994 earnings indicate only a slight improvement without an increase in electric base rates and a modest increase in gas rates. Cost sharing mechanisms for industrial customer discounts and the potential for loss of industrial customers in 1994 will place earnings at additional risk.

Even with modest earnings growth, the Company's relatively low payout ratio, as compared to the rest of the electric and gas utility industry, permitted an increase in the common stock dividend to an annual rate of $1.00 from $.80, or 25% in 1993.

The Company is increasingly challenged to maintain its financial condition under traditional regulation and in the face of expanding competition. While utilities across the nation must address these concerns to varying degrees, the Company may be more vulnerable than others to competitive threats. The following sections present an assessment of competitive threats and steps being taken to improve the Company's strategic and financial position.

Rating agencies, which evaluate the credit-worthiness of various securities, including the Company's, have expressed heightened concern about the future business prospects of the utility industry. Standard & Poors Corporation includes the Company in its "Below Average," or lowest rated group in its assessment of business position and has recently reduced the Company's credit ratings. A more extensive discussion of rating agency views is included under "Liquidity and Capital Resources."

Changing Competitive Environment

In 1993, the Company continued to address concerns relating to increasing competition in the utility industry. The enactment of the 1992 Federal Energy Policy Act (Act) has accelerated the trend toward competition and deregulation in the wholesale market (principally sales to others who will resell power to the retail market), by creating a class of generators, called Exempt Wholesale Generators (EWGs), which are able to sell power without the regulatory constraints placed on generators such as the Company. To further encourage wholesale competition, the Act opens access to utility transmission systems. The rules by which such access will be prioritized and priced have not been issued, and the potential impact on the Company, as owner and lessee of significant transmission assets, cannot be determined. Although the Act prohibits direct sales to a utility's retail customer, New York State retains the right to allow retail competition. In view of these developments, the Company undertook a Comprehensive Industry Restructuring and Competitive Assessment for the year 2000 (CIRCA 2000) to evaluate the means by which retail competition may develop and the Company's ability to respond to the associated threats and opportunities. While the future of wholesale and retail markets is uncertain, the Company determined through its CIRCA 2000 study that it must (a) reduce its total cost of doing business and (b) improve its responsiveness to changing business conditions.

Under the terms of its 1994 Rate Agreement, the Company is required to file a "competitiveness" study with the New York State Public Service Commission (PSC) by April 1, 1994.

Cost Control

Cost control extends beyond those areas traditionally thought to be under utility control, to all aspects of utility pricing, including unregulated generator purchases, tax burdens and mandated social and environmental programs. As a step towards improving its competitive position, in early 1993 the Company announced its intent to reduce its workforce by at least 1,400 positions by the end of 1995. While considerable progress was made toward this goal in 1993, rapidly changing competitive pressures made it clear that deeper cuts will be necessary. Consequently, in January 1994, the Company decided that further and faster workforce reductions would be necessary and announced a layoff over the next several months of approximately 900 employees, increasing the total reduction to approximately 1,500. Further reductions may be necessary.

Price Responsiveness

As described in more detail below under "1995 Five-Year Rate Plan Filing," the Company filed a five-year rate plan which would establish prices for 1995 and a method by which prices would be set for 1996 through 1999. The plan would cap the average annual rate at approximately the annual rate of inflation, but would also allow greater flexibility for Company pricing decisions within each rate class (e.g., residential, commercial and industrial) subject to the overall cap. The Company could, at its discretion, offer discounts to customers that might be able to leave the Company's system, but would in turn be limited to how much, if any, of the discounts could be recouped from other classes. While the focus of pricing innovation has principally been to retain industrial customers, the Company is also evaluating innovative pricing alternatives for residential and commercial customers.

The flexibility and responsiveness of the plan to changing business conditions is designed to better position the Company to meet the challenges of increasing competition to protect shareholder value. However, the Company must be disciplined in its spending based upon its projections of price increases, if any, sales and potential discounts during the five-year period.

The financial success of the Company under its price indexing rate proposal is dependent on the ability of the Company to control all of its costs. Because price indexing begins with base prices set for 1995, inclusive of such things as fuel, purchased power and taxes, the establishment of an appropriate base is critical to the financial results of the Company during the five-year period.

An ongoing generic investigation is being conducted by the PSC into the issue of how to design rates for customers with competitive electric and gas service

alternatives. The Company is developing proposals to further permit the necessary rate flexibility to respond to competitive conditions in the industry.

Unregulated Generators

In recent years, a leading factor in the increases in customer bills and deterioration of the Company's competitiveness is the requirement to purchase power from unregulated generators at prices in excess of the Company's internal cost of production and in volumes greater than the Company's needs. The Public Utility Regulatory Policies Act of 1978 (PURPA), New York State Law and PSC policies and procedures have collectively required that the Company purchase this power from qualified unregulated generators. The price used in negotiating purchased power contracts with unregulated generators (Long Run Avoided Costs or LRACs) is established periodically by the PSC. Until repeal in 1992, the statute which governed many of these contracts had established the floor on avoided costs at $0.06/kwh (the Six-Cent Law). The Six-Cent Law, in combination with other factors, attracted large numbers of unregulated generators projects to New York State and, in particular, to the Company's service territory.

As of December 31, 1993, 147 of these unregulated generators with a combined capacity of 2,253 MW were on line and selling power to the Company. The following table illustrates the actual and estimated growth in capacity, payments and relative magnitude of unregulated generator purchases compared to Company requirements:

	Actual			Estimated				
	1991	1992	1993	1994	1995	1996	1997	1998
MW's	1,027	1,549	2,253	2,354	2,391	2,391	2,391	2,391
Percent of Total Capability	13%	19%	25%	27%	27%	27%	28%	28%
Payments (millions)	$268	$543	$736	$932	$1,057	$1,111	$1,174	$1,220
Percent of Total Fuel and Purchased Power Costs	32%	56%	67%	70%	76%	77%	77%	77%

Most of the additional capacity will be grandfathered under the Six-Cent Law. Without any other actions, the Company's installed capacity reserve margin was projected to grow to 40%-50% before declining in the late 1990's, as compared to the minimum mandated requirement of 18%. While the Company favors the availability of unregulated generators in satisfying its generating needs, the Company believes it is paying a premium to unregulated generators for energy it does not currently need. The Company has initiated a series of actions to address this situation but expects in large part that the higher costs will continue.

On August 18, 1992, the Company filed a petition with the PSC which calls for the implementation of "curtailment procedures." Under existing Federal Energy Regulatory Commission (FERC) and PSC policy, this petition would allow the Company to limit its purchases from unregulated generators when demand is low. While the Administrative Law Judge has submitted recommendations to the PSC, the Company cannot now predict the outcome of this case. Also, the Company has commenced settlement discussions with certain unregulated generators regarding curtailments.

On October 23, 1992, the Company also petitioned the PSC to order unregulated generators to post letters of credit or other firm security to protect ratepayers' interests in advance payments made in prior years to these generators. The PSC dismissed the original petition without prejudice, which the Company believes would permit reinstatement of its request at a later date. The Company is conducting discussions with unregulated generators representing over 1,600 MW of capacity, addressing the issues contained in its petitions.

On February 4, 1994 the Company notified the owners of nine projects with contracts that provide for advance payments of the Company's demand for adequate assurance that the owners will perform all of their future repayment obligations, including the obligation to deliver electricity in the future at prices below the Company's avoided cost and to repay any advance payment which remains outstanding at the end of the contract. The projects at issue total 426 MW. The Company's demand is based on its assessment of the amount of advance payments to be accumulated under the terms of the contracts, future avoided costs and future operating costs of the projects. The Company cannot predict the outcome of this notification.

The Company and certain of its officers and employees have been named in complaints resulting from the alleged termination, among other matters, of purchase power contracts with Inter-Power of New York, Inc. and Fourth Branch Associates Mechanicville. The Company believes it has substantial defenses to both complaints but is unable to predict the outcome of these matters and, accordingly, has not established a provision for liability, if any, in the Company's financial statements.

Asset Management Studies - Fossil

The Company continually examines its competitive situation and future strategic direction. Among other things, it has studied the economics of continued operation of its fossil-fueled generating plants, given current forecasts of excess capacity. Growth in unregulated generator supply sources and compliance requirements of the Clean Air Act are key considerations in evaluating the Company's internal generation needs. While the Company's coal-burning plants continue to be cost advantageous, certain older units and certain gas/oil-burning units are being carefully assessed to evaluate their economic value and

estimated remaining useful lives. Due to projected excess capacity, the Company plans to retire or put certain units in long-term cold standby. A total of 340 MW's of aging coal fired capacity is to be retired by the end of 1999 and 850 MW's of oil fired capacity is to be placed in long-term cold standby in 1994. The Company is also continuing to evaluate under what circumstances the standby plants would be returned to service, but barring unforeseen circumstances it is not likely that a return would occur before the end of 1999. This action will permit the reduction of operating costs and capital expenditures for retired and standby plants. The Company believes that the remaining investment in these plants of approximately $300 million at December 31, 1993, will be fully recoverable in rates.

Asset Management Studies - Nine Mile Point Nuclear Station Unit No. 1

Under the terms of an earlier regulatory agreement, the Company agreed to prepare and update studies of the advantages and disadvantages of continued operation of Nine Mile Point Nuclear Station Unit No. 1 (Unit 1). In the November 1992 study, the continued operation of the unit under an "improved performance case" was expected to provide a net present value benefit in excess of $100 million. The unit operated within the parameters of the improved performance case in 1993 and the Company believes that continued operation of the Unit is warranted. The Company's net investment in Unit 1 is approximately $580 million and the estimated cost to decommission the Unit based on the Company's 1989 study is $257 million in 1993 dollars. The next update is due to be submitted to the PSC in late 1994. (See Note 7 of Notes to Consolidated Financial Statements under "Unit 1 Economic Study.")

Gas Competition

Portions of the natural gas industry have undergone significant structural changes. A major milestone in this process occurred in November 1993 with the implementation of FERC Order 636. FERC Order 636 requires interstate pipelines to unbundle pipeline sales services from pipeline transportation service. These changes enable the Company to arrange for its gas supply directly with producers, gas marketers or pipelines, at its discretion, as well as to arrange for transportation and gas storage services. The flexibility provided to the Company by these changes should enable it to protect its existing market and still expand its core and non-core market offerings. With these expanded opportunities come increased competition from gas marketers and other utilities.

In short, the electric and gas utility industry is undergoing changes and faces an uncertain future, therefore, those utilities that succeed must be prepared to respond quickly to change. Hence, the Company must be successful in, among other things, managing the economic operation of its nuclear units and addressing growing electric competition, expanded gas supply competition, and various cost impacts, which include excess high-cost unregulated generator power and increasing taxes. In addition, the Company must implement the requirements of the Clean Air Act Amendments of 1990 and also remediate hazardous waste sites. While the Company believes that full recovery of its investment will be provided through the rate setting process with respect to all of the issues described herein, a review of political and regulatory actions during the past 15 years with respect to industry issues indicates that utility shareholders may ultimately bear some of the burden of solving these probl

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.

1991 Financial Recovery Agreement

The 1991 Financial Recovery Agreement (1991 Agreement) established a $190.0 million electric rate increase effective January 1, 1991 and also provided for electric rate increases of 2.9% ($75.4 million) effective July 1, 1991 and 1.9% ($55.7 million) effective July 1, 1992. Gas rates increased 1.0% ($5.5 million) on July 1, 1992. The 1991 Agreement also implemented the Niagara Mohawk Electric Revenue Adjustment Mechanism (NERAM) and the Measured Equity Return Incentive Term (MERIT), which are discussed in more detail below.

The NERAM requires the Company to reconcile actual results to forecast electric public sales gross margin used in establishing rates. The NERAM produces certainty in the amount of electric gross margin the Company will receive in a given period to fund its operations. While reducing risk during periods of economic uncertainty and mitigating the variable effects of weather, the NE does not allow the Company to benefit from unfores growth in sales. Recovery or refund of accruals purs to the NERAM is accomplished by a surcharge (either plus or minus) to customers over a twelve month period, to begin when cumulative amounts reach certain levels specified in the 1991 Agreement. As of December 31, 1993, the Company had a recoverable NERAM balance (amounts subject to reconciliation) of $21.4 million.

The Company has proposed discontinuation of NERAM beginning in 1995 in exchange for greater pricing flexibility as discussed further below under the "1995 Five-Year Rate Plan Filing."

The MERIT program is the incentive mechanism which originally allowed the Company to earn up to $180 million of additional return on equity through May 31, 1994. The program was later amended to extend the performance period through 1995 and add $10 million to the total available award.

The PSC granted the full $30 million of MERIT award the Company claimed for the period January 1991 through May 1991, which was reflected in earnings in the third quarter of 1991 ($.14 per common share). The second MERIT period, June 1991 through December 1991, had a maximum award of $30 million. Of this amount, the PSC granted $22.8 million, or approximately $.11 per share, which the Company included in June 1992 earnings.

Measurement criteria for the $25 million of MERI 1992 focused on implementation of self-assessment recommendations, including measurements of responsiveness to customers, nuclear performance, cost management and environmental performance. The Company

claimed, and the PSC approved in 1993, a MERIT award of approximately $14.3 million of which $4 million was included in 1992 earnings. The shortfall from the full award available reflected the increasing difficulty of achieving the targets established in customer service and cost management, as well as lower than anticipated nuclear operating performance.

Overall goal targets and criteria for the 1993-1995 MERIT periods are results-oriented and are intended to measure change in key overall performance areas. The targets emphasize three main areas: (1) responsiveness to customer needs, (2) efficiency through cost management, improved operations and employee empowerment, and (3) aggressive, responsible leadership in addressing environmental issues.

A report supporting the achievement of MERIT goals for 1993 is anticipated to be submitted in February 1994 to the parties to the 1991 Agreement. The Company anticipates claiming an award of approximately $20 million, which would be expected to be billed to customers over a twelve-month period, after PSC confirmation of the earned award. The Company recorded $10 million of this award in 1993 based on management's assessment of the achievement of objectively measured criteria. The shortfall from the full award reflects the increasing difficulty of achieving the targets established in customer service and cost benchmarking with other utilities.

1993 Rate Agreement

On January 27, 1993, the PSC approved a 1993 Rate Agreement authorizing a 3.1% increase in the Company's electric and gas rates providing for additional annual revenues of $108.5 million (electric $98.4 million or 3.4%; gas $10.1 million or 1.8%). Retroactive application of the new rates to January 1, 1993 was authorized by the PSC.

The increase reflected an allowed return on equity of 11.4%, as compared to 12.3% authorized for 1992. The agreement also included extension of the NERAM through December 1993 and provisions to defer expenses related to mitigation of unregulated generator costs, (aggregating $50.7 million at December 31, 1993) including contract buyout costs and certain other items.

The Company and the local unions of the International Brotherhood of Electrical Workers, agreed on a two-year nine-month labor contract effective June 1, 1993. The new labor contract includes general wage increases of 4% on each June 1st through 1995 and changes to employee benefit plans including certain contributions by employees. Agreement was also reached concerning several work practices which should result in improved productivity and enhanced customer service. The PSC approved a filing resulting from the union settlement and authorized $8.1 million in additional revenues ($6.8 million electric and $1.3 million gas) for 1993.

1994 Rate Agreement

On February 2, 1994, the PSC approved an increase in gas rates of $10.4 million or 1.7%. The gas rates became effective as of January 1, 1994 and include for the first time a weather normalization clause.

The PSC also approved the Company's electric supplement agreement with the PSC Staff and other parties to extend certain cost recovery mechanisms in the 1993 Rate Agreement without increasing electric base rates for calendar year 1994. The goal of the supplement is to keep total electric bill impacts for 1994 at or below the rate of inflation. Modifications were made to the NERAM and MERIT provisions which determine how these amounts are to be distributed to various customer classes and also provide for the Company to absorb 20% of margin variances (within certain limits) originating from SC-10 rate discounts (as described below) and certain other discount programs for industrial customers as well as 20% of the gross margin variance from NERAM targets for industrial customers not subject to discounts. The Company estimates its total exposure on such variances for 1994 to be approximately $10 million, depending on the amount of discounts given. The supplement also allows the Company to begin recovery over three years of approximately $15 million of unregulated generator buyout costs, subject to final PSC determination with respect to the reasonableness of such costs.

The Company is experiencing a loss of industrial load through bypass across its system. Several substantial industrial customers, constituting approximately 85 MW of demand, have chosen to purchase generation from other sources, either from newly constructed facilities or under circumstances where they directly use the power they had been generating and selling to the Company under power purchase contracts mandated by PURPA and New York laws and PSC programs.

As a first step in addressing the threat of a loss of industrial load, the PSC approved a new rate (referred to as SC-10) under which the Company is allowed to negotiate individual contracts with some of its largest industrial and commercial customers to provide them with electricity at lower prices. Under the new rate, customers must demonstrate that leaving the Company's system is an economically viable alternative. The Company estimates that as many as 75 of its 235 largest customers may be inclined to bypass the utility's system by making electricity on their own unless they receive price discounts, which would cost about $26 million per year, while losing those 75 customers would reduce net revenues by an estimated $100 million per year. As of January 1994, the Company has offered annual SC-10 discounts to customers totaling $6.6 million, of which $2.7 million have been accepted.

On July 28, 1993, the Company petitioned the PSC for permission to offer competitively priced natural gas to customers who presently purchase gas from non-utility sources. The new rate is designed to regain a share of the industrial and commercial sales volume the Company lost in the 1980's when large customers were allowed to buy gas from non-utility sources. The Company will delay any implementation of this rate until the issues are further addressed in a comprehensive generic investigation, currently being conducted by the PSC, into the issue of how to design rates for customers with competitive electric and gas service alternatives.

1995 Five-Year Rate Plan Filing

On February 4, 1994, the Company made a combined electric and gas rate filing for rates to be effective January 1, 1995 seeking a $133.7 million (4.3%) increase in electric revenues and a $24.8 million (4.1%) increase in gas revenues. The electric filing includes a proposal to institute a methodology to establish rates beginning in 1996

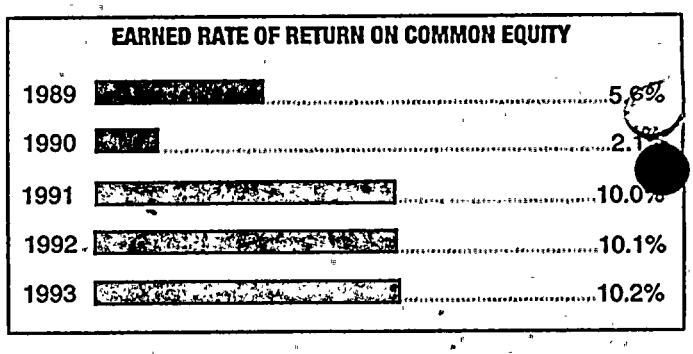
and running through 1999. The proposal would provide for rate indexing to a quarterly forecast of the consumer price index as adjusted for a productivity factor. The methodology sets a price cap, but the Company may elect not to raise its rates up to the cap. Such a decision would be based on the Company's assessment of the market. NERAM and certain expense deferrals would be eliminated, while the fuel adjustment clause would be modified to cap the Company's exposure to fuel and purchased power cost variances from forecast at $20 million annually. However, certain items which are not within the Company's control would be outside of the indexing; such items would include legislative, accounting, regulatory and tax law changes as well as environmental and nuclear decommissioning costs. These items and the existing balances of certain other deferral items such as MERIT and demand-side management (DSM), would be recovered or returned using a temporary rate surcharge. The proposal would also establish a minimum return on equity which, if not achieved, would permit the Company to refile and reset base rates subject to indexing or to seek some other form of rate relief. Conversely, in the event earnings exceed an established maximum allowed return on equity, such excess earnings would be used to accelerate recovery of regulatory or other assets. The proposal would provide the Company with greater flexibility to adjust prices within customer classes to meet competitive pressures from alternative electric suppliers while increasing the risk that the Company will earn less than its allowed rate of return. Gas rate adjustments beyond 1995 would follow traditional regulatory methodology.

Results of Operations

Earnings for 1993 were $240.0 million or $1.71 per share compared with $219.9 million or $1.61 per share in 1992 and $203.0 million or $1.49 per share in 1991. The primary factor contributing to the increase in earnings in 1993 as compared to 1992 was the impact of electric and gas rate increases effective January 1, 1993 and July 1, 1992. The 1992 increase over 1991 was due primarily to the rate increases for gas and electric customers effective July 1, 1992 and July 1, 1991, and cost management of operating expenses relative to amounts provided in rates, offset by oil and gas writeoffs.

In 1993, the Company's return on common equity improved slightly to 10.2% from 10.1% in 1992 and 10.0% in 1991. The Company's return on common equity for utility operations authorized in the rate setting process was 11.4% for the year ended December 31, 1993. Factors contributing to the earnings deficiency in 1993 included lower than anticipated results from the Company's subsidiaries, certain operating expenses which were not included in rates and exclusion of Nine Mile Point Nuclear Station Unit No. 2 (Unit 2) tax assets from the Company's rate base (upon which the Company would otherwise earn a return) as a consequence of prior year write-off of disallowed Unit 2 costs. The earnings deficiency experienced in 1992 resulted from similar causes, as well as from write-downs of Canadian oil and gas investments.

Non-cash earnings in 1993 were only about 3% of earnings available to common stockholders as compared to



16% in 1992. The Company estimates non-cash earnings will represent approximately 9% of total earnings in 1994.

The Company anticipates a return on equity of about 10% in 1994. The ability to achieve or exceed this level of earnings is dependent upon a number of key factors, including the ongoing control of expenses, earning MERIT and DSM incentives and realization of an anticipated growth in gas sales.

The following discussion and analysis highlights items having a significant effect on operations during the three-year period ended December 31, 1993. It may not be indicative of future operations or earnings. 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 increased $663.2 million or 24.8% over the three-year period. This increase results primarily from rate increases, NERAM revenues and other factors as indicated in the table at the top of the page. Approximately one-half of the increase in rates in 1991 through 1993 is the result of an increase in the base cost of fuel, which would typically result in a similar decrease in fuel and purchased power cost revenues, thus having a revenue neutral impact. However, purchased power costs have increased significantly during this period, offsetting much of the otherwise expected decrease in Fuel Adjustment Clause (FAC) revenues. See "Regulatory Agreements" above for a discussion of the rate increases and provisions of the regulatory agreements in effect during this period.

While sales to ultimate customers in 1993 were up slightly from 1992, this level of sales was substantially below the forecast used in establishing rates for the year. As a result, the Company accrued NERAM revenues of $65.7 million ($.31 per share) during 1993 as compared to $41.7 million ($.20 per share) of NERAM revenues in 1992.

Changes in fuel and purchased power cost revenues are generally margin-neutral, while sales to other utilities, because of regulatory sharing mechanisms, generally result in low margin contribution 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 and a Company incentive based on 10% of total net resource savings.

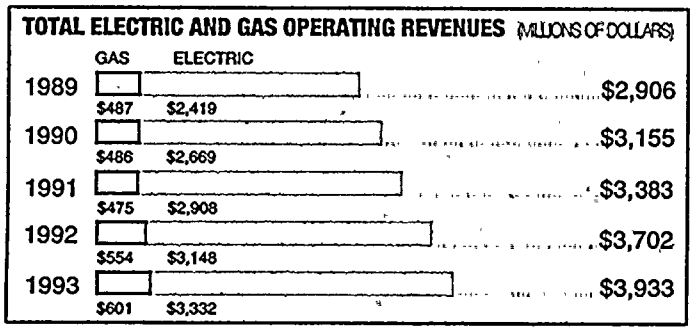
Electric kilowatt-hour sales were 37.7 billion in 1993, an increase of 3.0% from 1992 and an increase of 2.7%

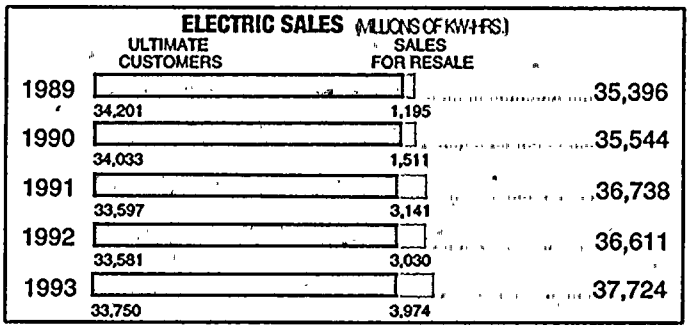
	Increase (decrease) from prior year (In millions of dollars)			
Electric revenues	1993	1992	1991	Total
Increase in base rates	$193.1	$250.6	$181.3	$625.0
Fuel and purchased power cost revenues	(42.6)	(6.4)	(83.0)	(132.0)
Sales to ultimate consumers	11.0	39.7	2.6	53.3
Sales to other electric systems	11.7	(12.8)	36.2	35.1
DSM revenue	(30.3)	(24.3)	17.2	(37.4)
Miscellaneous operating revenues	23.9	(11.3)	17.6	30.2
NERAM revenues	24.0	7.8	38.8	70.6
MERIT revenues	(6.0)	(2.9)	27.3	18.4
	$184.8	$240.4	$238.0	$663.2

over 1991. The 1993 increase reflects increased sales to other electric systems, while sales to ultimate consumers were generally flat. (See Electric and Gas Statistics - Electric Sales appearing on page 50.) The Company expects growth of approximately 1.2% in sales to ultimate consumers in 1994. The effects of the recession that began in 1990 are expected to continue to put downward pressure on industrial sales, which may be offset by growth in commercial and residential sales. The electric margin effect of actual sales in 1994 will be adjusted by the NERAM except for the large industrial customer class within which the Company will absorb 20% of the variance from the NERAM sales forecast. Industrial-Special sales are New York State Power Authority allocations of low-cost power to specified customers.

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

	1993 % of Electric Revenues	% Increase (decrease) from prior years					
		1993		1992		1991	
Class of service		Revenues	Sales	Revenues	Sales	Revenues	Sales
Residential	35.2%	6.9%	0.8%	11.3%	0.7%	7.4%	0.1%
Commercial	37.3	7.0	3.9	11.1	(0.5)	6.7	0.5
Industrial	16.6	(6.0)	(5.2)	13.0	(1.3)	2.4	(2.6)
Industrial - Special	1.3	9.1	0.8	11.8	1.9	4.8	(7.6)
Municipal service	1.5	0.6	(3.1)	5.8	(0.4)	6.1	0.9
Total to ultimate consumers	91.9	4.3	0.5	11.4	0.0	6.1	(1.3)
Other electric systems	3.1	12.6	31.2	(12.1)	(3.5)	51.9	107.9
Miscellaneous	5.0	40.6	—	(29.0)	—	44.2	—
Total	100.0%	5.9%	3.0%	8.3%	(0.3)%	8.9%	3.4%





As indicated in the table at the top of the next page, internal generation from fossil fuel sources continued to decline in 1993, principally at the Oswego oil-fired facility and Albany gas-fired station, corresponding to the increase in required unregulated generator purchases. Nuclear generation levels increased due to fewer unscheduled outages. Despite scheduled refueling and maintenance outages for both units during 1993, Unit 1 operated at a capacity factor of approximately 81% for 1993, while Unit 2 operated at approximately 78%. The next nuclear refueling outages at each unit are scheduled for 1995.

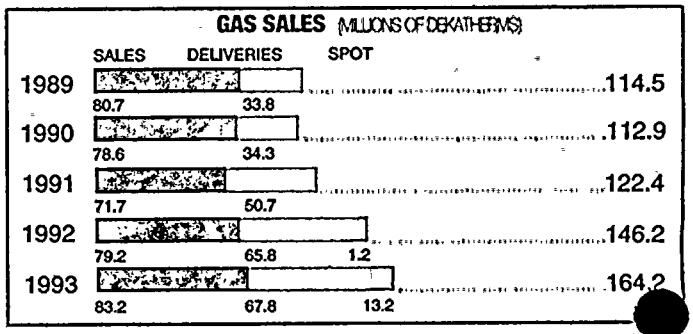
	1993		1992		1991		% Change from prior year 1993 to 1992		% Change from prior year 1992 to 1991	
Fuel for electric generation: *(in millions of dollars)*	GwHrs.	Cost	GwHrs.	Cost	GwHrs.	Cost	GwHrs.	Cost	GwHrs.	Co
Coal	7,088	$113.0	8,340	$128.8	8,715	$139.6	(15.0)%	(12.3)%	(4.3)%	(7.
Oil	2,177	74.2	3,372	106.6	5,917	187.6	(35.4)	(30.4)	(43.0)	(43.2)
Natural gas	548	12.5	1,769	44.6	1,980	54.6	(69.0)	(72.0)	(10.7)	(18.4)
Nuclear	7,303	43.3	5,031	28.9	6,561	45.2	45.2	49.8	(23.3)	(36.2)
Hydro	3,530	—	3,818	—	3,468	—	(7.5)	—	10.1	—
	20,646	243.0	22,330	308.9	26,641	427.0	(7.5)	(21.3)	(16.2)	(27.7)
Electricity purchased:										
Unregulated generators	11,720	735.7	8,632	543.0	4,303	268.1	35.8	35.5	100.6	102.5
Other	9,046	118.1	8,917	115.7	9,067	125.6	1.5	2.1	(1.7)	(7.9)
	20,766	853.8	17,549	658.7	13,370	393.7	18.3	29.6	31.3	67.3
Fuel adjustment clause	—	(2.2)	—	6.0	—	17.2	—	(136.7)	—	(65.1)
Losses/Company use	3,688	—	3,268	—	3,273	—	12.9	—	(0.2)	—
	37,724	$1,094.6	36,611	$973.6	36,738	$837.9	3.0%	12.4%	(0.3)%	16.2%

Gas revenues increased $115.5 million or 23.8% over the three-year period. As shown by the table below, this increase is primarily attributable to increased sales to ultimate customers, increased base rates and increased spot market sales. While spot market sales activity produced much of the revenue growth in 1993, these sales are generally from the higher priced gas available and therefore yield margins substantially lower than traditional sales to ultimate customers. Deregulation in the gas production and pipeline sectors has enabled the Company to expand into this activity. Rates for transported gas also yield lower margins than gas sold directly by the Company, therefore changes in gas revenues from transportation services have not had a significant impact on earnings. Also, changes in purchased gas adjustment clause revenues are generally margin-neutral.

	Increase (decrease) from prior year *(In millions of dollars)*			
Gas revenues	1993	1992	1991	To
Increase in base rates	$ 7.3	$ 4.7	$ 22.6	$3
Transportation of customer-owned gas	(9.7)	6.3	14.4	11.0
Purchased gas adjustment clause revenues	12.2	12.4	(25.7)	(1.1)
Spot market sales	27.2	2.6	—	29.8
MERIT revenues	(0.4)	(0.3)	2.7	2.0
Miscellaneous operating revenues	(4.6)	—	3.5	(1.1)
Sales to ultimate consumers and other sales	15.1	52.9	(27.7)	40.3
	$47.1	$78.6	$(10.2)	$115.5

Gas sales, excluding transportation of customer-owned gas and spot market sales, were 83.2 million dekatherms in 1993, a 5.1% increase from 1992 and a 16.0% increase from 1991. (See Electric and Gas Statistics - Gas Sales appearing on page 50.) The increase in 1993 includes a 1.8% increase in residential sales, a 6.5% increase in commercial sales, which were strongly influenced by weather, and a 143.6% increase in industrial sales. The Gas SBU has added 19,000 new customers since 1991, primarily in the residential class, an increase of 3.9%, and expects a continued increase in new customers in 1994. During 1993, there also was a shift from the transportation sales class to the industrial sales class resulting from the implementation of a stand-by industrial rate. The increase for 1992 included a 12.0% increase in sales in the residential class and a 10.2% increase in sales in the commercial class, reflecting milder weather factors, offset by a 2.2% decrease in sales in the industrial class reflecting the recession and fuel switching.

In 1993, the Company transported 67.8 million dekatherms (a slight increase from 1992) for customers purchasing gas directly from producers but expects a substantial increase in such transportation volumes in 1994 leading to a forecast increase in total gas deliveries in 1994 of 13.2% above 1993 weather-adjusted deliveries. Public sales are expected to decrease almost 1.0%. Factors affecting these forecasts include the economy, the relative price



differences between oil and gas in combination with the relative availability of each fuel, the expanded number of cogeneration projects served by the Company and increased marketing efforts. As authorized by the PSC, the

Company accrued $20.9 million of unbilled gas revenues as of December 31, 1993, which have been deferred and are expected to be used to reduce future gas revenue requirements. Changes in gas revenues and dekatherm sales by customer group are detailed in the table below:

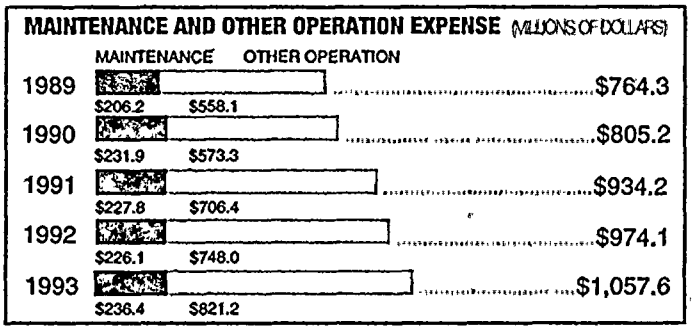
	1993 % of Gas	% Increase (decrease) from prior years					
		1993		1992		1991	
Class of service	Revenues	Revenues	Sales	Revenues	Sales	Revenues	Sales
Residential	61.6%	4.6%	1.8%	17.0%	12.0%	(1.4)%	(3.6)%
Commercial	24.1	9.2	6.5	16.6	10.2	(11.5)	(11.4)
Industrial	3.1	84.8	143.6	18.6	(2.2)	(56.4)	(56.0)
Total to ultimate consumers	88.8	7.4	6.4	16.9	11.1	(6.6)	(8.7)
Other gas systems	0.2	(77.5)	(80.3)	(32.0)	(21.7)	(11.9)	(11.8)
Transportation of customer-owned gas	5.8	(18.5)	2.9	17.2	30.0	65.0	47.9
Spot market sales	5.0	1,056.1	1,053.8	—	—	—	—
Miscellaneous	0.2	(79.4)	—	0.4	—	574.1	—
Total	100.0%	8.5%	12.3%	16.5%	19.5%	(2.1)%	8.4%

The cost of gas purchased increased 13.6% in 1993 and 16.1% in 1992 after having decreased 13.4% in 1991. The cost fluctuations generally correspond to sales volume changes, particularly in 1993, as spot market sales activity increased. The Company sold 13.2 million dekatherms on the spot market in 1993 as compared to 1.1 million in 1992. This activity accounted for two-thirds of the 1993 purchased gas expense increase. The purchased gas cost increase associated with purchases for ultimate consumers in 1993 resulted from an 8.7% increase in dekatherms purchased combined with a 2.1% increase in rates charged by suppliers offset by a $17.8 million decrease in purchased gas costs and certain other items recognized and recovered through the purchased gas adjustment clause. The increase associated with purchases for ultimate consumers for 1992 was the result of a 10.0% increase in dekatherms purchased, a 2.7% increase in rates charged by the Company's suppliers, combined with an increase of $5.2 million in purchased gas costs and certain other items recognized and recovered through the purchased gas adjustment clause. The Company's net cost per dekatherm purchased for sales to ultimate consumers decreased to $3.34 in 1993 from $3.47 in 1992 which was higher than the net cost of $3.31 in 1991.

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 fuel adjustment clause provides for partial pass-through of fuel and purchased power cost fluctuations from those forecast in rate proceedings, with the Company absorbing a specific portion of increases or retaining a portion of decreases to a maximum of $15 million per rate year. The amounts absorbed in 1991 through 1993 are not material.

Other operation expense, including wage increases in each year, increased $73.2 million or 9.8% in 1993 as compared to increases of 5.9% in 1992 and 7.8% in 1991. The 1993 increase is otherwise due to an increase in DSM program expenses, nuclear expenses related to increased production at Unit 1 and Unit 2 and refueling outages, amortization of regulatory assets deferred in prior years, increased recognition of other postretirement benefit costs and inflation. The 1992 increase was also due to increased computer software expenses and higher medical benefits paid. The 1991 increase was also due to increases in bad debt expense, environmental site investigation and remediation costs, DSM program expenses and research and development costs. Bad debts have increased during the recession and increased collection efforts and innovative collection management also contributed to the increased writeoffs.

Maintenance expense increased 4.5% in 1993 principally due to nuclear expenses incurred during the refueling outages at Unit 1 and Unit 2 offset by lower expenses on the fossil stations because of economically driven shutdowns at the Oswego and Albany plants as described above. Maintenance expense decreased slightly in 1992 as increased costs associated with outages at Unit 1 and refueling Unit 2 were offset by reduced transmission line maintenance expenses. Maintenance expense decreased 1.8% in 1991 due to lower Unit 2 maintenance partly offset by transmission line ice storm damage.



Depreciation and amortization expense for 1993 and 1992 increased 0.9% and 5.9% over 1992 and 1991, respectively. The increase is attributable to normal plant growth.

Net Federal and foreign income taxes for 1993 decreased due to the tax benefit derived from the Company's Canadian subsidiary upon the sale of its oil and gas investments. Net Federal and foreign income taxes for 1992 and 1991 increased because of increases in book taxable income. The increase in Other taxes in the three-year period is due principally to higher property taxes resulting from property additions combined with increased payroll and revenue-based taxes.

Other items, net, excluding Federal income taxes and allowance for funds used during construction (AFC), increased $23.4 million in 1993 and decreased $2.7 million in 1992. The 1993 increase was the effect of the recording in 1992 of a $45 million reserve against the carrying value of Canadian subsidiary oil and gas reserves, offset in part by the recognition of the Company's share of Unit 2 contractor litigation proceeds and increased earnings by the Company's independent power subsidiary. The 1991 decrease is primarily the result of a similar $22.7 million write-down of oil and gas reserves.

Net interest charges decreased $9.3 million in 1993 and $10.9 million in 1992, primarily as the result of the refinancing of debt at lower interest rates. Dividends on preferred stock decreased $4.7 million, $3.9 million and $1.9 million in 1993, 1992 and 1991, respectively, because of reductions in amounts of stock outstanding. The weighted average long-term debt interest rate and preferred dividend rate paid, reflecting the actual cost of variable rate issues, changed to 7.97% and 6.70%, respectively, in 1993, from 8.29% and 7.04%, respectively, in 1992, and from 8.74% and 7.53%, respectively, in 1991.

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 from the present. 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 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 assets with identical ones due to technological advances and regulatory changes that have occurred. In light of these considerations, the depreciation charges in operating expenses do not reflect the current cost of providing service. The Company, however, will seek additional revenue or reallocate resources to cover the costs of maintaining service as assets are replaced or retired.

Financial Position, Liquidity and Capital Resources

Financial Position

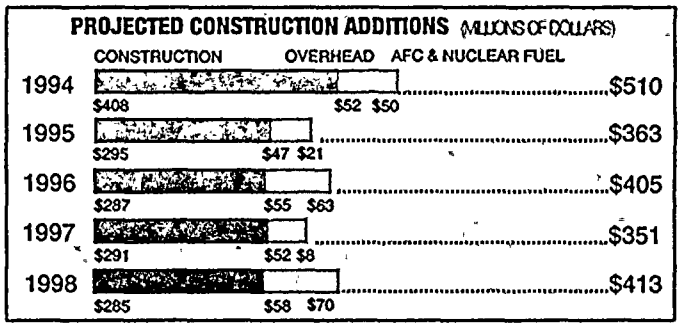
The Company's capital structure at December 31, 1993 was 54.6% long-term debt, 6.5% preferred stock and 38.9% common equity, as compared to 56.4%, 7.4% and 36.2%, respectively, at December 31, 1992. Book value of the common stock was $17.25 per share at December 31, 1993 as compared to $16.33 per share at December 31, 1992. The improvement in the capital structure and book value is attributable primarily to reinvested earnings and sales of common stock, although preferred stock redemptions also contributed.

The 1993 ratio of earnings to fixed charges was 2.31 compared to an average ratio nationally of approximately 3.0 for electric and gas utilities. The ratios of earnings to fixed charges for 1992 and 1991 were 2.24 and 2.09, respectively.

Firms which publish securities ratings have begun to impute 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 unregulated generator contracts. These firms believe that the financial structure of the unregulated generators (which typically have very high debt-to-equity ratios) and the character of their power purchase agreements increase the financial risk of utilities. The Company's reported interest coverage and debt-to-equity ratios have recently been discounted by varying amounts for purposes of establishing credit ratings. Because of growing commitments for unregulated generator purchases, the imputation can have a material negative impact on the Company's financial indicators.

Construction and Other Capital Requirements

The Company's total capital requirements consist of amounts for the Company's construction program, working capital needs, maturing debt issues and sinking fund provisions on preferred stock, and have been affected by the Company's efforts in recent years to lower capital costs through refinancing. Annual expenditures for the years 1991 to 1993 for construction and nuclear fuel, including related AFC and overheads capitalized, were $522.5 million, $502.2 million and $519.6 million, respectively.



The 1994 estimate for construction additions, including overheads capitalized, nuclear fuel and AFC, is approximately $510 million, of which approximately 90% is expected to be funded by cash provided from operations. Mandatory and optional debt and preferred stock retirements and other requirements are expected to add approximately another $545 million (expected to be refinanced from external sources) to the Company's capital requirements, for a total of $1,055 million. Current estimates of total capital requirements for the years 1995-1998 decrease considerably to $442, $474, $401 and $483 million, respectively, of which $363, $405, $351, and $413 million relates to expected construction additions. The

reductions are linked to the completion of debt refinancings as well as the reduced construction spending. The estimate of construction additions included in capital requirements for the period 1995 to 1998 will be reviewed by management during 1994 with the objective of further reducing these amounts where possible.

The provisions of the Clean Air Act Amendments of 1990 (Clean Air Act) are expected to have an impact on the Company's fossil generation plants during the period through 2000 and beyond. The Company is studying options for compliance with Phase I of the Clean Air Act, which becomes effective January 1, 1995 and continues through 1999.

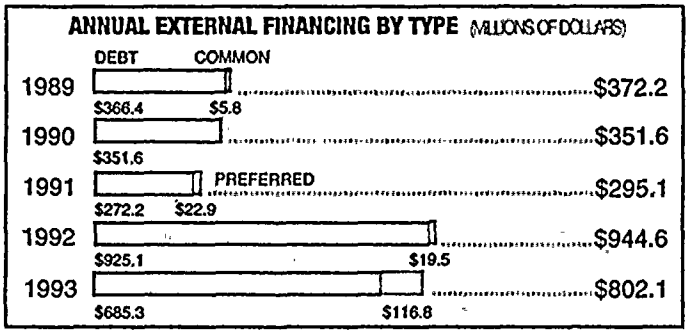
With respect to meeting sulfur dioxide emission limits in Phase I of the Clean Air Act, only Dunkirk units 3 and 4 are affected. Options under evaluation to comply with sulfur dioxide emission limits at these units include switching to a lower sulfur coal, reducing utilization of the units, and the purchase of emission allowances. The Company also must lower its nitrous oxide (NO_X) emissions in Phase I. The Company spent approximately $19 million in 1993 and has included $46 million in its construction forecast for 1994 through 1997 to make combustion modifications at its fossil fired plants including the installation of low NO_X burners at the Dunkirk and Huntley plants. With respect to Phase II, greater reductions will be required for both sulfur dioxide and NO_X emissions. The Company has conducted studies on its fossil fired units to examine compliance options. Preliminary estimates for Phase II compliance anticipate approximately $124 million in capital costs and $21 million in annual expenses. The Company believes that these capital costs, as well as incremental annual operating and maintenance costs and fuel costs, will be recoverable from ratepayers.

Liquidity and Capital Resources

Cash flows to meet the Company's requirements for operating, investing and financing activities during the past three years are reported in the Consolidated Statements of Cash Flows on page 32.

During 1993, the Company raised approximately $892 million from external sources, consisting of $635 million of First Mortgage Bonds, $116.7 million of common stock and a net increase of $140.3 million of short and intermediate term debt. The proceeds of the $635 million of First Mortgage Bonds were used to provide for the early redemption of approximately $602 million of higher coupon First Mortgage Bonds. The Company continues to investigate options to reduce its embedded cost of long-term debt by taking advantage of current lower interest rates.

External financing of approximately $750 million is expected for 1994, of which approximately $545 million would be used for scheduled and optional refundings. This external financing is projected to consist of $425 million in long-term debt, $200 million from sales of common stock, $200 million of preferred stock and a $75 million decrease in short-term debt. Common stock sales at this amount will require shareholder approval to increase the Company's common shares authorized and are consistent with management's goal to improve the Company's capital structure. External financing plans for 1995 to 1998 are subject to periodic revision as underlying assumptions are changed to reflect developments; still, the Company currently anticipates external financing over this period will diminish in the aggregate to approximately $420 million. Substantially all financing is for refunding, as cash provided by operations is expected to continue to provide funds for the Company's construction program. The ultimate level of financing during this four year period will reflect, among other things, the Company's competitive positioning, uncertain energy demand due to economic conditions and capital expenditures relating to distribution and transmission load reliability projects, as well as expansion of the gas business. Environmental standards compliance costs, the effects of rate regulation and various regulatory initiatives, the level of internally generated funds and dividend payments, the availability and cost of capital and the ability of the Company to meet its interest and preferred stock dividend coverage requirements, to satisfy legal requirements and restrictions in governing instruments and to maintain an adequate credit rating also will impact the amount and type of future external financing.



The Company has initiated a ten to fifteen year site investigation and remediation program that seeks a) to identify and remedy environmental contamination hazards in a proactive and cost-effective manner and b) to ensure financial participation by other responsible parties. The program involves sponsorship of investigation, remediation and selected research projects for 42 Company-owned waste sites and, where appropriate, participation in remedial action at 40 waste sites owned by others but where the Company is one of a number of potentially responsible parties (PRP).

The Company has accrued a minimum liability of $240 million at December 31, 1993 for its estimated liability for investigation and remediation of certain Company-owned and Company-associated hazardous waste sites, which represents the low end of a range of estimates developed from the Company's ongoing site investigation and remediation program. Of the $240 million accrued, $210 million relates to Company-owned sites and $30 million represents the Company's estimated cost contribution to sites with which it may be associated. The accrual of the Company's cost contribution for PRP sites is derived by estimating the total cost of clean-up of the sites and then applying a contribution factor to the estimated total cost. Total costs to investigate and remediate sites with which the Company is associated as a PRP are estimated to be approximately $590 million.

The Company believes that costs incurred in the investigation and remediation process are recoverable in the ratesetting process as currently in effect. (See Note 8 of

Notes to Consolidated Financial Statements under "Environmental Contingencies.") Rate agreements since 1991 have included a recovery mechanism and an annual allowance for costs expected to be incurred for waste site investigation and remediation. The recovery mechanism provides that expenditures over or under the allowance be deferred for future rate consideration. The Company does not expect these costs to impact external financing, although any such impact is dependent upon the timing of expenditures and associated recovery.

The Company also is undertaking environmental compliance audits at many of its facilities. These audits may result in additional expenditures for investigation and remediation that the Company cannot currently estimate.

The Nuclear Regulatory Commission (NRC) issued regulations in 1988 requiring owners of nuclear power plants to place costs associated with decommissioning activities for contaminated portions of nuclear facilities into an external trust. Further, the NRC established guidelines for determining minimum amounts that must be available in the trust for these specified decommissioning activities at the time of decommissioning. Applying the NRC guidelines, the Company has estimated that the minimum requirements for Unit 1 and its share of Unit 2, respectively, will be $372 million and $169 million in 1993 dollars. The Company is seeking an increase in its rate allowance for Unit 1 and Unit 2 decommissioning in 1995 to reflect new NRC minimum requirements. Amounts collected for the NRC minimum are being placed in an external trust. (See Note 7 of Notes to Consolidated Financial Statements under "Nuclear Plant Decommissioning.")

The Company believes that traditionally available sources of financing should be sufficient to satisfy the Company's external financing needs during the period 1994 through 1998. As of December 31, 1993, the Company could issue an additional $1,899 million aggregate principal amount of First Mortgage Bonds. This includes approximately $921 million from retired bonds without regard to an interest coverage test and approximately $978 million supported by additional property currently certified and available, assuming an 8% interest rate, under the applicable tests set forth in the Company's mortgage trust indenture. The Company also has authorized unissued Preferred Stock totaling approximately $390 million and a total of $200 million of Preference Stock is currently authorized for sale. The Company will continue to explore and use, as appropriate, other methods of raising funds.

Ordinarily, construction related short-term borrowings are refunded with long-term securities on a regular basis. This approach generally results in the Company showing a working capital deficit. Working capital deficits also may be temporarily created because 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. However, the Company has sufficient borrowing capacity to fund such a deficit as necessary. Bank credit arrangements which, at December 31, 1993, totaled $461 million are used by the Company to enhance flexibility as to the type and timing of its long-term security sales.

The Company's charter restricts the amount of unsecured indebtedness that may be incurred by the Company to 10% of consolidated capitalization plus $50 million. The Company has not reached this restrictive limit.

The Company's securities ratings at February 23, 1994, were:

	Secured Debt	Preferred Stock	Commer Paper
Standard & Poors Corporation	BBB-	BB+	A-3
Moody's Investors Service	Baa2	baa3	P-2
Duff & Phelps	BBB	BBB-	Not applicable
Fitch Investors Service	BBB	BBB-	Not applicable

The security ratings set forth above are subject to revision and/or withdrawal at any time by the respective rating organizations and should not be considered a recommendation to buy, sell or hold securities of the Company.

The Company's cost of financing and access to markets could be negatively affected by events outside its control. The Company's securities ratings could be negatively affected by, among other things, the continued growth in and its reliance on unregulated generator purchase power requirements. Rating agencies have expressed concern about the impact on Company financial indicators and risk that unregulated generator financial leveraging may have.

On October 27, 1993, Standard & Poors Corporation (S&P) issued their revised electric utility financial ratio benchmarks. S&P has made its benchmarks more stringent to counter increasing business risk caused by accelerating competition in the electric power industry as well as environmental and nuclear operating cost pressure and slow earnings growth prospects. S&P also observed that because of the more disparate business prospects for electric utilities, it was segregating companies into groups based upon competitive position, business prospects and predictability of cash flows to withstand greater financial risks. The Company was included in the "Below Average," or lowest rated group in S&P's assessment of business position. Based on this criteria, on February 23, 1994 S&P reduced the Company's credit ratings as disclosed above. In addition, S&P announced that although the Company has taken steps to control operating expenses and limit exposure to unregulated generator costs and to otherwise improve revenues, the ratings outlook for the Company would remain negative pending demonstrated financial improvement. A number of factors reflecting "prospects for insufficient financial improvement" were considered in S&P's decision to downgrade, including large and increasing purchased power costs required to be paid to unregulated generators, weak sales growth because of the sluggish economy in the Company's service territory and the potential for modest revenue losses resulting from discounted rates to larger customers who may otherwise bypass the Company's electric system for other suppliers. The Company is taking a number of steps to address these matters, as stated elsewhere in this report.

Moody's Investors Service also has indicated that it expects utility bond ratings will come under increasing pressure over the next three to five years because of changes in the business environment, although it indicated in

February 1994 that it would maintain current ratings on all existing debt.

These developments may increase the cost to issue new securities.

Report of Management

The consolidated financial statements of Niagara Mohawk Power Corporation 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 which 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, the Company's independent accountants, in accordance with generally accepted auditing standards. In planning and performing their 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 five 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.

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, 1993 and 1992, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1993, 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 Notes 1 and 5 to the financial statements, the Company adopted the provisions of Statements of Financial Accounting Standards No. 109, Accounting for Income Taxes, and No. 106, Accounting for Postretirement Benefits Other Than Pensions, respectively, in 1993.

As discussed in Note 8, the Company is a defendant in lawsuits relating to its actions with respect to certain purchased power contracts. Management is unable to predict whether the resolution of these matters will have a material effect on its financial position or results of operations. Accordingly, no provision for any liability that may result upon resolution of this uncertainty has been made in the accompanying 1993 financial statements.

Price Waterhouse

Syracuse, New York
January 27, 1994

Consolidated Balance Sheets

At December 31,	In thousands of dollars 1993	1992
ASSETS		
Utility plant (*Note 1*):		
Electric plant	$ 7,991,346	$ 7,590,062
Nuclear fuel	458,186	445,890
Gas plant	845,299	787,448
Common plant	244,294	231,425
Construction work in progress	569,404	587,437
Total utility plant	10,108,529	9,642,262
Less: Accumulated depreciation and amortization	3,231,237	2,975,977
Net utility plant	6,877,292	6,666,285
Other property and investments	221,008	274,169
Current assets:		
Cash, including temporary cash investments of $100,182 and $4,121, respectively	124,351	43,894
Accounts receivable (less allowance for doubtful accounts of $3,600) (*Note 8*)	258,137	221,165
Unbilled revenues (*Note 1*)	197,200	180,000
Electric margin recoverable	21,368	11,595
Materials and supplies, at average cost:		
Coal and oil for production of electricity	29,469	78,517
Gas storage	31,689	20,466
Other	163,044	172,637
Prepayments:		
Taxes	23,879	14,414
Pension expense (*Note 5*)	37,238	33,631
Other	29,498	32,522
	915,873	808,841
Regulatory and other assets:		
Unamortized debt expense	154,210	140,803
Deferred recoverable energy costs	67,632	61,944
Deferred finance charges (*Note 1*)	239,880	239,880
Income taxes recoverable (*Note 6*)	527,995	—
Recoverable environmental restoration costs (*Note 8*)	240,000	215,000
Other	175,187	183,613
	1,404,904	841,240
	$ 9,419,077	$ 8,590,535
CAPITALIZATION AND LIABILITIES		
Capitalization (*Note 4*):		
Common stockholders' equity:		
Common stock, issued 142, 427, 057 and 137,159, 607 shares, respectively	$ 142,427	$ 137,160
Capital stock premium and expense	1,762,706	1,658,015
Retained earnings	551,332	445,266
	2,456,465	2,240,441
Non-redeemable preferred stock	290,000	290,000
Mandatorily redeemable preferred stock	123,200	170,400
Long-term debt	3,258,612	3,491,059
Total capitalization	6,128,277	6,191,900
Current liabilities:		
Short-term debt (*Note 2*)	368,016	227,698
Long-term debt due within one year (*Note 4*)	216,185	57,722
Sinking fund requirements on redeemable preferred stock (*Note 4*)	27,200	27,200
Accounts payable	299,209	275,744
Payable on outstanding bank checks	35,284	41,738
Customers' deposits	14,072	13,059
Accrued taxes	56,382	52,033
Accrued interest	70,529	70,882
Accrued vacation pay	40,178	38,515
Other	82,145	40,220
	1,209,200	844,811
Regulatory and other liabilities:		
Accumulated deferred income taxes (*Note 1 and 6*)	1,313,483	755,421
Deferred finance charges (*Note 1*)	239,880	239,880
Unbilled revenues (*Note 1*)	94,968	77,768
Deferred pension settlement gain (*Note 5*)	62,282	68,292
Customers refund for replacement power cost disallowance	23,081	46,801
Other	107,906	150,662
	1,841,600	1,338,824
Commitments and contingencies (*Note 8*):		
Liability for environmental restoration	240,000	215,000
	$9,419,077	$8,590,535

Consolidated Statements of Income and Retained Earnings

For the year ended December 31,	In thousands of dollars 1993	1992	1991
Operating revenues:			
Electric	$3,332,464	$3,147,676	$2,907,293
Gas	600,967	553,851	475,225
	3,933,431	3,701,527	3,382,518
Operating expenses:			
Operation:			
Fuel for electric generation	231,064	323,200	438,957
Electricity purchased	863,513	650,379	398,882
Gas purchased	326,273	287,316	247,502
Other operation expenses	821,247	748,023	706,400
Maintenance	236,333	226,127	227,812
Depreciation and amortization (*Note 1*)	276,623	274,090	258,816
Federal and foreign income taxes (*Note 6*)	162,515	183,233	158,137
Other taxes	491,363	484,833	420,578
	3,408,931	3,177,201	2,857,084
Operating Income	524,500	524,326	525,434
Other income and deductions:			
Allowance for other funds used during construction (*Note 1*)	7,119	9,648	8,251
Federal and foreign income taxes (*Note 6*)	15,440	27,729	24,242
Other items (net)	7,035	(16,338)	(13,599)
	29,594	21,039	18,894
Income before interest charges	554,094	545,365	544,328
Interest charges:			
Interest on long-term debt	279,902	290,734	302,062
Other interest	11,474	9,982	9,577
Allowance for borrowed funds used during construction	(9,113)	(11,783)	(10,680)
	282,263	288,933	300,959
Net income	271,831	256,432	243,369
Dividends on preferred stock	31,857	36,512	40,411
Balance available for common stock	239,974	219,920	202,958
Dividends on common stock	133,908	103,784	43,552
	106,066	116,136	159,406
Retained earnings at beginning of year	445,266	329,130	169,724
Retained earnings at end of year	$ 551,332	$ 445,266	$ 329,130
Average number of shares of common stock outstanding (*in thousands*)	140,417	136,570	136,100
Balance available per average share of common stock	$ 1.71	$ 1.61	$ 1.49
Dividends paid per share	$ .95	$ .76	$ .32

( ) Denotes deduction

Consolidated Statements of Cash Flows

Increase (Decrease) in Cash

For the year ended December 31,	1993	1992	1991
	In thousands of dollars		
Cash flows from operating activities:			
Net income	$271,831	$256,432	$243,369
Adjustments to reconcile net income to net cash provided by operating activities:			
Amortization of nuclear replacement power cost disallowance	(23,720)	(39,547)	(28,820)
Depreciation and amortization	276,623	274,090	258,816
Amortization of nuclear fuel	35,971	26,159	38,687
Provision for deferred income taxes	30,067	55,929	68,138
Electric margin recoverable	(9,773)	3,670	(20,173)
Allowance for other funds used during construction	(7,119)	(9,648)	(8,251)
Deferred recoverable energy costs	(5,688)	(14,329)	4,931
(Gain) loss on investments — net	(5,490)	44,296	30,680
Deferred operating expenses	15,746	20,257	31,176
Increase in net accounts receivable	(36,972)	(44,969)	(25,900)
(Increase) decrease in materials and supplies	43,581	(28,293)	7,022
Increase in accounts payable and accrued expenses	15,716	31,025	4,221
Increase in accrued interest and taxes	3,996	10,133	447
Changes in other assets and liabilities	22,581	39,565	17,052
Net cash provided by operating activities	627,350	624,770	621,395
Cash flows from investing activities:			
Construction additions	(506,267)	(452,497)	(504,485)
Nuclear fuel	(12,296)	(37,247)	(13,236)
Less: Allowance for other funds used during construction	7,119	9,648	8,251
Acquisition of utility plant	(511,444)	(480,096)	(509,470)
(Increase) decrease in materials and supplies related to construction	3,837	(7,359)	4,682
Increase in accounts payable and accrued expenses related to construction	3,929	7,756	1,055
Increase in other investments	(38,731)	(11,615)	(69,648)
Proceeds from sale of investment in oil and gas subsidiary	95,408	—	—
Other	(15,260)	(31,588)	(13,72[illegible]
Net cash used in investing activities	(462,261)	(522,902)	(587,10[illegible]
Cash flows from financing activities:			
Proceeds from sale of common stock	116,764	13,340	—
Sale of mortgage bonds	635,000	835,000	195,600
Issuance of preferred stock	—	—	22,850
Redemption of preferred stock	(47,200)	(41,950)	(42,830)
Reductions of long-term debt	(641,990)	(796,795)	(231,941)
Net change in short-term debt and revolving credit agreements	50,318	90,130	76,606
Dividends paid	(165,765)	(140,296)	(83,963)
Other	(31,759)	(44,781)	(6,808)
Net cash used in financing activities	(84,632)	(85,352)	(70,486)
Net increase (decrease) in cash	80,457	16,516	(36,193)
Cash at beginning of year	43,894	27,378	63,571
Cash at end of year	$124,351	$ 43,894	$ 27,378
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest	$300,791	$323,972	$331,828
Income taxes	106,202	76,519	67,509
Supplemental schedule of noncash investing and financing activities:			
Liability for environmental restoration	$ 25,000	$ 15,000	$200,000

During 1992, the Company acquired all of the common stock of Syracuse Suburban Gas Company, Inc. in exchange for 353,775 shares of the Company's common stock having a value of $6,120,000.

Notes to Consolidated Financial Statements

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 maintains its accounting records on the basis of such regulation, which it believes complies with generally accepted accounting principles. The Company's accounting policies conform to generally accepted accounting principles, as applied to regulated public utilities, and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities.

Principles of Consolidation: The consolidated financial statements include the Company and its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated. Assets and liabilities of its Canadian energy subsidiary, Opinac Energy Corporation, are translated into U.S. dollars at the exchange rate in effect at the balance sheet date. Revenue and expense accounts are translated at the average exchange rate in effect during the year. Currency translation adjustments are recorded as a component of equity and do not have a significant impact on financial condition. The results of operations of the Company's oil and gas subsidiary are included in other income and deductions on the Consolidated Statements of Income and Retained Earnings.

Subsidiary Oil and Gas Properties: During 1993, the Company sold its interest in its Canadian oil and gas company, Opinac Exploration Limited. This was done to streamline the Company's business and focus on its core electric and gas utility assets. The sale did not have a material impact on the Company's results of operations or financial condition. The Company retained its ownership of Opinac Energy Corporation and the Company's subsidiary, Canadian Niagara Power Limited, an Ontario electric utility company.

The net book value of oil and gas properties and equipment, less related deferred income taxes, was limited to the sum of the after tax present value of net revenues from proved oil and gas reserves and the lower of cost or fair value of unproved properties. The calculation of future net revenues was based upon prices and costs in effect at the end of the year. Based upon the calculation of this "ceiling test" at December 31, 1991 and March 31, 1992, the Company recorded reserves of approximately $23 million and $21 million, or an after tax effect of $.07 and $.09 per share, respectively. At December 31, 1992, the Company recorded a valuation reserve of $24 million, or an after tax effect of $.09 per share, in light of a significant decline in previous estimates of proved reserves as indicated by lower than expected production volumes. The net investment in such properties was approximately $101 million at December 31, 1992.

Utility Plant: The cost of additions to utility plant and of replacements of retirement units of property is 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 to 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, 1993 was 6.5%. AFC is segregated into its two components, borrowed funds and other funds, and is reflected in the Interest Charges section and the Other Income and Deductions section, respectively, of the Consolidated Statements of Income.

In 1985, pursuant to PSC authorization, the Company discontinued accruing AFC on construction work in progress (CWIP) for which a cash return was being allowed through inclusion in rate base of that portion of the investment in Unit 2. Amounts equal to Unit 2's AFC which was no longer accrued have been accumulated in deferred debit and credit accounts up to the commercial operation date of Unit 2, (each amounting to $239.9 million at December 31, 1993 and 1992), and await future ratemaking 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.

Depreciation, Amortization and Nuclear Generating Plant Decommissioning Costs: For accounting and regulatory purposes, depreciation is computed on the straight-line basis using the average or remaining service lives by classes of depreciable property. The total provision for depreciation and amortization, including amounts charged to clearing accounts, was $277.9 million for 1993, $275.3 million for 1992, and $260.2 million for 1991. The percentage relationship between the total provision for depreciation and average depreciable property was 3.2% for 1993, 3.3% for 1992 and 3.2% for 1991. The Company performs depreciation studies on a continuing basis and, upon approval by the PSC, periodically adjusts the rates of its various classes of depreciable property.

Estimated decommissioning costs (costs to remove a nuclear plant from service in the future) for the Company's Nine Mile Point Nuclear Station Unit No. 1 (Unit 1) and its share of decommissioning costs of Unit 2 are being accrued over the service life of the Unit, recovered in rates through an annual allowance and charged to operations through depreciation (See Note 7. "Nuclear Plant Decommissioning"). The Company expects to commence decommissioning shortly after cessation of operations using a method which removes or decontaminates Unit components promptly.

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 kilowatt-hour of net generation available for sale, is based upon a contract with the U.S. Department of Energy. 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 bi-monthly. Although the Company commenced the practice in 1988 of accruing electric revenues for energy consumed and not billed at the end of the fiscal year, the impact of such accruals has not yet been fully recognized in the Company's results of operations. At December 31, 1993 and 1992, approximately $95.0 million and $77.8 million, respectively, of unbilled revenues remained unrecognized in results of operations and are included in Deferred Credits, and may be used to reduce future revenue requirements. The amount of the remaining deferred credit balance fluctuates as the amount of accrued electric unbilled revenues is recalculated each year end. At December 31, 1993, pursuant to PSC authorization the Company accrued $20.9 million of unbilled gas revenues which will similarly be used to reduce future gas revenue requirements, with a portion to be used in 1994.

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 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 fuel adjustment clause provides for partial pass-through of fuel and purchased power cost fluctuations from amounts forecast, with the Company absorbing a specific 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 to be 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 20% and passing 80% through to ratepayers. The amounts absorbed in 1991 through 1993 are not material.

Beginning in 1991, the Company's rate agreements provide for NERAM, which requires the Company to reconcile actual results to forecast electric public sales gross margin as defined and utilized in establishing rates. Depending on the level of actual sales, a liability to customers is created if sales exceed the forecast and an asset is recorded for a sales shortfall, thereby generally holding recorded electric gross margin to the level forecast in establishing rates. The 1994 rate settlement provides for the operation of the NERAM through December 31, 1994. Recovery or refund of accruals pursuant to the NERAM is accomplished by a surcharge (either plus or minus) to customers over a twelve month period, to begin when cumulative amounts reach certain specified levels.

Rate agreements since 1991 also include MERIT, under which the Company has the opportunity to achieve earnings above its allowed return on equity based on attainment of specified goals associated with its self-assessment process. The MERIT program provides for specific measurement periods and reporting for PSC approval of MERIT earnings. Approved MERIT awards are billed to customers over a period not greater than twelve months. The Company records MERIT earnings when attainment of goals is approved by the PSC or when objectively measured criteria are achieved.

Federal Income Taxes: In accordance with PSC requirements, the tax effect of book and tax timing differences is flowed through except as required by the Internal Revenue Code or unless authorized by the PSC to be deferred. As directed by the PSC, the Company defers any amounts payable pursuant to the alternative minimum tax rules. The Company has claimed investment tax credits and deferred the benefits of such credits as realized in accordance with PSC directives. Deferred investment credits are amortized to Other Income and Deductions over the useful life of the underlying property. For purposes of computing capital cost recovery deductions and normalization, the asset basis has been reduced by all or a portion of the credit claimed consistent with then current tax laws.

Since it is the Company's intention to reinvest the undistributed earnings of its foreign subsidiaries, no provision is made for federal income taxes on these earnings. At December 31, 1993, the cumulative amount of undistributed earnings of foreign subsidiaries on which the Company has not provided deferred taxes was approximately $109 million. It is expected that the federal income taxes associated with these undistributed earnings would be substantially reduced by foreign tax credits.

On January 1, 1993, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 109, Accounting for Income Taxes. The adoption of SFAS 109 changes the Company's method of accounting for income taxes from the deferred method to an asset and liability approach. The asset and liability approach requires the recognition of deferred tax liabilities and assets for the expected future tax consequences of temporary differences between the recorded book bases and the tax bases of assets and liabilities.

The adoption of SFAS 109 did not have a significant impact on the Company's 1993 results of operations, and accordingly the effect of adoption has been included in federal and foreign income taxes.

Amortization of Debt Issue Costs: The premium or discount and debt expenses on long-term debt issues and on certain debt retirements prior to maturity are amortized ratably over the lives of the related issues and included in interest on long-term debt in accordance with PSC directives.

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 1993 presentation.

2 Bank Credit Arrangements

December 31, 1993, the Company had $461 million bank credit arrangements with 19 banks. These credit arrangements consisted of $220 million in commitments under Revolving Credit Agreements (including a Revolving Credit Agreement for HYDRA-CO Enterprises, Inc., a wholly-owned subsidiary of the Company), $140 million in one-year commitments under Credit Agreements, $1 million in lines of credit and $100 million under a Bankers Acceptance Facility Agreement. The Revolving Credit Agreements which extend into 1994 are renewed annually, and the interest rate applicable to borrowing is based on certain rate options available under the Agreements. All of the other bank credit arrangements are subject to review on an ongoing basis with interest rates negotiated at the time of use. The Company also issues commercial paper. Unused bank credit facilities are held available to support the amount of commercial paper outstanding. In addition to these credit arrangements, the Company obtained $100 million in bank loans which will expire in 1994.

The Company pays fees for substantially all of its bank credit arrangements. The Bankers Acceptance Facility Agreement, which is used to finance the fuel inventory for the Company's generating stations, provides for the payment of fees only at the time of issuance of each acceptance.

The following table summarizes additional informtion applicable to short-term debt:

	In thousands of dollars	
At December 31:	**1993**	**1992**
Short-term debt:		
Commercial paper	$210,016	$ 93,248
Notes payable	153,000	104,450
Bankers acceptances	5,000	30,000
	$368,016	$227,698
Weighted average interest rate *(a)*	3.60%	4.33%
For Year Ended December 31:		
Daily average outstanding	$165,458	$110,313
Monthly weighted average interest rate *(a)*	3.72%	4.80%
Maximum amount outstanding	$368,016	$227,698

(a) Excluding fees

3 Jointly-Owned Generating Facilities

The following table reflects the Company's share of jointly-owned generating facilities at December 31, 1993. 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 and 2 *(a)*	25	$ 87,691	$ 40,263	$ 760
Oswego Steam Station Unit No. 6 *(b)*	76	$ 270,301	$ 97,856	$ 4,207
Nine Mile Point Nuclear Station Unit No. 2 *(c)*	41	$1,504,703	$214,825	$11,434

(a) The remaining ownership interests are Central Hudson Gas and Electric Corporation, the operator of the plant (35%) and Consolidated Edison Company of New York, Inc. (40%). Central Hudson Gas and Electric Corporation has agreed to acquire the Company's 25% interest in the plant in ten equal installments of 2.5% (30 mw.) starting on December 31, 1994 and on each December 31 thereafter. The Company then has the option to repurchase its 25% interest in 2004. The agreement is subject to PSC approval. 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 Rochester Gas and Electric Corporation (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 Long Island Lighting Company (18%), New York State Electric and Gas Corporation (18%), Rochester Gas and Electric Corporation (14%), and Central Hudson Gas and Electric Corporation (9%). Output of Unit 2, which has a capability of 1,062,000 kw., is shared in the same proportions as the cotenants' respective ownership interests.

4 Capitalization

Capital Stock

The Company is authorized to issue 150,000,000 shares of common stock, $1 par value; 3,400,000 shares of preferred st[illegible] $100 par value; 19,600,000 shares of preferred stock, $25 par value; and 8,000,000 shares of preference stock, $25 par va[illegible]. The table below summarizes changes in the capital stock issued and outstanding and the related capital accounts for 1991, 1992 and 1993:

	Common Stock $1 par value		Preferred Stock $100 par value			Preferred Stock $25 par value			Capital Stock Premium and Expense (Net)*
	Shares	Amount*	Shares	Non-Redeemable*	Redeemable*	Shares	Non-Redeemable*	Redeemable*	
December 31, 1990:	136,099,654	$136,100	2,548,000	$210,000	$44,800 *(a)*	11,789,204	$80,000	$214,730 *(a)*	$1,649,294
Issued	—	—	—	—	—	914,005	—	22,850	—
Redemptions			(58,000)	—	(5,800)	(1,481,204)	—	(37,030)	340
Foreign currency translation adjustment									678
December 31, 1991:	136,099,654	136,100	2,490,000	210,000	39,000 *(a)*	11,222,005	80,000	200,550 *(a)*	1,650,312
Issued	1,059,953	1,060	—	—	—	—	—	—	18,401
Redemptions			(78,000)	—	(7,800)	(1,366,000)	—	(34,150)	796
Foreign currency translation adjustment									(11,494)
December 31, 1992:	137,159,607	137,160	2,412,000	210,000	31,200 *(a)*	9,856,005	80,000	166,400 *(a)*	1,658,015
Issued	5,267,450	5,267	—	—	—	—	—	—	111,497
Redemptions			(18,000)	—	(1,800)	(1,816,000)	—	(45,400)	(2,471)
Foreign currency translation adjustment									(4,335)
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

* *In thousands of dollars*

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

The cumulative amount of foreign currency translation adjustment at December 31, 1993 was $(7,099).

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* 1993	1992	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:				
Adjustable Rate				
Series A	1,200,000	30,000	30,000	25.00
Series C	2,000,000	50,000	50,000	25.75*(1)*
		$290,000	$290,000	

(1) Eventual minimum $25.00

Mandatorily Redeemable Preferred Stock

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

	Shares		In thousands of dollars		Redemption price per share (Before adding accumulated dividends)	
Series	1993	1992	1993	1992	1993	Eventual minimum
Preferred $100 par value:						
7.45%	294,000	312,000	$ 29,400	$ 31,200	$102.65	$100.00
Preferred $25 par value:						
7.85%	914,005	914,005	22,850	22,850	(a)	25.00
8.375%	500,000	600,000	12,500	15,000	25.44	25.00
8.70%	600,000	1,000,000	15,000	25,000	25.50	25.00
8.75%	600,000	1,800,000	15,000	45,000	25.50	25.00
9.75%	276,000	342,000	6,900	8,550	25.26	25.00
Adjustable Rate						
Series B	1,950,000	2,000,000	48,750	50,000	25.75	25.00
			150,400	197,600		
Less sinking fund requirements			27,200	27,200		
			$123,200	$170,400		

(a) Not redeemable until 1996.

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 and 300,000 shares of the 9.75% 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 1994 through 1998 are as follows: $27,200; $12,200; $14,150; $10,120; and $10,120, respectively.

g-Term Debt

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

		In thousands of dollars	
Series	Due	1993	1992
First mortgage bonds:			
8 7/8%	1994	$ 150,000	$ 150,000
4 5/8%	1994	40,000	40,000
5 7/8%	1996	45,000	45,000
6 1/4%	1997	40,000	40,000
**9 7/8%	1998	—	200,000
6 1/2%	1998	60,000	60,000
10 1/4%	1999	100,000	100,000
10 3/8%	1999	100,000	100,000
9 1/2%	2000	150,000	150,000
**7 3/8%	2001	—	65,000
9 1/4%	2001	100,000	100,000
**7 5/8%	2002	—	80,000
**7 3/4%	2002	—	80,000
5 7/8%	2002	230,000	—
6 7/8%	2003	85,000	—
7 3/8%	2003	220,000	220,000
**8 1/4%	2003	—	80,000
8%	2004	300,000	300,000
6 5/8%	2005	110,000	—
9 3/4%	2005	150,000	150,000
**8.35%	2007	—	66,640
**8 5/8%	2007	—	30,000
*6 5/8%	2013	45,600	45,600
*11 1/4%	2014	75,690	75,690
*11 3/8%	2014	40,015	40,015
9 1/2%	2021	150,000	150,000
8 3/4%	2022	150,000	150,000
8 1/2%	2023	165,000	165,000
7 7/8%	2024	210,000	—
*8 7/8%	2025	75,000	75,000
Total First Mortgage Bonds		2,791,305	2,757,945
Promissory notes:			
*Adjustable Rate Series due			
July 1, 2015		100,000	100,000
December 1, 2023		69,800	69,800
December 1, 2025		75,000	75,000
December 1, 2026		50,000	50,000
March 1, 2027		25,760	25,760
July 1, 2027		93,200	93,200
Unsecured notes payable:			
Medium Term Notes, Various rates, due 1993-2004		55,500	87,700
Swiss Franc Bonds due December 15, 1995		50,000	50,000
Oswego Facilities Trust		—	90,000
Other		176,888	157,829
Unamortized premium (discount)		(12,656)	(8,453)
TOTAL LONG-TERM DEBT		3,474,797	3,548,781
Less long-term debt due within one year		216,185	57,722
		$3,258,612	$3,491,059

*Tax-exempt pollution control related issues **Retired prior to maturity

Several series of First Mortgage Bonds and Notes were issued to secure a like amount of tax-exempt revenue bonds issued by the New York State Energy Research and Development Authority (NYSERDA). Approximately $414 million of such notes 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 2.14% for 1993 and 2.43% for 1992 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 refund outstanding tax-exempt bonds and notes.

The $115.7 million of tax-exempt bonds due 2014 will be refinanced at 7.2% during 1994 pursuant to a forward refunding agreement entered into in 1992.

Notes Payable include a Swiss franc bond issue maturing in 1995 equivalent to $50 million in U.S. funds. Simultaneously with the sale of these bonds, the Company entered into a currency exchange agreement to fully hedge against currency exchange rate fluctuations.

Other long-term debt in 1993 consists of obligations under capital leases of approximately $45.3 million, a liability to the U.S. Department of Energy for nuclear fuel disposal of approximately $93.5 million (See Note 7. "Nuclear Fuel Disposal Costs") and liabilities for unregulated generator contract termination of approximately $38.1 million.

Certain of the Company's debt securities provide for a mandatory sinking fund for annual redemption. The aggregate maturities of long-term debt for the five years subsequent to December 31, 1993, excluding capital leases, are approximately $211 million, $73 million, $61 million, $46 million and $66 million, respectively.

5 *Pension and Other Retirement Plans*

The Company and certain of its subsidiaries have non-contributory, defined-benefit pension plans covering substantially all their employees. Benefits are based on the employee's years of service and compensation level. The pension cost was $16.9 million for 1993, $23.2 million for 1992 and $23.9 million for 1991 ($5.6 million for 1993, $6.2 million for 1992 and $6.0 million for 1991 was related to construction labor and, accordingly, was charged to construction projects). 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. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

Net pension cost for 1993, 1992 and 1991 included the following components:

	In thousands of dollars		
	1993	1992	1991
Service cost — benefits earned during the period	$ 30,100	$ 27,100	$ 27,000
Interest cost on projected benefit obligation	54,200	48,800	43,500
Actual return on Plan assets	(106,100)	(59,600)	(116,600)
Net amortization and deferral	38,700	6,900	70,000
Net pension cost	$ 16,900	$ 23,200	$ 23,900

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,	1993	1992
Actuarial present value of accumulated benefit obligations:		
Vested benefits	$501,900	$419,582
Non-vested benefits	64,973	46,563
Accumulated benefit obligations	566,873	466,145
Additional amounts related to projected pay increases	236,906	193,630
Projected benefits obligation for service rendered to date	803,779	659,775
Plan assets at fair value, consisting primarily of listed stocks, bonds, other fixed income obligations and insurance contracts	913,200	796,843
Plan assets in excess of projected benefit obligations	109,421	137,068
Unrecognized net obligation at January 1, 1987 being recognized over approximately 19 years	32,392	35,184
Unrecognized net gain from actual return on plan assets different from that assumed	(114,536)	(84,077)
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions amortized over 10 years	(39,652)	(90,636)
Prior service cost not yet recognized in net periodic pension cost	49,613	36,092
Pension costs included in the consolidated balance sheets	$ 37,238	$ 33,631

In 1993 and 1992, the discount rate and rate of increase in future compensation levels used in determining the actuarial present value of the projected benefit obligations were 7.3% and 8.25% and 3.25% and 4.25% (plus merit increases), respectively. The expected long-term rate of return on plan assets was 9.00% in 1993 and 1992.

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. These benefits are provided through insurance companies whose charges and premiums are based on the claims paid during the year.

On January 1, 1993, the Company adopted SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions (OPEB). This Statement requires accrual accounting by employers for postretirement benefits other than pensions reflecting currently earned benefits. During 1993 the Company established various trust funds to begin the funding of the OPEB obligation. The Company made an initial contribution, equal to the amount received in 1993 rates, of approximately $12 million and anticipates contributing approximately $23 million in 1994.

Net postretirement benefit cost for 1993 included the following components:

	In thousands of dollars 1993
Service cost — benefits attributed to service during the period	$ 12,300
Interest cost on accumulated benefit obligation	32,800
Amortization of the transition obligation over 20 years	20,400
Net postretirement benefit cost	$ 65,500

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

	In thousands of dollars
At December 31,	1993
Actuarial present value of accumulated benefit obligations:	
Retired and surviving spouses	$224,936
Active eligible	73,474
Active ineligible	220,420
Accumulated benefit obligations	518,830
Plan assets at fair value, consisting primarily of cash equivalents	11,967
Accumulated postretirement benefit obligation in excess of plan assets	506,863
Unrecognized net loss from past experience different from that assumed and effects of changes in assumptions	82,756
Unrecognized transition obligation to be amortized over 20 years	388,600
Accrued postretirement benefit liability included in the consolidated balance sheets	$ 35,507

At December 31, 1993, a pre-65 and post-65 health care cost trend rate of 10.05% and 7.05%, respectively, was assumed, trending down to 4.8% by 1999. If the health care cost trend rate was increased by one percent, the accumulated postretirement benefit obligation as of December 31, 1993 would increase by approximately 8.7% and the aggregate of the service and interest cost component of net periodic postretirement benefit cost for the year would increase by approximately 7.8%. The discount rate used in determining the accumulated postretirement benefit obligation was 7.3%.

During 1993, the PSC issued a Statement of Policy (SOP) regarding the accounting for pension and postretirement costs. With respect to postretirement benefits, the PSC mandated a transition to full accrual accounting in rates over a period not to exceed five years, with recovery of any resultant deferrals over a period not to exceed twenty years from the year of adoption. In accordance with its rate agreement and the SOP, the Company has a $30.7 million regulatory asset at December 31, 1993 relating to the rate transition for postretirement costs. The SOP requires deferral of the difference between actual costs and rate allowances and ten year amortization of actuarial gains and losses for both pensions and postretirement costs effective January 1, 1993. The 1993 pension cost was reduced by approximately $8 million to reflect the effect of the change in the amortization period of an actuarial gain of $90.6 million as of January 1, 1993. The Company does not expect the true-up requirements or the change to amortization of actuarial gains and losses to have a material impact on its periodic benefit costs or results of operations.

In November 1992, the FASB issued SFAS No. 112 "Employees' Accounting for Postemployment Benefits" which is effective for fiscal years beginning after December 15, 1993. This Statement, which the Company will adopt for 1994, requires employers to recognize 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. The Company typically accounts for such costs on a cash basis. The Company estimates the postemployment benefit obligation to be approximately $11.4 million at January 1, 1994. In its 1994 rates, the Company has included approximately $2.9 million, including capital, representing the pay-as-you-go portion of the postemployment benefit. The difference between the postemployment benefit obligation and the rate allowance will be deferred, with the proposed recovery occurring equally over three years beginning in 1995. The Company believes that these costs will be recovered based on current ratemaking principles.

6 Federal and Foreign Income Taxes

Components of United States and foreign income before income taxes:

	In thousands of dollars		
	1993	1992	1991
United States	$438,914	$410,283	$394,596
Foreign	(24,845)	18,394	(6,252)
Consolidating eliminations	4,837	(16,741)	(11,080)
Income before income taxes	$418,906	$411,936	$377,264

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:

SUMMARY ANALYSIS:

		In thousands of dollars		
		1993	1992	1991
Components of Federal and foreign income taxes:				
Current tax expense:	Federal	$118,918	$119,929	$ 75,452
	Foreign	8,445	915	597
		127,363	120,844	76,049
Deferred tax expense:	Federal	35,152	54,858	74,983
	Foreign	—	7,531	7,105
		35,152	62,389	82,088
Income taxes included in Operating Expenses		162,515	183,233	158,137
Current Federal and foreign income tax credits included in Other Income and Deductions		(16,061)	(31,787)	(24,734)
Deferred Federal and foreign income tax expense (credits) included in Other Income and Deductions		621	4,058	492
Total		$147,075	$155,504	$133,895
Components of deferred Federal and foreign income taxes *(Note 1)*:				
Depreciation related			$ 78,467	$ 90,897
Investment tax credit			(8,067)	(8,137)
Alternative minimum tax			(1,197)	(27,276)
Recoverable energy and purchased gas costs			(1,926)	8,066
Deferred operating expenses			10,867	(2,179)
Nuclear settlement disallowance			20,099	12,865
MERIT recovery			(4,263)	9,935
Opinac reserve for oil and gas properties			(19,706)	(13,083)
Bond reacquisition premium			7,379	—
Other			(15,206)	11,492
Deferred Federal income taxes (net)			$ 66,447	$ 82,580
Reconciliation between Federal and foreign income taxes and the tax computed at prevailing U.S. statutory rate on income before income taxes:				
Computed tax		$146,617	$140,058	$128,270
Reduction (increase) attributable to flow-through of certain tax adjustments:				
Depreciation		(35,153)	(37,543)	(36,440)
Allowance for funds used during construction		2,951	11,205	7,540
Cost of removal		7,822	6,845	5,781
Deferred investment tax credit amortization		8,018	8,024	7,891
Other		15,904	(3,977)	9,603
		(458)	(15,446)	(5,625)
Federal and foreign income taxes		$147,075	$155,504	$133,895

The Omnibus Budget Reconciliation Act of 1993 (OBRA of 1993) was signed into law in August 1993. One of the provisions of the OBRA of 1993 raises the federal corporate statutory tax rate from 34% to 35%, retroactive to January 1, 1993. A provision of the 1993 Settlement provides for the deferral of the effects of tax law changes.

SFAS 109 increased the accumulated deferred income tax liability at January 1, 1993 by approximately $507 million, represented substantially by tax benefits flowed-through to rate payers in prior years (in the form of lower rates) upon which deferred taxes had not been provided. At December 31, 1993, the deferred tax liabilities (assets) were comprised of the following:

	In thousands of dollars
Alternative minimum tax	$ (95,071)
Other	(208,217)
Total deferred tax assets	(303,288)
Depreciation related	1,318,600
Investment tax credit related	108,140
Other	190,031
Total deferred tax liabilities	1,616,771
Accumulated deferred income taxes	$1,313,483

The Company believes that the more significant effects of adopting this pronouncement are (i) providing deferred taxes for tax benefits flowed through to ratepayers, (ii) adjustment of deferred tax assets and liabilities for enacted changes in tax law or rates and (iii) prohibition of net-of-tax accounting.

The Company routinely collects the increased tax liability from previously flowed-through tax benefits. In addition, the PSC issued effective January 15, 1993 a Statement of Interim Policy on Accounting and Ratemaking Procedures to implement SFAS 109. The statement required adoption of SFAS 109 on a revenue-neutral basis, recognizing the PSC's policy of rate recovery when prior flow-through items reverse. The Company has recorded income taxes recoverable, a regulatory asset, in the amount of approximately $528 million, which is comprised of previously flowed-through tax benefits, and offset by temporary differences associated with deferred investment tax credits and excess deferred taxes established at tax rates greater than 35%. Substantially all of the excess deferred taxes relate to property and are not subject to immediate refund to customers in accordance with federal law.

7 *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 1,062 MW Nine Mile Point Nuclear Station Unit No. 2 (Unit 2). Unit 1 was placed in commercial operation in 1969 and Unit 2 in 1988.

Unit 1 Economic Study: Under the terms of a previous regulatory agreement, the Company agreed to prepare and update studies of the advantages and disadvantages of continued operation of Unit 1 prior to the start of the next two refueling outages. The first report, which recommended continued operation of Unit 1 over the remaining term of its license (2009), was filed with the PSC in March 1990.

On November 20, 1992 the Company submitted to the PSC an updated economic analysis which indicated that Unit 1 can be expected to provide value to customers and shareholders through its next fuel cycle, which will end in early 1995. The study also indicated that the Unit could continue to provide benefits for the full term of its license if operating costs can be reduced and generating output improved above its historical average.

The study analyzed a number of scenarios resulting in break-even capacity factors, ranging from 44% to 122%. The "base case" assumes a capacity factor of 61%, consistent with the target reflected in the Unit 1 operating incentive mechanism, and also assumes future operating and capital costs slightly lower than historical perfomance. While a marginal benefit would be realized from operating the Unit for at least the next two years (one fuel cycle) under the "base case," there would be a negative net present value in excess of $100 million if the Unit were to be operated over its remaining 17-year license period. Under an "improved performance case," the Unit is assumed to operate at a 70% capacity factor with future operating and capital costs consistent with average industry perfomance. The Company believes these goals are achievable for Unit 1, as indicated by Unit 1 operating and financial performance in 1993 that was better than the improved performance case. The "improved perfomance case" results in positive net present value in excess of $100 million if the Unit is operated over its remaining life. Such results demonstrate the volatility of the assumptions and uncertainties involved in developing the Unit's economic forecast. These assumptions include various levels of the Unit's capacity factor, operating and capital costs, demand for electricity, supply of electricity including unregulated generator power, implementation and compliance costs of the Clean Air Act and other federal and state environmental requirements and fuel availability and prices, especially natural gas. Given the potential for rapid and substantial change in any or all of these assumptions, the Company has developed operational and external criteria, other than refueling, which would initiate a prompt reassessment of the economic viability of the Unit.

An agreement with the PSC allows recovery of all reasonable and prudently-incurred sunk costs and costs of retirement, should a prudent decision be made to retire Unit 1 before early 1995. All parties to the 1991 Agreement reserve the right to petition the PSC to institute a formal investigation to review the prudence of any Company decision to retire Unit 1. Any such decision by the Company will be made in consultation with governmental and regulatory authorities. The Company's net investment in Unit 1 is approximately $580 million, exclusive of decommissioning costs. See Nuclear Plant Decommissioning.

Unit 1 Status: On February 20, 1993, Unit 1 was taken out of service for a planned 55 day refueling and maintenance outage. On April 15, 1993, Unit 1 returned to service ahead of schedule. The next refueling outage is

scheduled to begin in February 1995. Unit 1's capacity factor for 1993 was approximately 81%.

Unit 2 Status: On October 2, 1993, Unit 2 was taken out of service for a planned 60 day refueling and maintenance outage. On November 29, 1993, Unit 2 returned to service ahead of schedule. The next refueling outage is scheduled to begin in the spring of 1995. Unit 2's capacity factor for 1993 was approximately 78%.

Nuclear Plant Decommissioning: Based on a 1989 study, the cost of decommissioning Unit 1, which is expected to begin in the year 2009, is estimated by the Company to be approximately $416 million at that time ($257 million in 1993 dollars). The Company's 41% share of the total cost to decommission Unit 2, expected to begin in 2027, is estimated by the Company to be approximately $316 million ($109 million in 1993 dollars). The annual decommissioning allowance reflected in ratemaking is based upon these estimates which include amounts for both radioactive and non-radioactive dismantlement costs. The non-radioactive dismantlement costs are estimated in the 1989 study to be $24 million for Unit 1 and $18 million for its share of Unit 2, in 1993 dollars.

Decommissioning costs recovered in rates are reflected in Accumulated Depreciation and Amortization on the Balance Sheet and amount to $113.9 million and $90.5 million at December 31, 1993 and 1992, respectively. The annual allowance for Unit 1 and the Company's share of Unit 2 for the years ended December 31, 1993, 1992 and 1991 was approximately $18.7, $23.1 and $23.0 million, respectively.

The Company will update its Unit 1 decommissioning study in 1994 in support of the update of the Unit 1 economic study. The Unit 2 decommissioning study is also expected to be updated in 1994. Rate allowance adjustments will be sought when appropriate. There is no assurance that the decommissioning allowance recovered in rates will ultimately aggregate a sufficient amount to decommission the units. However, the Company believes that if decommissioning costs are higher than currently estimated, they will ultimately be recovered in the rate process.

The NRC issued regulations in 1988 requiring owners of nuclear power plants to place funds into an external trust to provide for the cost of decommissioning contaminated portions of nuclear facilities as well as establishing minimum amounts that must be available in such a trust for these specified decommissioning activities at the time of decommissioning. As of December 31, 1993, the Company has accumulated in an external trust $63.1 million for Unit 1 and $15.4 million for its share of Unit 2, which are included in Other Property and Investments. Earnings on such investments aggregate $8.6 million through December 31, 1993 and, because they 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 $35.4 million at December 31, 1993.

Based upon studies applying the 1988 NRC regulations, the Company had estimated that the minimum funding requirements for Unit 1 and its share of Unit 2, respectively, would be $191 million and $87 million in 1993 dollars. In May 1993, the NRC established new labor, energy and burial cost factors for determining the NRC minimum funding requirements. A substantial increase in burial costs, partly offset by reduced estimates in the volumes of waste to be disposed, increased the NRC minimum requirement for Unit 1 to $372 million in 1993 dollars and the Company's share of Unit 2 to $169 million in 1993 dollars. The Company has requested an annual aggregate increase of $10 million in the Unit 1 and Unit 2 decommissioning allowances as part of its 1995 rate request, to reflect the increased NRC minimum requirements.

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 August 1993, the statutory liability limits for the protection of the public under the Price-Anderson Amendments Act of 1988 (the Act) 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, was increased to approximately $8.8 billion. This limit would be funded by assessments of up to $75.5 million for each of the 116 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.

The Company's interest in Units 1 and 2 could expose it to a potential loss, for each accident, of $106.5 million 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 $800 million in excess of the $500 million primary nuclear insurance with the Nuclear Insurance Pools (ANI/MRP) and $1.4 billion, which is also in excess of the $500 million primary and the $800 million excess nuclear insurance, with Nuclear Electric Insurance Limited (NEIL). NEIL is a utility industry-owned mutual insurance company chartered in Bermuda. The total nuclear property insurance is $2.7 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 $11.3 million per loss.

Low Level Radioactive Waste: The Federal Low Level Radioactive Waste Policy Act requires states to join compacts or individually develop their own low level radioactive waste disposal site. In response to the Federal law,

New York State decided to develop its own site because of the large volume of low level radioactive waste it generates and committed by January 1, 1993 to develop a plan for the management of low level radioactive waste in New York State during the interim period until a disposal facility is available.

New York State is developing disposal methodology and acceptance criteria for a disposal facility. A revised New York State low level radioactive waste site development schedule now assumes two possible siting scenarios, a volunteer approach and a non-volunteer approach, either of which would begin operation in 2001. An extension of access to the Barnwell, South Carolina waste disposal facility was made available to out-of-region low level radioactive waste generators by the state of South Carolina through June 30, 1994, and New York State has elected to use this option. The Company has a low level radioactive waste management program and contingency plan so that Unit 1 and Unit 2 will be prepared to properly handle interim on-site storage of low level radioactive waste for at least a 10 year period, if required.

Nuclear Fuel Disposal Cost: In January 1983, the Nuclear Waste Policy Act of 1982 (the Nuclear Waste Act) established a cost of $.001 per kilowatt-hour of net generation for current disposal of nuclear fuel and provides for a determination of the Company's liability to the Department of Energy (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 1998, the year in which the Company had initially planned 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. 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 of as long as 20 years. With Unit 1 expected to be retired in 2009, the Company must consider some form of storage if it intends to begin immediate dismantlement. 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 the incurrence of additional costs. The Company does not believe that the possible unavailability of the DOE disposal facility until 2006 will inhibit operation of either Unit.

The Energy Policy Act provides for the establishment of a federal decontamination and decommissioning fund to provide for the environmentally safe closure of DOE uranium processing facilities, funded in part by nuclear utilities. The Company has recorded its estimated liability to this fund based on prior DOE nuclear fuel processing services it received and its initial assessment during 1993. The liability is expected to be recovered as a fuel expense as provided by the Act and is payable over 14 years ending in 2007, with annual assessments indexed for inflation.

8 *Commitments and Contingencies*

Construction Program: The Company is committed to an ongoing construction program to assure reliable delivery of its electric and gas services. The Company presently estimates that the construction program for the years 1994 through 1998 will require approximately $1.57 billion, excluding AFC, nuclear fuel and certain overheads capitalized. For the years 1994 through 1998, the estimates are $408 million, $295 million, $287 million, $291 million and $285 million, respectively. These amounts are reviewed by management as circumstances dictate.

Long-term Contracts for the Purchase of Electric Power: At January 1, 1994, the Company had long-term contracts to purchase electric power from the following generating facilities owned by the New York Power Authority (NYPA):

Facility	Expiration date of contract	Purchased capacity in kw.	Estimated annual capacity cost
Niagara hydroelectric project	2007	928,000	$20,300,000
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	year-to-year basis	40,000 *(a)*	7,200,000
		1,342,000	$36,300,000

(a) 40,000 kw for summer of 1994; 63,000 kw for winter of 1994-95.

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 $72.2 million, $64.4 million and $61.2 million for the years 1993, 1992 and 1991, respectively.

Under the requirements of the Federal Public Utility Regulatory Policies Act of 1978, the Company is required to purchase power generated by unregulated generators, as defined therein. Of the 147 facilities providing energy to the Company at December 31, 1993, five require the Company to make capacity payments, including payments when a production plant is not operating, and are subject to price escalation. Each facility must meet certain availability and performance obligations prior to receiving capacity payments. The terms of these five contracts allow the Company to schedule energy deliveries from the facilities and then pay for the energy that is delivered. These five facilities account for approximately 380,000 kw of capacity with contract lengths ranging from 20 to 35 years. The total cost of purchases under these five contracts in 1993 was $56.6 million and the 1994 estimated annual capacity and energy payments are estimated to be approximately $105.5 million and $50 million, respectively, subject to scheduling, the availability and tested capacity of these facilities, and price escalation. Capacity payments

under these five contracts for 1995 to 1998 would be $109 million, $120 million, $127 million and $130 million, respectively, and would aggregate to approximately $3.5 billion over the terms of the contracts. Contracts relating to the remaining facilities in service at December 31, 1993, require the Company to pay only when energy is delivered.

The Company paid approximately $736 million (including the amount discussed above), $543 million and $268 million in 1993, 1992 and 1991 for 11,720,000 mwhrs, 8,632,000 mwhrs and 4,303,000 mwhrs, respectively, of energy under all unregulated generator contracts.

Through December 31, 1993, the Company had entered into agreements with current and prospective unregulated generators for approximately 2,400 MW of capacity. The ultimate amount of the commitment and the available capacity are dependent upon the completion of these projects. Based upon these contracts as of December 31, 1993, the Company estimates that it will be obligated to make payments to unregulated generators of (in millions): $932 in 1994, $1,057 in 1995, $1,111 in 1996, $1,174 in 1997 and $1,220 in 1998. The Company recovers all payments to unregulated generators through base rates or through the FAC.

Sale of Customer Receivables: The Company has an agreement whereby it can sell an undivided interest in a designated pool of customer receivables, including accrued unbilled electric revenues, up to a maximum of $200 million. At December 31, 1993 and 1992, respectively, $200 million of receivables had been sold under this agreement. The undivided interest in the designated pool of receivables was sold with limited recourse. The agreement provides for a loss reserve pursuant to which additional customer receivables are assigned to the purchaser to protect against bad debts. To the extent actual loss experience of the pool receivables exceeds the loss reserve, the purchaser absorbs the excess. 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.

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 Federal income tax liability by approximately $80 million before assessment of penalties and interest. Included in these proposed adjustments are several potentially 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 in 1990, to the extent the IRS is able to sustain disallowances, the Company will be required to absorb a portion of any disallowance. The Company believes any such disallowance will not have a material impact on its financial position or results of operations.

Litigation: On March 22, 1993, a complaint was filed in the Supreme Court of the State of New York, Albany County, against the Company and certain of its officers and employees. The plaintiff, Inter-Power of New York, Inc. (Inter-Power), alleges, among other matters, fraud, negligent misrepresentation and breach of contract in connection with the Company's alleged termination of a power purchase agreement in January 1993. The power purchase agreement was entered into in early 1988 in connection with a 200 MW cogeneration project to be developed by Inter-Power in Halfmoon, New York. The plaintiff is seeking enforcement of the original contract or compensatory and punitive damages on fourteen causes of action in an aggregate amount that would not exceed $1 billion, excluding pre-judgment interest.

The Company believes it has done no wrong, and intends to vigorously defend against this action. On May 7, 1993, the Company filed an answer denying liability and raising certain affirmative defenses. Thereafter, the Company and Inter-Power filed cross-motions for summary judgment. The court dismissed two of Inter-Power's fourteen causes of action but otherwise denied the Company's motion. The court also dismissed two of the Company's affirmative defenses and otherwise denied Inter-Power's cross-motion. Both parties have filed Notices of Appeals regarding these dismissals. Discovery is in progress. The ultimate outcome of the litigation cannot presently be determined.

On November 12, 1993, Fourth Branch Associates Mechanicville ("Fourth Branch"), filed suit against the Company and several of its officers and employees in the New York Supreme Court, Albany County, seeking compensatory damages of $50 million, punitive damages of $100 million and injunctive and other related relief. The suit grows out of the Company's termination of a contract for Fourth Branch to operate and maintain a hydroelectric plant the Company owns in the Town of Halfmoon, New York. Fourth Branch's complaint also alleges claims based on the inability of Fourth Branch and the Company to agree on terms for the purchase of power from a new facility that Fourth Branch hoped to construct at the Mechanicville site. On January 3, 1994, the defendants filed a joint motion to dismiss Fourth Branch's complaint. The Company believes that it has substantial defenses to Fourth Branch's claims, but is unable to predict the outcome of this litigation.

Accordingly, no provision for liability, if any, that may result from either of these suits 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. These wastes or by-products may not have previously been considered hazardous, and may not be considered hazardous currently, but may be identified as such by Federal, state or local authorities in the future. 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 been advised that various Federal, state or local agencies believe that certain properties require investigation and has prioritized the sites based on available information in order to enhance the management of investigation and remediation, if determined to be necessary.

The Company is currently aware of 82 sites with which it has been or may be associated, including 42 which are Company-owned. The Company-owned sites include 23 former coal gasification (MGP) sites, 14 industrial waste sites and 5 operating property sites where corrective actions may be deemed necessary to prevent, contain and/or remediate contamination of soil and/or water in the vicinity. Of these Company-owned sites, Saratoga Springs is on the Federal National Priorities List for Uncontrolled Hazardous Waste Sites (NPL) as published by the Environmental Protection Agency in the Federal Register. The 40 non-owned sites with which the Company has been or may be associated are generally industrial waste sites where the Company is alleged to be a Potentially Responsible Party (PRP) and may be required to contribute some proportionate share towards investigation and clean-up. Not included in the 82 sites are seven sites where the Company has reached settlement agreements with other PRP's and three sites where remediation activities have been completed. There also exist approximately 20 formerly-owned MGP sites with which the Company has been or may be associated that may require future investigation and remediation. To date, the Company has not been made aware of any claims. Also, approximately 22 fire training sites owned or used by the Company have been identified but not investigated. Presently, the Company is unable to determine its potential involvement with such sites and has made no provision for liability, if any, at this time.

Investigations at each of the Company-owned sites are designed to (1) determine if environmental contamination problems exist, (2) determine the extent, rate of movement and concentration of pollutants, (3) if necessary, determine the appropriate remedial actions required for site restoration and (4) where appropriate, identify other parties who should bear some or all of the cost of remediation. Legal action against such other parties, if necessary, will be initiated. After site investigations have been completed, the Company expects to determine site-specific remedial actions necessary and to estimate the attendant costs for restoration. However, since technologies are still developing and the Company has not yet undertaken any full-scale remedial actions following regulatory requirements at any identified sites, nor have any detailed remedial designs been prepared or submitted to appropriate regulatory agencies, the ultimate cost of remedial actions may change substantially as investigation and remediation progresses.

The Company has estimated that it is probable that 36 of the 42 owned sites will require some degree of investigation, remediation and monitoring. This conclusion is based upon a number of factors, including the nature of the identified or potential contaminants, the location and size of the site, the proximity of the site to sensitive resources, the status of regulatory investigation and knowledge of activities at similarly situated sites. Although the Company has not extensively investigated many of those sites, it believes it has sufficient information to estimate a range of cost of investigation and remediation. As a consequence of site characterizations and assessments completed to date, the Company has accrued a liability of $210 million for these owned sites, representing the low end of the range of the estimated cost for investigation and remediation. The high end of the range is presently estimated at approximately $520 million.

The majority of these cost estimates relate to the MGP sites. Of the 23 MGP sites, Harbor Point (Utica, NY) and Saratoga Springs are subject to regulatory enforcement actions and to date have remedial investigation and/or feasibility study work in progress. The remaining 21 MGP sites are the subject of an Order on Consent executed with the New York State Department of Environmental Conservation (DEC) providing for an investigation and remediation program over approximately ten years. Preliminary site assessments have been conducted or are in process at five of these 21 sites, with remedial investigations either currently in process or scheduled for 1994. Remedial investigations were also conducted for two industrial waste sites and for three operating properties where corrective actions were considered necessary.

The Company does not currently believe that a clean-up will be required at the 6 remaining Company-owned sites, although some degree of investigation of these sites is included in its investigation and remediation program.

With respect to the 40 sites with which the Company has been or may be associated as a PRP, 9 are on the NPL. Total costs to investigate and remediate the sites with which the Company is associated as a PRP are estimated to be approximately $590 million; however, the Company estimates its share of this total at approximately $30 million and this amount has been accrued at December 31, 1993.

The seven settlement agreements reached with other PRPs were settled in an amount not material to the Company. Two of these (Ludlow Landfill and Wide Beach) are on the NPL and have been settled by the Company in an aggregate amount of less than $300,000. For the 9 sites included on the NPL, the Company's potential contribution factor varies for each site. The estimated aggregate liability for these sites is not material and is included in the determination of the amounts accrued.

Estimates of the Company's potential liability for PRP sites are derived by estimating the total cost of site clean-up and then applying the related Company contribution factor to that estimate. Estimates of the total clean-up costs are determined by using the Company's investigation to date, if any, discussions with other PRPs and, where no information is known at the time of estimate, Environmental Protection Agency (EPA) estimates based on average costs disclosed in the Federal Register of June 23, 1993. The contribution factor is calculated using either the Company's percentage share based upon the total number of PRPs named or otherwise identified, which assumes all PRPs will contribute equally, or the percentage agreed upon with other PRPs through steering committee negotiations or by other means. Actual Company expenditures for these sites 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.

The EPA advised the Company by letter that it is one of 833 PRPs under Superfund for the investigation and clean-up of the Maxey Flats Nuclear Disposal Site in Morehead, Kentucky. The Company has contributed to a study of this site and estimates that the cost to the Company for its share of investigation and remediation based on its contribution factor of 1.3% would approximate $1 million, which the Company believes will be recoverable in the ratesetting process.

On July 21, 1988, the Company received notice of a motion by Reynolds Metals Company to add the Company as a third party defendant in an ongoing Superfund lawsuit in Federal District Court, Northern District of New York. This suit involves PCB oil contamination at the York Oil Site in Moira, New York. Waste oil was transported to the site during the 1960's and 1970's by contractors of Peirce Oil Company (owners/operators of the site) who picked up waste oil at locations throughout Central New York, allegedly including one or more Company facilities. On May 26, 1992, the Company was formally served in a Federal Court action initiated by the government against 8 additional defendants. Pursuant to the requirements of a case management order issued by the Court on March 13, 1992, the Company has also been served in related third and fourth-party actions for contribution initiated by other defendants. Discovery is now in progress. The goal of this effort is to provide adequate information to form a basis for achieving a voluntary allocation of liability among the parties.

The Company believes that costs incurred in the investigation and restoration process for both Company-owned sites and sites with which it is associated will be recoverable in the ratesetting process. Rate agreements in effect since 1991 provide for recovery of anticipated investigation and remediation expenditures, although the PSC Staff reserves the right to review the appropriateness of the costs incurred. While the PSC Staff has not challenged any remediation costs to date, the PSC Staff asserted in the recently decided gas rate proceeding that the Company must, in future rate proceedings, justify why it is appropriate that remediation costs associated with non-utility property owned by the Company be recovered from ratepayers. The Company's 1994 rate settlement includes $21.7 million for site investigation and remediation. Based upon management's assessment that remediation costs will be recovered from ratepayers, a regulatory asset has been recorded representing the future recovery of remediation obligations accrued to date.

The Company also agreed in rate agreements to a cost sharing arrangement with respect to one industrial waste site. The Company does not believe that this cost sharing agreement, as it relates to this particular industrial waste site, will have a material effect on the Company's financial position or results of operations.

The Company is also in the process of providing notices of insurance claims to carriers with respect to the investigation and remediation costs for manufactured gas plant and industrial waste sites. The Company is unable to predict whether such insurance claims will be successful.

Federal Energy Regulatory Commission Order 636: In 1992, the FERC issued Order 636, which requires interstate pipelines to unbundle pipeline sales services from pipeline transportation service. These changes enable the Company to arrange for its gas supply directly with producers, gas marketers or pipelines, at its discretion, as well as arrange for transportation and gas storage services.

As a result of these structural changes, pipelines face "transition" costs from implementation of the Order. The principal costs are: unrecovered gas cost that would otherwise have been billable to pipeline customers under previously existing rules, costs related to restructuring existing gas supply contracts and costs of assets needed to implement the order (such as meters, valves, etc.). Under the Order, pipelines are allowed to recover 100% of prudently incurred costs from customers. Prudence will be determined by FERC review.

The amount of restructuring costs ultimately billed to the Company will be determined in accordance with pipeline restructuring plans which have been submitted to the FERC for approval. There are four pipelines to which the Company has some liability. The Company is actively participating in FERC hearings on these matters to ensure an equitable allocation of costs. The restructuring costs will be primarily reflected in demand charges paid to reserve space on the various interstate pipelines and will be billed over a period of approximately 7 years with billings more heavily weighted to the first 3 years.

Based upon information presently available to the Company from the petitions filed by the pipelines, the Company's participation in settlement negotiations, and the three settlements to which it is a party, its liability for the pipelines' unrecovered gas costs is expected to be as much as $31 million and its liability for pipeline restructuring costs could be as much as $38 million. The Company has recorded a liability of $31 million at December 31, 1993, representing the low end of the range of such transition costs. The Company is unable to predict the final outcome of current pipeline restructuring settlements and the ultimate amounts for which it will be liable or the period over which this liability will be billed.

Based upon Management's assessment that transition costs will be recovered from ratepayers, a regulatory asset has been recorded representing the future recovery of transition costs accrued to date. Currently, such costs billed to the Company are treated as a cost of purchased gas and recoverable through the operation of the gas adjustment clause mechanism.

9 *Information Regarding the Electric and Gas Business*

The Company is engaged in the electric and natural gas utility businesses. Certain information regarding these 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 practice established for regulatory purposes. Identifiable assets include net utility plant, materials and supplies, deferred finance charges, deferred recoverable energy costs and certain other deferred debits. Corporate assets consist of other property and investments, cash, accounts receivable, prepayments, unamortized debt expense and other deferred debits.

	In thousands of dollars		
	1993	1992	1991
Operating revenues:			
Electric	$3,332,464	$3,147,676	$2,907,293
Gas	600,967	553,851	475,225
Total	$3,933,431	$3,701,527	$3,382,518
Operating income before taxes:			
Electric	$ 625,852	$ 645,696	$ 644,084
Gas	61,163	61,863	39,487
Total	$ 687,015	$ 707,559	$ 683,571
Pretax operating income, including AFC:			
Electric	$ 641,435	$ 666,269	$ 662,258
Gas	61,812	62,721	40,244
Total	703,247	728,990	702,502
Income taxes, included in operating expenses:			
Electric	148,695	176,901	152,840
Gas	13,820	6,332	5,297
Total	162,515	183,233	158,137
Other (income) and deductions	(22,475)	(11,391)	(10,643)
Interest charges	291,376	300,716	311,639
Net income	$ 271,831	$ 256,432	$ 243,369
Depreciation and amortization:			
Electric	$ 255,718	$ 255,256	$ 240,887
Gas	20,905	18,834	17,929
Total	$ 276,623	$ 274,090	$ 258,816
Construction expenditures: (including nuclear fuel):			
Electric	$ 429,265	$ 442,741	$ 445,298
Gas	90,347	59,503	77,176
Total	$ 519,612	$ 502,244	$ 522,474
Identifiable assets:			
Electric	$7,042,762	$7,000,659	$6,760,375
Gas	926,648	783,766	725,553
Total	7,969,410	7,784,425	7,485,928
Corporate assets	1,449,667	806,110	755,548
Total assets	$9,419,077	$8,590,535	$8,241,476

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 Investments: The carrying value and market value are not material to the financial statements.

Mandatorily Redeemable Preferred Stock: Fair value of the mandatorily redeemable preferred stock has been determined by one of the Company's brokers or estimated by management based on discounted cash flows.

Long-term Debt: The fair value of the Company's long-term debt has been estimated by one of the Company's brokers. The carrying value of NYSERDA bonds, the Oswego Facilities Trust and other long-term debt are considered to approximate fair value.

The estimated fair values of the Company's financial instruments are as follows:

	In thousands of dollars			
At December 31,	1993		1992	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and short-term investments	$ 124,351	$ 124,351	$ 43,894	$ 43,894
Mandatorily redeemable preferred stock	150,400	155,326	197,600	199,114
Long-term debt: First Mortgage Bonds	2,791,305	2,969,228	2,757,945	2,888,022
Medium Term Notes	55,500	62,458	87,700	93,890
NYSERDA bonds	413,760	413,760	413,760	413,760
Swiss franc bond	50,000	73,794	50,000	62,374
Other	131,587	131,587	104,665	104,665
Oswego Facilities Trust	—	—	90,000	90,000

11 *Quarterly Financial Data (Unaudited)*

Operating revenues, operating income, net income and earnings per common share by quarters from 1993, 1992 and 1991, 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.

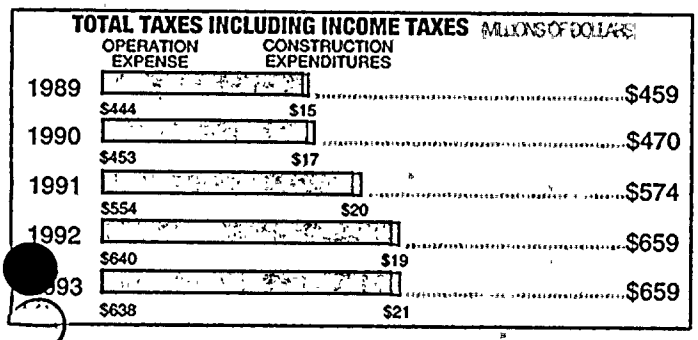
	In thousands of dollars			
Quarter Ended	Operating revenues	Operating income	Net income	Earnings per common share
December 31, 1993	$ 988,195	$ 73,466	$ 30,955	$ .16
1992	963,629	119,181	41,835	.24
1991	848,593	117,139	35,111	.18
September 30, 1993	$ 879,952	$108,539	$ 48,595	$ .29
1992	822,530	89,658	40,401	.23
1991	734,446	102,627	40,783	.23
June 30, 1993	$ 929,245	$154,826	$ 65,325	$ .41
1992	881,427	137,515	71,734	.46
1991	807,024	127,159	57,691	.35
March 31, 1993	$1,136,039	$187,669	$126,956	$ .86
1992	1,033,941	177,972	102,462	.68
1991	992,455	178,509	109,784	.73

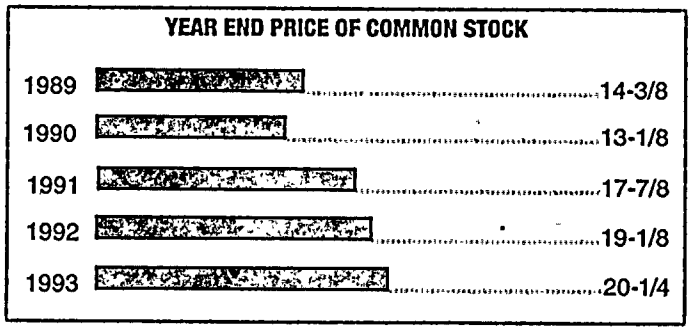
In the second quarter of 1992 and the third quarter of 1993 and 1991, the Company recorded $22.8 million ($.11 per common share), $10.3 million ($.05 per common share) and $30 million ($.14 per common share), respectively, for MERIT earned in accordance with the 1991 Agreement. In the first quarter of 1992 and the fourth quarter of 1992 and 1991, the Company recorded $21 million ($.09 per common share), $24 million ($.09 per common share) and $23 million ($.07 per common share), respectively, to write-down its subsidiary investment in oil and gas properties.

Selected Financial Data

As discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations and Notes to Consolidated Financial Statements, certain of the following selected financial data may not be indicative of the Company's future financial condition or results of operations.

	1993	1992	1991	1990	1989
Operations: (000's)					
Operating revenues	$3,933,431	$3,701,527	$3,382,518	$3,154,719	$2,906,043
Net income	271,831	256,432	243,369	82,878	150,783
Common stock data:					
Book value per share at year end	$17.25	$16.33	$15.54	$14.37	$14.07
Market price at year end	20 1/4	19 1/8	17 7/8	13 1/8	14 3/8
Ratio of market price to book value at year end	117.4%	117.1%	115.0%	91.4%	102.2%
Dividend yield at year end	4.9%	4.2%	3.6%	0.0%	0.0%
Earnings per average common share	$ 1.71	$ 1.61	$ 1.49	$ .30	$ .78
Rate of return on common equity	10.2%	10.1%	10.0%	2.1%	5.6%
Dividends paid per common share	$ .95	$ .76	$ .32	$ .00	$ .60
Dividend payout ratio	55.6%	47.2%	21.5%	0.0%	76.9%
Capitalization: (000's)					
Common equity	$2,456,465	$2,240,441	$2,115,542	$1,955,118	$1,914,531
Non-redeemable preferred stock	290,000	290,000	290,000	290,000	290,000
Redeemable preferred stock	123,200	170,400	212,600	241,550	267,530
Long-term debt	3,258,612	3,491,059	3,325,028	3,313,286	3,249,328
Total	6,128,277	6,191,900	5,943,170	5,799,954	5,721,389
First mortgage bonds maturing within one year	190,000	—	100,000	40,000	50,000
Total	$6,318,277	$6,191,900	$6,043,170	$5,839,954	$5,771,389
Capitalization ratios: *(including first mortgage bonds maturing within one year):*					
Common stock equity	38.9%	36.2%	35.0%	33.5%	33.2%
Preferred stock	6.5	7.4	8.3	9.1	9.6
Long-term debt	54.6	56.4	56.7	57.4	57.2
Financial ratios:					
Ratio of earnings to fixed charges	2.31	2.24	2.09	1.41	1.71
Ratio of earnings to fixed charges without AFC	2.26	2.17	2.03	1.35	1.66
Ratio of AFC to balance available for common stock	6.7%	9.7%	9.3%	52.8%	18.3%
Ratio of earnings to fixed charges and preferred stock dividends	2.00	1.90	1.77	1.17	1.41
Other ratios-% of operating revenues:					
Fuel, purchased power and purchased gas	36.1%	34.1%	32.1%	36.9%	36.5%
Other operation expenses	20.9	19.7	20.0	19.9	19.7
Maintenance, depreciation and amortization	13.0	13.5	14.4	14.4	14.4
Total taxes	16.2	17.3	16.4	14.4	15.3
Operating income	13.3	14.2	15.5	14.3	14.2
Balance available for common stock	6.1	5.9	6.0	1.3	3.6
Miscellaneous: (000's)					
Gross additions to utility plant	$ 519,612	$ 502,244	$ 522,474	$ 431,579	$ 413,492
Total utility plant	10,108,529	9,642,262	9,180,212	8,702,741	8,324,112
Accumulated depreciation and amortization	3,231,237	2,975,977	2,741,004	2,484,124	2,283,307
Total assets	9,419,077	8,590,535	8,241,476	7,765,406	7,562,472





ELECTRIC STATISTICS

	1993	1992	1991
Electric sales *(Millions of kw-hrs.)*:			
Residential	10,475	10,392	10,321
Commercial	12,079	11,628	11,686
Industrial	7,088	7,477	7,578
Industrial – Special	3,888	3,857	3,784
Municipal service	220	227	228
Other electric systems	3,974	3,030	3,141
	37,724	36,611	36,738
Electric revenues *(Thousands of dollars)*:			
Residential	$1,171,787	$1,096,418	$ 985,347
Commercial	1,241,743	1,160,643	1,044,725
Industrial	553,921	589,258	521,670
Industrial – Special	42,988	39,409	35,264
Municipal service	50,642	50,327	47,566
Other electric systems	105,044	93,283	106,066
Miscellaneous	166,339	118,338	166,655
	$3,332,464	$3,147,676	$2,907,293
Electric customers *(Average)*:			
Residential	1,398,756	1,389,470	1,378,484
Commercial	143,078	142,345	145,098
Industrial	2,132	2,197	2,220
Industrial – Special	76	72	63
Other	3,438	3,262	3,231
	1,547,480	1,537,346	1,529,096
Residential *(Average)*:			
Annual kw-hr. use per customer	7,489	7,479	7,487
Cost to customer per kw-hr.	11.19¢	10.55¢	9.55¢
Annual revenue per customer	$837.74	$789.09	$714.80

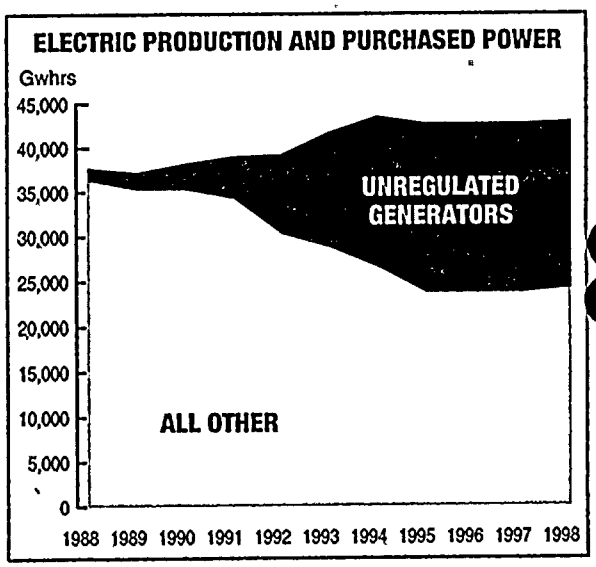
GAS STATISTICS

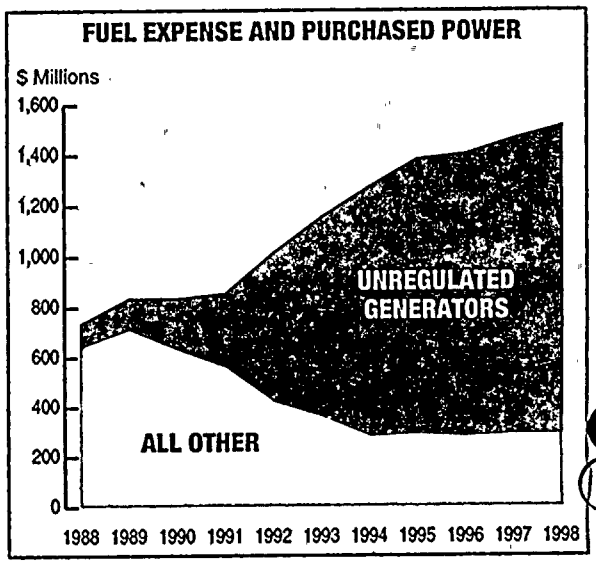
	1993	1992	1991
Gas sales *(Thousands of dekatherms)*:			
Residential	54,908	53,945	48,172
Commercial	23,743	22,289	20,226
Industrial	4,316	1,772	1,812
Other gas systems	234	1,190	1,519
Total sales	83,201	79,196	71,729
Spot market	13,223	1,146	—
Transportation of customer-owned gas	67,741	65,845	50,631
Total gas delivered	164,165	146,187	122,360
Gas revenues *(Thousands of dollars)*:			
Residential	$370,565	$354,429	$302,900
Commercial	144,834	132,609	113,727
Industrial	18,482	10,001	8,430
Other gas systems	1,066	4,737	6,964
Spot market	29,782	2,576	—
Transportation of customer-owned gas	34,843	42,726	36,455
Miscellaneous	1,395	6,773	6,749
	$600,967	$553,851	$475,225
Gas customers *(Average)*:			
Residential	455,629	446,571	438,581
Commercial	39,662	38,675	37,727
Industrial	233	234	260
Other	1	1	2
Transportation	673	673	625
	496,198	486,154	477,195
Residential *(Average)*:			
Annual dekatherm use per customer	120.5	120.8	109.8
Cost to customer per dekatherm	$6.75	$6.57	$6.29
Annual revenue per customer	$813.30	$793.67	$690.64
Maximum day gas sendout (dekatherms)	929,285	905,872	852,404

ELECTRIC CAPABILITY

December 31,	1993	%	1992	1991
	Thousands of kilowatts			
Owned:				
Coal	1,285	14.4	1,285	1,285
Oil	1,496	16.8	1,496	1,96[illegible]
Dual Fuel — Oil/Gas	700	7.8	700	40[illegible]
Nuclear	1,048	11.8	1,059	1,059
Hydro	700	7.8	706	708
Natural Gas	74	0.8	108	164
	5,303	59.4	5,354	5,577
Purchased:				
New York Power Authority				
— Hydro	1,302	14.6	1,302	1,283
— Nuclear	65	0.7	67	76
Unregulated generators	2,253	25.3	1,549	1,027
	3,620	40.6	2,918	2,386
Total capability *	8,923	100.0	8,272	7,963
Electric peak load	6,191		6,205	6,093

*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.





Directors

William F. Allyn *(B, C, F)*
President & Chief Executive Officer
Welch Allyn, Inc., Skaneateles Falls, NY

Lawrence Burkhardt, III *(F)*
Former Executive Vice President
Nuclear Operations

Douglas M. Costle *(D, F)*
Distinguished Senior Fellow,
Institute for Sustainable Communities
Montpelier, VT

Edmund M. Davis *(A, B, D, E)*
Partner, Hiscock & Barclay
Attorneys-at-Law, Syracuse, NY

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

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

Edward W. Duffy *(A, B, F)*
Former Chairman of the Board and
Chief Executive Officer,
Marine Midland Banks, Inc.
Sarasota, FL

John M. Endries
President

Dr. Bonnie Guiton Hill *(C, D)*
Dean, McIntire School of Commerce
University of Virginia,
Charlottesville, VA

John G. Haehl, Jr.
Former Chairman of the Board and
Chief Executive Officer

Gary A. Panasci, Jr. *(A, B, E)*
Chairman of the Board and
Chief Executive Officer
Fay's Incorporated, Liverpool, NY

Dr. Patti McGill Peterson *(C, D)*
President, St. Lawrence University
Canton, NY

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

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

John G. Wick *(C, D, E)*
Of Counsel, Falk & Siemer
Attorneys-at-Law, Buffalo, NY

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

Officers

William E. Davis
Chairman of the Board and
Chief Executive Officer
(Effective May 1, 1993)

William J. Donlon
Chairman of the Board and
Chief Executive Officer
(Retired July 1, 1993)

John M. Endries
President

B. Ralph Sylvia
Executive Vice President, Nuclear

David J. Arrington
Senior Vice President
Human Resources

John P. Hennessey
Senior Vice President
Electric Customer Service
(Retired December 31, 1993)

Darlene D. Kerr
Vice President
Gas Marketing and Rates
(Effective January 1, 1994, Senior Vice President Electric Customer Service)

Gary J. Lavine
Senior Vice President
Legal & Corporate Relations

Robert J. Patrylo
Senior Vice President
Gas Customer Service

John W. Powers
Senior Vice President
Finance and Corporate Services

Michael P. Ranalli
Senior Vice President
Electric Supply and Delivery

Joseph T. Ash
Vice President
Consumer Services

Nicholas J. Ashooh
Vice President
Public Affairs and Corporate Communications

Thomas H. Baron
Vice President
Fossil & Hydro Generation

Harold J. Bogan
Secretary

Michael J. Cahill
Vice President
Electric Customer Service

Neil S. Carns
Vice President
Nuclear Generation
(Resigned June 30, 1993)

Norman E. Crowe, Jr.
Vice President
Electric Customer Service

Thomas R. Fair
Vice President
Environmental Affairs

Theresa A. Flaim
Vice President
Corporate Planning
(Effective April 1, 1993)

Joseph F. Firlit
Vice President
Nuclear Support
(Resigned January 15, 1993)

Edward F. Hoffman
Vice President
Power Delivery

Paul J. Kaleta
Vice President
Law and General Counsel
(Effective April 1, 1993)

Samuel F. Manno
Vice President
Purchasing and Corporate Services

Douglas R. McCuen
Vice President
Government and Regulatory Relations

Clement E. Nadeau
Vice President
Power Transactions and Planning

James A. Perry
Vice President
Quality Assurance

Arthur W. Roos
Vice President-Treasurer
(Effective December 1, 1993)

Richard H. Ryczek
Vice President
Gas Customer Service Operations

Jack R. Swartz
Vice President
Employee Relations
(Retired December 31, 1993)

William J. Synwoldt
Vice President
Information Systems and Chief Information Officer

Steven W. Tasker
Vice President-Controller
(Effective December 1, 1993)

Carl D. Terry
Vice President
Nuclear Engineering

Andrew M. Vesey
Vice President
Operations Support

Stanley W. Wilczek, Jr.
Vice President
Special Projects

Corporate Information

Annual Meeting
The annual meeting of shareholders will be held at The Onondaga County Convention Center, 800 South State Street, Syracuse, N.Y. at 10:30 a.m., Tuesday, May 3, 1994. A notice of the meeting, proxy statement and form of proxy will be sent in March to holders of common stock.

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, N.Y. 13202.

Shareholders 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 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.

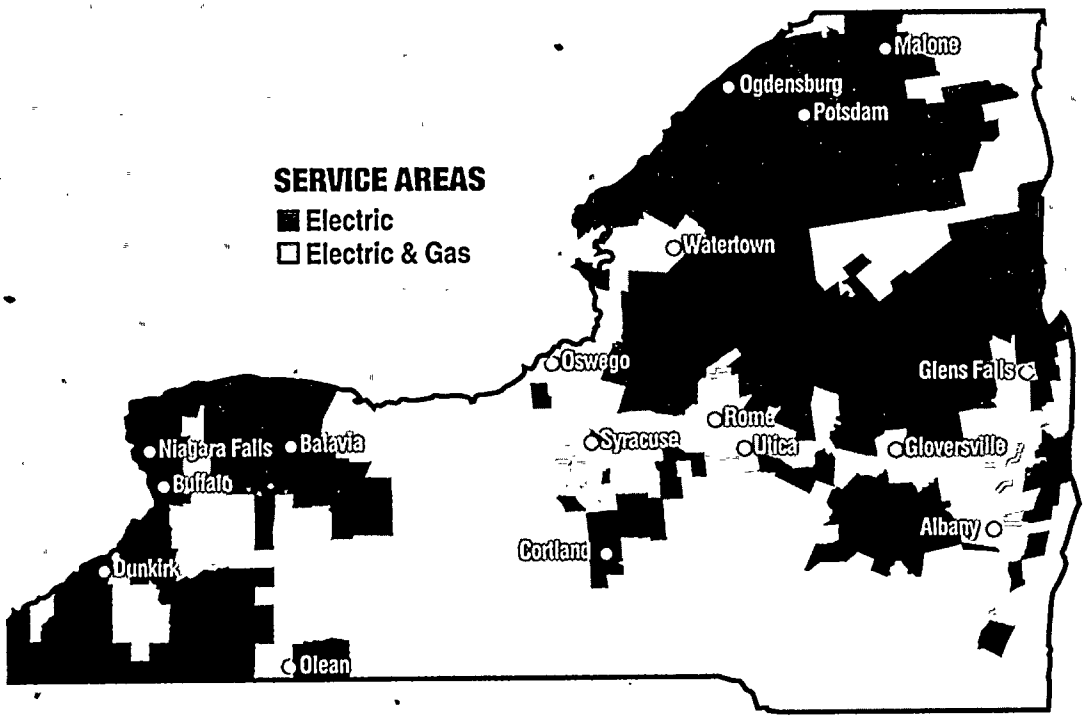
Bonds are traded on the New York Stock Exchange.

Disbursing Agent
Common and Preferred Stocks:
Niagara Mohawk Power Corp.
300 Erie Boulevard West
Syracuse, N.Y. 13202

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

Transfer Agents and Registrars
Common and Preferred Stock:
Chemical Bank
450 West 33rd Street
New York, N.Y. 10001

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



Serving Our Customers

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 generated units. Electricity is transmitted through an integrated operating network that is linked to other systems in the Northeast for economic exchange and mutual reliability.

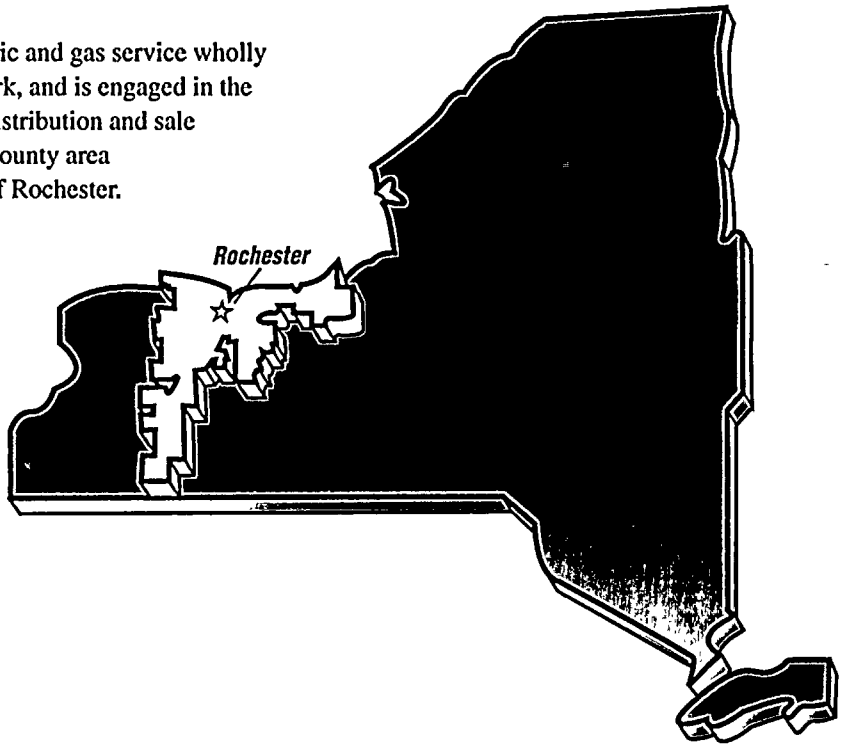
Our natural gas system provides service to nearly 500,000 residential and business customers on a retail basis, as well as a growing number of customers from whom we transport gas that they purchase directly from suppliers.

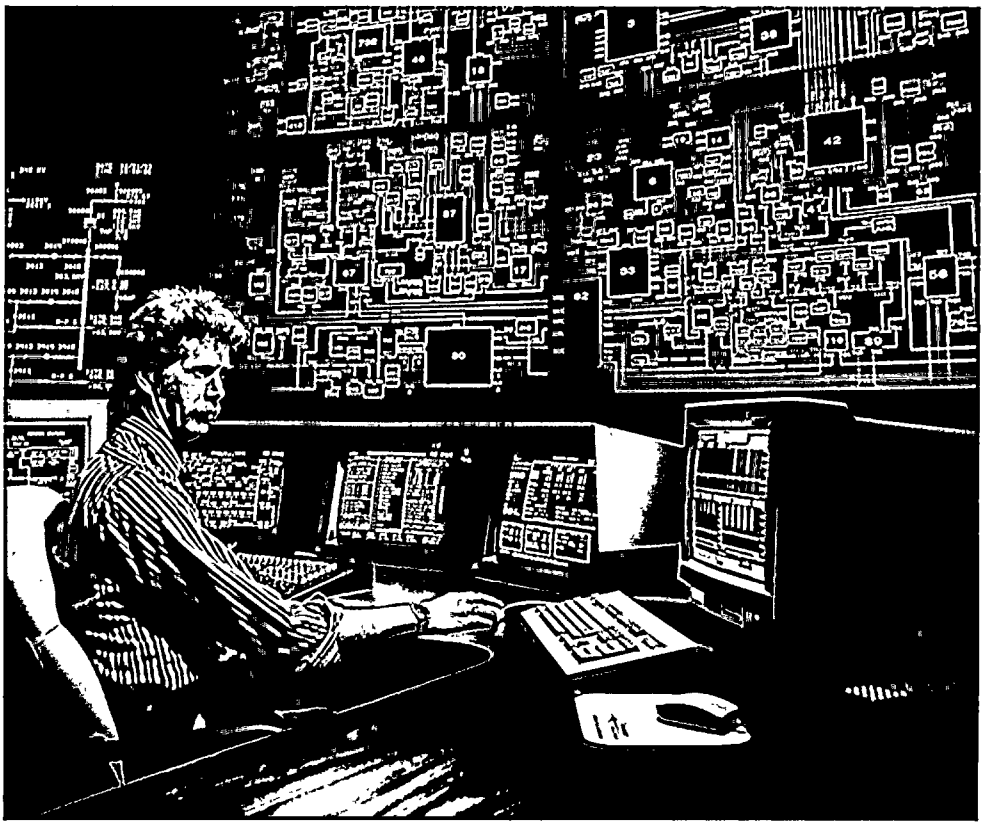
We also operate subsidiary companies in the United States and Canada. HYDRA-CO Enterprises builds and operates power production facilities. Opinac Energy Corp. operates the electric utility Canadian Niagara Power.

RG&E Service Area/Business

The Company supplies electric and gas service wholly within the State of New York, and is engaged in the production, transmission, distribution and sale of these services in a nine-county area centering around the City of Rochester.

The Company's territory, which has a population of approximately one million, is well diversified among residential, commercial and industrial customers. In addition to the City of Rochester, which is the third largest city and a major industrial center in the State, it includes a large and prosperous farming area.





COVER—
Rochester's skyline highlights RG&E's new energy-efficient logo sign atop corporate headquarters. Blending with the photo at the bottom is the new Energy Control Center that monitors and controls electric and gas operations around the clock.

An RG&E Energy Control Center operator checks systems status as part of the ongoing operations at the new facility.

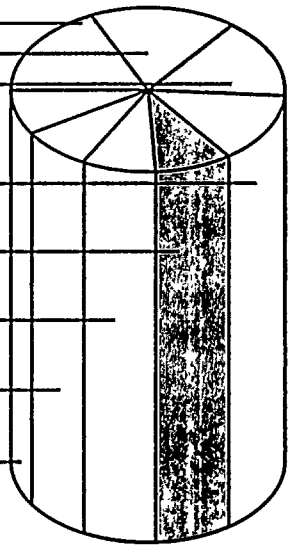
The RG&E lighted logo sign uses energy-efficient illumination.

Contents

1993 Revenue Dollar

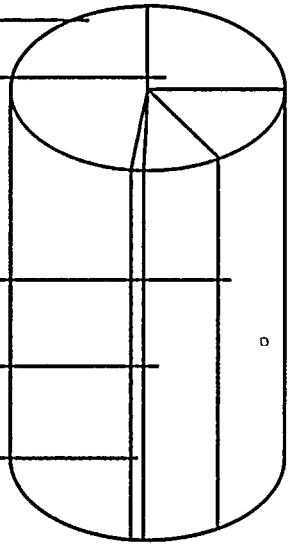
Use of 1993 Revenue Dollar

Taxes	18¢
Other Operations	18¢
Purchased Gas	18¢
Wages & Benefits	15¢
Depreciation & Amortization	9¢
Electric Fuel & Purchased Electricity	8¢
Dividends & Reinvested Earnings	8¢
Interest	6¢



Source of 1993 Revenue Dollar

Residential (25¢ Electric, 21¢ Gas)	46¢
Commercial (21¢ Electric, 5¢ Gas)	26¢
Industrial (15¢ Electric, 1¢ Gas)	16¢
Other (6¢ Electric, 4¢ Gas)	10¢
Electric Sales to Other Utilities	2¢

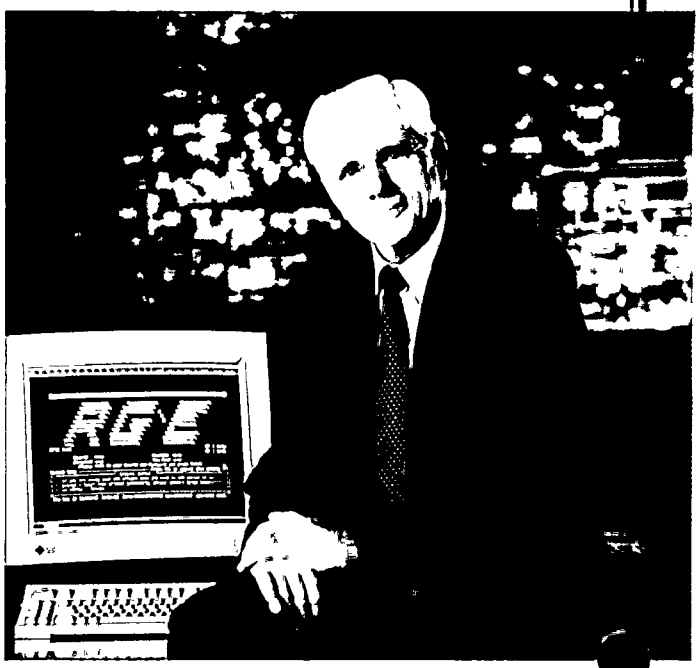


Financial Highlights

	1993	1992	% Change
Financial Data (Dollars in Thousands)			
Operating revenues: Electric	$655,316	$633,808	3
Gas	$293,708	$261,724	12
Operating expenses	$801,791	$761,588	5
Operating income	$147,233	$133,944	10
Net income	$ 78,563	$ 70,439	12
Earnings applicable to common stock	$ 71,263	$ 62,149	15
Rate of return on average common equity	10.25%	9.98%	3
Common Stock Data			
Weighted average number of shares outstanding (thousands)	35,599	33,258	7
Per common share:			
Earnings	$2.00	$1.86	8
Dividends	$1.72	$1.68	2
Book Value (year end)	$19.70	$18.92	4
Year-end market price	$26.25	$24.50	7
Number of Common Stock Shareholders at December 31	38,102	39,017	(2)
Operating Data			
Sales (thousands)			
Kilowatt-hours to customers	6,507,064	6,455,986	1
Kilowatt-hours to other utilities	743,588	1,062,738	(30)
Therms of gas sold and transported	529,505	525,387	1
Customers (year end)			
Electric	335,874	333,674	1
Gas	271,353	267,954	1
Construction expenditures, less allowance for funds used during construction (thousands)	$139,407	$125,207	11
Employees (year end)	2,536	2,702	(6)

To Shareholders

Nineteen ninety-three was a good year for our shareholders, customers and employees alike. It's been a while since we could make a statement like that. All the indicators are favorable. Earnings were up, dividends were up, year-end common stock market price was up, sales of electricity and natural gas to customers were up, and so was favorable public opinion as measured by our annual customer attitude survey. At the same time, operation and maintenance expenses came in under forecast. The real driving force behind this improved performance is our highly motivated work force and a strong commitment to our Corporate Business Plan.



Roger W. Kober

Our 1991 annual report described our business plan and its major objectives. We seek to improve customer service, make the price of our products more competitive, help ensure safety for employees and the public, maximize employee effectiveness and achieve higher degrees of public acceptance. We have recorded substantial progress in all these areas. And, as we predicted, progress in achieving these goals has improved financial performance.

Rate Settlement Agreement Milestone

In covering what I believe to be the key accomplishments of 1993, I cite our successful negotiation of a rate settlement agreement with the New York State Public Service Commission (PSC) as a prime example of our new approach in managing this Company and the competitive forces it confronts. The rate settlement agreement was a long time in the making. More than a dozen interested parties debated and negotiated components of a settlement that could work to the advantage of customers and the Company. It was a long process, but the approved agreement sets new precedents in our ratemaking procedures.

The three-year rate settlement agreement sets caps on the amount of additional revenues the Company may seek through rate relief. These caps are in the range of

current inflation rates. However, the agreement provides incentives where superior performance brings rewards in shareholder earnings. Of course, penalties apply in the event our performance falls short of the negotiated goals.

Our rate settlement agreement includes a unique performance incentive. Our performance will be measured against other New York investor-owned power companies in the areas of production, electric transmission and effectiveness of demand side management programs.

We continue to move aggressively in the area of demand side management, or Energy Utilization Services as we now call it. Successful efforts to curb electric load growth through promotion of energy efficiency programs and the creation of energy

Leading The Way In Customer Service

partnerships with commercial and industrial accounts will be recognized under the settlement agreement.

We are fully committed to the rate settlement agreement and are prepared to demonstrate it as a successful ratemaking method that benefits all. It's my intention to do everything I can to avoid increases in the price of our products. I've made it clear to RG&E people that there's no such thing as an "uncontrollable cost." We should be able to find ways to exert influence on any expenses we encounter. And that includes taxes. We successfully reduced property taxes substantially at one of our power plants through an exhaustive audit of the assessments. We are finding better ways to do things. I have great expectations for the rate settlement agreement and its role in keeping us competitive.

Cost Control

It was the company-wide determination of RG&E people that really turned things around.

The price at which we can keep our products competitive is largely a function of controlling our operating expenses. In 1993 we managed to come in $13 million under our operation and maintenance forecast. This saving was achieved by improved employee productivity and ingenuity. A cost saving of $4.4 million was also brought about through aggressive refinancing of our long-term debt.

Retirement Enhancement

It was time in 1993 as a result of the new competitive environment to take action to reduce the number of employees and payroll expense. That time came for us in late 1993. Two retirement enhancement programs were offered. Of the 217 eligible employees, 173 opted for early retirement. This is not a temporary measure; it's a permanent reduction in our complement. The downsizing of the work force will improve financial performance and help us remain competitive in the years ahead. We're reshaping the corporate culture and moving the Company and its people into the mainstream of the competitive marketplace. We will remain competitive and we will remain the customers' energy supplier of choice.

Process Improvement

The system we use at RG&E to improve performance is very simple. We look at everything we do. We study the individual processes and procedures we use in our work. Then we take each process and ask ourselves how valuable it is to us and our customers. If we decide a process is not contributing to the success of our Corporate Business Plan, we get rid of it. If we see it as worthwhile, we keep it. If we can find a way to improve it, we do. And here's a key point. The "we" I refer to is not just the Executive Management Team sitting around a table making judgments. The "we" in our improvement efforts is our employees. They have been empowered and encouraged to step back, look at what we do, and then subject it to our improvement process tests. I can tell you it's working. In 1993 dozens of procedures and practices were changed at RG&E. All for the better.

Customer Service Center

Probably the most striking example of our rededication to improved customer service and satisfaction is our new Customer Service Center in Rochester. A completely renovated, 153,000-square-foot industrial complex now houses the majority of our Rochester District customer service operations under one roof. Customer contact telephone service, energy control center, computer data center, customer service departments, telecommunications, service vehicle garage and supply warehouse are now positioned in the complex to best accommodate customer needs and maintain the high level of energy reliability. Our vision had been to create a "one-stop-shopping" convenience for our customers and the highest degree of system reliability and response. Whatever the issue, our customers can now call or visit one location and get all of their needs accommodated. This new facility is a major milestone in our corporate history, and we feature it in this report.

Our strategy is consistent with our intent to break away from the old, more vulnerable utility business thinking.

Empire Pipeline

The Empire State Pipeline was completed in 1993 as scheduled. We own a share of this major natural gas transmission pipeline project that runs 156 miles from Grand Island near Buffalo to Syracuse. The 24-inch-diameter pipeline brings another source of natural gas to Upstate New York from northern fields. The pipeline is expected to supply half of our gas customers' requirements.

CO Detector

One of our corporate objectives is to maintain high levels of safety and safety awareness on the part of our employees and the public. There had been two fatalities in our area a year ago as a result of carbon monoxide poisoning. We responded by developing a safety awareness campaign that warned people of the symptoms and dangers and urged them to get their furnaces inspected annually.

RG&E People Made All The Difference

In a further effort to prevent carbon monoxide poisonings we launched an aggressive marketing campaign in October that offers industry-approved carbon monoxide detectors at our cost. They're available to customers and non-customers alike. Nearly 20,000 have been placed into operation, and we know of some 20 cases already where the detectors alerted residents to the presence of carbon monoxide.

This effort was conceived, developed and placed into action by RG&E people. Aside from its perfect fit into the corporate safety objective, I see it as another excellent example of RG&E's growth as a thinking, progressive company with talented people taking initiatives under our practice of empowerment and process improvement.

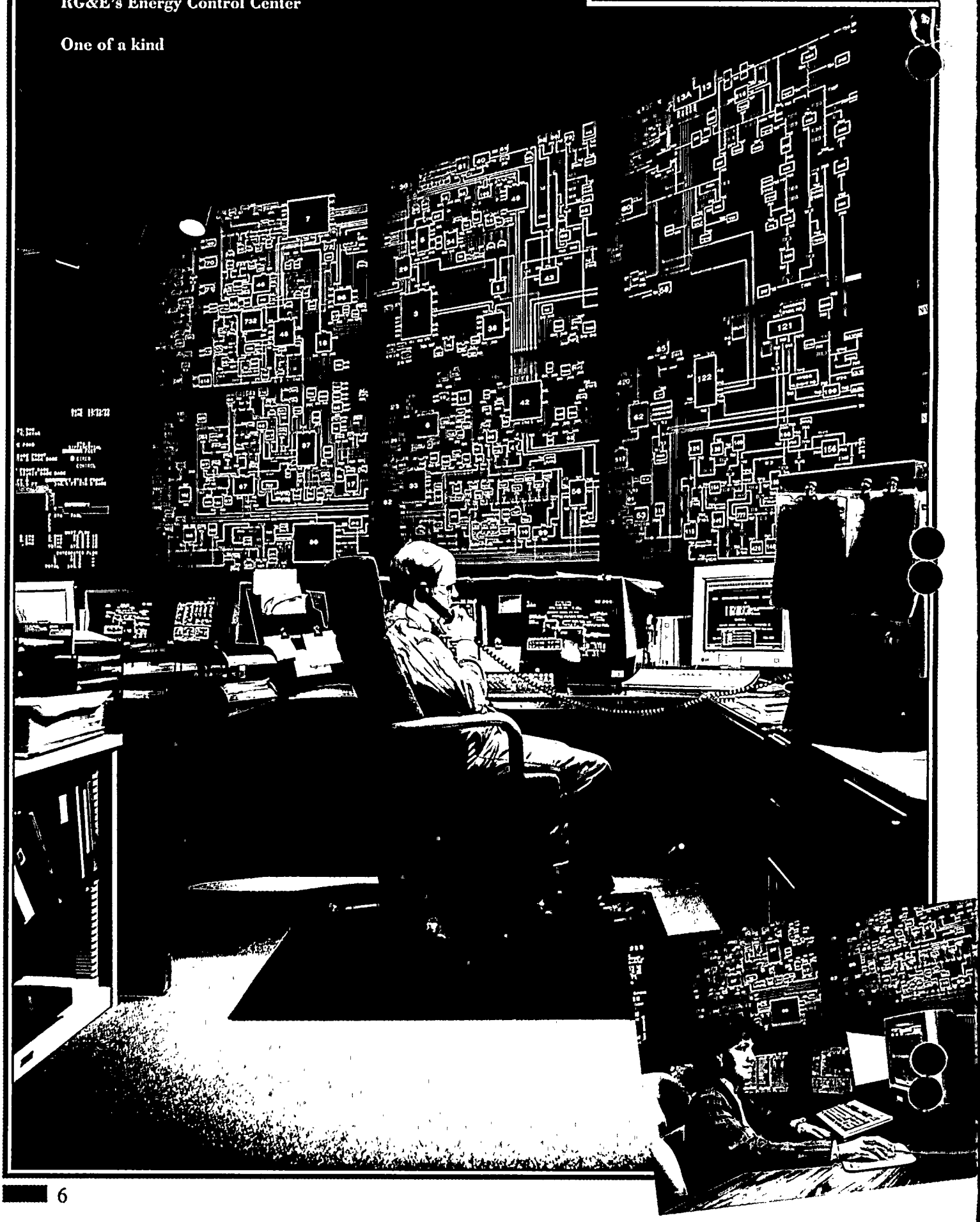
Outlook

I am very pleased with the progress we are making along the lines of the Corporate Business Plan. There's ample evidence that we have indeed turned the corner in the conduct of our business and gotten hold of our future. This is a new beginning for us, and our efforts to improve and prosper in the competitive marketplace continue with intensity.

Roger W. Kober
Chairman of the Board, President and
Chief Executive Officer
January 25, 1994

RG&E's Energy Control Center

One of a kind



Vision Becomes Reality

RG&E is looking for ways to make its dealings with customers as productive and supportive as possible and, in that process, bring about satisfactory financial results as well. These days it's hard to find any company's business plan that doesn't mention those kinds of goals. But there's a big difference between the words and the performance; between the vision and the reality.

Rochester Gas and Electric Corporation brought life to a corporate vision with the opening of a new Customer Service Center in Rochester. Using advanced office design and state-of-the-art computer systems, the Center houses key components of RG&E customer account service groups along with computer, voice communications, energy control and storm emergency response operations.

The modern, convenient service area allows easy, "one-stop shopping" for customers.

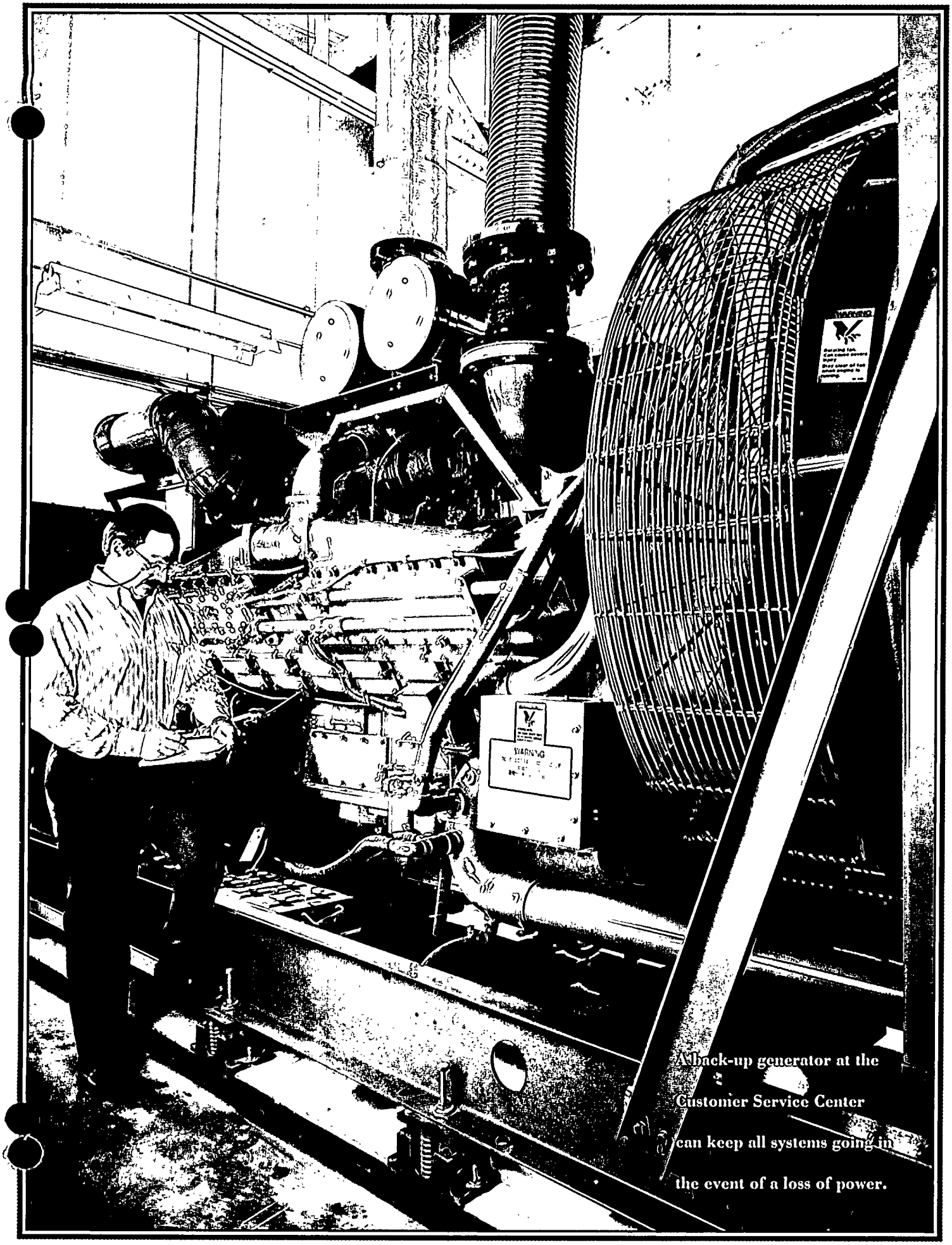
Just minutes from the heart of downtown Rochester at 400 West Avenue, the 153,000-square-foot facility took shape from a complete renovation of a vacated industrial complex. It offers a centralized location for customers visiting the center along with the convenience of easy access and ample, free parking.

Customer Satisfaction By Design

The Customer Service Center offers a spacious customer transaction area. Customer service and billing departments are located near the service area so that customer account matters can be resolved at the Center in person or over the phone from one centralized location. Conference rooms are also available for planning consultations with commercial and industrial customers.

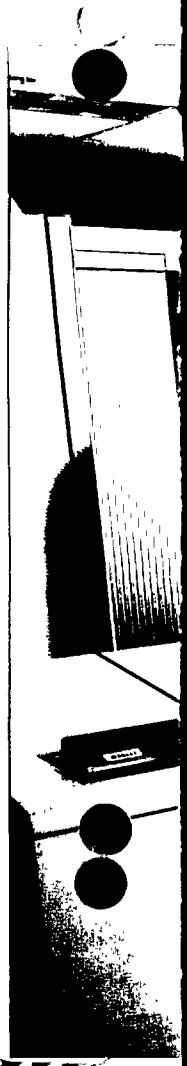
Customer telephone representatives are well equipped to resolve account matters by phone. Advanced computer systems help experienced customer service representatives with a full range of instantly available account information. More than one million customer telephone calls a year are handled by the RG&E telephone service representatives and switchboard operators.

The Customer Telephone Service Department matches experienced representatives with state-of-the-art data systems offering "one-stop shopping" to customers by phone.



A back-up generator at the Customer Service Center can keep all systems going in the event of a loss of power.

Energy Control Center



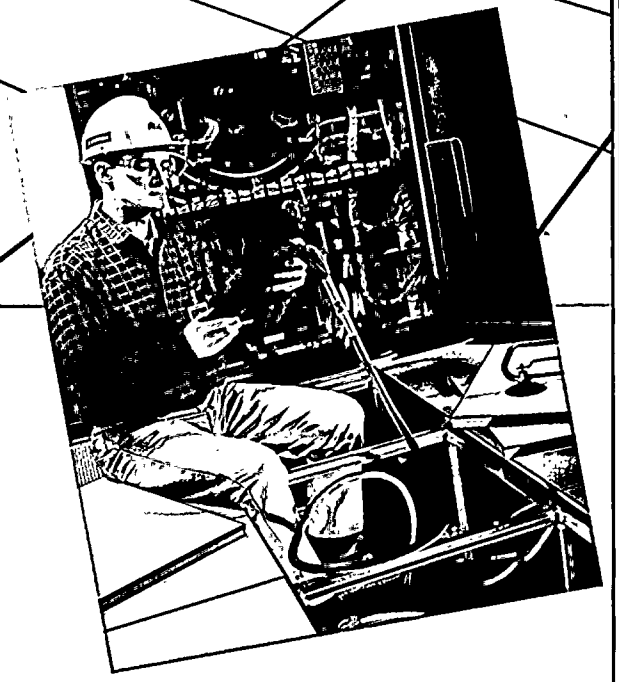
Energy reliability is crucial to good customer service. The West Avenue Customer Service Center houses a unique Energy Control Center from which electric and gas operations are orchestrated and monitored 24 hours a day. New computer systems precisely track real-time electric power and natural gas systems status. A unique array of rear-screen projections creates a valuable tool to improve routine operations and enable more effective restoration response in emergencies.

Emergency Response

Aside from its daily function as a customer service and energy control center, the Customer Service Center is specially designed to handle RG&E's emergency response activities. Restoration of electric or gas services disrupted by severe storms or other events will be directed and controlled from the Energy Control Center. The locations of the operations centers and the communication links that connect them are custom engineered to allow the most rapid and efficient energy service restorations using RG&E's emergency response plans.

Computer Data Center

Advanced computer systems are central to the accumulation and retrieval of data. The Customer Service Center is home to RG&E's main frame computers and company computer support services. Voice communications activities are also coordinated at the Center for RG&E's telecommunications systems.



The Data Center in the Customer Service Center is home to RG&E's main frame computers and computer service operations.

Truck Bay

Who would think a garage would make a big difference? Well it does at the Customer Service Center where a 22,000-square-foot truck bay comfortably houses a fleet of electric and gas service trucks and vehicles—even those with heavy construction equipment attached. With a large supply storehouse next door, equipment for jobs is quickly and easily placed aboard the trucks. They can then quickly roll out of a warm, dry garage to the job sites on cold or wet days. Besides being easier on the crews and trucks, this convenience saves time and provides more efficient response in the field.

Uninterrupted Electric Power

One thing RG&E has to think about for its service facilities is what it does if it loses power itself. The RG&E Customer Service Center is equipped with redundant electric power sources and power switching units. Main frame computer operations are protected with alternative, uninterruptable power supplies. That includes a battery array that protects the equipment and data by supplying power to the main frame computers in an emergency. And, if all else fails, a 1,500-kilowatt generator inside the Customer Service Center can supply full power requirements for the whole facility indefinitely in the event all outside power is lost.

Alternative power systems help guarantee uninterrupted electric service for all systems in the Customer Service Center

A Part Of The Whole

While the West Avenue Customer Service Center is a focal point for RG&E's drive to improve customer service and energy reliability, it's not the whole story. Besides 400 employees staffing the Customer Service Center, more than 2,000 other RG&E people go about their jobs, doing their best, too, for the one million residents in the Company's 2,700-square-mile service franchise territory.

A 22,000-square-foot truck bay allows maximum readiness for RG&E's service fleet at the Customer Service Center.

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

The following is Management's assessment of significant factors which affect the Company's financial condition and operating results.

Liquidity and Capital Resources

During 1993 cash flow from operations, together with proceeds from external financing activity (see Consolidated Statement of Cash Flows), provided the funds for construction expenditures and the retirement and refinancing of long-term debt and preferred stock. Capital requirements during 1994, including debt maturity and sinking fund obligations, are anticipated to be satisfied primarily from the use of internally generated funds. Some external financing, mainly in the form of short-term debt, is expected to be incurred. Any refinancing activity would require additional external financing.

Projected Capital and Other Requirements

The Company's capital requirements relate primarily to expenditures for electric generation, transmission and distribution facilities and gas mains and services as well as the repayment of existing debt. Construction programs of the Company focus on the need to serve new customers, to provide for the replacement of obsolete or inefficient utility property and to modify facilities consistent with the most current environmental and safety regulations.

The Company has no current plans to install additional baseload generation. The Company either has contracts or is continuing negotiations for the realization of approximately 24 megawatts of capacity savings being phased-in over the 1993–1996 period under its demand side management program and, beginning in late 1994 or early 1995, expects approximately 55 megawatts of capacity to be supplied by a cogenerator under contract with the Company. The Company has no other obligations with non-utility generating companies at this time.

In June 1992 the Company filed with the New York State Public Service Commission (PSC) an Integrated Resource Plan (IRP) which is a long-range plan examining options for the future with regard to generating resources and alternative methods of meeting electric capacity requirements. The plan covers a 15-year period, beginning in 1992, and provides current strategies and alternatives for meeting customer energy requirements in a changing business and technological environment. The IRP takes into account anticipated capacity requirements and available resource options, as well as factors such as reliability, price of product, public acceptance, financial integrity, environmental issues, the competitive marketplace, demand side management and potential new technologies.

One result of the IRP was the decision made by the Company in December 1992 to replace the two steam generators at the Ginna nuclear plant in 1996. Like similar plants, the Ginna nuclear plant has experienced degradation in some of the tubes that make up each steam generator. About 30 percent of these tubes have required repair. In addition, a chemical buildup in some of the tubes has reduced their heat transfer capability. Both conditions would continue to erode the plant's performance if the existing steam generators were left in place. Installation of new steam generators was determined by the Company to be the most cost-effective, reliable and environmentally compatible option for the plant. The new steam generators should result in

reduced maintenance costs and help sustain a high level of plant availability. Cost of replacement is estimated at $115 million, and preparation to replace these generators began during the plant's routine 1993 fuel outage.

As a part of the on-going IRP process, the Company in mid-1993 made a decision to place Unit 1 at Russell Station (47 MW) on cold standby, while modifying Units 2, 3 and 4 with new burners to meet Federal Environmental Protection Agency standards. Unit 1 is expected to be in cold standby by early 1994. Modification of Units 3 and 4 is expected to be completed by March 1995 at a cost of approximately $4.6 million. In addition, Unit 12 at Beebee Station and Unit 2 at Russell Station will be adjusted to produce fewer nitrogen oxides (NOx) by converting a third of the burners in each to achieve overfire air capability at a cost of approximately $1.2 million. These actions will allow the Company to comply with Phase I-Title I, NOx controls requirements of the Federal Clean Air Act, to meet projected load demands in its service territory, and to maintain a mix of fuel generation while remaining competitive and retaining wholesale sales opportunities.

Outlined below are other results of the IRP process to date:

- The plan calls for evaluating the possibility of using either alternative generation or current generating equipment in partnership with certain large industrial customers.
- The Company will continue to use demand side management programs to reduce the need for generating capacity.
- The Company will consider phasing out its coal-fired Beebee Station by the year 2000, unless it is converted to natural gas and operated under a partnership arrangement with a large customer.

The Company's capital expenditures program is under continuous review and will be revised depending upon the progress of construction projects, customer demand for energy, rate relief, government mandates and other factors. In addition to its projected construction requirements, the Company may consider, as conditions warrant, the redemption or refinancing of certain long-term securities.

Capital Requirements and Electric Operations. Electric production plant expenditures in 1993 included $42 million of expenditures made at the Company's Ginna nuclear plant, of which $15 million was incurred for preparation to replace the steam generators. In addition, nuclear fuel expenditures of $11 million were incurred at Ginna during 1993. A refueling outage at Ginna normally occurs annually for a period of approximately 40 to 50 days.

Exclusive of fuel costs, the Company's 14 percent share of electric production plant expenditures at the Nine Mile Two nuclear facility totaled $6 million in 1993. Expenditures of $5 million during 1993 were made for the Company's share of nuclear fuel at Nine Mile Two. On October 2, 1993 Nine Mile Two was taken out of service for a scheduled refueling outage. Refueling was completed and Nine Mile Two resumed full operation on December 3, 1993. The prior refueling outage occurred in 1992 from early March to early July. The next refueling outage for Nine Mile Two is anticipated to begin in May 1995.

Electric transmission and distribution expenditures, as presented in the table on page 16, totaled $29 million in 1993, of which $24 million was for the upgrading of electric distribution facilities to meet the energy requirements of new and existing customers.

Capital Requirements and Gas Operations. Construction began in June 1993 on the Empire State Pipeline (Empire), an intrastate natural gas pipeline subject to PSC regulation between Grand Island and Syracuse, New York. The Company received its first gas deliveries through

the pipeline in early November 1993. This pipeline will provide capacity for up to 50 percent of the Company's gas requirements by its second year of operation. The Company is participating as an equity owner of Empire, along with subsidiaries of Coastal Corporation and Westcoast Energy Inc. In June 1991 the PSC authorized the Company to invest up to $20 million in Empire subject to certain conditions, notably that the investment not be included in rate base. In 1992 the Company formed a wholly owned subsidiary, Energyline Corporation, to acquire its ownership interest in Empire. The Company's share of ownership in Empire will be dependent upon final project costs and the timing and method of financing selected by the Company. In June 1993 Empire secured a $150 million credit agreement, the proceeds of which are to finance approximately 75 percent of the total construction cost. At December 31, 1993 the Company had invested a net amount of $10.2 million in Energyline ($9.9 million in 1992 and $0.3 million in 1993) and was committed for $9.7 million of the borrowings under the credit agreement. In December 1993 the Company's investment in Energyline was consolidated for accounting and reporting purposes into the accounts of the Company. Such consolidation resulted in a $0.5 million charge to Other Income during 1993.

In addition to the Empire project discussed above, construction expenditures in the Gas Department totaled $20 million and were principally for the replacement of older cast iron mains with longer-lasting and less expensive plastic and coated steel pipe, the relocation of gas mains for highway improvement, and the installation of gas services for new load.

Environmental Issues

The production and delivery of energy are necessarily accompanied by the release of by-products subject to environmental controls. In recognition of the Company's responsibility to preserve the quality of the air, water, and land it shares with the community it serves, the Company has taken a variety of measures (e.g., self-auditing, recycling and waste

Capital Requirements

	Actual			Projected		
Type of Facilities	1991	1992	1993	1994	1995	1996
	(Millions of Dollars)					
Electric Property:						
Production	$ 44	$ 47	$ 54	$ 55	$ 66	$ 76
Transmission and Distribution	29	35	29	26	36	40
Street Lighting and Other	2	2	2	1	2	2
Subtotal	75	84	85	82	104	118
Nuclear Fuel	12	11	16	20	20	22
Total Electric	87	95	101	102	124	140
Gas Property	22	19	20	19	28	25
Common Property	13	15	21	15	16	16
Total	122	129	142	136	168	181
Carrying Costs:						
Allowance for Funds Used During Construction (AFUDC)	4	2	2	2	3	3
Deferred Financing Charges Included in Other Income	5	3	1	–	–	–
Total Construction Requirements	131	134	145	138	171	184
Securities Redemptions, Maturities and Sinking Fund Obligations*	92	160	212	39	3	21
Total Capital Requirements	$223	$294	$357	$177	$174	$205

*Excludes prospective refinancings.

minimization, training of employees in hazardous waste management) to reduce the potential for adverse environmental effects from its energy operations and, specifically, to manage and appropriately dispose of wastes currently being generated. The Company, nevertheless, has been contacted, along with numerous others, concerning wastes shipped off-site to licensed treatment, storage and disposal sites where authorities have later questioned the handling of such wastes. In such instances, the Company typically seeks to cooperate with those authorities and with other site users to develop cleanup programs and to fairly allocate the associated costs.

As a part of its commitment to environmental excellence, the Company is conducting proactive Site Investigation and Remediation (SIR) efforts at Company-owned sites where past waste handling and disposal may have occurred. The Company currently estimates the total costs it could incur for SIR activities at Company-owned sites to be about $20 million. This estimate will vary as better site information is available. The Company anticipates spending $10 million over the next 5 years on SIR initiatives. Approximately $4.5 million has been provided for in rates through June 1996 for recovery of SIR costs. To the extent actual expenditures differ from this amount, they will be deferred for future disposition and recovery as authorized by the PSC. Additional environmental issues are discussed in Note 10 of the Notes to Financial Statements.

The Company is developing strategies responsive to the Federal Clean Air Act Amendments of 1990 (Amendments). The Amendments primarily affect air emissions from the Company's fossil-fueled electric generating facilities (see Note 10 of the Notes to Financial Statements). The Company is in the process of identifying the optimum mix of control measures that will allow the fossil fuel based portion of the generation system to fully comply with applicable regulatory requirements. Although work is continuing, not all compliance control measures have been determined. The Company has adopted control measures for NOx emissions which must be in effect by the federally mandated compliance date of May 31, 1995. These control measures are discussed under Projected Capital and Other Requirements. Capital costs for NOx controls and the installation of continuous emission monitoring systems are not expected to exceed $6.8 million and will be incurred during 1994 and 1995. A range of capital costs between $20 million and $30 million (1993 dollars) has been estimated for the implementation of several potential scenarios which would enable the Company to meet the foreseeable future NOx and sulphur dioxide requirements of the Amendments. These capital costs would be incurred between 1996 and 2000. The Company currently estimates that it could also incur up to $2 million (1993 dollars) of additional annual operating expenses, excluding fuel, to comply with the Amendments. The use of scrubbing equipment is not presently being considered. Likewise, the purchase or sale of "emission allowances", as allowed by the Amendments, is not currently being considered. The Company anticipates that the costs incurred to comply with the Amendments will be recoverable through rates based on previous rate recovery of environmental costs required by governmental authorities.

Competition

The Company is operating in an increasingly competitive environment. In its electric business, this environment includes a federal trend toward deregulation and a state trend toward incentive regulation. In addition, excess capacity in the region, new technology and cost pressures on major customers have created incentives for major customers to investigate different electric supply options. Initially, those options will include various forms of self generation, but may eventually include customer access to the transmission system in order to purchase electricity from suppliers other than the Company. As discussed under the Regulatory Matters section, the passage of the National Energy Policy Act of 1992 has accelerated these competitive challenges.

The Company accepts these challenges and is working to anticipate the impact of the increased competition. Its Business Plan, both in detail for one year and in summary for five years, focuses on improving service while reducing expenses. The Company is engaged in a continuous process improvement program to find opportunities for improved service and efficiency and has implemented an early retirement program in which 173 people, representing approximately seven percent of its workforce, have retired early and will not be replaced. In addition, the Company has agreed to a three-year rate settlement which includes caps on rate increases that approximate or are less than projected inflation, contains incentive programs that tie performance to earnings and stabilizes revenue through revenue adjustment mechanisms. An agreement has been reached with the PSC Staff and others on the terms of a competitive rate tariff that would allow negotiated rates with larger industrial and commercial customers that have competitive electric supply options. These regulatory changes are discussed in more detail in the Regulatory Matters section.

Competition in the Company's gas business has existed for some time, as the larger customers have had the option of obtaining their own gas supply and transporting it through the Company's distribution system. This process has been accelerated with FERC Order 636, discussed in more detail in the Regulatory Matters section. In addition to the matters discussed above, the Company has responded to the changes in the gas business by positioning itself to obtain greater access to both U.S. and Canadian natural gas supplies and storage, so that it can take advantage of the unbundling of services that results from FERC Order 636. A major element of this strategy went into place in 1993 with the start-up of the Empire State Pipeline. The Company is engaged in various aspects of capacity release and is investigating other options available to it to mitigate its cost and increase its revenue in the new gas regulatory environment.

Beyond the Company's efforts to remain competitive in its core business, it is conducting a broad review of its general business strategy to identify opportunities that will exist in this changed environment. This may result in expansion of various elements of the core business or engaging in new, but related, business activity.

Redemption of Securities

Discretionary first mortgage bond redemptions totaled $120 million during 1993. A $75 million first mortgage bond maturity and $17 million of sinking fund obligations were also a part of the Company's capital requirements in 1993.

Capital requirements in 1992 included a $75 million first mortgage bond maturity, and discretionary first mortgage bond redemptions of $79.5 million.

Capital Requirements—Summary

The Company's capital program is designed to maintain reliable and safe electric and natural gas service, to improve the Company's competitive position, and to meet future customer service requirements. Capital requirements for the three-year period 1991 to 1993 and the current estimate of capital requirements through 1996 are summarized in the table on page 16.

For the period 1994 through 1996, the Company anticipates construction requirements to total approximately $493 million. Replacement of the steam generators at the Ginna nuclear plant is scheduled to be completed in 1996. Electric production plant expenditures over the period include $16 million in 1994, $29 million in 1995, and $50 million in 1996 for that replacement. In addition to its construction expenditures, the Company has security maturities and sinking fund obligations totaling $63 million over the three-year period 1994 through 1996. Excluded from the capital requirements table on page 16 are expenditures associated with the Company's obligations to the United States Department of Energy for nuclear waste disposal

and the Department of Energy's uranium enrichment facility decommissioning (see Notes 1 and 10 of the Notes to Financial Statements).

Financing and Capital Structure

Capital requirements in 1993 were satisfied by a combination of long-term debt and equity issues, internally generated funds, and short-term borrowings. Common shareholders equity increased during 1993 as the result of a public issue of one and one-half million shares of Common Stock in September. Favorable market conditions allowed the Company to refinance $120 million of its higher-cost long-term debt in 1993. In addition, the Company was able to refinance at a lower interest rate $75 million of its First Mortgage, 8.60% Bonds, Series LL, which matured on August 1. Such refinancing activity over the past three years has helped to reduce the annual cost of long-term debt by approximately $8.8 million and contributed to a drop in the Company's embedded cost of long-term debt from 8.6% at year-end 1990 to 7.4% at the end of 1993.

The Company believes that an average of approximately 85 percent to 90 percent of the funds required per year for its 1994 through 1996 construction program will be generated internally and the balance will be obtained through the issue of securities and short-term borrowings. The Company is utilizing its credit agreements to meet any interim external financing needs prior to issuing any long-term securities. As financial market conditions warrant, the Company may, from time to time, issue securities to permit the early redemption of higher-cost senior securities. The Company's financing program is under continuous review and may be revised depending upon the level of construction, financial market conditions, rate relief, cost of capital and other factors.

Financing. Interim financing is available from certain domestic banks in the form of short-term borrowings under a $90 million revolving credit agreement which continues until December 31, 1996 and may be extended annually. Borrowings under this agreement are secured by a subordinate mortgage on substantially all of the Company's property except cash and accounts receivable. In addition, the Company entered into a Loan and Security Agreement with a domestic bank until December 31, 1994 providing for up to $20 million of short-term debt. Borrowings under this agreement, which can be renewed annually, are secured by the Company's accounts receivable. The Company also has unsecured short-term credit facilities totaling $70 million. At December 31, 1993 the Company had short-term borrowings outstanding of $68.1 million, consisting of $51.3 million of unsecured short-term debt and $16.8 million of secured short-term debt.

Under provisions of the Company's Certificate of Incorporation (Charter), the Company may not issue unsecured debt if immediately after such issuance the total amount of unsecured debt outstanding would exceed 15 percent of the Company's total secured indebtedness, capital, and surplus without the approval of at least a majority of the holders of outstanding Preferred Stock. Under this restriction, the Company as of December 31, 1993 was able to issue $19.2 million of additional unsecured debt. Additional interim financing capability remains available with secured borrowings under the Company's credit agreements, as discussed above.

During 1993 the Company sold several issues of First Mortgage Bonds, Designated Secured Medium-Term Notes, Series A aggregating $200 million principal amount. Proceeds from the sale of the medium-term notes were used to redeem prior to maturity, at lower interest rates, $120 million principal amount of first mortgage bonds, to pay at maturity $75 million principal amount of first mortgage bonds and to repay short-term debt of $5 million.

In July 1993 the Company filed a shelf registration on Form S-3 providing for the offering of $250 million of new securities. The Company may use the shelf registration to offer, from time to time, its first mortgage bonds in one or more series, its Preferred Stock in one or more series and/or its Common Stock depending on market conditions and Company requirements. This

Registration Statement became effective August 1993 and allows the Company financing flexibility regarding the timing of new issues. The net proceeds from the sale of the securities will be used to finance a portion of the Company's capital requirements, to discharge or refund certain outstanding indebtedness or preferred stock of the Company, to satisfy certain sinking fund obligations, or for general corporate purposes.

In September 1993 the Company sold 1,500,000 shares of new Common Stock in a public offering under the shelf registration discussed above. The offering raised $43.1 million in net proceeds, which were used to retire short-term debt incurred in the Company's construction program.

During 1993 approximately 515,000 new shares of Common Stock were sold through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan (ADR Plan), providing approximately $14.1 million to help finance its capital expenditures program. New shares issued in 1992 and 1993 through the ADR Plan were purchased from the Company at a market price above the book value per share at the time of purchase.

Capital Structure. The public sale of Common Stock in 1992 and 1993 strengthened the Company's common equity. The Company's retained earnings at December 31, 1993 were $75.1 million, an increase of approximately $8.1 million compared with a year earlier. Common equity (including retained earnings) comprised 44.0 percent of the Company's capitalization at December 31, 1993, with the balance being comprised of 6.6 percent preferred equity and 49.4 percent long-term debt. At December 31, 1993 the Company had $21.3 million of long-term debt due within one year and $6.0 million of preferred stock redeemable within one year which, if included in capitalization, would increase the long-term debt component of capitalization at 1993 year-end to 49.8 percent, raise the preferred equity to 6.9 percent and reduce common equity to 43.3 percent of capitalization. As presented, these percentages are based on the Company's capitalization inclusive of its long-term liability to the United States Department of Energy (DOE) for nuclear waste disposal as explained in Note 1 of the Notes to Financial Statements. It is the Company's long-term objective to move to a less leveraged capital structure and to increase the common equity percentage of capitalization toward the 45 percent range. To improve its capital structure, the Company anticipates the issuance of new shares of common stock, primarily through the Company's ADR Plan, and will consider the redemption of higher-cost senior securities.

Regulatory Matters

New York State Public Service Commission (PSC). The Company is subject to regulation of rates, service, and sale of securities, among other matters, by the PSC. On August 24, 1993 the PSC issued an order approving a settlement agreement (1993 Rate Agreement) among the Company, PSC Staff and other interested parties. This agreement resolves the Company's rate case proceedings initiated in July 1992. Retroactive application of new rates to July 1, 1993 was authorized by the PSC. The 1993 Rate Agreement will determine the Company's rates through June 30, 1996 and includes certain incentive arrangements providing for both rewards and penalties. A summary of recent PSC rate decisions is presented in the table on page 22. The 1993 Rate Agreement amounts are based on an allowed return on common equity of 11.50% through June 30, 1996. Earnings between 8.50% and 14.50% will be absorbed/retained by the Company. Earnings above 14.50% will be refunded to the customers. If, but not unless, earnings fall below 8.50%, or cash interest coverage falls below 2.2 times, the Company can seek relief by petitioning the PSC for a review of the 1993 Rate Agreement terms.

The following measures were incorporated into the 1993 Rate Agreement:

- Incentive mechanisms that have the potential to either increase or reduce earnings from 5 to 70 basis points each, depending on the Company's ability to meet a variety of prescribed targets in the areas of electric fuel costs, demand side management, service quality, and integrated resource management (relative electric production efficiency). During the rate year ending June 30, 1994, these incentives have the potential to affect earnings by approximately $12 million.
- Mechanisms for sharing costs between customers and shareholders for operation and maintenance expenses. In general, non-fuel operation and maintenance expense variations are treated in three different ways depending upon the amount of control the Company can exert over them. Those costs that are directly manageable (approximately $172 million in the first rate year) have no sharing and are absorbed by the Company, those costs that are not significantly affected by management action in the short run (approximately $34 million in the first rate year) are trued up 100% and variances resulting from all other such costs (approximately $110 million in the first rate year) are shared 50% by customers and 50% by the Company.
- Mechanisms for sharing 50% of overspending variances between forecasted and actual electric capital expenditures related to production and transmission facilities. The Company will retain the savings for cost of money and depreciation on underspending variances. The settlement also provides for a sharing mechanism regarding the replacement of the Ginna nuclear station steam generators. A graduated sharing percentage is applied for up to $15 million of variances, plus or minus, from the forecasted cost of $115 million. Variances above $130 million or below $100 million are absorbed by the Company.
- An Electric Revenue Adjustment Mechanism (ERAM) designed to stabilize electric revenues by eliminating the impact of variations in electric sales. A gas weather normalization clause previously in place was retained.

To the extent incentive and sharing mechanisms apply, the negotiated rate increases shown in the table on page 22 may be adjusted up or down in the second and third year of the agreement. Negotiated electric rate increases could be reduced to zero or increased up to an additional 1.5% in year two, 1.6% in year three and 1.8% in the subsequent year. Negotiated gas rate increases could also be reduced to zero or increased up to an additional 0.8% in year two, 0.9% in year three, and 1.1% in the subsequent year, exclusive of the impact of the Empire State Pipeline going into service.

In July 1993 the Company requested approval from the PSC for a new flexible pricing tariff for major industrial and commercial electric customers. A settlement in this matter was filed with the PSC on November 19, 1993 and a decision on whether or not to approve the settlement is expected early in 1994. Such a tariff would allow the Company to negotiate competitive electric rates at discount prices to compete with alternative power sources, such as customer-owned generation facilities. Under the terms of the settlement, the Company would absorb 30 percent of any net revenues lost as a result of such discounts through June 1996, while the remainder would be recovered from other customers. The portion recoverable after June 1996 is expected to be determined in a generic proceeding currently being conducted by the PSC.

In September 1993 the PSC instituted a formal proceeding to investigate what the Company believes are undercharges to gas customers for certain gas purchases for the period August 1990 to August 1992. The Company's estimate of these undercharges is approximately $7.5 million, of which $2.3 million had been previously expensed and $5.2 million had been deferred on the Company's balance sheet. The PSC has made the Company's current gas rates under the 1993 Rate Agreement temporary solely to consider the impact of these under-

Rate Increases

Granted

Class of Service	Effective Date of Increase	Amount of Increase (Annual Basis) (000's)	Percent Increase	Authorized Rate of Return on Rate Base	Authorized Rate of Return on Equity
Electric	July 12, 1990	$36,059	6.6%	9.91%	12.10%
	July 1, 1991	33,133	5.5	9.66	11.70
	July 1, 1992	32,220	5.2	9.31	11.00
	July 1, 1993*	18,500	2.8	9.46	11.50
	July 1, 1994*	20,900	2.9	9.39	11.50
	July 1, 1995*	21,800	2.9	9.41	11.50
Gas	July 12, 1990	4,250	1.7	9.91	12.10
	July 1, 1991	1,148	0.4	9.66	11.70
	July 1, 1992	12,316	4.1	9.31	11.00
	July 1, 1993*	2,600	1.1	9.46	11.50
	July 1, 1994*	4,400	1.8	9.39	11.50
	July 1, 1995*	4,300	1.7	9.41	11.50

*See under heading Regulatory Matters for additional details.

charges. On December 30, 1993, a proposed settlement among the Company, PSC Staff and another party was filed with the PSC. It provides for the recovery in rates of $3.2 million over three years, subject to audit and to limitations on rate adjustments established in the August 24 Order. The Company wrote off the $2.0 million balance of the undercharges as of December 31, 1993. That write-off amounts to a reduction in 1993 earnings of approximately $.04 per share, net of tax. Although no party, to the Company's knowledge, opposes the proposed settlement, the Company is unable to predict whether the PSC will approve it. A PSC decision on whether to approve this settlement is not expected before March 1994.

In its June 1992 rate decision, the PSC allowed the Company to defer and recover through rates over a period of ten years approximately $21.3 million of non-capital incremental storm-damage repair costs which the Company had incurred as a result of a March 1991 ice storm. The PSC has permitted the unamortized balance of these allowed costs to be included in rate base. Rate recovery of an additional $8.2 million of non-capital storm-damage costs incurred by the Company was denied by the PSC and the Company accordingly recorded in the second quarter of 1992 a charge to earnings in the amount of $8.2 million, equivalent to approximately $.15 per share, net of tax, after issuance of the two million shares of stock in August 1992.

Pursuant to a November 1991 Order approving a settlement agreement between the PSC Staff and the Company relating to the Staff's audit of the Company's fuel procurement practices, the Company refunded $10 million to its electric customers through adjustments to their energy bills over a twelve-month period beginning in January 1992. The Company recorded a $6.6 million net-of-tax reduction to net income, thereby reducing earnings per share by approximately $.21 for the fourth quarter of 1991.

National Energy Policy Act of 1992. The National Energy Policy Act (Energy Act) was signed into law in 1992. Major provisions of the Energy Act, as they relate to the Company, include energy efficiency, promoting competition in the electric power industry at the wholesale level, streamlining of federal licensing of nuclear power plants, encouraging development and production of coal resources, and ensuring that a new class of independent power producers established under the bill, as well as qualified facilities and other electric utilities, can achieve access to utility-owned transmission facilities upon payment of appropriate prices.

Under the Energy Act, FERC may order utilities to provide wholesale transmission services for others only if, among other things, the order meets certain requirements as to cost recovery and fairness of rates. FERC is prohibited, however, from ordering retail wheeling, i.e. transmitting power directly to a customer from a supplier other than the customer's local utility. The law, however, does not prevent state regulatory commissions from allowing or ordering intrastate retail wheeling; and, New York State is currently considering the issue of retail wheeling through various studies and hearings. The Company believes this Act could lead to enhanced competition among the Company and other service providers in the electric industry.

FERC Order 636. In April 1992 FERC issued Order No. 636 with the intention of fostering competition and improving access of customers to gas supply sources. In essence, FERC Order No. 636 requires interstate natural gas companies to offer customers "unbundled", or separate, sales and transportation services. FERC Order 636 enables the Company and other gas utilities to contract directly with gas producers for supplies of natural gas. With the unbundling of services, primary responsibility for reliable natural gas supply has shifted from interstate pipeline companies to local distribution companies, such as the Company. Since 1988 the Company has endeavored to diversify both its natural gas supply sources and the pipelines on which that supply is delivered to the Company's distribution system. The unbundling of services as required under FERC Order 636 and the commencement of Empire State Pipeline operation have enabled the Company to achieve those goals, which should enhance its competitive position. As a result of FERC Order 636, the Company does face certain restructuring transition costs as explained under the heading Energy Costs and Supply—Gas.

Results of Operations

The following financial review identifies the causes of significant changes in the amounts of revenues and expenses, comparing 1993 to 1992 and 1992 to 1991. The Notes to Financial Statements on pages 36 to 53 of this report contain additional information.

Operating Revenues and Sales

Compared with a year earlier, operating revenues rose six percent in 1993 following a five percent increase in 1992. Gains in retail customer electric and gas revenues offset a decline in electric revenues from the sale of electric energy to other utilities. Customer revenue increases in 1993 resulted primarily from rate relief and the impact of warmer weather on air conditioning usage. Details of the revenue changes are presented in the table on page 24. As presented in this table, the base cost of fuel has been excluded from customer consumption and is included under fuel costs, revenue taxes are included as a part of other revenues, and unbilled revenues are included in each caption as appropriate.

Unbilled revenues are the estimated revenues attributable to energy which has been delivered to customers but for which the metered amount has not been read and recorded on the Company's books. Such revenues do not enhance the Company's cash position. The Company records monthly accruals for unbilled revenues. The Company's Statement of Income reflects net unbilled revenues of $18.7 million in 1993, $(0.8) million in 1992, and $2.6 million in 1991. Primarily as a result of the seasonal nature of gas revenues, unbilled revenues can fluctuate from month to month and will normally be near their maximum around January and at their minimum near the end of June.

Under the ERAM provisions of the 1993 Rate Agreement, as discussed under Regulatory Matters, the Company is comparing, on a monthly basis, actual results to forecast electric gross margins as defined (basically, revenues less incremental cost of fuel) and utilized in establishing rates. Variations between these target margins and the Company's actual margins may

be deferred and either recovered from or returned to customers. As discussed earlier, the 1993 Rate Agreement "caps", that is limits, the amount of revenue increases that can be obtained each rate year. At the end of each rate year (i.e. June 30) any balance for ERAM will be taken into consideration along with other balances eligible for passback or surcharge to customers (primarily incentive and expense sharing provisions) to determine the final disposition of the balance. As of December 31, 1993 no provisions to accrue or defer revenues associated with any of the ERAM incentive or sharing provisions under the 1993 Rate Agreement had been made, except for fuel adjustment clause revenues.

Changes in fuel and purchased power cost revenues are normally earnings neutral. The Company, however, does have fuel clause provisions which currently provide that customers and shareholders will share, generally on a 50%/50% basis subject to certain incentive limits, the benefits and detriments realized from actual electric fuel costs, generation mix, sales of gas to dual-fuel customers and sales of electricity to other utilities compared with PSC-approved forecast, or base rate, amounts. As a result of these sharing arrangements, discussed further in Note 1 of the Notes to Financial Statements, pretax earnings were increased by $4.4 million in 1992 and in 1993, primarily reflecting actual experience in both electric fuel costs and generation mix compared with rate assumptions. Fuel clause revenues also include the recovery of incremental margins that vary from those provided for in base rates for the implementation of the Company's energy efficiency programs (discussed below in this section). Beginning in October 1993, the Company also began the recovery through its fuel adjustment clause of deferred costs associated with the DOE's assessment for future uranium enrichment decontamination. For the 1992 comparison period, fuel clause revenues were reduced due to a refund to electric customers resulting from a PSC fuel audit settlement as described in the last paragraph under the heading New York State Public Service Commission.

The effect of weather variations on operating revenues is most measurable in the Gas Department, where revenues from space heating customers comprise about 85 to 90 percent of total gas operating revenues. Variation in weather conditions can also have a meaningful impact on the volume of gas delivered and the revenues derived from the transportation of customer-owned gas since a substantial portion of these gas deliveries is ultimately used for space heating. After experiencing unseasonably mild weather during the 1991 heating season, weather in the Company's service area during 1992 and 1993 was colder than normal. Gas sales were enhanced as a result of this cooler weather, while unseasonably warm summer weather during 1993 boosted electric energy sales to meet the demand for air conditioning usage, compared with the cool, wet 1992 summer weather conditions. The decoupling, or

Operating Revenues

Increase or (Decrease) from Prior Year

	Electric Department		Gas Department	
(Thousands of Dollars)	1993	1992	1993	1992
Customer Revenues (Estimated) from:				
Rate Increases	$21,827	$28,138	$ 8,087	$ 3,644
Fuel Costs	9,093	(9,633)	25,593	11,512
Weather Effects (Heating)	200	1,236	700	5,722
Customer Consumption	4,374	(2,826)	1,381	1,098
Other	(4,806)	2,422	(3,777)	4,020
Total Change in Customer Revenues	30,688	19,337	31,984	25,996
Electric Sales to Other Utilities	(9,180)	(3,071)	—	—
Total Change in Operating Revenues	$21,508	$16,266	$31,984	$25,996

separation, of sales level fluctuations from revenue through the ERAM provisions, discussed under Regulatory Matters, and a gas normalization weather clause (see following paragraph) may mitigate the effect of abnormal weather conditions on earnings.

As part of the June 1992 rate decision, retail customers who use gas for spaceheating became subject to a weather normalization adjustment to reflect the impact of variations from normal weather on a billing cycle month basis for the months of October through May, inclusive. The weather normalization adjustment for a billing cycle will apply only if the actual heating degree days are lower than 97.5 percent or higher than 102.5 percent of the normal heating degree days. Weather normalization adjustments lowered gas revenues in 1993 by approximately $1.2 million and in 1992 by approximately $1.8 million. The potential for such adjustments continues through June 1996 under the terms of the 1993 Rate Agreement.

Compared with the prior year, kilowatt-hour sales of energy to retail customers in 1993 climbed about one percent after being nearly flat in 1992. Electric demand for air conditioning usage had a significant impact on such sales in 1993 and 1992. During 1993, an increase in sales to both residential and commercial customers more than offset a decline in sales to industrial customers. Kilowatt-hour sales of energy in 1993 reflect the impact of approximately 2,200 new electric customers, which follows the addition of nearly 2,400 customers a year earlier.

Like many other electric utilities, the Company is encouraging energy efficiency through demand side management (DSM) programs. Objectives of the DSM programs include increasing the efficiency with which electricity is used and shifting electric load from peak to non-peak times, thus helping to save energy and delay the need to add new generating capacity. DSM programs include rebates for energy-efficient equipment, audits which focus on potential techniques for saving energy, consumer information and outreach, and design assistance to encourage energy-efficient new construction. In general, the Company is being allowed to amortize major DSM program expenditures over a five-year period. An incentive allowance (award) of approximately $0.6 million was provided for in the Company's rates based on the Company's DSM performance during 1992. Lost margins resulting from DSM activities are estimated and recovered in base rates. Variances between actual results and such estimates are recovered through fuel clause revenue adjustments, subject to certain incentive limitations.

Fluctuations in revenues from electric sales to other utilities are generally related to the Company's customer energy requirements, New York Power Pool energy market and transmission conditions and the availability of electric generation from Company facilities. Such revenues in 1992 and 1993 reflect the sale of energy at a lower average rate per megawatt hour, a result, in part, of competition and greater availability of energy. With more open access to transmission services as provided for under the Energy Act, the Company is examining alternative markets and procedures to meet what it believes will be increased competition for the sale of electric energy to other utilities.

The transportation of gas for large-volume customers who are able to purchase natural gas from sources other than the Company remains an important component of the Company's marketing mix. Company facilities are used to transport this gas, which amounted to 12.4 million dekatherms in 1993 and 12.6 million dekatherms in 1992. These purchases have caused decreases in customer revenues, with offsetting decreases in purchased gas expenses, but do not adversely affect earnings because transportation customers are billed at rates which, except for the cost of gas, approximate the rates charged the Company's other gas service customers. Gas supplies transported in this manner are not included in Company therm sales, depressing reported gas sales to non-residential customers.

Therms of gas sold and transported, including unbilled sales, were nearly flat in 1993, following an 11.8 percent increase in 1992. These changes reflect, primarily, the effect of weather variations on therm sales to customers with space heating. If adjusted for normal weather conditions, residential gas sales would have decreased about 0.3 percent in 1993 over 1992, while nonresidential sales, including gas transported, would have decreased approximately 2.1 percent in 1993. The average use per residential gas customer, when adjusted for normal weather conditions was slightly down in 1993, following a modest increase in 1992. Total therms of gas transported increased in 1992 primarily as a result of higher sales to certain large industrial and municipal transportation customers. Sales to these customers in 1993 were down compared with 1992 sales.

Fluctuations in "Other" customer revenues shown in the table on page 24 for both comparison periods are largely the result of revenue taxes, deferred fuel costs, and miscellaneous revenues.

Operating Expenses

Compared with the prior year, operating expenses were up $40.2 million in 1993 after increasing $33.1 million in 1992. Approximately two-thirds of the increase in 1993 operating expenses resulted from higher gas purchased for resale costs. The increase in operating expenses for the 1993 comparison period was mitigated by the Company's continuing efforts to curtail increases in other operation expenses. Operating expenses are summarized in the table on page 27.

Energy Costs—Electric. An electric generation mix favoring less expensive nuclear fuel, compared with the cost of coal or oil, resulted in fuel expenses not increasing at the same rate as electric generation for the 1993 comparison period. For the 1992 comparison period, fuel expense for electric generation was lower by $16.7 million due, in part, to a refund to electric customers as described in the last paragraph under the heading New York State Public Service Commission. For both comparison periods, the average cost of coal declined.

Average rates for purchased electricity declined in 1993, after increasing in 1992. Such average rates partially offset an increase in kilowatt-hours purchased in 1993. For the 1992 comparison period, the increase in purchased electricity expense was caused by higher average rates during the year.

Energy Costs and Supply—Gas. As a result of the implementation of FERC Order 636, and the commencement of operation of the Empire State Pipeline, the Company now purchases all of its required gas supply directly from numerous producers and marketers under contracts containing varying terms and conditions. The Company holds firm transportation capacity on nine major pipelines, giving the Company access to the major gas-producing regions of North America. In addition to firm pipeline capacity, the Company also has obtained contracts for firm storage capacity on the CNG Transmission Corporation (CNG) system (10.4 billion cubic feet) and on the ANR Pipeline system (6.4 billion cubic feet) which are used to help satisfy its customers' winter demand requirements. With the commencement of operation of the Empire State Pipeline, the Company placed into operation its new Mendon gate station which is capable of supplying up to one-half of the Company's gas supply needs while also maintaining the various gate station interconnections with the CNG system that, prior to Empire, had supplied all of the Company's needs.

The transportation service to be provided by Empire was scheduled to phase in over 12 months, at which point the combined CNG and Empire transportation capacity would have exceeded the Company's current requirements. Therefore, the Company recently entered into a marketing agreement with CNG, pursuant to which CNG will assist the Company in obtaining permanent replacement customers for the transportation capacity the Company will not require. It may renegotiate its arrangements with CNG and/or Empire or it may negotiate assignment,

on a permanent or temporary basis, of the transportation capacity that exceeds the requirements of its customers. In addition, under FERC rules, the Company may sell its excess transportation capacity in the market. While CNG has already secured letters of intent for a substantial portion of such capacity, whether and to what extent CNG and/or the Company can successfully negotiate the assignment or sale of the excess capacity, or at what price, cannot be determined at the present time. The retention of some or all of this excess transportation capacity may cause an increase in the Company's gas supply costs. This would be in addition to any increase caused by other aspects of the gas transportation restructuring.

As a result of the restructuring of the gas transportation industry by the FERC, there will be a number of changes in this aspect of the Company's business over the next several years. These changes, which will apply throughout the industry, will affect different companies differently and may result, at least initially, in increases in the gas transportation costs of the Company. The Company will also be required to pay a share of certain transition costs incurred by the pipelines as a result of the FERC restructuring. These include costs related to restructuring existing gas supply contracts, unrecovered gas costs that would otherwise have been billable to pipeline customers under previous regulation and other related costs deemed reasonable by the FERC. Although the final amounts of such transition costs are subject to continuing negotiations with several pipelines and ongoing pipeline filings requiring FERC approval, the Company expects such costs to range between $43.5 and $52.0 million. A substantial portion of such costs will be on the CNG system of which approximately $27 million was billed to the Company on December 3, 1993 payable over the following three years. The Company recorded a regulatory asset on its Balance Sheet and concurrently recognized a liability totaling approximately $43.5 million for estimated restructuring transition costs under FERC Order 636. The Company expects these transition costs to be recoverable in its rates.

The volume of gas purchased increased in both comparison periods primarily due to higher combined residential and commercial spaceheating sales, reflecting colder weather. The effect of higher-volume purchases was partially offset by lower average rates in 1992. In contrast to 1992, however, it was primarily an increase in these rates that pushed up the cost of gas purchased for resale in 1993. These higher rates reflect, in part, increased demand charges and, to a lesser extent, newly assessable gas service restructuring charges as a result of FERC Order 636.

Operating Expenses

Increase or (Decrease) from Prior Year

(Thousands of Dollars)	1993	1992
Fuel for Electric Generation	$ (2,505)	$(16,729)
Purchased Electricity	1,857	2,023
Gas Purchased for Resale	25,593	11,512
Other Operation	8,757	18,184
Maintenance	(1,027)	(2,695)
Depreciation	(176)	478
Amortization of Other Plant	(675)	369
Taxes Charged to Operating Expenses		
Local, State and Other Taxes	2,640	10,603
Federal Income Tax	5,739	9,332
Total Change in Operating Expenses	$ 40,203	$ 33,077

Operating Expenses, Excluding Fuel. Other operation expenses rose over both comparison periods as shown by the table on page 27. The recording of certain postretirement benefits other than pensions, as required by Statement of Financial Accounting Standards No. 106 (SFAS-106) and discussed in the following paragraph, increased other operation expenses in 1992 by $4.9 million. Compared with a year earlier, other operation expenses in 1992 also reflect an increase of $3.0 million for transmission wheeling charges, $1.9 million due to increased amortization of costs associated with the Company's demand side management programs, and additional expenses of about $1.6 million associated with the Company's share of Nine Mile Two operation expenses. As stated earlier, the growth in other operation expenses was significantly less over the 1993 comparison period, a direct result, in part, of enhanced cost control efforts by the Company's employees. Compared with 1992, operating expenses associated with fire and liability insurance, transportation, materials and supplies, legal expenses, and the Company's share of Nine Mile Two operation expenses declined in 1993. The change in other operation expenses for the 1993 comparison period reflects primarily increased payroll costs and demand side management expenses.

During the first quarter of 1992, the Company adopted the Financial Accounting Standards Board's (FASB) SFAS-106 for financial accounting purposes. Among other things, SFAS-106 requires accrual accounting for postretirement benefits other than pensions. Based on accrual accounting required by SFAS-106, the Company's net periodic cost for postretirement benefits other than pension was $7.5 million in 1993 and $7.8 million in 1992. The PSC has allowed the Company revenues in rates based on SFAS-106. In September 1993, the PSC issued a "Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other Than Pensions." The Statement's provisions require, among other things, ten-year amortization of actuarial gains and losses and deferral of differences between actual costs and rate allowances. The Company adopted the Statement in 1993 for regulatory accounting purposes.

In November 1992, the FASB issued SFAS-112 entitled "Employees' Accounting for Postemployment Benefits" which is effective for fiscal years beginning after December 15, 1993. This Statement requires the Company to recognize the obligation to provide postemployment benefits to former or inactive employees after employment but before retirement. Employers must accrue an obligation if the benefits are attributable to service already rendered, the benefits accumulate or vest, payment is probable, and the amounts can be reasonably estimated. The Company must adopt SFAS-112 not later than the first quarter of 1994. The Company is currently evaluating the impact of SFAS-112; however, based on studies the Company has performed to date, the adoption of SFAS-112 is not expected to have a material effect on the Company's financial condition or results of operations.

Reduced maintenance expense in both comparison periods was largely due to lower maintenance expenses incurred at nuclear production facilities and the effect of increased activity in 1991 associated with electric distribution facilities.

Despite an increase in depreciable plant in both comparison periods, depreciation and amortization of other plant fluctuated only moderately due mainly to a decrease in the depreciation and accrued decommissioning expenses related to the Ginna nuclear plant because of a three-year extension of its operating license and the completion in July 1992 of amortization of the Sterling property previously abandoned.

Taxes Charged to Operating Expenses. The increase in local, state and other taxes in both comparison periods resulted primarily from an increase in revenues combined with an increase in the revenue tax rate, and increased property tax rates and higher property assessments. The 1993 increase in local, state and other taxes was mitigated by the effect of the relative magnitude of these factors compared with 1992. The increase in these taxes for the 1992 comparison

period reflects an adjustment for a one-half percent increase in the New York State gross revenue tax rate accounted for beginning in October 1991 retroactive to January 1, 1991.

During the first quarter of 1993, the Company adopted SFAS-109 entitled "Accounting for Income Taxes" issued by the FASB in February 1992. Among other things, SFAS-109 requires that a deferred tax liability be recognized on the balance sheet for tax differences previously flowed through to customers. The Company's adoption of SFAS-109 in the first quarter of 1993 did not have a material effect on the Company's results of operations although since then, reflection of a deferred tax liability, together with a corresponding regulatory asset, caused total assets and liabilities to increase significantly. See Note 2 of the Notes to Financial Statements for further discussion of SFAS-109 and an analysis of Federal income taxes.

In August 1993, the Revenue Reconciliation Act of 1993 (1993 Tax Act) was signed into law. Among other provisions, the 1993 Tax Act provides for a Federal corporate income tax rate of 35% (previously 34%) retroactive to January 1, 1993. The Company has adjusted its tax reserve balances to reflect this new rate. There was no earnings impact since the effects of the tax change have been deferred. The Company petitioned the PSC in late 1993 for recognition and recovery of this incremental tax liability which was not reflected in the provisions of its 1993 Rate Agreement. The Company's ability to recover this cost is dependent upon the PSC issuing a generic ruling on the treatment of the 1993 Tax Act.

Other Statement of Income Items

AFUDC variances are generally related to the amount of utility plant under construction and not included in rate base. AFUDC levels also reflect decreases in the gross rate to 3.90 percent effective September 1, 1993 from earlier rates of 4.50 percent, 5.50 percent, and 7.10 percent.

Variations in non-operating Federal income tax reflect mainly accounting adjustments related to retirement enhancement programs (see following paragraph), regulatory disallowances, and an employee performance incentive program (discussed below in this section).

Recorded under the caption Other Income and Deductions is the recognition of retirement enhancement programs designed to reduce overall labor costs which were implemented by the Company during the third and fourth quarters of 1993. A total of 173 employees elected to participate under these programs. The Company does not plan to replace any of those employees. Total estimated pretax costs of $8.2 million associated with these programs were recognized by the Company in its 1993 Statement of Income, thereby reducing after-tax earnings by approximately $.15 per share for the year. The Company estimates that the net pre-tax savings through 1997 resulting from these programs will amount to about $8.9 million.

Recorded under the caption Regulatory Disallowances is the recognition of the 1991 PSC order associated with the Company's fuel procurement practices, the 1992 PSC order related to the March 1991 ice storm, and the 1993 settlement with the PSC regarding certain alleged gas purchase undercharges, each discussed under the heading New York State Public Service Commission.

Other Income in 1992 includes $3.5 million of proceeds received in settlement of lawsuits filed against certain contractors involved in the construction of the Nine Mile Two nuclear plant. Non-cash earnings associated with the amortization of customer prepaid Nine Mile Two financing costs of $4.8 million in 1991, $2.5 million in 1992, and $1.2 million in 1993 are also included in Other Income. The decline in Other—Net Income and Deductions for the 1993 comparison period results mainly from the recognition of an employee performance incentive program for 1993. This program recognizes employees' achievements in meeting corporate goals and reducing expenses. Compared with a year earlier, Other—Net Income and Deductions also reflects lower miscellaneous interest revenues in 1993 and the recognition of

Energyline earnings (losses) upon consolidation with the accounts of the Company as discussed under Capital Requirements and Gas Operations.

Both mandatory and optional redemptions of certain higher-cost first mortgage bonds have helped to reduce long-term debt interest expense over the three-year period 1991–1993, despite the issuance of additional long-term debt in 1991 and 1992. In 1992, the effect of lower interest rates on debt expense was partially offset by increased short-term borrowings. The level of short-term debt borrowings decreased in 1993.

Earnings/Summary

Presented below is a table which summarizes the Company's Common Stock earnings on a per-share basis. Certain non-recurring items and their effect on earnings per share have been identified in this table. Compared with a year earlier, earnings per share were up in 1993 and 1992 despite the effect of a public issuance of Common Stock in each year. Future earnings will be affected, in part, by the Company's success in achieving demand side management and other incentive goals, as well as controlling operating and capital costs, within levels provided for in rates under the terms of the 1993 Rate Agreement.

In December 1992 the Company announced a quarterly dividend increase from $.42 to $.43 per share of Common Stock payable in January 1993. Subsequently, in December 1993 the Company announced a new quarterly dividend rate of $.44 per share payable in January 1994. The Company's Charter provides for the payment of dividends on Common Stock out of the surplus net profits (retained earnings) of the Company. Accordingly, dividend payments are dependent on future earnings, in addition to financial requirements and other factors.

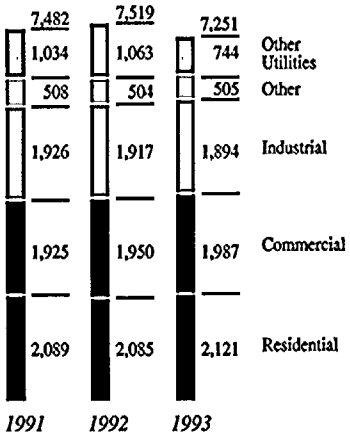
Earnings per Share—Summary

(Dollars per Share)	1993	1992	1991
Earnings per Share Before Non-recurring Items	$2.19	$1.91	$1.81
Non-recurring Items			
Gas Under-recovery Writeoff	(.04)		
Retirement Enhancement Programs	(.15)		
Nine Mile Two Litigation Proceeds		.10	
Ice Storm Disallowance		(.15)	
Fuel Procurement Audit			(.21)
Total Non-recurring Items	$(.19)	$(.05)	$(.21)
Reported Earnings per Share	$2.00	$1.86	$1.60

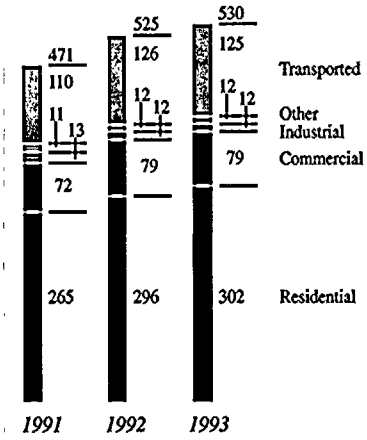
Financial Reports

Financial Profile

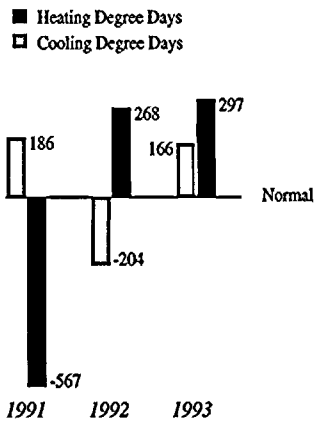
Electric Market Profile
(thousands of mwh sold)



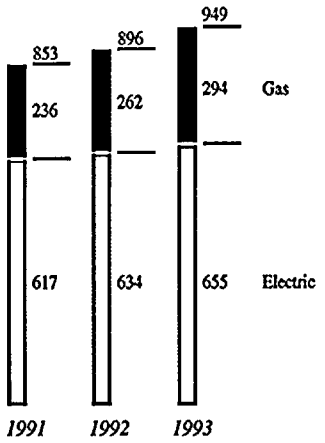
Gas Market Profile
(millions of therms sold and transported)



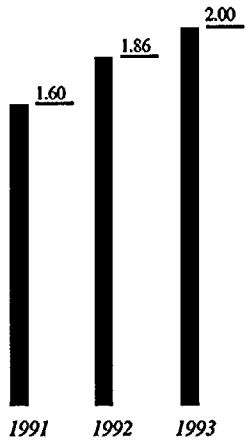
Degree Day Variations From Normal



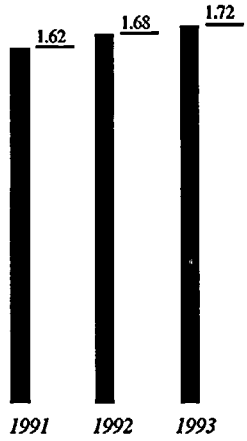
Operating Revenues
(millions of dollars)



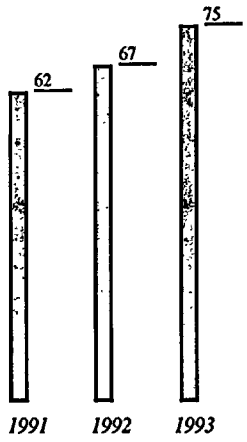
Earnings Per Share Of Common Stock
(dollars)



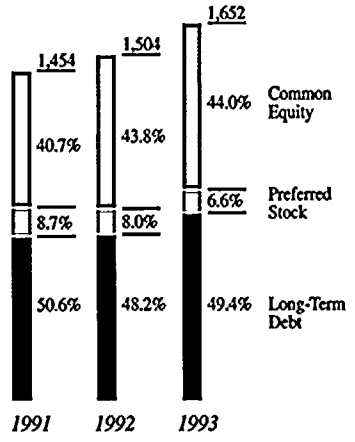
Dividends Per Share Of Common Stock
(dollars)



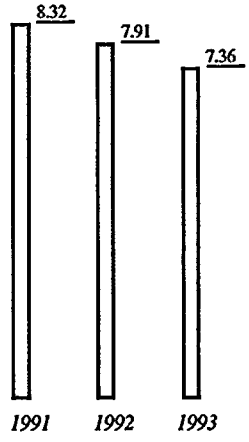
Retained Earnings At December 31
(millions of dollars)



Capitalization At December 31
(millions of dollars)



Embedded (Annual) Cost Of Long-Term Debt At Year End
(percent)



Consolidated Statement of Income

(Thousands of Dollars) Year Ended December 31	1993	1992	1991
Operating Revenues			
Electric	$ 638,955	$ 608,267	$ 588,930
Gas	293,708	261,724	235,728
	932,663	869,991	824,658
Electric sales to other utilities	16,361	25,541	28,612
Total Operating Revenues	949,024	895,532	853,270
Operating Expenses			
Fuel Expenses			
Fuel for electric generation	45,871	48,376	65,105
Purchased electricity	31,563	29,706	27,683
Gas purchased for resale	166,884	141,291	129,779
Total Fuel Expenses	244,318	219,373	222,567
Operating Revenues Less Fuel Expenses	704,706	676,159	630,703
Other Operating Expenses			
Operations excluding fuel expenses	235,381	226,624	208,440
Maintenance	61,693	62,720	65,415
Depreciation and amortization	84,177	85,028	84,181
Taxes—local, state and other	126,892	124,252	113,649
Federal income tax	49,330	43,591	34,259
Total Other Operating Expenses	557,473	542,215	505,944
Operating Income	147,233	133,944	124,759
Other Income and Deductions			
Allowance for other funds used during construction	153	164	675
Federal income tax	9,827	4,195	4,580
Pension Plan Curtailment	(8,179)	—	—
Regulatory disallowances	(1,953)	(8,215)	(10,000)
Other, net	(7,074)	6,155	6,078
Total Other Income and (Deductions)	(7,226)	2,299	1,333
Income Before Interest Charges	140,007	136,243	126,092
Interest Charges			
Long term debt	56,451	60,810	63,918
Other, net	6,707	7,178	7,082
Allowance for borrowed funds used during construction	(1,714)	(2,184)	(2,905)
Total Interest Charges	61,444	65,804	68,095
Net Income	78,563	70,439	57,997
Dividends on Preferred Stock	7,300	8,290	6,963
Earnings Applicable to Common Stock	$ 71,263	$ 62,149	$ 51,034
Weighted Average Number of Shares for Period (000's)	35,599	33,258	31,794
Earnings per Common Share	$ 2.00	$ 1.86	$ 1.60

Consolidated Statement of Retained Earnings

(Thousands of Dollars) Year Ended December 31	1993	1992	1991
Balance at Beginning of Period	$ 66,968	$ 61,515	$ 62,542
Add			
Net Income	78,563	70,439	57,997
Adjustment Associated with Stock Redemption	(933)	—	—
Total	144,598	131,954	120,539
Deduct			
Dividends declared on capital stock			
Cumulative preferred stock	7,300	8,290	6,963
Common stock	62,172	56,696	52,061
Total	69,472	64,986	59,024
Balance at End of Period	$ 75,126	$ 66,968	$ 61,515

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

Consolidated Balance Sheet

(Thousands of Dollars) At December 31	1993	1992
Assets		
Utility Plant		
Electric	$ 2,234,530	$ 2,175,255
Gas	356,484	341,466
Common	125,428	123,034
Nuclear fuel	174,357	158,826
	2,890,799	2,798,581
Less: Accumulated depreciation	1,190,801	1,125,502
Nuclear fuel amortization	144,282	127,615
	1,555,716	1,545,464
Construction work in progress	112,750	83,834
Net Utility Plant	1,668,466	1,629,298
Current Assets		
Cash and cash equivalents	2,327	1,759
Accounts receivable, net of allowance for doubtful accounts: 1993—$600; 1992—$500	104,753	92,292
Unbilled revenue receivable	61,330	60,184
Materials and supplies, at average cost		
Fossil fuel	5,983	12,273
Construction and other supplies	13,644	13,130
Gas stored underground	38,989	9,998
Prepayments	21,563	19,985
Total Current Assets	248,589	209,621
Investment in Empire	38,560	9,846
Deferred Debits		
Regulatory Asset—Income Taxes	241,741	—
Deferred finance charges—Nine Mile Two	19,242	20,492
Deferred ice storm charges	21,621	24,197
Uranium enrichment decommissioning deferral	23,421	28,613
Nuclear generating plant decommissioning fund	38,930	29,549
Nine Mile Two deferred costs	34,513	34,300
FERC 636 Transition Costs	41,265	—
Unamortized debt expense	19,326	13,553
Other	61,956	49,972
Total Deferred Debits	502,015	200,676
Total Assets	$ 2,457,630	$ 2,049,441
Capitalization and Liabilities		
Capitalization		
Long term debt—mortgage bonds	$ 655,731	$ 566,980
—promissory notes	91,900	91,900
Preferred stock redeemable at option of Company	67,000	67,000
Preferred stock subject to mandatory redemption	42,000	54,000
Common shareholders' equity		
Common stock	652,172	591,532
Retained earnings	75,126	66,968
Total Common Shareholders' Equity	727,298	658,500
Total Capitalization	1,583,929	1,438,380
Long Term Liabilities (Department of Energy):		
Nuclear waste disposal	68,055	65,989
Uranium enrichment decommissioning	21,749	28,613
Total Long Term Liabilities	89,804	94,602
Current Liabilities		
Long term debt due within one year	21,250	110,250
Preferred stock redeemable within one year	6,000	6,000
Note Payable—Empire	29,600	—
Short term debt	68,100	50,800
Accounts payable	52,596	40,578
Dividends payable	18,066	17,035
Taxes accrued	6,472	13,743
Interest accrued	12,955	15,461
Other	19,491	13,409
Total Current Liabilities	234,530	267,276
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes	425,648	171,673
Deferred finance charges—Nine Mile Two	19,242	20,492
Pension costs accrued	31,919	20,278
Other	72,558	36,740
Total Deferred Credits and Other Liabilities	549,367	249,183
Commitments and Other Matters (Note 10)	—	—
Total Capitalization and Liabilities	$ 2,457,630	$ 2,049,441

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

Consolidated Statement of Cash Flows

(Thousands of Dollars) Year Ended December 31	1993	1992	1991
Cash Flow from Operations			
Net income	$ 78,563	$ 70,439	$ 57,997
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation and amortization	84,177	85,028	84,181
Amortization of nuclear fuel	18,861	18,803	23,606
Deferred fuel—electric	(2,072)	2,543	4,122
Deferred fuel—gas	(11,500)	4,896	2,166
Deferred income taxes	15,232	10,466	9,124
Allowance for funds used during construction	(1,867)	(2,348)	(3,580)
Unbilled revenue, net	(5,107)	(6,631)	(8,931)
Ice storm costs	2,576	12,234	(36,431)
Nuclear generating plant decommissioning	(9,381)	(10,328)	(15,581)
Changes in certain current assets and liabilities:			
Accounts receivable	(12,461)	(8,239)	(4,773)
Materials and supplies—fossil fuel	6,290	(1,507)	7,506
—construction and other supplies	(514)	(591)	(315)
Gas stored underground	(28,991)	(2,942)	(7,057)
Taxes accrued	(7,271)	1,693	1,444
Accounts payable	12,018	(13,404)	6,914
Interest accrued	(2,506)	(852)	1,722
Other current assets and liabilities, net	6,113	(2,528)	(592)
Other, net	10,966	(5,832)	(2,075)
Total Operating	$ 153,126	$ 150,900	$ 119,447
Cash Flow from Investing Activities			
Utility Plant			
Plant additions	$ (125,744)	$ (115,792)	$ (114,579)
Nuclear fuel additions	(15,530)	(11,763)	(13,058)
Less: Allowance for funds used during construction	1,867	2,348	3,580
Additions to Utility Plant	(139,407)	(125,207)	(124,057)
Investment in Empire—net	884	(9,846)	—
Other, net	(1,907)	490	(685)
Total Investing	$ (140,430)	$ (134,563)	$ (124,742)
Cash Flow from Financing Activities			
Proceeds from:			
Sale/Issue of common stock	$ 61,254	$ 63,928	$ 13,446
Sale of preferred stock	—	—	30,000
Sale of long term debt, mortgage bonds	200,000	160,500	100,000
Short term borrowings	17,300	(8,700)	17,100
Retirement of long term debt	(200,249)	(160,000)	(92,334)
Retirement of preferred stock	(12,000)	—	—
Capital stock expense	(615)	(1,735)	(495)
Discount and expense of issuing long term debt	(7,909)	(6,368)	(3,310)
Dividends paid on preferred stock	(7,548)	(8,290)	(6,396)
Dividends paid on common stock	(60,893)	(55,216)	(51,308)
Other, net	(1,468)	(185)	(464)
Total Financing	$ (12,128)	$ (16,066)	$ 6,239
Increase in cash and cash equivalents	$ 568	$ 271	$ 944
Cash and cash equivalents at beginning of year	$ 1,759	$ 1,488	$ 544
Cash and cash equivalents at end of year	$ 2,327	$ 1,759	$ 1,488

Supplemental Disclosure of Cash Flow Information

(Thousands of Dollars) Year Ended December 31	1993	1992	1991
Cash Paid During the Year			
Interest paid (net of capitalized amount)	$ 60,852	$ 64,431	$ 63,848
Income taxes paid	$ 32,779	$ 22,911	$ 20,399

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

Notes to Financial Statements

Note 1. Summary of Accounting Principles

General.

The Company is subject to regulation by the Public Service Commission of the State of New York (PSC) under New York statutes and by the Federal Energy Regulatory Commission (FERC) as a licensee and public utility under the Federal Power Act. The Company's accounting policies conform to generally accepted accounting principles as applied to New York State public utilities giving effect to the rate-making and accounting practices and policies of the PSC.

In June 1988, the Board of Directors authorized the creation of Utilicom, Inc. as a wholly owned subsidiary. Utilicom develops and markets computer software to assist customers in complying with state and federal environmental and safety regulations. On August 31, 1993, the Company sold the assets of Utilicom and liquidated the subsidiary. The subsidiary activity prior to and including disposition was insignificant to the Company's financial position and results of operation.

In April 1990, the Board of Directors authorized the creation of Energyline Corporation, a wholly owned subsidiary, which was incorporated in July 1992. Energyline was formed as a gas pipeline corporation to fund the Company's investment in the Empire State Pipeline project. On November 1, 1993 Empire commenced service to the Company's gas distribution facilities. The Company has authority to invest up to $20 million in Empire. In June 1993 Empire secured a $150 million credit agreement, the proceeds of which are to finance approximately 75 percent of the total construction cost and initial operating expenses. Energyline is obligated to pay up to 20% of the balance outstanding subject to a commitment of $9.7 million under the credit agreement. Excluding the loan commitment, at December 31, 1993 the Company had invested a net amount of $10.2 million in Energyline.

A description of the Company's principal accounting policies follows.

Rates and Revenue.

Revenue is recorded on the basis of meters read. In addition, the Company records an estimate of unbilled revenue for service rendered subsequent to the meter-read date through the end of the accounting period.

Tariffs for electric and gas service include fuel cost adjustment clauses which adjust the rates monthly to reflect changes in the actual average cost of fuels. The electric fuel adjustment provides that ratepayers and the Company will share the effects of any variation from forecast monthly unit fuel costs on a 50%/50% basis up to a $5.6 million cumulative annual gain or loss to the Company. Thereafter, 100 percent of additional fuel clause adjustment amounts are assigned to customers. The electric fuel cost adjustment also provides that any variation from forecast margins below $7.1 million or above $8.5 million on sales to electric utilities be shared with retail customers on a 50%/50% basis.

In addition, there is a similar 50%/50% sharing process of variances from forecasted margins derived from sales and the transportation of privately owned gas to large customers that can use alternate fuels.

Under the Company's Electric Revenue Assurance Mechanism (ERAM), which was established in the 1993 multi-year rate settlement, any variations between actual margins and the established targets may be recovered from or returned to customers. Other performance incentives or penalties were established in the settlement and under some circumstances could be recognized periodically. However, through December 31, 1993, no amount was recognized as recoverable or payable to customers.

Retail customers who use gas for spaceheating are subject to a weather normalization adjustment to reflect the impact of variations from normal weather on a billing month basis for the months of October through May, inclusive. The weather normalization adjustment for a billing cycle will apply only if the actual heating degree days are lower than 97.5 percent or higher than 102.5 percent of the normal heating degree days. Weather normalization adjustments lowered gas revenues in 1993 and 1992 by approximately $1.2 million and

$1.8 million respectively. These adjustments will continue through June 1996 in accordance with the 1993 multi-year rate settlement agreement.

Deferred Fuel Costs.

The Company practices fuel cost deferral accounting as described above. A reconciliation of recoverable gas costs with gas revenues is done annually as of August 31, and the excess or deficiency is refunded to or recovered from the customers during a subsequent twelve-month period beginning in December. These deferred fuel costs are included as a component of unbilled revenues.

Utility Plant, Depreciation and Amortization.

The cost of additions to utility plant and replacement of retirement units of property is capitalized. Cost includes labor, material, and similar items, as well as indirect charges such as engineering and supervision, and is recorded at original cost. The Company capitalizes an allowance for funds used during construction approximately equivalent to the cost of capital devoted to plant under construction that is not included in its rate base. Replacement of minor items of property is included in maintenance expenses. Costs of depreciable units of plant retired are eliminated from utility plant accounts, and such costs, plus removal expenses, less salvage, are charged to the accumulated depreciation reserve.

Depreciation in the financial statements is provided on a straight-line basis at rates based on the estimated useful lives of property, which have resulted in provisions of 2.9%, 2.9% and 3.3% per annum of average depreciable property in 1993, 1992 and 1991, respectively. The decrease in depreciation provision percentages from 1991 to 1992 is principally the result of a 3½ year extension of the Ginna Nuclear Plant license term and lengthening estimated useful lives at other property.

Nuclear Fuel Disposal Costs.

The Nuclear Waste Policy Act (Act) of 1982, as amended, requires the United States Department of Energy (DOE) to establish a nuclear waste disposal site and to take title to nuclear waste. A permanent DOE high-level nuclear waste repository is not expected to be operational before the year 2010. The DOE is pursuing efforts to establish a monitored retrievable interim storage facility which may allow it to take title to and possession of nuclear waste prior to the establishment of a permanent repository. The Act provides for a determination of the fees collectible by the DOE for the disposal of nuclear fuel irradiated prior to April 7, 1983 and for three payment options. The option of a single payment to be made at any time prior to the first delivery of fuel to the DOE was selected by the Company in June 1985. The Company estimates the fees, including accrued interest, owed to the DOE to be $68.1 million at December 31, 1993. The Company is allowed by the PSC to recover these costs in rates. The estimated fees are classified as a long-term liability and interest is accrued at the current three-month Treasury bill rate, adjusted quarterly. The Act also requires the DOE to provide for the disposal of nuclear fuel irradiated after April 6, 1983, for a charge of one mill ($.001) per KWH of nuclear energy generated and sold. This charge is currently being collected from customers and paid to the DOE pursuant to PSC authorization. The Company expects to utilize on-site storage for all spent or retired nuclear fuel assemblies until an interim or permanent nuclear disposal facility is operational.

Nuclear Decommissioning Costs.

Decommissioning costs (costs to take the plant out of service in the future) for the Company's Ginna Nuclear Plant are estimated to be approximately $150.7 million, and those for the Company's 14% share of Nine Mile Two's decommissioning costs are estimated to be approximately $34.3 million (January 1993 dollars). Through December 31, 1993, the Company has accrued and recovered in rates $61.2 million for this purpose and is currently accruing and recovering decommissioning costs at a rate of approximately $8.9 million per year based on the use of a combination of internal and external sinking funds. (See Note 10.)

(Note 1 continued on page 38)

(continued from page 37)

The decommissioning costs, which form the basis for current accruals, were derived from the record of the Company's prior rate proceeding (PSC Opinion 93-19, issued August 1993) and were estimated principally by reference to a formula prescribed by the NRC for the purpose of providing for adequate funding at the time of the decommissioning.

Uranium Enrichment Decontamination and Decommissioning Fund.

As part of the National Energy Act (Act) issued in October 1992, utilities with nuclear generating facilities are assessed an annual fee payable over 15 years to pay for the decommissioning of Federally owned uranium enrichment facilities. The assessments for Ginna and Nine Mile Two are estimated to total $24.1 million, excluding inflation and interest. The first installment of $1.6 million was paid in 1993 and recovered through the fuel adjustment clause. A liability has been recognized on the financial statements along with a corresponding regulatory asset. The Company believes that the full amount of the assessment will be recoverable in rates as described in the Act.

FERC Order 636.

Under this order, gas supply and pipeline companies are allowed to pass restructuring and transition costs associated with the implementation of the order on to their customers. The Company, as a customer, has estimated a total of $43.5 million which will be paid to its suppliers. A regulatory asset and related deferred credit have been established on the balance sheet to account for these estimated costs. Approximately $2.2 million of these costs were paid during 1993 to various suppliers, and have been included in purchased gas costs (see Note 10).

Allowance for Funds Used During Construction.

The Company capitalizes an Allowance for Funds Used During Construction (AFUDC) based upon the cost of borrowed funds for construction purposes, and a reasonable rate upon the Company's other funds when so used. AFUDC is segregated into two components and classified in the Statement of Income as Allowance for Borrowed Funds Used During Construction, an offset to Interest Charges, and Allowance for Other Funds Used During Construction, a part of Other Income.

The rates approved by the PSC for purposes of computing AFUDC were: 3.9% from September 1, 1993 through December 31, 1993; 4.5% from September 1, 1992 through August 31, 1993; 5.5% from April 1, 1992 through August 31, 1992; 7.1% from July 1, 1991 through March 31, 1992; 8.6% from February 1, 1991 through June 30, 1991; 9.6% from January 1, 1991 through January 31, 1991.

In 1984, the Company discontinued accruing AFUDC on a portion of its investment in Nine Mile Two for which a cash return was allowed. Amounts were accumulated in deferred debit and credit accounts equal to the amount of AFUDC which was no longer accrued. The balance in the deferred credit account was intended to reduce future cash revenue requirements over a period substantially shorter than the life of Nine Mile Two, and the balance in the deferred debit account would then be collected from customers over a longer period of time. The current balances of $19.2 million are expected to remain on the Company's books for future application by the PSC as a rate moderator.

Federal Income Tax.

For income tax purposes, depreciation is generally computed using the most liberal methods permitted. The resulting tax reductions are offset by provisions for deferred income taxes only to the extent ordered or permitted by regulatory authorities.

Statement of Financial Accounting Standards (SFAS) 109, Accounting for Income Taxes, was adopted by the Company during the first quarter of 1993. SFAS-109 requires that a deferred tax liability must be recognized on the balance sheet for tax differences previously flowed through to customers. Substantially all of these flow-through adjustments relate to property plant and equipment and related investment tax credits and will be amortized

consistent with the depreciation of these accounts. The net amount of the additional liability at December 31, 1993 was $241 million. In conjunction with the recognition of this liability, a corresponding regulatory asset was also recognized.

SFAS-109 also requires that a deferred tax liability or asset be adjusted in the period of enactment for the effect of changes in tax laws or rates. During the year the statutory income tax rate was increased one percent to 35%. This resulted in increases of $.6 million and $1.3 million for current and deferred tax liabilities, respectively. There was no earnings impact since the effects of the tax change have been deferred for future recovery.

The Company uses the separate-period approach in calculating the interim quarterly tax provision.

Retirement Health Care and Life Insurance Benefits.

The Company provides certain health care and life insurance benefits for retired employees and health care coverage for surviving spouses of retirees. Substantially all of the Company's employees may become eligible for these benefits if they reach retirement age while working for the Company. These and similar benefits for active employees are provided through insurance policies whose premiums are based upon the experience of benefits actually paid.

In December 1990, the FASB issued SFAS-106 entitled "Accounting for Postretirement Benefits Other than Pensions" effective for fiscal years beginning after December 15, 1992. Among other things, SFAS-106 requires accrual accounting by employers for postretirement benefits other than pensions reflecting currently earned benefits. The Company adopted this accounting practice in 1992.

In September 1993, the PSC issued a "Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other than Pensions". The Statement's provisions require, among other things, ten-year amortization of actuarial gains and losses and deferral of differences between actual costs and rate allowances. The effects of applying the ten year amortization of actuarial gains were deferred.

Postemployment Benefits.

In November 1992, the FASB issued SFAS-112 entitled "Employees' Accounting for Postemployment Benefits" which is effective for fiscal years beginning after December 15, 1993. This Statement requires the Company to recognize the obligation to provide post-employment benefits to former or inactive employees after employment but before retirement. The Company must adopt SFAS-112 not later than the first quarter of 1994. The Company is currently evaluating the impact of SFAS-112; however, based on studies the Company has performed to date, the adoption of SFAS-112 is not expected to have a material effect on the Company's financial condition or results of operations.

Earnings Per Share.

Earnings applicable to each share of common stock are based on the weighted average number of shares outstanding during the respective years.

Note 2. Federal Income Taxes

The provision for Federal income taxes is distributed between operating expense and other income based upon the treatment of the various components of the provision in the rate-making process. The following is a summary of income tax expense for the three most recent years.

(Thousands of Dollars)	1993	1992	1991
Charged to operating expense:			
Current	$33,453	$36,101	$28,766
Deferred	15,877	7,490	5,493
Total	49,330	43,591	34,259
Charged (Credited) to other income:			
Current	(9,182)	(7,171)	(8,211)
Deferred	(645)	2,976	3,631
Total	(9,827)	(4,195)	(4,580)
Total Federal income tax expense	$39,503	$39,396	$29,679

The following is a reconciliation of the difference between the amount of Federal income tax expense reported in the Statement of Income and the amount computed by multiplying the income by the statutory tax rate.

(Thousands of Dollars)	1993		1992		1991	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
Net Income	$ 78,563		$ 70,439		$57,997	
Add: Federal income tax expense	39,503		39,396		29,679	
Income before Federal income tax	$118,066		$109,835		$87,676	
Computed tax expense	$ 41,323	35.0	$ 37,344	34.0	$29,810	34.0
Increases (decreases) in tax resulting from:						
Difference between tax depreciation and amount deferred	6,337	5.4	6,775	6.2	5,606	6.4
Investment tax credit	(2,432)	(2.1)	(2,426)	(2.2)	(2,432)	(2.8)
Miscellaneous items, net	(5,725)	(4.8)	(2,297)	(2.1)	(3,305)	(3.7)
Total Federal income tax expense	$ 39,503	33.5	$ 39,396	35.9	$29,679	33.9

A summary of the components of the net deferred tax liability is as follows:

(Thousands of Dollars)	1993	1992
Nuclear decommissioning	$(11,518)	$(13,087)
Nine Mile disallowance	(15,200)	(19,569)
Alternative minimum tax	(27,908)	(27,611)
Accelerated depreciation	164,821	174,237
Investment tax credit	34,305	55,206
Ice storm	5,642	6,519
Depreciation and ITC previously flowed through	246,127	—
Other	29,379	(4,022)
Total	$425,648	$171,673

In 1993, the regulatory asset recognized by the Company as a result of adopting SFAS No. 109 is attributed to $222 million in depreciation, $18 million to property taxes, $18 million of deferred finance charges—Nine Mile Two and $4 million of miscellaneous items offset by $21 million attributed to investment tax credits.

Note 3. Pension Plan and Other Retirement Benefits

The Company has a defined benefit pension plan covering substantially all of its employees. The benefits are based on years of service and the employee's compensation during the last three years of employment. The Company's funding policy is to contribute annually an amount consistent with the requirements of the Employee Retirement Income Security Act and the Internal Revenue Code. These contributions are intended to provide for benefits attributed to service to date and for those expected to be earned in the future.

The plan's funded status and amounts recognized on the Company's balance sheet are as follows:

(Millions)	1993	1992
Accumulated benefit obligation, including vested benefits of $286.1 in 1993 and $249.6 in 1992	$(309.3)*	$(268.1)*
Projected benefit obligation for service rendered to date	$(429.5)*	$(378.0)*
Less—Plan assets at fair value, primarily listed stocks and bonds	490.3	449.9
Plan assets in excess of projected benefits	60.8	71.9
Unrecognized net loss (gain) from past experience different from that assumed and effects of changes in assumptions	(110.6)	(102.4)
Prior service cost not yet recognized in net periodic pension cost	13.7	5.4
Unrecognized net obligation at December 31	4.2	4.8
Pension costs accrued	$ (31.9)**	$(20.3)

*Actuarial present value
**Includes $9.2 million pension plan curtailment charge.

Net pension cost included the following components:

(Millions)	1993	1992	1991
Service cost—benefits earned during the period	$ 8.7	$ 8.8	$ 7.1
Interest cost on projected benefit obligation	30.0	27.9	26.4
Actual return on plan assets	(60.2)	(35.1)	(58.6)
Net amortization and deferral	24.3	5.5	33.1
Net periodic pension cost	$ 2.8	$ 7.1	$ 8.0

The projected benefit obligation at December 31, 1993 and 1992 assumed discount rates of 7¼ percent and 7¾ percent, respectively and long-term rate of increase in future compensation levels of 6 percent and 6½ percent, respectively. The assumed long-term rate of return on plan assets for 1993 and 1992 was 8½ percent. The unrecognized net obligation is being amortized over 15 years beginning January 1986.

In September 1993, the PSC issued a "Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other than Pensions" (Statement). The 1993 pension cost reflects adoption of the Statement's provisions which, among other things, requires ten-year amortization of actuarial gains and losses and deferral of differences between actual costs and rate allowances.

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits to retired employees and health care coverage for surviving spouses of retirees. Substantially all of the Company's employees are eligible provided that they retire as employees of the Company. In 1993, the health care benefit consisted of a contribution of up to $175 per month towards the cost of a group health policy provided by the Company. The life insurance benefit consists of a Basic Group Life benefit, covering substantially all employees, providing a death benefit equal to one-half of the retiree's final pay. In addition, certain employees and retirees, employed by the Company at December 31, 1982, are entitled to a Special Group Life benefit providing a death benefit equal to the employee's December 31, 1982 pay.

(Note 3 continued on page 42)

(continued from page 41)

The Company adopted SFAS-106, "Accounting for Postretirement Benefits Other than Pensions" as of January 1, 1992 for financial accounting purposes. Subsequently, with the issuance of the Statement referenced above, the Company's application of SFAS-106 will extend to ratemaking purposes as well. The Company has elected to amortize the unrecognized, unfunded Accumulated Postretirement Benefit Obligation at January 1, 1992 over twenty years as provided by SFAS-106. The Company intends to continue funding these benefits on a pay-as-you-go basis.

The plans' funded status reconciled with the Company's balance sheet is as follows:

(Millions)	1993	1992
Accumulated postretirement benefit obligation:		
Retired employees	$(39.9)	$(35.3)
Active employees	(24.9)	(23.6)
	$(64.8)	$(58.9)
Less—Plan assets at fair value	0.0	0.0
Accumulated postretirement benefit obligation (in excess of) less than fair value of assets	(64.8)	(58.9)
Unrecognized net loss (gain) from past experience different from that assumed and effects of changes in assumptions	2.9	0.0
Prior service cost not yet recognized in net periodic pension cost	1.7	0.0
Unrecognized net obligation at December 31	50.7	53.6
Accrued postretirement benefit cost	$ (9.5)	$ (5.3)

Net periodic postretirement benefit cost included the following components:

(Millions)	1993	1992
Service cost—benefits attributed to the period	$ 0.7	$ 0.7
Interest cost on accumulated postretirement benefit obligation	4.6	4.3
Actual return on plan assets	0.0	0.0
Net amortization and deferral	2.2	2.8
Net periodic postretirement benefit cost	$ 7.5	$ 7.8

The Accumulated Postretirement Benefit Obligation at December 31, 1993 and 1992 assumed discount rates of 7¼ percent and 7¾ percent, respectively and long-term rate of increase in future compensation levels of 6 percent and 6½ percent, respectively.

Note 4. Departmental Financial Information

The Company's records are maintained by operating departments, in accordance with PSC accounting policies, giving effect to the ratemaking process. The following is the operating data for each of the Company's departments, and no interdepartmental adjustments are required to arrive at the operating data included in the Statement of Income.

(Thousands of Dollars)	1993	1992	1991
Electric			
Operating Information			
Operating revenues	$ 655,316	$ 633,808	$ 617,542
Operating expenses, excluding provision for income taxes	486,951	482,968	478,101
Pretax operating income	168,365	150,840	139,441
Provision for income taxes	43,845	38,046	31,390
Net operating income	$ 124,520	$ 112,794	$ 108,051
Other Information			
Depreciation and amortization	$ 72,326	$ 73,213	$ 72,746
Nuclear fuel amortization	$ 18,861	$ 18,803	$ 23,606
Capital expenditures	$ 112,022	$ 100,974	$ 97,294
Investment Information			
Identifiable assets (a)	$1,978,009	$1,671,492	$1,607,210
Gas			
Operating Information			
Operating revenues	$293,708	$261,724	$ 235,728
Operating expenses, excluding provision for income taxes	265,510	235,029	216,151
Pretax operating income	28,198	26,695	19,577
Provision for income taxes	5,485	5,545	2,869
Net operating income	$ 22,713	$ 21,150	$ 16,708
Other Information			
Depreciation and amortization	$ 11,851	$ 11,815	$ 11,435
Capital expenditures	$ 27,385	$ 24,231	$ 26,763
Investment Information			
Identifiable assets (a)	$491,563	$354,528	$ 325,451

(a) Excludes cash, unamortized debt expense and other common items.

Note 5. Jointly-Owned Facilities

The following table sets forth the jointly-owned electric generating facilities in which the Company is participating. Both Oswego Unit No. 6 and Nine Mile Point Nuclear Plant Unit No. 2 have been constructed and are operated by Niagara Mohawk Power Corporation. Each participant must provide its own financing for any additions to the facilities. The Company's share of direct expenses associated with these two units is included in the appropriate operating expenses in the Statement of Income. Various modifications will be made throughout the lives of these plants to increase operating efficiency or reliability, and to satisfy changing environmental and safety regulations.

	Oswego Unit No. 6	Nine Mile Point Nuclear Unit No. 2
Net megawatt capacity	850	1,080
RG&E's share—megawatts	204	151
—percent	24	14
Year of completion	1980	1988
	Millions of Dollars at December 31, 1993	
Plant In Service Balance	$97.7	$869.8
Accumulated Provision For Depreciation	$32.0	$441.1
Plant Under Construction	$ 0.5	$ 12.4

The Plant in Service and Accumulated Provision for Depreciation balances for Nine Mile Point Nuclear Unit No. 2 shown above have been increased by the disallowed costs of $374.3 million. Such costs, net of income tax effects, were previously written off in 1987 and 1989.

Note 6. Long Term Debt

First Mortgage Bonds

%	Series	Due	(Thousands) Principal Amount December 31 1993	1992
4⅝	U	Sept. 15, 1994	$ 16,000	$ 16,000
5.30	V	May 1, 1996	18,000	18,000
6¼	W	Sept. 15, 1997	20,000	20,000
6.7	X	July 1, 1998	30,000	30,000
8.00	Y	Aug. 15, 1999	30,000	30,000
9⅛	Z	Sept. 1, 2000	—	30,000
9¼	BB	June 15, 2006	—	50,000
8⅜	CC	Sept. 15, 2007	50,000	50,000
9½	DD	Dec. 1, 2003	—	40,000
6½	EE (a)	Aug. 1, 2009	10,000	10,000
10.95	FF	Feb. 15, 2005	2,750	5,500
13⅞	JJ	June 15, 1999	15,000	17,500
8.6	LL	Aug. 1, 1993	—	75,000
8⅜	OO (a)	Dec. 1, 2028	25,500	25,500
9⅜	PP	Apr. 1, 2021	100,000	100,000
8¼	QQ (b)	Mar. 15, 2002	100,000	100,000
6.35	RR (a)	May 15, 2032	10,500	10,500
6.50	SS (a)	May 15, 2032	50,000	50,000
7.00	(b) (c)	Jan. 14, 2000	30,000	—
7.15	(b) (c)	Feb. 10, 2003	39,000	—
7.13	(b) (c)	Mar. 3, 2003	1,000	—
7.64	(c)	Mar. 15, 2023	33,000	—
7.66	(c)	Mar. 15, 2023	5,000	—
7.67	(c)	Mar. 15, 2023	12,000	—
6.375	(b) (c)	July 30, 2003	40,000	—
7.45	(c)	July 30, 2023	40,000	—
			677,750	678,000
Net bond discount			(769)	(770)
Less: Due within one year			21,250	110,250
Total			$655,731	$566,980

(a) The Series EE, Series OO, Series RR and Series SS First Mortgage Bonds equal the principal amount of and provide for all payments of principal, premium and interest corresponding to the Pollution Control Revenue Bonds, Series A, Series C, and Pollution Control Refunding Revenue Bonds, Series 1992 A, Series 1992 B (Rochester Gas and Electric Corporation Projects), respectively, issued by the New York State Energy Research and Development Authority through a participation agreement with the Company. Payment of the principal of, and interest on the Series 1992 A and Series 1992 B Bonds are guaranteed under a Bond Insurance Policy by Municipal Bond Investors Assurance Corporation. The Series EE Bonds are subject to a mandatory sinking fund beginning August 1, 2000 and each August 1 thereafter. Nine annual deposits aggregating $3.2 million will be made to the sinking fund, with the balance of $6.8 million principal amount of the bonds becoming due August 1, 2009.

(b) The Series QQ First Mortgage Bonds and 7%, 7.15%, 7.13% and 6.375% medium-term notes described below are generally not redeemable prior to maturity.

(c) In 1993 the Company issued $200 million under a medium-term note program entitled "First Mortgage Bonds, Designated Secured Medium-Term Notes, Series A" with maturites that range from seven years to thirty years.

The First Mortgage provides security for the bonds through a first lien on substantially all the property owned by the Company (except cash and accounts receivable).

Sinking and improvement fund requirements aggregate $333,540 per annum under the First Mortgage, excluding mandatory sinking funds of individual series. Such requirements may be met by certification of additional property or by depositing cash with the Trustee. The 1992 and 1993 requirements were met by certification of additional property.

Sinking fund requirements and bond maturities for the next five years are:

(Thousands)	1994	1995	1996	1997	1998
Series FF (d)	$ 2,750				
Series JJ (e)	2,500	$2,500	$ 2,500	$ 2,500	$ 2,500
Series U	16,000				
Series V			18,000		
Series W				20,000	
Series X					30,000
	$21,250	$2,500	$20,500	$22,500	$32,500

(d) The Series FF First Mortgage Bonds are subject to a mandatory sinking fund of $2.75 million annually each February 15.

(e) The Series JJ First Mortgage Bonds are subject to a mandatory sinking fund of $2.5 million annually each June 15.

Promissory Notes

		(Thousands) December 31	
Issued	Due	1993	1992
November 15, 1984 (f)	October 1, 2014	$51,700	$51,700
December 5, 1985 (g)	November 15, 2015	40,200	40,200
Total		$91,900	$91,900

(f) The $51.7 million Promissory Note was issued in connection with NYSERDA's Floating Rate Monthly Demand Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), Series 1984. This obligation is supported by an irrevocable Letter of Credit expiring October 15, 1994. The interest rate on this note for each monthly interest payment period will be based on the evaluation of the yields of short term tax-exempt securities at par having the same credit rating as said Series 1984 Bonds. The average interest rate was 2.19% for 1993, 2.74% for 1992 and 4.32% for 1991. The interest rate will be adjusted monthly unless converted to a fixed rate.

(g) The $40.2 million Promissory Note was issued in connection with NYSERDA's Adjustable Rate Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), Series 1985. This obligation is supported by an irrevocable Letter of Credit expiring November 30, 1996. The annual interest rate was adjusted to 4.50% effective November 15, 1991, to 3.10% effective November 15, 1992 and to 2.75% effective November 15, 1993. The interest rate will be adjusted annually unless converted to a fixed rate.

The Company is obligated to make payments of principal, premium and interest on each Promissory Note which correspond to the payments of principal, premium, if any, and interest on certain Pollution Control Revenue Bonds issued by the New York State Energy Research and Development Authority (NYSERDA) as described above. These obligations are supported by certain Bank Letters of Credit discussed above. Any amounts advanced under such Letters of Credit must be repaid, with interest, by the Company.

Based on an estimated borrowing rate at year-end 1993 of 6.68% for long term debt with similar terms and average maturities (14 years), the fair value of the Company's long term debt outstanding (including Promissory Notes as described above) is approximately $816 million at December 31, 1993.

Note 7. Preferred and Preference Stock

Type, by Order of Seniority	Par Value	Shares Authorized	Shares Outstanding
Preferred Stock (cumulative)	$100	2,000,000	1,150,000*
Preferred Stock (cumulative)	25	4,000,000	—
Preference Stock	1	5,000,000	—

*See below for mandatory redemption requirements

No shares of preferred or preference stock are reserved for employees, or for options, warrants, conversions, or other rights.

A. Preferred Stock, not subject to mandatory redemption:

%	Series	Shares Outstanding December 31, 1993	(Thousands) December 31 1993	1992	Optional Redemption (per share)#
4	F	120,000	$12,000	$12,000	$105
4.10	H	80,000	8,000	8,000	101
4¾	I	60,000	6,000	6,000	101
4.10	J	50,000	5,000	5,000	102.5
4.95	K	60,000	6,000	6,000	102
4.55	M	100,000	10,000	10,000	101
7.50	N	200,000	20,000	20,000	102
Total		670,000	$67,000	$67,000	

#May be redeemed at any time at the option of the Company on 30 days minimum notice, plus accrued dividends in all cases

B. Preferred Stock, subject to mandatory redemption:

%	Series	Shares Outstanding December 31, 1993	(Thousands) December 31 1993	1992	Optional Redemption (per share)
8.25	R	180,000	$18,000	$30,000	$102.00 Before 3/1/94+
7.45	S	100,000	10,000	10,000	Not applicable
7.55	T	100,000	10,000	10,000	Not applicable
7.65	U	100,000	10,000	10,000	Not applicable
		480,000	$48,000	$60,000	
Less: Due within one year		60,000	6,000	6,000**	
Total		420,000	$42,000	$54,000	

+Thereafter at $100.00
**Excludes $6 million optional redemption effective March 1, 1993

Mandatory Redemption Provisions.

In the event the Company should be in arrears in the sinking fund requirement, the Company may not redeem or pay dividends on any stock subordinate to the Preferred Stock.

Series R. Mandatory redemption of 60,000 shares per year at $100 per share commenced on March 1, 1993 for Series R and on each March 1 thereafter, so long as any shares remain outstanding. In addition, the Company has the non-cumulative right to redeem up to an additional 60,000 shares on the same terms and dates applicable to the mandatory sinking fund redemptions. The Company redeemed 120,000 shares on March 1, 1993 and the Company has the right to redeem up to the remaining 180,000 shares on March 1, 1994.

Series S, Series T, Series U. All of the shares are subject to redemption pursuant to mandatory sinking funds on September 1, 1997 in the case of Series S, September 1, 1998 in the case of Series T and September 1, 1999 in the case of Series U; in each case at $100 per share.

Based on an estimated dividend rate at year-end 1993 of 5.25% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (3.25 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $53 million at December 31, 1993.

Note 8. Common Stock

At December 31, 1993, there were 50,000,000 shares of $5 par value Common Stock authorized, of which 36,911,265 were outstanding. No shares of Common Stock are reserved for options, warrants, conversions, or other rights. There were 1,193,613 shares of Common Stock reserved and unissued for shareholders under the Automatic Dividend Reinvestment and Stock Purchase Plan and 253,090 shares reserved and unissued for employees under the RG&E Savings Plus Plan.

Common Stock

	Per Share	Shares Outstanding	Amount (Thousands)
Balance, January 1, 1991		31,421,268	$516,388
Automatic Dividend Reinvestment and Stock Purchase Plan	$18.750–$23.163	571,669	11,252
Savings Plus Plan	$19.375–$23.563	108,202	2,194
Capital Stock Expense			(495)
Balance, December 31, 1991		32,101,139	$529,339
Sale of Stock	$24.000	2,000,000	48,000
Automatic Dividend Reinvestment and Stock Purchase Plan	$21.325–$24.850	584,854	13,338
Savings Plus Plan	$22.063–$25.188	110,666	2,590
Capital Stock Expense			(1,735)
Balance, December 31, 1992		34,796,659	$591,532
Sale of Stock	$29.625	1,500,000	44,438
Automatic Dividend Reinvestment and Stock Purchase Plan	$25.475–$29.413	515,036	14,076
Savings Plus Plan	$25.813–$29.250	99,570	2,741
Capital Stock Expense			(615)
Balance, December 31, 1993		36,911,265	$652,172

Note 9. Short Term Debt

At December 31, 1993 and December 31, 1992, the Company had short term debt outstanding of $68.1 million and $50.8 million, respectively. The weighted average interest rate on short term debt outstanding at year end 1993 was 3.46% and was 3.48% for borrowings during the year. For 1992, the weighted average interest rate on short term debt outstanding at year end was 3.99% and was 4.28% for borrowings during the year.

On December 1, 1988 the Company renewed its $90 million revolving credit facility for a period of three years and this agreement has been regularly extended. In November of 1993 the Company was granted a one-year extension of the commitment termination date to December 31, 1996. Commitment fees related to this facility amounted to $169,000 in 1993, $169,000 in 1992 and $149,000 in 1991.

The Company's Charter provides that unsecured debt may not exceed 15 percent of the Company's total capitalization (excluding unsecured debt). As of December 31, 1993, the Company would be able to incur $19.2 million of additional unsecured debt under this provision. In order to be able to use its revolving credit agreement, the Company has created a subordinate mortgage which secures borrowings under its revolving credit agreement that might otherwise be restricted by this provision of the Company's Charter.

Since June 1990 the Company has had a credit agreement with a domestic bank providing for up to $20 million of short term debt. Borrowings under this agreement, which has been extended to December 31, 1994, are secured by the Company's accounts receivable.

Also, additional unsecured short term borrowing capacity of up to $70 million is available from domestic banks, at their discretion.

Note 10. Commitments and Other Matters

Capital Expenditures.

The Company's 1994 construction expenditures program is currently estimated at $138 million, including $16 million related to replacement of the steam generators at the Ginna Nuclear Plant and $2 million of Allowance for Funds Used During Construction. The Company has entered into certain commitments for purchase of materials and equipment in connection with that program.

Nuclear-Related Matters.

Decommissioning Trust. Under accounting procedures approved by the PSC, the Company has been collecting in its electric rates amounts for the eventual decommissioning of its Ginna Plant and for its 14% share of the decommissioning of Nine Mile Two. The operating licenses for these plants expire in 2009 and 2026, respectively. The Company has collected approximately $61.2 million through December 31, 1993.

The Nuclear Regulatory Commission (NRC) requires reactor licensees to submit funding plans that establish minimum external funding levels for reactor decommissioning. The Company's plan consists principally of an external decommissioning trust fund covering both its Ginna Plant and its Nine Mile Two share. Since 1990, the Company has contributed some $36.9 million to this fund. In addition, the Company maintains an internal reserve to fund the removal of non-radioactive structures, a feature not covered by the NRC minimum funding.

In connection with the Company's rate settlement completed in August 1993, the PSC approved the collection during the rate year ending June 30, 1994 of an aggregate $8.9 million for decommissioning, covering both nuclear units. The amount allowed in rates is based on estimated ultimate decommissioning costs of $150.7 million for Ginna and $34.3 million for the Company's 14% share of Nine Mile Two (January 1993 dollars). This estimate is based principally on the application of a NRC formula to determine minimum funding. Site-specific studies of the anticipated costs of actual decommissioning are required to be submitted to the NRC at least five years prior to the expiration of the license. The Company intends to fund the external decommissioning trust in the amount of the NRC minimum funding requirement. The difference between the amount to be collected and the NRC minimum will be held in an internal reserve.

The Company is aware of recent NRC activities related to upward revisions to the required minimum funding levels. These activities, primarily focused on disposition of low level radioactive waste, may require the Company to increase funding. The Company continues to monitor these activities but cannot predict what regulatory actions the NRC may ultimately take.

Uranium Enrichment Decontamination and Decommissioning Fund. Nuclear reactor licensees in the U.S. are assessed annually for the decontamination and decommissioning of Department of Energy (DOE) enrichment facilities. The Company made the first of 15 annual payments for this purpose in September 1993, remitting approximately $1.6 million ($1.5 million for the Ginna Plant and $0.1 million for its share of the Nine Mile Two plant). For the two facilities the Company recognized liabilities at December 31, 1993 of $23.4 million ($21.7 million as a long-term liability and $1.7 million as a current liability). In October 1993, the Company began recovery of this deferral through its fuel adjustment clause.

Insurance Program. The Price-Anderson Act establishes a federal program, providing indemnification and insurance against public liability, applicable in the event of a nuclear accident at a licensed U.S. reactor. As a result of amendments to the Act in 1988, the limit of liability has increased to approximately $9.4 billion. Also in 1988 coverage was expanded to include precautionary evacuations and the Act was extended until the year 2002. Under the program, claims would first be met by insurance which licensees are required to carry in the maximum amount available (currently $200 million). If claims exceed that amount, licensees are subject to a retrospective assessment up to $75.5 million per licensed facility for each nuclear incident, payable at a rate not to exceed $10 million per year. Those assessments are subject to periodic inflation-indexing and to a 5% surcharge if funds prove insufficient to pay claims. In addition, the retrospective assessments would be subject to a three percent charge for premium tax. The Company's interests in two nuclear units could thus expose it to a potential liability for each accident of $86.1 million through retrospective assessments of $11.4 million per year in the event of a sufficiently serious nuclear accident at its own or another U.S. commercial nuclear reactor.

Beginning in 1988, coverage for claims alleging radiation-induced injuries to some workers at nuclear reactor sites was removed from the nuclear liability insurance policies purchased by the

Company. Coverage for workers first engaged in nuclear-related employment at a nuclear site prior to 1988 continues to be provided under then-existing nuclear liability insurance policies. Those workers first employed at a nuclear facility in 1988 or later are covered under a separate, industry-wide insurance program. That program contains a retrospective premium assessment feature whereby participants in the program can be assessed to pay incurred losses that exceed the program's reserves. Under the plan as currently established, the Company could be assessed a maximum of $3.1 million over the life of the insurance coverage.

The Company is a member of Nuclear Electric Insurance Limited, which provides insurance coverage for the cost of replacement power during certain prolonged accidental outages of nuclear generating units and coverage for property losses in excess of $500 million at nuclear generating units. As of December 31, 1993, the Company is purchasing a weekly indemnity limit of $3.5 million in the NEIL I replacement power expense program and full policy limits of $1.4 billion in the NEIL II Property Insurance Program for the Ginna Nuclear Power Plant. Coverage under the Property Insurance Program includes the shortfall in the NRC required external trust fund resulting from the premature decommissioning of a nuclear power plant following an accident with property damage in excess of $500 million. The Company currently has designated $166 million as a sublimit for this coverage at the Ginna Nuclear Power Plant. For its share in the generation of Nine Mile Two the Company purchases a weekly indemnity limit of $.5 million in the NEIL I replacement power expense program. The owners at Nine Mile Two purchase the full policy limit of $1.4 billion in the NEIL II Property Insurance Program and the Company pays its proportionate share of those premiums. The owners at Nine Mile Two have selected the maximum available sublimit of $250 million for premature decommissioning. If an insuring program's losses exceeded its other resources available to pay claims, the Company could be subject to maximum assessments in any one policy year of approximately $4.9 million and $14.9 million in the event of losses under the replacement power and property damage coverages, respectively.

Environmental Matters.

The production and delivery of energy are necessarily accompanied by the release of by-products subject to environmental controls. In recognition of the Company's responsibility to preserve the quality of the air, water, and land it shares with the community it serves, the Company has taken a variety of measures (e.g., self-auditing, recycling and waste minimization, training of employees in hazardous waste management) to reduce the potential for adverse environmental effects from its energy operations and, specifically, to manage and appropriately dispose of wastes currently being generated. The Company, nevertheless, has been contacted, along with numerous others, concerning wastes shipped off-site to licensed treatment, storage and disposal sites where authorities have later questioned the handling of such wastes. In such instances, the Company typically seeks to cooperate with those authorities and with other site users to develop cleanup programs and to fairly allocate the associated costs.

As part of its commitment to environmental excellence, the Company is conducting proactive Site Investigation and Remediation (SIR) efforts at Company-owned sites where past waste handling and disposal may have occurred. The Company currently estimates the total costs it could incur for SIR activities at Company-owned sites to be about $20 million. This estimate will vary as better site information is available. The Company anticipates spending $10 million over the next 5 years on SIR initiatives. Approximately $4.5 million has been provided for in rates through June 1996 for recovery of SIR costs. To the extent actual expenditures differ from this amount, they will be deferred for future disposition and recovery as authorized by the PSC.

In 1985, the New York State Department of Environmental Conservation (NYSDEC) identified property in the vicinity of the Lower Falls of the Genesee River (the Lower Falls) in Rochester as an inactive hazardous waste disposal site. The Company owns, and was the prior owner or operator of, a number of locations within the Lower Falls. In mid-1991, NYSDEC advised the Company that it had delisted the Lower Falls site, i.e., removed it from its Registry of Inactive Hazardous Waste Disposal Sites. The effect of delisting is to terminate the Company's status as a potentially responsible party for the Lower Falls site, to discontinue the pending NYSDEC review of a joint Company/City of Rochester proposal for a limited further investigation of the Lower Falls, to defer the prospect of remedial action and perhaps to end any Company sharing of the cost thereof. However, NYSDEC also stated its intention to consider listing individual coal gasification sites within the larger, original site once the State of New York adopts new federal hazardous waste

(Note 10 continued on page 50)

(continued from page 49)

criteria. There is at least some material at one of the individual coal gasification sites that could trigger relisting. The Company is unable to predict what further listing action NYSDEC may take, but regards the delisting as a positive development.

The Company and its predecessors formerly owned and operated coal gasification facilities within the Lower Falls. In September 1991 the Company initiated a study of subsurface conditions in the vicinity of retired facilities at its West Station property and has since commenced the removal of soils containing hazardous substances in order to minimize any potential long-term exposure risks. Cleanup efforts have been temporarily suspended while the Company investigates more cost effective remedial technologies. Activities are expected to resume within a year.

On a portion of the Company's property in the Lower Falls, and elsewhere in the general area, the County of Monroe has installed and operates sewer lines. During sewer installation, the County constructed over Company property, pursuant to an easement which the Company granted the County, certain retention ponds which reportedly received from the sewer construction area certain fossil-fuel-based materials ("the materials") found there. In July 1989 the Company received a letter from the County asserting that activities of the Company left the County unable to effect a regulatorily-approved closure of the retention pond area. The County's letter takes the position that it intends to seek reimbursement for its additional costs incurred with respect to the materials once the NYSDEC identifies the generator thereof and that any further cleanup action which the NYSDEC may require at the retention pond site is the Company's responsibility. In the course of discussions over this matter, the County has claimed, without offering any evidence, that the Company was the original generator of the materials. It asserts that it will hold the Company liable for all County costs—presently estimated at $1.5 million—associated both with the materials' excavation, treatment and disposal and with effecting a regulatorily-approved closure of the retention pond area. The Company could incur costs as yet undetermined if it were to be found liable for such closure and materials handling, although provisions of the easement afford the Company rights which may serve to offset all or a portion of any such County claim. To date, the Company has agreed to pay a 20% share of the County's investigation of this area, which commenced in September 1993 and which is estimated to cost no more than $150,000, but no commitment has been made toward any remedial measures which may be recommended by the investigation.

In the letter announcing the delisting of the Lower Falls site, NYSDEC indicated an intention to pursue appropriate closure of the County's former retention pond area, suggesting that it will be evaluated separately to determine whether it meets the criteria of a hazardous waste site. The Company is unable to assess what implications the NYSDEC letter may have for the County's claim against it.

At another location along the River where the Company owns property, a boring taken in Fall 1988 for a sewer system project showed a layer containing a black viscous material. The Company undertook an investigation to determine the extent of the layer. The study found that some of the soil and ground water on-site had been adversely impacted by the hazardous substance constituents of the black viscous material, but evidence was inadequate to determine whether the material or its constituents had migrated off-site. The matter was reported to the NYSDEC and, in September 1990, the Company also provided the agency with a risk assessment for its review. That assessment concluded that the findings warranted no agency action and that site conditions posed no significant threat to the environment. Although NYSDEC could require the Company to undertake further investigation and/or remediation, the agency has taken no action in the nearly three and one-half years since the report's submittal.

In August 1990 the Company was notified of the existence of a federal Superfund site located in Syracuse, NY, known as the Quanta Resources Site. The federal Environmental Protection Agency (EPA) has included the Company in its list of approximately 25 potentially responsible parties (PRPs) at the site, but no data has been produced showing that any of its wastes were delivered to the site. In return for its release from liability for that phase, the Company has joined other PRPs in agreeing to divide among them, utilizing a two-tier structure, EPA's cost of a contractor-performed removal action intended to stabilize the site. The Company, in the lower tier of PRPs, paid its $27,500 share of such cost. The NYSDEC has not yet made an assessment for certain response and investigation costs it has incurred at the site, nor is there as yet any information on which to base an estimate of the cost to design and conduct at the site any remedial measures which federal or state authorities may require.

On May 21, 1993, the Company was notified by NYSDEC that it was considered a potentially responsible party (PRP) for the Frontier Chemical Pendleton Superfund Site located in Pendleton, NY. The Company has signed a PRP Agreement with approximately 15 parties and is participating in negotiations for an Administrative Order on Consent with NYSDEC. The PRPs have negotiated a workplan for site remediation and have retained a consulting firm to implement the workplan. Preliminary estimates indicate site remediation will be between $6 and $8 million. The Company is participating with the group to allocate costs among the PRPs. An allocation scheme has yet to be developed.

Monitoring wells installed at another Company facility in 1989 revealed that an undetermined amount of leaded gasoline had reached the groundwater. The Company has continued to monitor free product levels in the wells, and has begun a modest free product recovery project, reports on both of which are routinely furnished to the NYSDEC: Free product levels in the wells have declined, but authorities may require further remediation once most of the free product has been recovered.

The Company is developing strategies responsive to the Federal Clean Air Act Amendments of 1990 (Amendments). The Amendments will primarily affect air emissions from the Company's fossil-fueled electric generating facilities. The Company is in the process of identifying the optimum mix of control measures that will allow the fossil fuel based portion of the generation system to fully comply with applicable regulatory requirements. Although work is continuing, not all compliance control measures have been determined. The Company has adopted control measures for nitrogen oxides (NOx) emissions which must be in effect by the federally mandated compliance date of May 31, 1995. The chosen NOx control measures consist of the installation of low NOx burners on some units, the derating of unit generation by taking burners out of service on other units and placing one unit on cold standby with the redistribution of load to the remaining more efficient units. Capital costs for NOx controls and the installation of continuous emission monitoring systems are not expected to exceed $6.8 million and will be incurred during 1994 and 1995. A range of capital costs between $20 million and $30 million (1993 dollars) has been estimated for the implementation of several potential scenarios which would enable the Company to meet the foreseeable future NOx and sulphur dioxide requirements of the Amendments. These capital costs would be incurred between 1996 and 2000. The Company currently estimates that it could also incur up to $2 million (1993 dollars) of additional annual operating expenses, excluding fuel, to comply with the Amendments. The use of scrubbing equipment is not presently being considered. Likewise, the purchase or sale of "emission allowances," as allowed by the Amendments, is not currently being considered. The Company anticipates that the costs incurred to comply with the Amendments will be recoverable through rates based on previous rate recovery of environmental costs required by governmental authorities.

Gas Cost Recovery.

Many interstate gas pipeline companies entered into contracts with gas producers which required the pipeline companies to pay for a minimum amount of gas whether or not the gas is actually taken from the producer (take-or-pay costs). Pursuant to FERC authorization, the Company's gas suppliers have included certain amounts of their take-or-pay costs in the rates charged to the Company.

The PSC instituted a proceeding in October 1988 to determine the extent to which the gas distribution companies in New York State would be permitted to recover in rates the take-or-pay costs imposed upon them. Through a series of subsequent settlements between the Staff of the PSC and the Company, the Company was permitted to recover in rates 87.5% of the first $12 million of the pipeline take-or-pay costs imposed upon it and all such costs in excess thereof except for a maximum of $562,500.

As of December 31, 1993 the Company had been billed for $17.6 million of take-or-pay costs and has thus far recovered $16.4 million from its customers. The Company expects only insignificant amounts of take-or-pay costs remain to be billed to the Company.

As a result of the restructuring of the gas transportation industry by the FERC, there will be a number of changes in this aspect of the Company's business over the next several years. These changes, which will apply throughout the industry, will affect different companies differently and may result, at least initially, in increases in the gas transportation costs of the Company. The Company will also be required to pay a share of certain transition costs incurred by the pipelines as a result of the FERC restructuring. Although the final amounts of such transition costs are subject to continuing negotiations with several pipelines and ongoing pipeline filings requiring FERC

(Note 10 continued on page 52)

(continued from page 51)

approval, the Company expects such costs to range between $43.5 and $52.0 million. A substantial portion of such costs will be on the CNG Transmission Corporation (CNG) system of which approximately $27 million was billed to the Company on December 3, 1993 payable over the following three years. The Company expects these transition costs to be recoverable in its rates.

In a related matter, in connection with the development of the Empire State Pipeline ("Empire"), the Company is committed as of November 1993, to transportation capacity from Empire, to upstream pipeline transportation and storage service and to the purchase of natural gas in quantities corresponding to these transportation and storage arrangements. The Company also has certain contractual obligations with CNG whereby the Company is subject to demand charges for transportation capacity for a period of eight years. In October 1993, the effective date of implementation of pipeline restructuring pursuant to FERC Order No. 636 and CNG's individual restructuring in Docket No. RS92-14, CNG's transportation rights on upstream pipelines were assigned to its customers, including the Company. The Company has concluded the corresponding contracts with those upstream pipelines.

The transportation service to be provided by Empire was scheduled to phase in over 12 months, at which point the combined CNG and Empire transportation capacity would have exceeded the Company's current requirements. Therefore, the Company recently entered into a marketing agreement with CNG, pursuant to which CNG will assist the Company in obtaining permanent replacement customers for the transportation capacity the Company will not require. It may renegotiate its arrangements with CNG and/or Empire or it may negotiate assignment, on a permanent or temporary basis, of the transportation capacity that exceeds the requirements of its customers. In addition, under FERC rules, the Company may sell its excess transportation capacity in the market. While CNG has already secured letters of intent for a substantial portion of such capacity, whether and to what extent CNG and/or the Company can successfully negotiate the assignment or sale of the excess capacity, or at what price, cannot be determined at the present time. The retention of some or all of this excess transportation capacity may cause an increase in the Company's gas supply costs. This would be in addition to any increase caused by other aspects of the gas transportation restructuring.

Gas Purchase Undercharges.

The Company became aware during 1993 that it did not account properly for certain gas purchases for the period August 1990–August 1992 resulting in undercharges to gas customers of approximately $7.5 million. The Company had previously estimated the effect to approximate as much as $10 million; however, further review determined that the magnitude of the error on previously reported operations was substantially less.

The undercharges arose from the increased complexity arising from the federal deregulation of the gas industry and the Company's transition from a full requirements customer of one gas supplier to the purchase of gas transportation service and natural gas on the open market. Problems of this type are routinely corrected through the Gas Adjustment Clause process and appropriate amounts are collected from or refunded to customers. Of the total undercharges, $2.3 million has previously been expensed and $5.2 million had been deferred on the Company's balance sheet.

The Company advised the PSC and all parties to the Company's most recent rate proceeding of the undercharges. In its August 24, 1993 Order approving the Company's three-year rate settlement the PSC made the Company's current gas rates temporary solely to consider the impacts of the erroneous gas accounting, and in a September 13, 1993 Order the PSC instituted a proceeding to investigate the resulting undercollections and the recoverability of such amounts from customers. In its September 13 Order the PSC directed the Company to demonstrate fully the existence and amount of the undercharges, to explain the reasons for the errors, and to address possible general and specific legal limitations on the Company's right to recover portions of the undercharges. The Company filed evidence and analysis responsive to that Order on October 27, 1993.

On December 30, 1993, a proposed settlement among the Company, PSC Staff and another party was filed with the PSC. It provides for the recovery in rates of $3.2 million over three years, subject to audit and to limitations on rate adjustments established in the August 24 Order. The Company wrote off the $2.0 million balance of the undercharges as of December 31, 1993. That write-off amounts to a reduction in 1993 earnings of four cents per share, net of tax. Although no party, to the Company's knowledge, opposes the proposed settlement, the Company is unable to predict whether the PSC will approve it.

Other Matters.

Regulatory Disallowances. In June 1992 the Company recorded a charge to earnings of $8.2 million in connection with ice storm restoration costs disallowed by the PSC. In December 1991, the Company recorded a non-cash charge against earnings of $10 million for refunds to be made to customers in connection with a PSC fuel procurement audit.

Nuclear Fuel Enrichment Services. The Company has a contract with the United States Enrichment Corporation (USEC), formerly with the DOE, for nuclear fuel enrichment services which assures provision of 70% of the Ginna Nuclear Plant's requirements throughout its service life or 30 years, whichever is less. No payment obligation accrues unless such enrichment services are needed. Annually, the Company is permitted to decline USEC-furnished enrichment for a future year upon giving ten years' notice. Consistent with that provision, the Company has terminated its commitment to USEC for the years 2000, 2001 and 2002. The USEC waived, for an interim period, the obligation to give ten years' notice for 2003. The Company has secured the remaining 30% of its Ginna requirements for the reload years 1994 through 1995 under different arrangements with USEC. The Company plans to meet its enrichment requirements for years beyond those already committed by making further arrangements with USEC or by contracting with third parties. The cost of USEC enrichment services utilized for the next seven reload years (priced at the most current rate) ranges from $4 million to $7 million per year.

Assertion of Tax Liability. The Company's federal income tax returns for 1987 and 1988 have been examined by the Internal Revenue Service (IRS) which has proposed adjustments of approximately $29 million.

The adjustments at issue generally pertain to the characterization and treatment of events and relationships at the Nine Mile Two project and to the appropriate tax treatment of investments made and expenses incurred at the project by the Company and the other co-tenants. A principal issue appears to be the year in which the plant was placed in service.

The Company has filed a protest of the IRS adjustments to its 1987–88 tax liability and has had an initial hearing before the appeals officers. The Company believes it has sound bases for its protest, but cannot predict the outcome thereof. Generally, the Company would expect to receive rate relief to the extent it was unsuccessful in its protest except for that part of the IRS assessment stemming from the Nine Mile Two disallowed costs, although no such assurance can be given.

Report of Independent Accountants

Price Waterhouse

1900 Chase Square
Rochester, New York 14604-1984
January 14, 1994

To the Shareholders and Board of Directors of
Rochester Gas and Electric Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, retained earnings and cash flows present fairly, in all material respects, the financial position of Rochester Gas and Electric Corporation and its subsidiaries at December 31, 1993 and 1992, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1993 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 1 to the financial statements, the Company adopted the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" in 1993.

Price Waterhouse

Report of Management

The management of Rochester Gas and Electric Corporation has prepared and is responsible for the financial statements and related financial information contained in this Annual Report. Management uses its best judgements and estimates to ensure that the financial statements reflect fairly the financial position, results of operations and cash flows of the Company in accordance with generally accepted accounting principles. Management maintains a system of internal accounting controls over the preparation of its financial statements designed to provide reasonable assurance as to the integrity and reliability of the financial records.

This system of internal control includes documented policies and guidelines and periodic evaluation and testing by the internal audit department.

The Company's financial statements have been examined by Price Waterhouse, independent accountants, in accordance with generally accepted auditing standards. Their examination includes a review of the Company's system of internal accounting control and such tests and other procedures necessary to express an opinion as to whether the Company's financial statements are presented fairly in all material respects in conformity with generally accepted accounting principles. The report of Price Waterhouse is presented on page 53.

The Audit Committee of the Board of Directors is responsible for reviewing and monitoring the Company's financial reporting and accounting practices. The Audit Committee meets regularly with management and the independent accountants to review auditing, internal control and financial reporting matters. The independent accountants have direct access to the Audit Committee, without management present, to discuss the results of their examinations and their opinions on the adequacy of internal accounting controls and the quality of financial reporting.

Management believes that, at December 31, 1993, the Company maintained an effective system of internal control over the preparation of its published financial statements.

Roger W. Kober
Chairman of the Board, President and Chief Executive Officer

Thomas S. Richards
Senior Vice President, Finance and General Counsel

January 22, 1994

Interim Financial Data

In the opinion of the Company, the following quarterly information includes all adjustments, consisting of normal recurring adjustments, necessary for a fair statement of the results of operations for such periods. The variations in operations reported on a quarterly basis are a result of the seasonal nature of the Company's business and the availability of surplus electricity.

	(Thousands of Dollars)				
Quarter Ended	Operating Revenues	Operating Income	Net Income	Earnings on Common Stock	Earnings per Common Share (in dollars)
December 31, 1993*	$256,219	$43,756	$22,366	$20,541	$ .55
September 30, 1993**	217,278	38,058	20,204	18,379	.51
June 30, 1993	203,252	21,295	6,909	5,084	.15
March 31, 1993	272,275	44,124	29,084	27,259	.78
December 31, 1992	$244,290	$41,744	$29,146	$27,073	$ .77
September 30, 1992	198,341	33,006	17,507	15,435	.45
June 30, 1992***	195,154	16,460	(4,579)	(6,651)	(.20)
March 31, 1992	257,747	42,735	28,365	26,293	.81
December 31, 1991****	$229,331	$38,578	$14,911	$12,467	$ .38
September 30, 1991	195,629	31,752	17,262	15,756	.49
June 30, 1991	182,637	17,230	1,538	32	—
March 31, 1991	245,673	37,198	24,286	22,780	.72

*Includes recognition of $1.9 million net-of-tax pension plan curtailment.
**Includes recognition of $3.4 million net-of-tax pension plan curtailment.
***Includes recognition of $5.4 million net-of-tax ice storm disallowance.
****Includes recognition of $6.6 million net-of-tax fuels audit disallowance.

Common Stock and Dividends

Earnings/Dividends	1993	1992	1991
Earnings per weighted average share	$2.00	$1.86	$1.60
Dividends paid per share	$1.72	$1.68	$1.62

Shares/Shareholders	1993	1992	1991
Number of shares (000's)			
Weighted average	35,599	33,258	31,794
Actual number at December 31	36,911	34,797	32,101
Number of shareholders at December 31	38,102	39,017	39,157

Tax Status of Cash Dividends

Cash dividends paid in 1993, 1992 and 1991 were 100 percent taxable for Federal income tax purposes.

Dividend Policy

The Company has paid cash dividends quarterly on its Common Stock without interruption since it became publicly held in 1949. The level of future cash dividend payments will be dependent upon the Company's future earnings, its financial requirements and other factors. The Company's Certificate of Incorporation provides for the payment of dividends on Common Stock out of the surplus net profits (retained earnings) of the Company.

Quarterly dividends on Common Stock are generally paid on the twenty-fifth day of January, April, July and October. In January 1994, the Company paid a cash dividend of $.44 per share on its Common Stock, up $.01 from the prior quarterly dividend payment of $.43. The January 1994 dividend payment is equivalent to $1.76 on an annual basis.

Common Stock Trading

Shares of the Company's Common Stock are traded on the New York Stock Exchange under the symbol "RGS".

	1993	1992	1991
Common Stock—Price Range			
High			
1st quarter	28¾	23¼	20¾
2nd quarter	28	24	20½
3rd quarter	29¾	24¾	20⅞
4th quarter	29¼	25¼	23⅞
Low			
1st quarter	24⅛	20⅞	17¾
2nd quarter	25½	21¼	19
3rd quarter	27¾	22¾	19
4th quarter	24¾	23⅛	20⅞
At December 31	26¼	24½	23¼

Selected Financial Data

(Thousands of Dollars) Year Ended December 31	1993	1992	1991	1990	1989	1988
Consolidated Summary of Operations						
Operating Revenues						
Electric	$638,955	$608,267	$588,930	$551,930	$543,096	$514,637
Gas	293,708	261,724	235,728	236,496	264,573	231,217
	932,663	869,991	824,658	788,426	807,669	745,854
Electric sales to other utilities	16,361	25,541	28,612	42,465	38,028	29,966
Total Operating Revenues	949,024	895,532	853,270	830,891	845,697	775,820
Operating Expenses						
Fuel Expenses						
Electric fuels	45,871	48,376	65,105	76,420	75,873	65,787
Purchased electricity	31,563	29,706	27,683	34,264	39,645	30,299
Gas purchased for resale	166,884	141,291	129,779	132,512	152,623	129,596
Total Fuel Expenses	244,318	219,373	222,567	243,196	268,141	225,682
Operating Revenues Less Fuel Expenses	704,706	676,159	630,703	587,695	577,556	550,138
Other Operating Expenses						
Operations excluding fuel expenses	235,381	226,624	208,440	194,594	173,764	159,689
Maintenance	61,693	62,720	65,415	62,391	64,316	52,575
Depreciation and Amortization	84,177	85,028	84,181	77,767	75,063	69,703
Taxes—local, state and other	126,892	124,252	113,649	101,035	95,341	88,635
Federal income tax—current	33,453	36,101	28,766	20,661	20,509	20,363
—deferred	15,877	7,490	5,493	13,829	17,330	20,299
Total Other Operating Expenses	557,473	542,215	505,944	470,277	446,323	411,264
Operating Income	147,233	133,944	124,759	117,418	131,233	138,874
Other Income and Deductions						
Allowance for other funds used during construction	153	164	675	2,689	2,261	2,047
Federal income tax	9,827	4,195	4,580	2,459	1,439	1,683
Pension plan curtailment	(8,179)	—	—	—	—	—
Regulatory disallowances	(1,953)	(8,215)	(10,000)	—	(2,100)	—
Other, net	(7,074)	6,155	6,078	4,062	8,328	6,901
Total Other Income and (Deductions)	(7,226)	2,299	1,333	9,210	9,928	10,631
Income Before Interest Charges	140,007	136,243	126,092	126,628	141,161	149,505
Interest Charges						
Long term debt	56,451	60,810	63,918	64,873	68,628	72,270
Short term debt	1,487	1,950	2,623	1,070	—	—
Other, net	5,220	5,228	4,459	3,523	3,115	2,898
Allowance for borrowed funds used during construction	(1,714)	(2,184)	(2,905)	(2,719)	(2,026)	(1,777)
Total Interest Charges	61,444	65,804	68,095	66,747	69,717	73,391
Net Income	78,563	70,439	57,997	59,881	71,444	76,114
Dividends on Preferred Stock, at Required Rates	7,300	8,290	6,963	6,025	6,025	7,348
Earnings Applicable to Common Stock	$ 71,263	$ 62,149	$ 51,034	$ 53,856	$ 65,419	$ 68,766
Weighted Average Number of Shares Outstanding in Each Period (000's)	35,599	33,258	31,794	31,293	31,090	30,513
Earnings per Common Share	$2.00	$1.86	$1.60	$1.72	$2.10	$2.25
Cash Dividends Paid per Common Share	$1.72	$1.68	$1.62	$1.56	$1.50	$1.50

Condensed Consolidated Balance Sheet

(Thousands of Dollars) At December 31	1993	1992	1991	1990	1989	1988
Assets						
Utility Plant	$2,890,799	$2,798,581	$2,706,554	$2,310,294	$2,208,158	$2,122,922
Less: Accumulated depreciation and amortization	1,335,083	1,253,117	1,178,649	812,994	730,621	653,876
	1,555,716	1,545,464	1,527,905	1,497,300	1,477,537	1,469,046
Construction work in progress	112,750	83,834	76,848	82,663	68,784	41,044
Net utility plant	1,668,466	1,629,298	1,604,753	1,579,963	1,546,321	1,510,090
Current Assets	248,589	209,621	189,009	176,045	190,321	213,626
Investment in Empire	38,560	9,846	—	—	—	—
Deferred Debits	502,015	200,676	160,034	108,451	102,729	102,015
Total Assets	$2,457,630	$2,049,441	$1,953,796	$1,864,459	$1,839,371	$1,825,731
Capitalization and Liabilities						
Capitalization						
Long term debt	$ 747,631	$ 658,880	$ 672,322	$ 721,612	$ 764,627	$ 792,976
Preferred stock redeemable at option of Company	67,000	67,000	67,000	67,000	67,000	67,000
Preferred stock subject to mandatory redemption	42,000	54,000	60,000	30,000	30,000	30,000
Common shareholders' equity						
Common stock	652,172	591,532	529,339	516,388	513,560	504,907
Retained earnings	75,126	66,968	61,515	62,542	57,983	39,710
Total common shareholders' equity	727,298	658,500	590,854	578,930	571,543	544,617
Total Capitalization	1,583,929	1,438,380	1,390,176	1,397,542	1,433,170	1,434,593
Long Term Liabilities (Department of Energy)	89,804	94,602	63,626	59,989	55,502	51,016
Current Liabilities	234,530	267,276	267,601	183,720	137,899	126,661
Deferred Credits and Other Liabilities	549,367	249,183	232,393	223,208	212,800	213,461
Total Capitalization and Liabilities	$2,457,630	$2,049,441	$1,953,796	$1,864,459	$1,839,371	$1,825,731

Financial Data

At December 31	1993	1992	1991	1990	1989	1988
Capitalization Ratios(a) (percent)						
Long term debt	49.4	48.2	50.6	53.6	55.1	56.8
Preferred stock	6.6	8.0	8.7	6.7	6.5	6.5
Common shareholders' equity	44.0	43.8	40.7	39.7	38.4	36.7
Total	100.0	100.0	100.0	100.0	100.0	100.0
Book Value per Common Share—Year End	$19.70	$18.92	$18.41	$18.42	$18.28	$17.69
Rate of Return on Average Common Equity (percent)	10.25	9.98	8.60	9.29	11.56(b)	12.68
Embedded Cost of Senior Capital (percent)						
Long term debt	7.36	7.91	8.32	8.59	8.74	8.71
Preferred stock	6.69	6.98	6.97	6.72	6.72	6.72
Effective Federal Income Tax Rate (percent)	33.5	35.9	33.9	34.8	33.8	33.9
Depreciation Rate (percent)—Electric	2.62	2.69	3.05	3.33	3.25	3.56
—Gas	2.60	2.78	2.94	2.94	2.96	2.96
Interest Coverages(b)(c)						
Before federal income taxes (incld. AFUDC)	3.03	2.74	2.38	2.32	2.53	2.53
(excld. AFUDC)	3.00	2.70	2.33	2.25	2.47	2.48
After federal income taxes (incld. AFUDC)	2.35	2.12	1.91	1.86	2.02	2.01
(excld. AFUDC)	2.32	2.08	1.86	1.78	1.96	1.96

(a)Includes Company's long term liability to the Department of Energy (DOE) for nuclear waste disposal. Excludes DOE long term liability for uranium enrichment decommissioning and amounts due or redeemable within one year.
(b)Excludes disallowed Nine Mile Two plant costs written off in 1989.
(c)The recognition by the Company in 1991 of a fuel procurement audit approved by the New York State Public Service Commission (PSC) has been excluded from 1991 coverages. Likewise, recognition by the Company in 1992 of disallowed ice storm costs as approved by the PSC has been excluded from 1992 coverages. Coverages for 1993 exclude the effects of retirement enhancement programs recognized by the Company during the year and certain gas purchase undercharges written off in December 1993.

Electric Department Statistics

Year Ended December 31	1993	1992	1991	1990	1989	1988
Electric Revenue (000's)						
Residential	$235,286	$220,866	$212,327	$197,612	$191,732	$188,451
Commercial	196,456	184,815	181,561	165,445	155,076	149,663
Industrial	147,396	142,392	141,001	130,012	124,634	120,490
Other (Includes Unbilled Revenue)	59,817	60,194	54,041	58,861	71,654	56,033
Electric revenue from our customers	638,955	608,267	588,930	551,930	543,096	514,637
Other electric utilities	16,361	25,541	28,612	42,465	38,028	29,966
Total electric revenue	655,316	633,808	617,542	594,395	581,124	544,603
Electric Expense (000's)						
Fuel used in electric generation	45,871	48,376	65,105	76,420	75,873	65,787
Purchased electricity	31,563	29,706	27,683	34,264	39,645	30,299
Other operation	188,684	183,118	168,610	155,289	137,458	124,871
Maintenance	52,464	53,714	57,032	53,880	55,915	44,060
Depreciation and Amortization	72,326	73,213	72,746	67,302	65,287	60,444
Taxes—local, state and other	96,043	94,841	86,925	77,323	71,361	66,426
Total electric expense	486,951	482,968	478,101	464,478	445,539	391,887
Operating Income before Federal Income Tax	168,365	150,840	139,441	129,917	135,585	152,716
Federal income tax	43,845	38,046	31,390	30,670	29,887	34,093
Operating Income from Electric Operations (000's)	$124,520	$112,794	$108,051	$ 99,247	$105,698	$118,623
Electric Operating Ratio %	48.6	49.7	51.6	53.8	53.2	48.7
Electric Sales—KWH (000's)						
Residential	2,124,763	2,084,466	2,085,429	2,075,072	2,072,047	2,051,808
Commercial	1,987,490	1,937,950	1,928,730	1,897,583	1,832,521	1,792,162
Industrial	1,894,026	1,929,498	1,917,796	1,931,633	1,906,429	1,869,417
Other	505,341	503,330	507,765	490,077	491,905	483,730
Total billed	6,511,620	6,455,244	6,439,720	6,394,365	6,302,902	6,197,117
Unbilled sales	(4,556)	742	7,657	(25,421)	33,406	—
Total customer sales	6,507,064	6,455,986	6,447,377	6,368,944	6,336,308	6,197,117
Other electric utilities	743,588	1,062,738	1,034,370	1,316,379	1,255,282	1,149,900
Total electric sales	7,250,652	7,518,724	7,481,747	7,685,323	7,591,590	7,347,017
Electric Customers at December 31						
Residential	302,219	300,344	298,440	296,110	293,418	290,037
Commercial	29,635	29,339	28,856	28,804	28,386	27,888
Industrial	1,382	1,386	1,388	1,428	1,422	1,392
Other	2,638	2,605	2,558	2,553	2,512	2,326
Total electric customers	335,874	333,674	331,242	328,895	325,738	321,643
Electricity Generated and Purchased—KWH (000's)						
Fossil	1,520,936	2,197,757	2,146,664	2,505,110	2,578,006	2,214,588
Nuclear	4,495,457	4,191,035	4,391,480	4,016,721	3,659,185	3,884,884
Hydro	199,239	278,318	174,239	244,539	175,085	169,002
Pumped storage	233,477	226,391	240,206	269,966	290,582	292,305
Less energy for pumping	(355,725)	(344,245)	(364,520)	(405,966)	(429,895)	(430,401)
Other	2,559	811	1,269	20,408	54,893	2,195
Total generated—Net	6,095,943	6,550,067	6,589,338	6,650,778	6,327,856	6,132,573
Purchased	1,583,582	1,389,875	1,451,208	1,498,089	1,757,413	1,705,755
Total electric energy	7,679,525	7,939,942	8,040,546	8,148,867	8,085,269	7,838,328
System Net Capability—KW at December 31						
Fossil	541,000	541,000	541,000	541,000	541,000	541,000
Nuclear	620,000	617,000	622,000	621,000	621,000	621,000
Hydro	47,000	47,000	47,000	47,000	47,000	47,000
Other	29,000	29,000	29,000	29,000	29,000	29,000
Purchased	347,000	348,000	354,000	356,000	369,000	360,000
Total system net capability	1,584,000	1,582,000	1,593,000	1,594,000	1,607,000	1,598,000
Net Peak Load—KW	1,333,000	1,252,000	1,297,000	1,208,000	1,249,000	1,275,000
Annual Load Factor—Net %	59.1	62.5	61.7	64.6	62.4	59.7

Gas Department Statistics

Year Ended December 31	1993	1992	1991	1990	1989	1988
Gas Revenue (000's)						
Residential	$ 5,526	$ 6,456	$ 6,354	$ 6,508	$ 6,770	$ 6,439
Residential spaceheating	196,411	183,405	157,458	159,501	165,832	150,383
Commercial	45,620	44,274	40,196	43,534	46,897	44,781
Industrial	6,346	6,418	6,761	9,674	9,371	9,859
Municipal and other (Includes Unbilled Revenue)	39,805	21,171	24,959	17,279	35,703	19,755
Total gas revenue	293,708	261,724	235,728	236,496	264,573	231,217
Gas Expense (000's)						
Gas purchased for resale	166,884	141,291	129,779	132,512	152,623	129,596
Other operation	46,697	43,506	39,830	39,307	36,306	34,818
Maintenance	9,229	9,006	8,383	8,510	8,401	8,515
Depreciation	11,851	11,815	11,435	10,465	9,776	9,259
Taxes—local, state and other	30,849	29,411	26,724	23,711	23,980	22,209
Total gas expense	265,510	235,029	216,151	214,505	231,086	204,397
Operating Income before Federal Income Tax	28,198	26,695	19,577	21,991	33,487	26,820
Federal income tax	5,485	5,545	2,869	3,820	7,952	6,569
Operating Income from Gas Operations (000's)	$ 22,713	$ 21,150	$ 16,708	$ 18,171	$ 25,535	$ 20,251
Gas Operating Ratio %	75.9	74.1	75.5	76.3	74.6	74.8
Gas Sales—Therms (000's)						
Residential	6,735	8,780	9,068	9,644	10,321	10,374
Residential spaceheating	289,252	287,614	253,655	262,458	277,267	267,697
Commercial	77,326	78,993	71,509	77,617	84,152	86,413
Industrial	11,792	12,437	13,000	18,536	17,873	20,174
Municipal	11,947	11,410	10,580	13,350	12,319	15,514
Total billed	397,052	399,234	357,812	381,605	401,932	400,172
Unbilled sales	8,017	13	3,291	(22,840)	20,320	—
Total gas sales	405,069	399,247	361,103	358,765	422,252	400,172
Transportation of customer-owned gas	124,436	126,140	109,835	101,985	105,303	83,594
Total gas sold and transported	529,505	525,387	470,938	460,750	527,555	483,766
Gas Customers at December 31						
Residential	18,389	19,114	21,448	22,410	23,321	24,139
Residential spaceheating	231,937	228,096	222,918	219,242	215,120	210,710
Commercial	18,636	18,378	18,151	17,920	17,677	17,213
Industrial	924	932	921	960	1,095	1,042
Municipal	1,001	1,010	983	984	1,067	1,039
Transportation	466	424	423	401	367	270
Total gas customers	271,353	267,954	264,844	261,917	258,647	254,413
Gas—Therms (000's)						
Purchased for resale	347,778	360,493	384,643	366,684	426,941	408,044
Gas from storage	76,378	53,757	16,755	—	—	—
Other	1,039	1,061	1,617	2,525	1,764	1,967
Total gas available	425,195	415,311	403,015	369,209	428,705	410,011
Cost of gas per therm (cents)	36.79¢	35.35¢	32.96¢	36.03¢	35.74¢	31.76¢
*Total Daily Capacity—Therms at December 31**	4,485,000	4,485,000	4,485,000	4,485,000	4,485,000	4,485,000
Maximum daily throughput—Therms	3,864,850	3,768,470	3,539,260	3,539,820	3,719,050	3,744,500
Degree Days (Calendar Month)						
For the period	7,044	6,981	6,146	5,924	7,109	6,862
Percent colder (warmer) than normal	4.4	3.4	(8.4)	(11.8)	5.9	1.6

*Method for determining daily capacity, based on current network analysis, reflects the maximum demand which the transmission systems can accept without a deficiency.

Investor Information

Requests for Information
Investors and security analysts seeking information about the Company should contact David C. Heiligman, Vice President, Secretary and Treasurer.

Form 10-K Annual Report
Shareholders may obtain a copy of the Company's 1993 annual report on Form 10-K, as filed with the Securities and Exchange Commission, without charge, by writing to the Secretary.

Shareholder Services
Shareholders with questions about dividend payments, address changes, missing certificates, ownership changes and other account information should contact our transfer agent.

Dividend Payment Dates
RG&E's Board of Directors meets quarterly to consider the payment of dividends. Dividends on Common Stock are normally paid on or about the 25th of January, April, July and October. Dividends on the Preferred Stocks are payable, as declared, on or about the 1st of March, June, September and December.

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

Dividend Reinvestment
Common Stock shareholders who wish to acquire additional shares free of brokerage commissions or service charges are invited to join RG&E's Automatic Dividend Reinvestment and Stock Purchase Plan. Under the plan, shareholders authorize an independent agent to purchase shares of RG&E Common Stock with their cash dividends. Shareholders may also participate in the plan by making optional cash payments, even if they decide not to reinvest their dividends. For further information, contact our transfer agent.

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

Stock Listings
RG&E's Common Stock is listed on the New York Stock Exchange and is identified by the stock symbol RGS. The Preferred Stock issues are traded on the over-the-counter market.

Corporate Office
Rochester Gas and
Electric Corporation
89 East Avenue
Rochester, NY 14649-0001
(716) 546-2700

Agent for Automatic Dividend Reinvestment and Stock Purchase Plan
The First National Bank of Boston
Dividend Reinvestment Unit
Mail Stop: 45-01-06
P.O. Box 1681
Boston, MA 02105-1681
(800) 442-2001

Transfer Agent and Registrar
The First National Bank of Boston
Shareholder Services Division
Mail Stop: 45-02-09
P.O. Box 644
Boston, MA 02102-0644
(800) 442-2001

First Mortgage Bond Trustee and Paying Agent
Bankers Trust Company
Attn: Security Holder Relations
P.O. Box 9006
Church Street Station
New York, NY 10249
(800) 735-7777

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Officers
(as of January 1, 1994)

Roger W. Kober
Chairman of the Board, President and Chief Executive Officer
Age 60, Years of Service, 28

David K. Laniak
Senior Vice President, Gas, Electric Distribution and Customer Services
Age 58, Years of Service, 39

Thomas S. Richards
Senior Vice President, Finance and General Counsel
Age 50, Years of Service, 2

Robert E. Smith
Senior Vice President, Production and Engineering
Age 56, Years of Service, 34

David C. Heiligman
Vice President, Secretary and Treasurer
Age 53, Years of Service, 30

Robert C. Mecredy
Vice President, Ginna Nuclear Production
Age 48, Years of Service, 22

Wilfred J. Schrouder, Jr.
Vice President, Employee Relations, Public Affairs and Materials Management
Age 52, Years of Service, 31

Daniel J. Baier
Assistant Controller
Age 47, Years of Service, 10

John M. Kuebel
Auditor
Age 58, Years of Service, 29

Officer Appointment

In October 1993, Thomas S. Richards was elected Senior Vice President, Finance and General Counsel. Mr. Richards had previously been General Counsel of the Company.

Board of Directors
(as of January 1, 1994)

William Balderston III *‡√
Former Executive Vice President,
The Chase Manhattan Corporation

Angelo J. Chiarella †
President and Chief Executive Officer,
Midtown Holdings Corp.

Allan E. Dugan *†
Senior Vice President,
Corporate Strategic Services,
Xerox Corporation

William F. Fowble †‡
Former Senior Vice President and
Executive Vice President, Imaging,
Eastman Kodak Company

Jay T. Holmes √
Senior Vice President—Corporate
Affairs and Secretary,
Bausch & Lomb Incorporated

Roger W. Kober *
Chairman of the Board, President
and Chief Executive Officer,
Rochester Gas and Electric Corporation

Theodore L. Levinson †
Former President and
Chief Executive Officer,
Star Supermarkets, Inc.

Constance M. Mitchell †√
Former Program Director,
Industrial Management Council of
Rochester, New York, Inc.

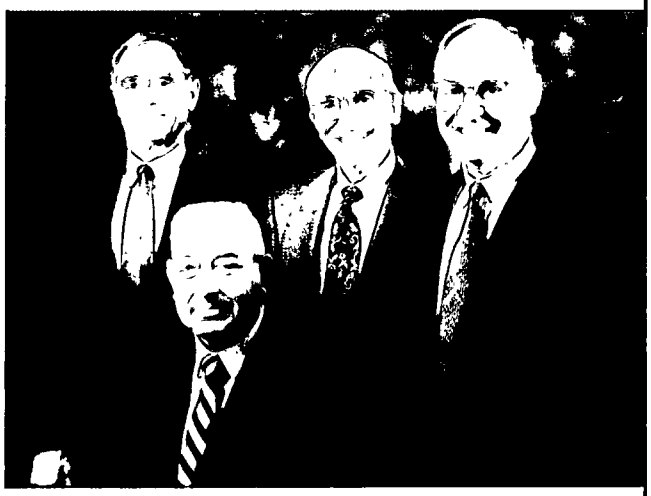
Cornelius J. Murphy *‡
Senior Vice President,
Goodrich & Sherwood Company

Arthur M. Richardson *‡√
President,
Richardson Capital Corporation

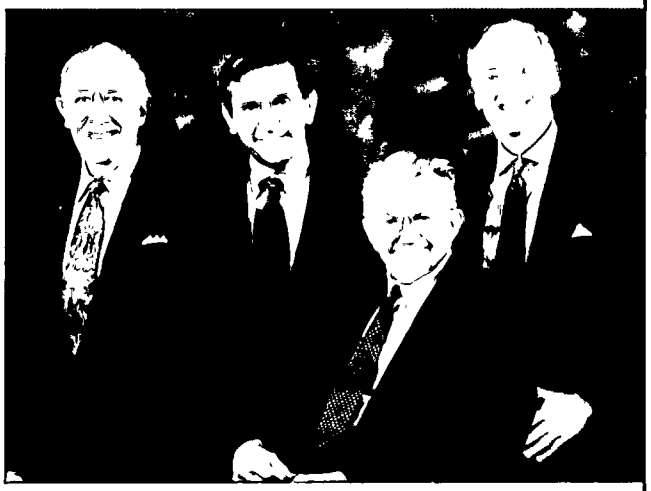
M. Richard Rose †‡
Former President,
Rochester Institute of Technology

Harry G. Saddock *√
Former Chairman of the Board and
Chief Executive Officer,
Rochester Gas and Electric Corporation

* MEMBER OF EXECUTIVE AND FINANCE COMMITTEE
† MEMBER OF AUDIT COMMITTEE
‡ MEMBER OF COMMITTEE ON MANAGEMENT
√ MEMBER OF NOMINATING COMMITTEE



Class II—Term Expiring in 1994, from left,
M. Richard Rose, Theodore L. Levinson,
Arthur M. Richardson, Allan E. Dugan.



Class III—Term Expiring in 1995, from left,
Cornelius J. Murphy, Angelo J. Chiarella,
Harry G. Saddock, Jay T. Holmes.

Class I—Term Expiring in 1996, from left,
Roger W. Kober, William Balderston III,
William F. Fowble, Constance M. Mitchell.

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