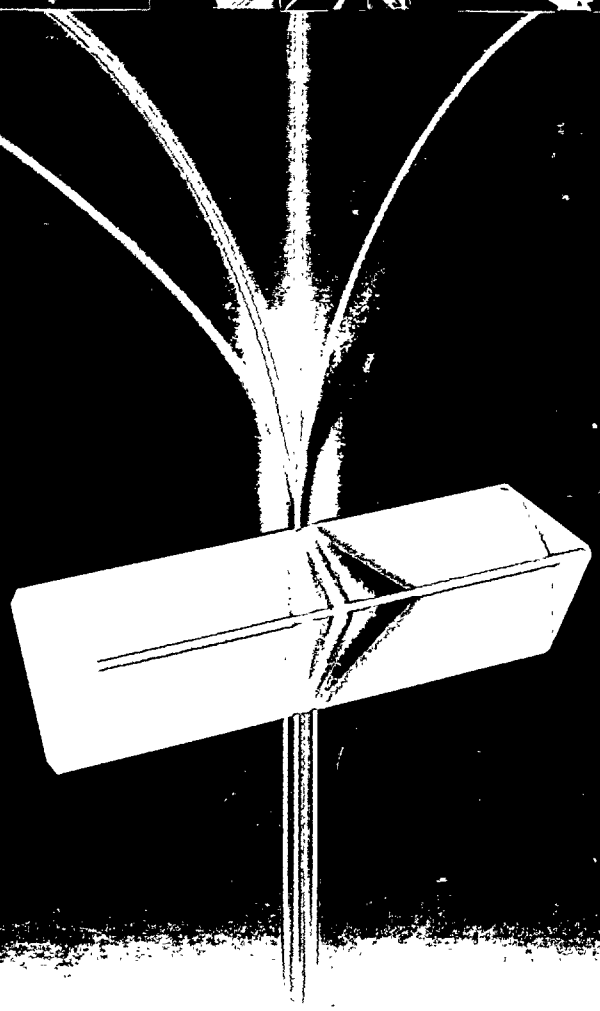
ROCHESTER GAS AND ELECTRIC CORPORATION

ANNUAL REPORT 1991

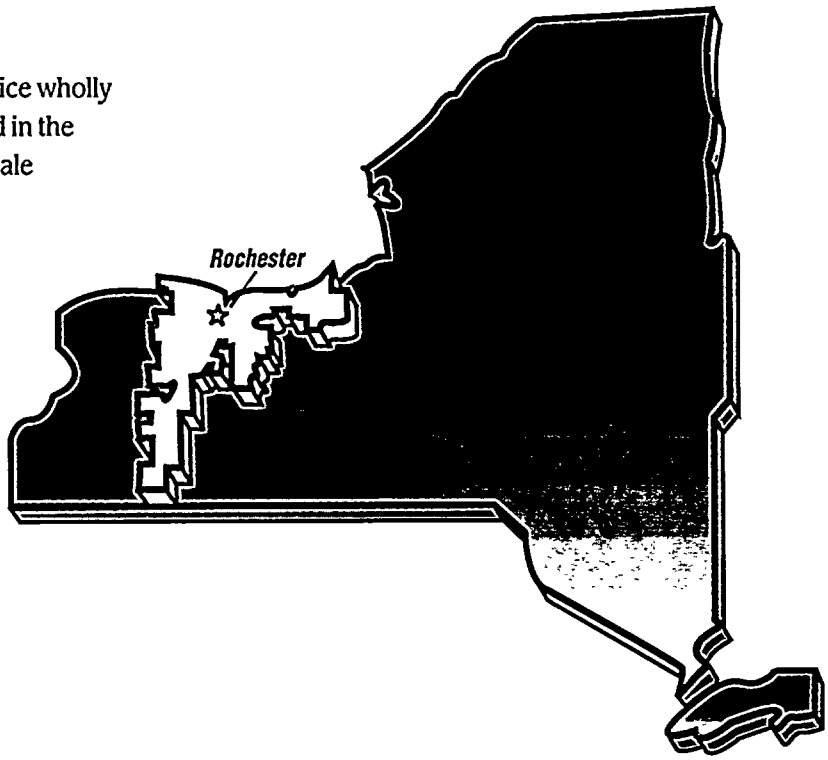


CUSTOMER SATISFACTION

RG&E Service Area/Business

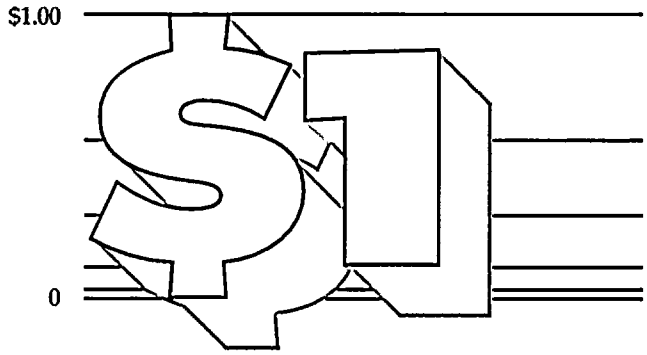
The Company supplies electric and gas service wholly within the State of New York, and is engaged in the production, transmission, distribution and sale of these services in a nine-county area centering around the City of Rochester.

The Company's territory, which has a population of approximately 920,000, 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.



Contents

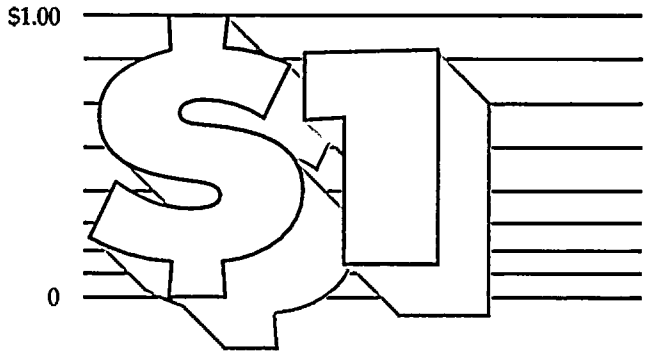
Where the 1991 Revenue Dollar Came From and How It Was Used



45¢ Residential (25¢ Electric, 20¢ Gas)

26¢ Commercial (21¢ Electric, 5¢ Gas)

18¢ Industrial (17¢ Electric, 1¢ Gas)
8¢ Other (6¢ Electric, 2¢ Gas)
3¢ Electric Sales to Other Utilities



17¢ Taxes
17¢ Other Operations
15¢ Purchased Gas
15¢ Wages and Benefits
11¢ Electric Fuel and Purchased Electricity
10¢ Depreciation & Amortization
8¢ Interest
7¢ Dividends & Reinvested Earnings

Financial Highlights

	1991	1990	% Change
FINANCIAL DATA (Dollars in thousands)			
Operating revenues: Electric	**$617,542**	$594,395	4
Gas	**$235,728**	$236,496	—
Operating expenses	**$728,511**	$713,473	2
Operating income	**$124,759**	$117,418	6
Net income	**$ 57,997**	$ 59,881	(3)
Earnings applicable to common stock	**$ 51,034**	$ 53,856	(5)
Rate of return on average common equity	**8.60%**	9.29%	(7)
COMMON STOCK DATA			
Weighted average number of shares outstanding (thousands)	**31,794**	31,293	2
Per common share:			
Earnings	**$1.60**	$1.72	(7)
Dividends	**$1.62**	$1.56	4
Book Value (year end)	**$18.41**	$18.42	—
Year-end market price	**$23.25**	$19.50	19
OPERATING DATA			
Sales (thousands)			
Kilowatt-hours to customers	**6,447,377**	6,368,944	1
Kilowatt-hours to other utilities	**1,034,370**	1,316,379	(21)
Therms of gas sold and transported	**470,938**	460,750	2
Customers (year end)			
Electric	**331,242**	328,895	1
Gas	**264,844**	261,917	1
Construction expenditures, less allowance for funds used during construction (thousands)	**$124,057**	$126,776	(2)
Employees (year end)	**2,755**	2,759	—

To Our Shareholders

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

Imagine RG&E receiving checks from each of its customers with "thank you" written on the bottom. Getting 343,000 notes of appreciation sounds unlikely, I admit. But nonetheless, that's the spirit of our goal. To earn the appreciation of all of our customers.

Here's the point of all of this. **Nothing is as important to RG&E as satisfied customers.** It's that simple. That's why 1991 saw the redoubling of our efforts and the renewing of our commitment to achieving the highest possible levels of customer satisfaction.

To accomplish that objective, we're unveiling a bright vision for the future. It includes simplification, instilling a new feeling of competitiveness, streamlining of operations, and eliminating layers of bureaucracy. And most of all, rededicating our efforts and renewing our commitment to customer satisfaction.

All of this is outlined in our brand new Corporate Business Plan, the culmination of more than a year of intense study, research, discussion and debate. Specifics of this plan follow. But first, a look at the events of the past year will help show why this new plan is so critical to our continued success up the road.

The Storm

On Sunday, March 3, 1991, the worst natural disaster in New York State's history began. During this ice storm, two thirds of our 330,000 electric customers were affected by power outages. Nearly half of our electric distribution system was damaged or destroyed. After one week, we had restored power to half of the customers affected. At the end of 13 days, all were back in power.

While the storm was the worst in our history, I believe it brought out our best. I stand by our assessment that our people and our mutual aid crews put forth the finest restoration efforts on behalf of our customers.

In our self-assessment process, we felt there were some shortcomings and announced those findings at our 1991 annual meeting in May. The full report was released with our pledge to improve our capability for damage assessment and for providing customer information in the form of a new storm response plan. That plan, developed in conjunction with local officials and emergency planning agencies, was delivered ahead of schedule to the Public Service Commission (PSC).

Retirement

Another unexpected event was the retirement of our former chairman and chief executive officer for health reasons. Harry G. Saddock, who rose to the top of this company over his 41-year career, has guided RG&E through many difficult years.

I have assumed the duties of the chairman of the board, president, and chief executive officer. While Harry will be missed, we'll benefit from his active participation on our board, just as we've profited from his leadership in the past.

Our fuel procurement audit question was resolved in 1991. The PSC audited our fuel purchasing practices for the years 1978 to 1989. Although we believe the purchases were sound and prudent, we ended lengthy proceedings and negotiations by agreeing to a settlement with the PSC. This avoids litigation and we will refund $10 million to electric customers over a 12-month period beginning in 1992. The settlement reduced 1991 fourth quarter per-share earnings by 21 cents.

Revenues and Sales

Although total revenues of $853 million reflected an increase of $22 million over 1990, the weather, which was 8.4 percent warmer than normal, restricted growth in revenues and unit sales. Electric kilowatt-hour unit sales to customers rose slightly in 1991 by 1.2 percent from the previous year due to a strong third quarter spurred by air conditioning sales and the addition of 2,347 new electric customers. Electric sales to other utilities were down 21.4 percent because of lower New York Power Pool requirements and a reduction in contract sales. Total therms of natural gas sold and transported were up 2.2 percent over 1990, but were hampered by unseasonably mild weather during the heating months. The addition of 2,927 new gas customers during 1991 added to the increase in therm sales.

Earnings, Dividends and Stock Price

Earnings per common share were $1.60, down from $1.72 in 1990. The reported per-share earnings reflect the fuel procurement settlement write-off of 21 cents in the fourth quarter. Lost revenues associated with the ice storm also reduced earnings per share by an estimated 11 cents, including carrying costs on deferred storm restoration costs.

We maintained our stated objective of achieving a common stock dividend payout of between 8.5 and 9.0 percent of book value. On December 19, 1991, the board of directors authorized a one-and-a-half cent increase in quarterly dividends from 40.5 cents to 42 cents per common share, effective with the January 1992 payment. Our common stock hit several 52-week highs during the year and reached $23.25 by year's end, up 19 percent from the 1990 year-end market price of $19.50.

RATES

In July 1991 we were authorized additional revenues in a rate proceeding before the PSC. We were allowed an opportunity to earn an additional $33.1 million annually in electric revenues and $1.1 million in gas revenues. The PSC ruled that $4 million of the electric revenue authorization is subject to refund if we did not submit an acceptable interim storm emergency plan by year's end. We submitted the plan on October 30, and are confident that the plan satisfies the requirement.

In August we filed for additional revenue increases to become effective in July of 1992. We are seeking $38.2 million in annual electric revenues and $15.1 million in gas revenues. In this rate case, we are seeking full recovery of the estimated $36.4 million cost of the ice storm to be amortized over a period of years.

The PSC staff and some intervenors have been critical of our performance during the ice storm and are seeking to eliminate part or all of the storm cost from the case. As I said before, I believe the physical response in the restoration of power was remarkable under the circumstances. However, we have no way of predicting the outcome of the treatment of the storm costs in the pending rate case.

I personally announced the latest rate filing to news media on August 2, 1991 because I wanted to make our company's rededication to customer satisfaction absolutely clear. I also promised that we would attempt to minimize future rate increases by controlling as many costs as possible. Our success in meeting this goal depends on the fulfillment of our new Corporate Business Plan, as well as on watching expenses.

ELECTRIC OPERATIONS

Our power plants continued to operate at high efficiency levels. The Ginna nuclear power plant that supplies about half of our electric customers' requirements operated 86 percent of the time in 1991, and had a capacity factor of 84 percent for the year. Both of those measures are above the national average for comparable nuclear plants. Our coal-fired units once again achieved excellent operating records. Russell Station had an availability factor of 90 percent and a capacity factor of 62 percent. Beebee Station achieved factors of 88 percent and 68 percent, respectively, all above the national average.

In June 1991 the Nuclear Regulatory Commission (NRC) removed the Nine Mile Two nuclear power plant in which we own a 14 percent share from its watch list which cites nuclear plants that require improvement in some operating areas. The NRC concluded that the plant had demonstrated sustained improvement in performance. Also in 1991, the NRC's assessment of licensee performance noted overall improvement.

The Nine Mile Two plant is operated by Niagara Mohawk Power Corporation. An interim operating agreement, however, has established a council composed of RG&E and other non-operating owners to oversee management of the plant.

GAS OPERATIONS

In June 1991 we received permission from the PSC to form a wholly-owned subsidiary that would acquire a 20 percent ownership in the Empire State Pipeline Project. This project proposes to construct a natural gas supply pipeline running between Grand Island near Niagara Falls, New York, and Syracuse, New York.

There are two petitions for rehearings placed by intervenors before the PSC. This could delay the project. More important yet is a decision pending from the Canadian National Energy Board on whether or not they will reverse an early denial to construct a pipeline extension to the Niagara River.

The pipeline would offer us an alternative gas supply and could benefit gas customers by helping ensure competitive pricing. At the same time, an ownership in the pipeline is expected to contribute to revenues.

Demand Side Management

We are making great progress with energy management programs that promote improved energy efficiency on our customers' part. Our major promotional campaign began in 1992, and includes advertising, direct mail and exhibits. These materials will provide useful information and incentives to the residential, commercial, industrial, and agricultural customers who can best take advantage of them.

These energy efficiency guidelines, called the RG&E E.Z. Saver Programs, are being introduced by a fictional character named E.Z. Saver. In commercials on television and radio, newspaper ads, and in printed materials, he will be telling customers about the programs we are making available, and how RG&E can become their partner in helping them become more energy efficient. The success of these programs can delay the purchase or construction of new, expensive energy options in the near future.

The RG&E Corporate Business Plan

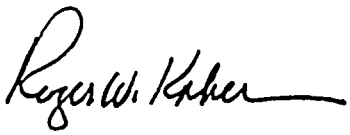
In 1991 we arrived at new crossroads. Signs were pointing to dramatic changes in the industry. Recognizing these markers, we've prepared a new vision, set new goals, and made strategic plans to meet the future.

Our corporate vision for tomorrow is based on a proud tradition of service to our customers, innovation, commitment to our employees, and active participation in our community. Our first priority is customer satisfaction earned by providing safe, reliable, environmentally responsible, cost-efficient energy and service. But we need to keep working to improve our performance until it becomes the standard of excellence against which other utilities will be measured.

While traditions serve as our foundation, we're poised to take advantage of every opportunity possible resulting from new technology, regulatory changes, and competition. These forces are transforming our industry, making it essential for RG&E to take a proactive approach. That's why we're staying at the forefront of developments, becoming more customer-focused, competitive, and market-driven than ever before.

How do we bring this vision to life? Through a five-year venture concentrating on five critical areas: customer service, price of product, safety, employee achievement, and public acceptance. When we reach our goals in these areas, we will have achieved our customer satisfaction goal, as well. And customer satisfaction is the only sure way to improve our financial performance.

In the following pages, we'll describe this important new plan and how it contributes to turning our vision into reality.



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

February 3, 1992

CUSTOMER SATISFACTION AND THE BOTTOM LINE

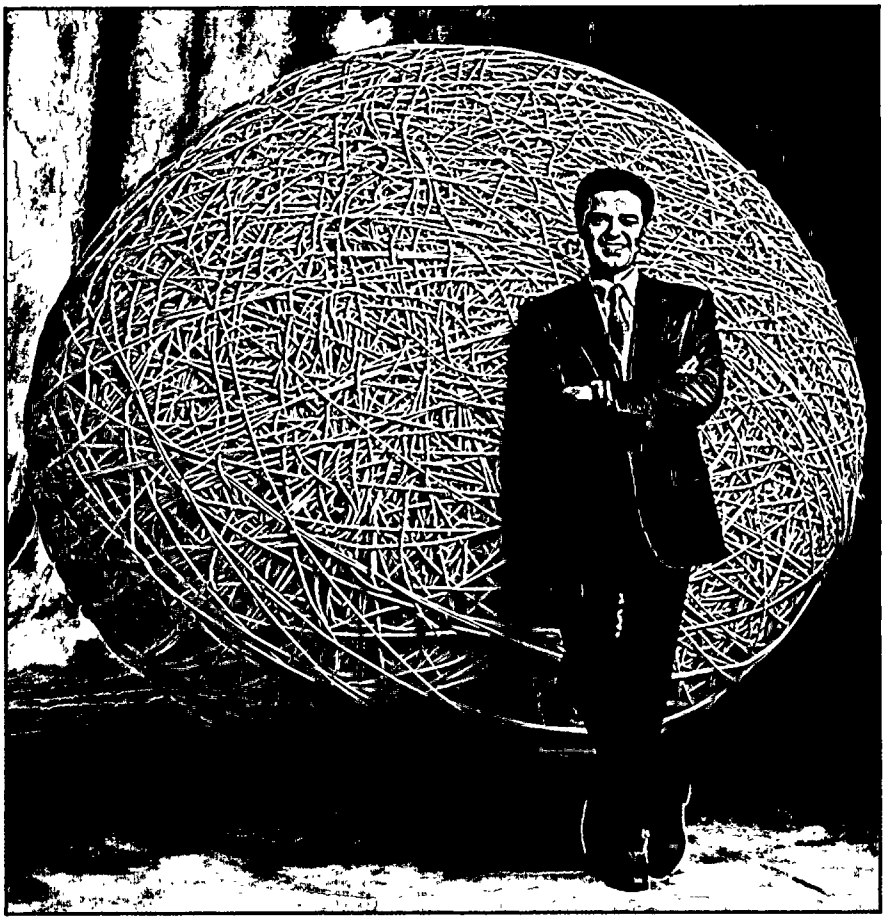
RG&E's new Corporate Business Plan is complex, but simple in purpose. CUSTOMER SATISFACTION is the sole purpose. While RG&E is not unique in focusing on this purpose—many companies today list customer satisfaction as paramount in their plans—we may be singled out as one where senior management has personally and unanimously endorsed the effort in writing.

The Plan is not one that was created overnight. The completion of the corporate plan document in late 1991 was the culmination of more than a year of intense study, research, discussion and debate.

Nor is the Plan by any means a rigid, unbending document. As we proceed through the Plan's five-year projected time frame, we will measure progress often and alter our strategies as necessary to reach the ultimate goals.

To construct a workable plan, the company's senior management agreed to a set of shared values that will guide the overall effort. Those shared values are posted prominently in the planning document.

Demand Side Management's E.Z. Saver offers incentives on energy-efficient lighting.



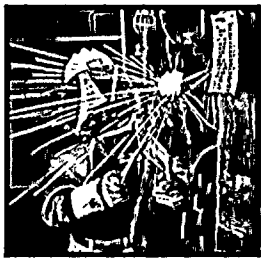
Demand Side Management programs are introduced by a fictional character named E.Z. Saver.

The Savingpower analysis continues to show residential customers how they can stay comfortable with money-saving energy measures.

The Hyatt Regency Hotel, destined to become a dramatic landmark in downtown Rochester, will also become energy efficient thanks to the cooperative efforts of its owners, developer, design firm and RG&E's Demand Side Management New Construction program.

- **INTEGRITY**—We must be honest and straightforward in our statements and actions.
- **COMPETENCE**—We must fully understand the consequences of our actions.
- **SAFETY**—We must protect the health and well-being of our community and our employees.
- **ENVIRONMENTAL RESPONSIBILITY**—We must act to preserve the quality of the air, water and land that we share with our community.
- **CITIZENSHIP**—We must be involved with our community and informed about local issues and concerns.
- **EFFICIENCY**—We must support the wise use of resources in our operations and in the use of our products and services.
- **COMPLIANCE WITH LAWS AND REGULATIONS**—We must act in ways that conform with public mandates as expressed in law and regulation.

There are five major components of the new Plan and each has a specific set of goals along with performance indicators. The first objective is **CUSTOMER SERVICE**, and covers the wide spectrum of activities that relate to our day-to-day dealings with our consumers.



RG&E linemen offer live, graphic illustrations of hazards to avoid around electric lines in the newly opened Live Line facility.

Within the objectives are strategies. With regard to customer service, the strategies include measuring our performance against certain standards. We must understand what they want; what is of most value to them and what is of least value. Customers should have a single point of contact when dealing with the company and, through tracking customer transactions, we will routinely assess how well we are doing.

Audiences from all age levels are awed by the Live Line demonstrations.

We will assess performance not only with our external customers, but the internal ones as well who are served by our service departments. Promoting energy efficiency and energy-saving incentive programs for customers is also a strategy of the customer service goal.

PRICE OF PRODUCT is another objective. We want to limit the increase in unit price of our products and services so that our prices are less than those of our competitors. Strategies for this objective include better examination of our competition and improved cost effectiveness.

SAFETY is another objective, and strategies there call for development of annual health and safety programs for employees and improved public safety awareness.

EMPLOYEE ACHIEVEMENT is an objective that has the goal of attaining a high level of employee productivity, innovation and satisfaction. Strategies include reallocation of human resources to better fit some employees' talents and skills with the job. Incentive-based compensation programs will be created and there is a move to decrease the layers of management in the organization for better effectiveness. The strategies will bring

School children, youth groups, fire fighters, police officers, construction workers and employees are some of the many audiences who have seen the 45-minute Live Line demonstration. When Live Line is not in use for the public, the indoor area is used for electric and gas training.

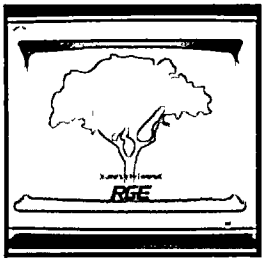
more decision-making opportunities to employees and promote a stronger sense of participation in the management of the company.

PUBLIC ACCEPTANCE is the fifth objective and it seeks to improve the public perception of the company. Strategies involve implementation of new, valuable community programs relating to our business, establishing an environmental excellence program and identifying the company's actions with the public interest.

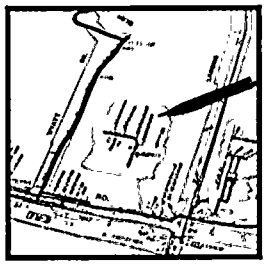
These are the major components of the Business Plan. As investors you may have noticed the absence of an objective you think should be there– **FINANCIAL PERFORMANCE.**

In fact, **FINANCIAL PERFORMANCE** is an objective and part of the written Plan, but it is separated from the actions in the Plan themselves. We believe if the five objectives are achieved, a better financial performance will follow as a natural result.

The student-centered and teacher-empowered "In Concert with the Environment" program, funded by RG&E, allows students to examine their home energy usage and recycling practices. It provides alternative energy-saving options that not only save on utility bills, but help preserve the environment as well.



And, if the objectives are achieved, it will also follow that we will have achieved our ultimate goal of a high level of **CUSTOMER SATISFACTION.** That's what the Plan is about, and that is our commitment.



Speeding up response time through faster communications by use of FAX machines installed in Company vehicles is one of the many employee suggestions implemented in 1991. Customer and Company energy facilities are pinpointed from maps that are miles away from job locations.

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

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

March 1991 Ice Storm

On March 3 and 4, 1991 the City of Rochester, New York and surrounding counties were hit by a severe ice storm which was the worst storm in the history of the Company's service territory. It is estimated that storm damage to the Company's facilities and equipment caused about 206,000 of the Company's 330,000 electric customers to lose electric power. Company crews, in addition to crews from other utilities, worked steadily under adverse conditions to restore service to customers during the days following the storm. Due to the severity of the storm and resultant damage to Company facilities, power was not restored to all customers until March 16. Many of the Company's customers who use natural gas for heating their residences were unable to use their gas furnaces due to the loss of electric power.

As a result of the storm, the Company also lost significant electric and gas revenues during early March. The Company estimates that the loss of revenues reduced earnings per common share by eleven cents ($.11), including carrying costs, for the calendar year 1991.

The Company has incurred incremental storm damage repair costs of approximately $36.4 million, all of which the Company believes to be prudent and, therefore, recoverable in rates and none of which is reimbursable through insurance coverage. This amount is currently reflected as a deferred debit on the Company's balance sheet. The Company estimates approximately 20 percent of these deferred costs are related to capital improvements, with operating and maintenance expenses comprising the balance.

The Company is currently seeking approval from the New York State Public Service Commission (PSC) in its pending rate case for recovery of deferred ice storm costs over a period of years. Various parties are opposing recovery of these costs. Additional details of this request are discussed under Rate Base and Regulatory Policies and in Note 10 of the Notes to Financial Statements.

Nine Mile Two

The Nine Mile Two nuclear power plant was constructed and is being operated by Niagara Mohawk Power Corporation (Niagara) near Oswego, New York. The Company has a 14 percent ownership in this 1,080,000 kilowatt nuclear generating unit (the Unit or Nine Mile Two).

On March 14, 1991 the PSC issued an Order regarding a settlement agreement (the 1990 Settlement Agreement) among the Nine Mile Two Owners, the PSC Staff, and other intervenors resolving all open ratemaking issues with respect to the construction of the Unit and its operation through January 19, 1990. Under the provisions of the 1990 Settlement Agreement, a Nine Mile Two commercial operation date of April 5, 1988 has been recognized by the PSC with respect to the rates and accounts of the Company. Accordingly, final accounting entries reflecting recognition of the 1990 Settlement Agreement in conformity with the Uniform Systems of Accounts of the PSC were made in the first quarter of 1991 increasing electric utility plant together with a corresponding increase in accumulated depreciation. The 1990 Settlement Agreement also provides that any settlement or award, in excess of legal costs, received by the Company from litigation against contractors and suppliers used during the construction of Nine Mile Two, be shared equally between the Company and its electric customers. In addition, the 1990 Settlement Agreement required the

Company to refund to its electric customers $2.9 million and such amount was applied as a credit against fuel costs incurred by these customers over essentially a three-month period beginning in May 1991.

A supplemental agreement to the 1990 Settlement Agreement (the 1991 Supplemental Agreement) was negotiated by the Nine Mile Two cotenants, PSC Staff, and other parties and is expected to receive final PSC approval in early 1992. The 1991 Supplemental Agreement establishes for each cotenant an allowed level of operating and maintenance expenses for ratemaking purposes through December 31, 1992. Included are those expenses associated with the Unit's second refueling outage, scheduled to commence in late February 1992.

In June 1991, the Nuclear Regulatory Commission (NRC) announced that Nine Mile Two had demonstrated sustained improvement in performance and, therefore, would no longer be listed among plants requiring close monitoring by it. Similarly, the spring 1991 NRC systematic assessment of licensee performance (or SALP) for the Unit also noted overall improvement in performance compared to prior assessments.

Although Niagara Mohawk is the operator of Nine Mile Two, an interim operating agreement provides for management oversight of the Unit by the four non-operating owners.

Liquidity and Capital Resources

Funds for construction expenditures and the retirement of long-term debt were provided by cash flow from operations, together with external financing activity during 1991 (see Statement of Cash Flows, page 31). During 1992, additional external financing is anticipated by the Company to satisfy capital requirements including security maturities and sinking fund obligations.

Capital Requirements

The Company's capital program is designed to maintain reliable and safe electric and natural gas service and to meet future customer service requirements. Capital requirements for the three-year period 1989 to 1991 and the current estimate of capital requirements through 1994 are summarized in the table below. Capital expenditures during

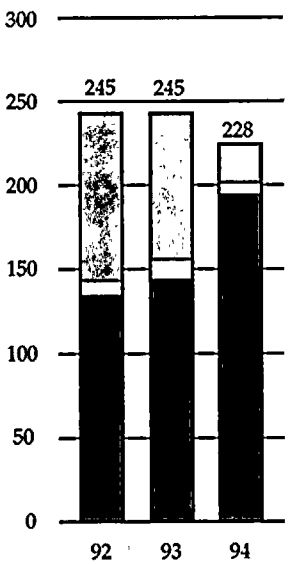
CAPITAL REQUIREMENTS

	Actual			Projected		
Type of Facilities	1989	1990	1991	1992	1993	1994
	(Millions of Dollars)					
Electric Property:						
Production	$ 48	$ 47	$ 44	$ 48	$ 48	$ 90
Transmission and Distribution	28	31	29	34	35	38
Street Lighting and Other	2	2	2	4	3	2
Subtotal	78	80	75	86	86	130
Nuclear Fuel	12	7	12	13	19	13
Total Electric	90	87	87	99	105	143
Gas Property	17	20	22	19	24	23
Common Property	12	15	13	17	17	28
Total	119	122	122	135	146	194
Carrying Costs:						
Allowance for Funds Used During Construction (AFUDC)	4	5	4	5	5	7
Deferred Financing Charges Included in Other Income	2	3	5	5	8	–
Total Construction Requirements	125	130	131	145	159	201
Securities Redemptions, Maturities and Sinking Fund Obligations*	38	28	92	100	86	27
Total Capital Requirements	$163	$158	$223	$245	$245	$228

*Excludes prospective refinancings.

1991 associated with the March 1991 ice storm have been deferred, as previously discussed, and are excluded from this table.

For the period 1992 to 1994, the Company anticipates construction requirements to total approximately $500 million. Expenditures made at the Company's nuclear facilities to improve operating efficiency and reliability and to comply with regulatory requirements are a significant component of production plant costs over the period. In addition to its construction expenditures, the Company has security maturities and sinking fund obligations totaling $213 million over the three-year period 1992 to 1994 as shown by the graph to the left. Excluded from the capital requirements table on page 13 are payments by the Company to an external nuclear decommissioning trust which payments are being recovered in rates (see Notes 1 and 10 of the Notes to Financial Statements).



PROJECTED CAPITAL REQUIREMENTS
(millions of dollars)

- Mandatory retirement of securities
- Carrying costs
- Cash expenditures for construction

Providing funds for debt maturities and sinking fund obligations is a significant part of 1992 and 1993 financing requirements.

The AFUDC amounts included in the table on page 13 are the financing costs associated with major projects under construction. This carrying cost becomes a part of the capitalized cost of the related project. The Company begins to earn a cash return on its investment, including this carrying cost, when the cost of the project is included in rate base, which generally is at the time the project enters service. In addition to AFUDC, carrying charges include the recognition of certain customer prepaid financing costs, as further discussed on page 18 under Rate Base and Regulatory Policies.

1991 Capital Requirements. Electric production plant expenditures in 1991 included $34 million of expenditures made at the Company's Ginna nuclear plant and $2 million for its 14 percent share of expenditures at Nine Mile Two, exclusive of fuel costs. The upgrading of electric distribution facilities to meet the energy requirements of new and existing customers required construction expenditures totaling $25 million in 1991. Other Electric Department capital expenditures during the year included $7 million and $5 million for fuel at the Ginna nuclear plant and at Nine Mile Two, respectively.

Construction expenditures in the Gas Department totaled $22 million in 1991, 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. Of particular interest in 1991 was the construction of a 5.0 mile, 24-inch gas pipeline during the year at a cost of approximately $3.3 million. This pipeline was placed in service January 1992 and will improve supply reliability in the northwestern quadrant of the Company's gas franchise area.

Capital requirements in 1991 also included sinking fund redemptions totaling $28 million, of which $20 million was spent to satisfy the final sinking fund requirement of the Series NN First Mortgage Bonds. Also, a first mortgage bond maturity and discretionary first mortgage bond redemption totaled $64.3 million during 1991.

Projected Capital and Other Requirements. The Company has no current plans to install additional baseload generation. The Company recently accepted bids from suppliers who wished to meet long-term Company needs for peaking generation capacity or demand-side management capacity savings. Based on a review of those bids and reflecting recent information concerning the large amount of capacity to be installed elsewhere in New York State during the next decade, the Company chose to contract for approximately 24 megawatts of capacity savings offered by demand-side

projects. The capacity savings will be phased in over the 1992 through 1994 period and sustained for 15 years. No long-term peaking contracts will be signed as a result of the completed competitive bidding process. The Company expects approximately 55 megawatts of capacity to be provided to the electric system by a cogenerator under contract with the Company, beginning in 1994 and continuing for 25 years.

The Company continues to make generating plant modifications and its construction program focuses 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. Nuclear plant expenditures to meet the Company's commitment to maintain a high level of nuclear safety and performance and to satisfy regulatory requirements and industry standards are reflected in its projected construction program. Construction requirements also include additional expenditures to be made at the Company's fossil-fueled and hydro generating plants.

Expenditures for electric production plant in 1994 include $21 million for the possible replacement of the steam generators at the Ginna nuclear plant. During 1991, studies were initiated to determine the best steam generator strategy for the remaining life of the Ginna nuclear plant. These studies included various strategies such as continued repair, chemical cleaning and replacement. Portions of these studies are ongoing with completion scheduled for early 1992. It is anticipated that a decision on steam generator replacement will be made following completion of these studies. If the decision is made to replace steam generators, the anticipated replacement date is 1995 or 1996 with an estimated cost of $100 million.

In June 1991 the Company received permission from the PSC to form a wholly-owned subsidiary which would acquire a 20 percent ownership in the Empire State Pipeline Project (Empire). Empire is proposed to be an intrastate natural gas pipeline subject to PSC regulation to be constructed between Grand Island and Syracuse, New York. The construction of Empire was approved by the PSC in an Order issued March 1991. On October 23, 1991, however, two parties to this PSC case commenced separate proceedings for judicial review of the PSC decision certificating the project. It is possible that these proceedings could result in delaying the commencement of construction of the pipeline. 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. The investment in Empire is excluded from the capital expenditures table on page 13. The construction of Empire currently hinges on a reversal of the Canadian National Energy Board's (CNE Board) original decision in July 1991 to deny a Trans Canada Pipelines Limited extension of its existing line to the Niagara River where it could be connected to Empire's proposed line. The Company and others have applied to the CNE Board for a review of its original decision. A final decision from the CNE Board is not expected before July 1992.

The Company's capital expenditures program is under continuous review and will be revised depending upon the progress of major 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.

ENVIRONMENTAL MATTERS

The production and delivery of energy results in the emission of pollutants that may

be harmful to the environment. 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 environmental damage 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 it has sent 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. None of these have been or are expected to be material. In other circumstances, including some where impact on Company property is alleged, questions of fact remain unresolved and ultimate responsibility for cleanup, if any, has yet to be determined.

In November 1990 the Federal Clean Air Act Amendments of 1990 (Amendments) became law. The Amendments will affect air emissions and quality control measures primarily at the Company's fossil-fueled electric generating facilities. The Amendments incorporate a two-phase emission reduction program. The first phase becomes effective in 1995, while the second phase, which contains more stringent provisions, will become effective in the year 2000. The Company is not affected by the first phase of the Act. A Clean Air Act Task Force has been formed within the Company to review compliance with the second phase of the Amendments and has begun the process of identifying the optimum mix of control measures and/or associated technology changes that will allow the fossil fuel based portion of the generation system to fully comply with state and federal environmental requirements. While work has begun, the appropriate compliance control options have not as yet been determined.

LIQUIDITY, FINANCING AND CAPITAL STRUCTURE

Capital requirements in 1991 were satisfied by a combination of internally generated funds, the sale of securities, and short-term borrowings. In addition to obtaining funds to finance a portion of its construction requirements, the Company entered the financial markets to refinance its First Mortgage 11¼% Bonds, Series KK. This refinancing, the result of favorable market rates and security provisions which allowed early redemption, contributed to a drop in the Company's embedded cost of long-term debt from 8.6% at the end of 1990 to 8.3% at year-end 1991.

The Company projects that an average of approximately 80 percent to 85 percent of the funds required per year for its 1992 through 1994 construction program will be generated internally and the balance will be obtained through the sale of securities and short-term borrowings. The Company also anticipates that the sale of securities and short-term borrowings will be required to satisfy security maturities and sinking fund obligations over the three years 1992 through 1994. Although the Company expects to issue securities during 1992, it is the Company's intention to utilize its credit agreements to meet any interim external financing needs prior to the issue of such 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.

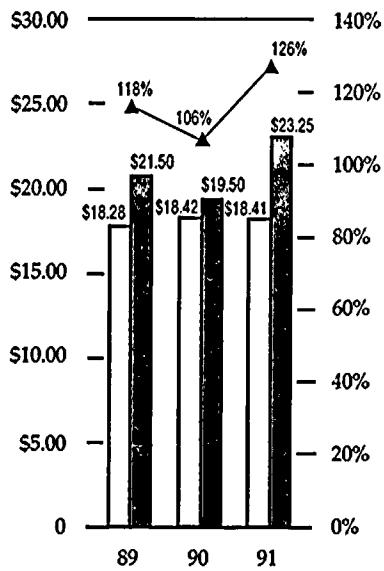
Financing. Interim financing is available from certain domestic banks in the form of short-term borrowings under a $90 million revolving credit agreement which continues until December 31, 1994 and may be extended annually. Borrowings under this agreement are secured by a subordinate mortgage. In addition, the Company has a credit agreement with a domestic bank 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. At December 31, 1991 the Company had $59.5 million of secured short-term debt outstanding.

Under provisions of the Company's Certificate of Incorporation, 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, 1991 was able to issue $5.2 million of unsecured debt. Additional interim financing capability remains available with secured borrowings under the Company's credit agreements, as discussed above.

On April 9, 1991 the Company completed the public sale of $100 million principal amount of First Mortgage 9⅜% Bonds, due 2021, Series PP. Proceeds to the Company of approximately $98.7 million, excluding underwriting commissions and accrued interest, were used to redeem $49.3 million principal amount of First Mortgage 11¼% Bonds, due 1995, Series KK, on May 15, 1991 at a redemption price of 101.61 percent of the principal amount and to repay a portion of the Company's short-term debt.

On October 2, 1991, the Company completed the public sale of 100,000 shares of 7.45% Preferred Stock, Series S; 100,000 shares of 7.55% Preferred Stock, Series T; and 100,000 shares of 7.65% Preferred Stock, Series U (Cumulative, $100 par value per share). Aggregate net proceeds to the Company of $29.7 million were used to repay certain of the Company's outstanding short-term debt.

Effective October 1, 1990, the Company's Automatic Dividend Reinvestment and Stock Purchase Plan (ADR Plan) was amended to allow shares acquired for participating shareholders to be either newly-issued shares purchased from the Company or outstanding shares purchased on the open market. For one year prior to that time, all shares for the ADR Plan had been purchased entirely on the open market. As amended, the Plan allows the Company the opportunity to obtain funds to finance a portion of its capital expenditures program and to raise additional equity capital. During 1991, the Company raised a total of $11.3 million to help finance its capital expenditures program by issuing approximately 572,000 new shares of Common Stock through its ADR Plan. New shares issued in 1990 and 1991 through the



MARKET AND BOOK VALUE PER SHARE OF COMMON STOCK—YEAR END

□ Book Value
■ Market Value
▲ Percent of Market Value to Book Value

The market to book ratio for the Company's Common Stock at year-end 1991 was 126 percent.

ADR Plan were purchased from the Company at a market price above the book value per share at the time of purchase. On page 17 is a graph which presents the Company's book value and market value per share of common stock at year-end over the past three years.

Capital Structure. Earnings were reduced by $6.6 million in December 1991 when the Company recorded the after-tax effect of a fuel audit settlement with the PSC (discussed below under New York State Public Service Commission). The Company's retained earnings at December 31, 1991 were $61.5 million, a decrease of approximately $1.0 million compared with December 31, 1990. Common equity (including retained earnings) comprised 40.7 percent of the Company's capitalization at December 31, 1991, with the balance being comprised of 8.7 percent preferred equity and 50.6 percent long-term debt. Adding $96.8 million of long-term debt due within one year at year-end 1991 increases the long-term debt component of capitalization at December 31, 1991 to 53.7 percent and conversely reduces common equity to 38.1 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 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 will consider the redemption of high-cost senior securities and the issuance of new shares of common stock.

RATE BASE AND REGULATORY POLICIES

The Company is subject to regulation of rates, service, and sale of securities, among other matters, by the PSC. The Company was granted authority to increase its rates for electric and gas service effective July 1991. These new rates were based on a forecasted test year for the twelve months ending June 30, 1992. The Company has filed a request with the PSC to increase base rates for electric and gas service effective July 1992. In its rate filing, the Company is seeking full recovery of costs incurred as a result of the March 1991 ice storm discussed on page 12. Other parties in the rate proceedings have proposed various disallowances of these costs. A final decision from the PSC is not expected before June 1992; and, the Company is unable to predict what action the PSC may ultimately take regarding the Company's rate request, including the recovery of storm-related costs.

New York State Public Service Commission (PSC). Recent PSC rate decisions and the Company's pending rate requests are summarized in the table on page 19. Despite a lower authorized return on common equity than that previously allowed, the PSC concluded that the July 1991 rate increases should, for the twelve months ending June 1992, allow the Company to achieve approximately a 2.58 times pretax interest coverage, exclusive of AFUDC and the amortization of deferred Nine Mile Two customer prepaid financing costs (see following paragraph). In addition to the amounts indicated in the table on page 19, the July 1991 PSC rate order authorized the amortization of certain non-cash rate moderators (primarily deferred Nine Mile Two customer prepaid financing costs and unbilled gas revenues) totaling $4.0 million in the Electric Department and $3.5 million in the Gas Department. The July 1991 rate order also provided that $4.0 million of allowed electric revenue increases be subject to refund to customers if the Company did not submit an acceptable interim storm emergency plan by July 1, 1991 and complete its final storm plan update by December 31, 1991 consistent with a PSC review of the Company's response to the

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	January 4, 1988	$ 2,413*	0.5%	10.48%	13.20%
	July 26, 1988	—	—	10.39**	13.40
	July 12, 1990	36,059	6.6	9.91	12.10
	July 1, 1991	33,133	5.5	9.66	11.70
Gas	July 26, 1988	—	—	10.39**	13.40
	July 12, 1990	4,250	1.7	9.91	12.10
	July 1, 1991	1,148	0.4	9.66	11.70

*Second step increase allowed.
**Beginning August 1, 1989, the authorized rate of return on rate base was 10.46%.

Pending

Class of Service	Date of Filing	Amount of Increase* (Annual Basis) (000's)	Percent Increase*	Requested Rate of Return on Rate Base	Requested Rate of Return on Equity
Electric	August 2, 1991	$38,162	6.1%	10.01%	12.50%
Gas	August 2, 1991	15,124	5.0	10.01	12.50

*As amended.

March 1991 ice storm. On June 28, 1991, the Company submitted an interim storm emergency plan to the PSC. On October 30, 1991, the Company forwarded the PSC a copy of its updated storm plan and a minor revision was forwarded in December 1991. Final approval of the plan is pending. While the Company believes that plan substantially satisfies the PSC requirement for a final storm plan, no assurance can be given since such plan is subject to further revision resulting from the Company's own and PSC review.

In a series of rate orders preceding the commercial operation of Nine Mile Two, the Company was allowed to include certain Nine Mile Two plant costs in rate base prior to commercial operation. AFUDC was not accrued on these amounts. Instead, the Company accumulated a similarly calculated amount until commercial operation and recorded it on the Balance Sheet as a deferred credit (liability), with an equivalent amount recorded as a deferred debit (asset). The deferred credit represents customer prepaid financing costs, while the deferred debit represents financing costs (or AFUDC). The latter is expected to be recovered over the life of the facility through amortization if the PSC chooses to utilize these prepaid financing costs to moderate customer rates. For the rate year beginning July 1991, the Company started amortizing $2.5 million of these deferred credits to Other Income as permitted by the PSC's June 1991 rate order. Amortization of these deferred credits to Other Income has aggregated $18.9 million through December 31, 1991. The June 1991 rate order also authorized the Company to write off $6.3 million of deferred and other expenses as an offset to these deferred credit balances. If not used by mid-1994 as non-cash earnings for rate moderation purposes, both the remaining deferred credit and deferred debit balances (estimated to be $24 million at June 30, 1992) would be eliminated by offset. In its 1991 rate filing (see following paragraph), the Company has proposed to amortize an additional $8.3 million of such deferred credits over the rate year ending June 30, 1993.

In August 1991 the Company filed rate requests with the PSC as summarized under the heading "Pending" in the table above. The higher rates have been requested to cover those increases in capital and operating costs projected for the rate year ending June 30, 1993 that are neither adequately provided for

in present rates nor expected to be offset by increased revenues from sales. A PSC decision on this filing is not expected before June 1992.

In its August 1991 rate filing and in a separate petition to the PSC on August 8, 1991, the Company is seeking full recovery of costs incurred as a result of the March 1991 ice storm (see March 1991 Ice Storm, page 12). Storm damage repair costs of $36.4 million have been reflected under deferred debits on the Company's December 31, 1991 balance sheet and a portion of such amount (estimated at 20 percent) is expected to be capitalized as plant additions. The Company has requested recovery of deferred storm-related costs other than capital additions over a period of 25 years, with carrying charges. The staff of the PSC and intervenors have been critical of the Company's performance during the ice storm. The PSC is currently reviewing the Company's request for recovery of storm-related costs, as well as the Company's performance during the storm. The Company believes the storm damage repair costs to be prudent and, therefore, recoverable in rates, but it cannot predict to what extent the recovery of such costs may be affected by the PSC's pending review of the Company's action in response to the storm. Additional information about the March 1991 ice storm may be found in Note 10 of the Notes to Financial Statements.

In November 1991 the PSC issued an order accepting an agreement between the Company and the Staff of the PSC relating to the Company's fuel procurement practices. Under the agreement, the Company will refund $10 million to its electric customers through adjustments on their energy bills over a twelve-month period beginning in January 1992. The Company recognized the settlement agreement in December 1991 and accordingly 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. The Company has agreed to certain changes in its fuel procurement practices, the costs of which will be deferred pending PSC review. The Company believes its fuel procurement operations to be sound and prudent at the time when the decisions were made. The Company, however, would likely have faced years of time-consuming expensive litigation with the PSC and in court to resolve differing views, with no assurance that its views would prevail.

Approval by the PSC of the 1990 Settlement Agreement, which is discussed under the heading Nine Mile Two, resolves all open ratemaking issues with respect to the construction of Nine Mile Two and its operation through January 19, 1990. Currently pending before the PSC is approval of the 1991 Supplemental Agreement, which establishes for Nine Mile Two an allowed level of operating and maintenance expenses for ratemaking purposes through December 31, 1992 (see page 13).

Results of Operations

The following financial review identifies the causes of significant changes in the amounts of revenues and expenses, comparing 1991 to 1990 and 1990 to 1989. The Notes to Financial Statements on pages 32 to 45 of this report contain additional information.

Operating Revenues and Sales

Following a two percent decline in 1990, operating revenues in 1991 were up three percent compared with a year earlier. Increased revenues from the sale of energy to retail electric customers more than offset a decline in gas revenues and electric revenues from the sale of energy to other electric utilities. Rate increases pushed electric retail revenues higher in 1991, while a rate increase to gas customers was more than offset by the weather effect on gas revenues. Details of the revenue changes are presented in the table on page 21.

OPERATING REVENUES

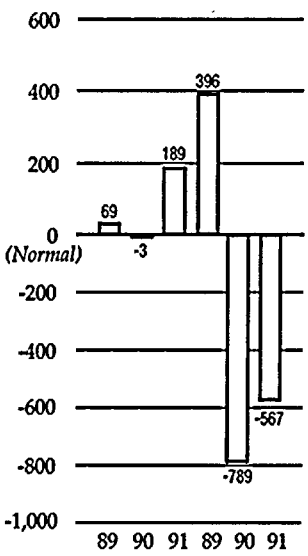
Increase or (Decrease) from Prior Year (Thousands of Dollars)	Electric Department 1991	Electric Department 1990	Gas Department 1991	Gas Department 1990
Customer Revenues (Estimated) from:				
Rate Increases	$33,666	$15,452	$3,106	$ 1,644
Unbilled Revenues, Net	(9,894)	(13,956)	7,557	(22,458)
Fuel Clause Adjustments	2,236	(378)	(4,052)	(298)
Weather Effects (Heating)	(204)	(1,233)	(3,333)	(17,291)
Customer Consumption	7,197	5,202	(3,181)	4,469
Transportation Gas, Net Effect	—	—	(4,036)	(334)
Other	3,999	3,747	3,171	6,191
Total Change in Customer Revenues	37,000	8,834	(768)	(28,077)
Electric Sales to Other Utilities	(13,853)	4,437	—	—
Total Change in Operating Revenues	$23,147	$13,271	$ (768)	$(28,077)

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. Approximately $42 million associated with a 1988 change in accounting to recognize unbilled revenues was amortized to income during the period July 1988 to July 1990. An additional $1.5 million was amortized to income over the twelve-month period ending June 1991. The remaining $3.5 million balance of gas unbilled revenues associated with this change in accounting is being amortized to income over the rate year commencing July 1991. The Company also records monthly accruals for unbilled revenues. The Company's Statement of Income reflects net unbilled revenues of $41.4 million in 1989, $5.0 million in 1990, and $2.6 million in 1991. Primarily as a result of the seasonal nature of gas revenues, unbilled revenues will normally be near their maximum around January and at their minimum near the end of June.

The Company's fuel clause provisions currently provide that customers and shareholders will share, generally on an 80%/20% basis, respectively, 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 amounts. As a result of these sharing arrangements, discussed further in Note 1 of the Notes to Financial Statements, pretax earnings were increased $2.6 million in 1990 and increased $2.4 million in 1991, primarily reflecting actual experience in both electric fuel costs and generation mix compared with rate assumptions. In addition, beginning in September 1990, fuel clause revenues include the recovery of margins (revenues less incremental cost of fuel) not currently provided for in base rates and which are not collected due to the implementation of the Company's energy efficiency programs (discussed below in this section).

The effect of weather variations on operating revenues is most measurable in the Gas Department, where revenues from space heating customers comprise about 85 percent of total gas operating revenues. As displayed by the graph to the left on page 22, the Company's service area experienced unseasonably mild weather during the 1990 heating months, and this pattern continued into 1991. Aside from 1990s first quarter, the first quarter of 1991 had the fewest degree days since 1983, and on a calendar month heating degree day basis, the second quarter of 1991 was 26.4 percent warmer than the comparable period a year earlier. Warmer-than-normal weather, which contributed to lower earnings earlier in the year, worked in the Company's

favor in the third quarter of 1991 when hot, dry conditions led to increased kilowatt-hour sales of electricity to meet the demand for air conditioning usage. Overall, 1991 was 8.4 percent warmer than normal but 3.7 percent cooler than 1990. This continues a trend established in 1990, when the weather was 11.8 percent warmer than normal and 16.7 percent warmer than 1989.



DEGREE DAY VARIATIONS FROM NORMAL

☐ Cooling Degree Days* (May-Sept.)
☐ Heating Degree Days* (Jan.-Dec.)

Normal	
Heating degree days	6,713
Cooling degree days	531

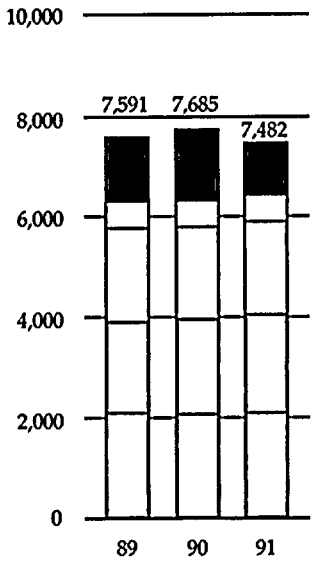
** Each degree of mean daily temperature above 65 degrees is considered to be one cooling degree day; below 65 degrees is considered to be one heating degree day.*

Kilowatt-hour sales of energy to retail customers continued to grow in 1991, up one percent over 1990, as indicated by the graph to the lower right. Excluding the effects of the March 1991 ice storm, these sales would have been stronger. During 1991, an increase in sales to residential and commercial customers more than offset a decline in sales to industrial customers. Industrial sales were down as certain local manufacturing companies felt the constraints of the national economy. After a relatively cool summer in 1990, warmer weather during the 1991 summer months boosted electric energy sales for air conditioning usage. Electric energy sales in 1991 were also boosted by the impact of over 2,300 new customers added during the year.

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. A small incentive allowance (award) of approximately $367,000 was provided for in the Company's June 1991 rate decision based on the Company's DSM performance through December 31, 1990. The reduction in margins (revenues less incremental cost of fuel) resulting from the implementation of DSM projects is estimated and recovered in rates.

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. Compared with 1989, electric energy sales to other utilities in 1990 also reflect the impact of higher contract sales of energy. A decline in these contract sales, together with generally lower New York Power Pool requirements, led to lower kilowatt-hour sales to other utilities in 1991.

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 10.9 million

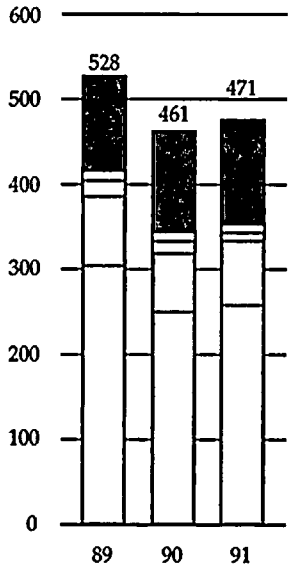


ELECTRIC MARKET PROFILE
(thousands of mwh sold)

■ Other Utilities
☐ Other
☐ Industrial
☐ Commercial
☐ Residential

Electric energy sales reflect a well-balanced sales mix.

dekatherms in 1991 and 9.9 million dekatherms in 1990. These purchases have caused decreases in customer revenues, as shown in the table on page 21, with offsetting decreases in fuel 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.



GAS MARKET PROFILE
(millions of therms sold and transported)

- Transported
- Other
- Industrial
- Commercial
- Residential

The Company's gas market profile reflects a balanced mix between residential and non-residential customers.

After falling 12.7 percent in 1990, total therms of gas sold and transported, including unbilled sales, increased 2.2 percent as shown by the graph to the left. These fluctuations reflect, primarily, the effect of weather variations on therm sales to customers with space heating. If adjusted for normal weather conditions and the March 1991 ice storm, residential gas sales would have declined about one percent in 1991 over 1990, while nonresidential sales, including gas transported, in 1991 would have decreased by approximately 2.2 percent compared with a year earlier. The average use per residential gas spaceheating customer, when adjusted for normal weather conditions, was down in 1991; but, the effects of this decline were moderated by a growth in customers. Total therms of gas transported increased in 1991, primarily as a result of higher sales to certain large industrial and municipal transportation customers.

Increases in "Other" customer revenues shown in the table on page 21 for both comparison periods is largely the result of revenues associated with New York State taxes enacted in 1990 and 1991 (see Taxes Charged to Operating Expenses), increased miscellaneous gas revenues, and, for 1990, the effect of more customer consumption (billing) days compared with a year earlier.

OPERATING EXPENSES

Compared with a year earlier, operating expenses climbed a modest two percent in 1991 after remaining nearly flat in 1990. A significant share of the increase in 1991 operating expenses over 1990 resulted from higher local, state and other taxes. A summary of the change in operating expenses for the 1991 and 1990 comparison periods is presented in the table below. Non-fuel pretax operating expenses estimated by the Company to be approximately $29 million and which were associated with a severe ice storm during 1991 are being deferred pending the PSC's review of the recovery of storm-related costs (see New York State Public Service Commission).

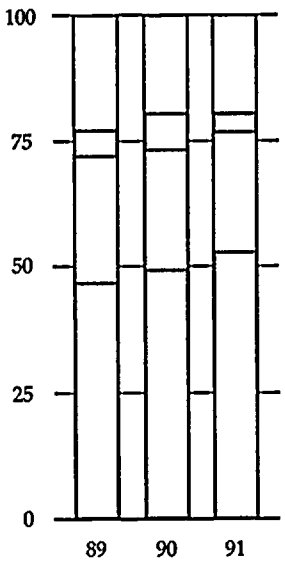
Energy Costs—Electric. For the 1991 comparison period, less generation from the Company's fossil-fueled units was largely responsible for the decrease in fuel expenses

OPERATING EXPENSES

Increase or (Decrease) from Prior Year

(Thousands of Dollars)	1991	1990
Fuel for Electric Generation	**$ (11,315)**	$ 547
Purchased Electricity	**(6,581)**	(5,381)
Gas Purchased for Resale	**(2,733)**	(20,111)
Other Operation	**13,846**	20,830
Maintenance	**3,024**	(1,925)
Depreciation	**8,346**	7,783
Amortization of Other Plant	**(1,932)**	(5,079)
Taxes Charged to Operating Expenses		
Local, State and Other Taxes	**12,614**	5,694
Federal Income Tax	**(231)**	(3,349)
Total Change in Operating Expenses	**$ 15,038**	$ (991)

for electric generation. In addition, lower nuclear fuel costs during 1991 contributed to a drop in fuel expenses. Likewise, an electric generation mix favoring less expensive nuclear fuel, compared with the cost of coal or oil, kept the increase in fuel expenses relatively less than the increase in electric generation for the 1990 comparison period. To the left is a graph which presents the Company's electric generation mix by fuel type.



SOURCES OF ELECTRIC GENERATION BY FUEL TYPE
(percent)

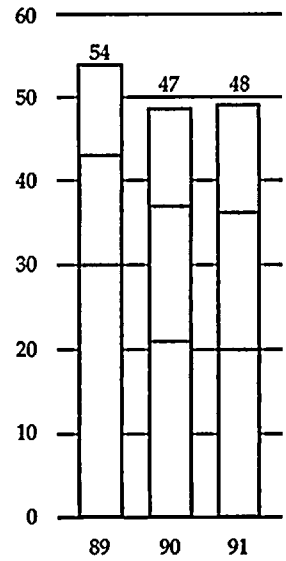
- Purchased Power
- Other (Oil, Gas, Hydro)
- Coal
- Nuclear

Not having to rely on one type of fuel provides the Company with more reliable energy supplies.

Average rates for purchased electricity declined in 1991, after increasing during 1990. These lower average rates, in addition to a drop in kilowatt-hours purchased, also contributed to a lower purchased electricity expense in 1991. The decrease in purchased electricity expense for the 1990 comparison period resulted from fewer kilowatt-hours being purchased.

Energy Costs and Supply—Gas. The Company has renegotiated its contract with CNG Transmission Corporation (CNG), such that CNG is to provide a combination of unbundled services (storage and transmission of Company-purchased gas) for approximately 20% of the Company's annual gas purchases, and bundled sales services (including gas supply, storage and transmission) for the remainder of the Company's annual supplies not otherwise purchased for transport to the Company via the proposed Empire project (see Projected Capital and Other Requirements). The Company began receiving service under this new contract on July 1, 1991, for a period of ten years. The Company further expects that it will annually purchase a quantity of gas equal to 25% of the CNG bundled sales service gas supply from other sources under short-term contracts when: 1) those supplies are available at prices lower than CNG's commodity price and 2) the acquisition of those short-term supplies would not jeopardize the reliability of the Company's long-term supply or unduly increase its cost. Sources of gas supplied to the Company over the past three years are presented by the graph below. Under its contract with CNG, the Company has obtained rights to 4.2 million dekatherms of CNG storage capacity. With underground natural gas storage capability, the Company will be in a better position to take advantage of off-peak season purchases of gas and enhance its supply reliability. Also, in connection with the Empire project, additional transportation agreements have been entered into with pipelines upstream of Empire that permit the Company to directly access U.S. and Canadian natural gas supplies and storage facilities once Empire becomes operational.

Compared with a year earlier, the average rate for gas purchased for resale in 1991 declined. These lower average rates were partially offset by an increase in the volume of gas purchased for resale, in contrast to 1990 when lower volumes of gas purchased led to a drop in the cost of gas purchased for resale. The average rate for gas purchased for resale in 1990 was slightly higher than in 1989.



GAS SUPPLY FOR DISTRIBUTION
(millions of dekatherms)

- Transportation gas
- Gas purchased on spot market
- Gas purchased under firm contract

Gas purchased on the spot market is expected to continue to be a part of the Company's total gas supply.

Operating Expenses, Excluding Fuel. Other operation expenses rose over both comparison periods, as shown in the table on page 23; however, the increase in these costs for the 1991 comparison period was lower by $7 million. Both the 1991 and 1990 comparison periods reflect higher payroll costs. In 1991, these costs were partially offset by lower payments for external contractor and consulting services. Increasing other operation expenses in 1991 by $5.9 million were higher transmission wheeling charges on purchased electricity and increased NRC and PSC regulatory assessments. Compared with a year earlier, other operation expenses in 1990 reflect about $3.8 millon of expense associated with the effects of accounting procedures to recognize certain deferred Nine Mile Two revenues and expenses. The 1990 comparison period also reflects additional expense of $5.6 million associated with the Company's share of Nine Mile Two operation expenses. Compared with 1990, these Nine Mile Two costs were down slightly in 1991.

The Company will be adopting new accounting principles for financial reporting purposes effective the first quarter of 1992 as set forth in a Statement of Financial Accounting Standards entitled "Accounting for Postretirement Benefits Other Than Pensions" (SFAS-106) which was issued by the Financial Accounting Standards Board (FASB) in December 1990. Among other things, SFAS-106 requires accrual accounting for postretirement benefits other than pensions. The Company had recorded the cost of such benefits on a current basis. In conformity with the accounting principles set forth in SFAS-106, the Company will begin to recognize a portion of the actuarial present value of the estimated benefits to be paid to active employees after they retire. In addition, the Company has estimated the actuarial present value of its accrued liability for postretirement benefits for past years of employment for both current employees and current retirees and will amortize that liability over a twenty-year period. Adoption by the Company of SFAS-106 will increase the Company's annual expense for postretirement benefits, but the impact on the Company's expenses is moderated by the defined-dollar nature of its benefits. The initial incremental cost under SFAS-106 at the time of its adoption is estimated to be $4.3 million pretax, and recognition of these costs through July 1, 1992 was included in the Company's June 1991 rate decision.

Maintenance expense was up in 1991 primarily as a result of increased activity associated with electric production facilities at the Ginna nuclear plant and electric distribution facilities. Following the additional expense associated with an intensive ten-year inspection at the Company's Ginna nuclear plant a year earlier, maintenance expense declined in 1990.

Depreciation increased in both comparison periods primarily due to increases in depreciable plant. In addition, depreciation expense includes an accrual for future nuclear plant decommissioning expenses; and, an increase of approximately $3 million in such accrued expense contributed to higher depreciation expense for each of the comparison periods. Amortization expense was reduced as a result of a reduction in the amortization of the Sterling project property loss.

Taxes Charged to Operating Expenses. The increase in local, state and other taxes for both comparison periods resulted from increases in revenue taxes which were impacted by a one-half percent increase in the New York State gross revenue tax beginning in July 1991, retroactive to January 1, 1991 and a New York State 15 percent surtax on gross receipts beginning in July 1990, retroactive to January 1, 1990. Also, higher assessments and tax rates on property increased these taxes.

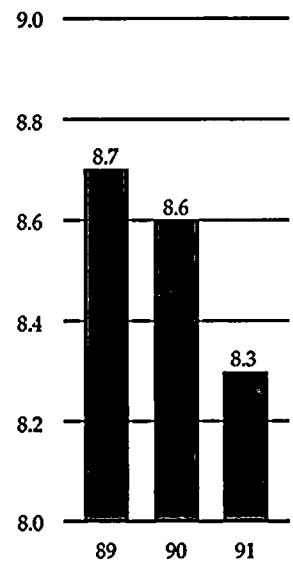
In December 1987, the FASB issued a Statement of Financial Accounting Standards entitled "Accounting for Income Taxes" (SFAS-96). Among other things, SFAS-96 requires the Company to adjust certain of its deferred tax assets and liabilities to reflect periodic changes in tax rates. In addition, the Company may also be required to provide deferred taxes for the effect of tax benefits previously flowed through to the Income Statement. SFAS-96 is currently not required to be adopted by the Company. An exposure draft which presents a comprehensive accounting standard built largely on the existing SFAS-96, but which has been modified in many respects, was issued by the FASB in July 1991 and, if ultimately adopted, would supersede SFAS-96. This exposure draft continues to be deliberated by the FASB. Since the Company's deferred taxes have been adjusted for regulatory purposes to the current statutory rate where permissible, the impact of either SFAS-96 or the accounting requirements contained in the exposure draft is believed to be immaterial. See Note 2 of the Notes to Financial Statements for an analysis of federal income taxes.

Other Statement of Income Items

Recognition of the 1991 PSC order relating to the Company's fuel procurement practices (see page 20) is recorded under the caption "Other Income and Deductions" on the Statement of Income. Also reported under this caption is the Company's 1989 writeoff of additional disallowed Nine Mile Two plant costs.

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 7.10 percent effective July 1991 from earlier rates of 8.60 percent, 9.60 percent and 10.25 percent.

Other Income includes $4.8 million of non-cash earnings in 1991 and $3.3 million in 1990 associated with the amortization of customer prepaid Nine Mile Two financing costs which had been deferred, as discussed under the heading New York State Public Service Commission (PSC). The fluctuation in Other Income for the 1990 comparison period primarily reflects a decrease in interest income received from temporary cash investments.



Embedded Cost of Long-term Debt—Year End
(percent)

The refinancing of high-cost bonds helped to reduce the embedded cost of long-term debt in 1991.

Both mandatory and optional redemptions of certain higher-cost first mortgage bonds have helped to reduce long-term debt expense interest over the three-year period 1989-1991, despite the issuance of additional long-term debt in 1991. A graph of the Company's embedded cost of long-term debt is presented above.

Earnings/Summary

Presented on page 27 is a table which summarizes the Company's Common Stock earnings in total and on a per-share basis as reported and as modified to exclude disallowed Nine Mile Two costs written off in 1989. As previously explained, Common Stock earnings per share in 1991 were reduced by an estimated $.11 as a result of the March ice storm and by $.21 per share in the fourth quarter when the Company recorded the

effects of the fuel procurement settlement approved by the PSC. Future earnings may be affected by the outcome of the PSC's review of the Company's request to recover deferred storm-related costs associated with the March 1991 ice storm, as discussed on page 20.

In December 1990 the Company announced a quarterly dividend increase from $.39 to $.405 per share of Common Stock payable in January 1991. Subsequently, on December 18, 1991 the Company announced a new quarterly dividend rate of $.42 per share payable in January 1992. 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. Accordingly, dividend payments are dependent on future earnings, in addition to financial requirements and other factors.

EARNINGS SUMMARY

	Earnings (Thousands of Dollars)	Shares[1] (Thousands)	Earnings per Share
1991			
As Reported	$51,034	31,794	$1.60
1990			
As Reported	$53,856	31,293	$1.72
1989			
As Reported	$65,419	31,090	$2.10
Excluding Nine Mile Two Write-Off Adjustment	$66,819[2]	31,090	$2.15

[1]Weighted average shares outstanding.
[2]Reported earnings modified to exclude disallowed Nine Mile Two costs written off in 1989.

Board Appointment

At the 1991 annual meeting of shareholders in May, Allan E. Dugan was elected to the board of directors. He is senior vice president, corporate strategic services, of Xerox Corporation. Mr. Dugan replaced Mr. E. Kent Damon, former vice president and secretary of Xerox Corporation, who retired from the board after 19 years of service as a director.

FINANCIAL REPORTS

TABLE OF CONTENTS	PAGE

Statement of Income

(Thousands of Dollars) Year Ended December 31	1991	1990	1989
Operating Revenues			
Electric	$588,930	$551,930	$543,096
Gas	235,728	236,496	264,573
	824,658	788,426	807,669
Electric sales to other utilities	28,612	42,465	38,028
Total Operating Revenues	853,270	830,891	845,697
Operating Expenses			
Fuel Expenses			
Fuel for electric generation	65,105	76,420	75,873
Purchased electricity	27,683	34,264	39,645
Gas purchased for resale	129,779	132,512	152,623
Total Fuel Expenses	222,567	243,196	268,141
Operating Revenues Less Fuel Expenses	630,703	587,695	577,556
Other Operating Expenses			
Operations excluding fuel expenses	208,440	194,594	173,764
Maintenance	65,415	62,391	64,316
Depreciation and amortization	84,181	77,767	75,063
Taxes—local, state and other	113,649	101,035	95,341
Federal income tax	34,259	34,490	37,839
Total Other Operating Expenses	505,944	470,277	446,323
Operating Income	124,759	117,418	131,233
Other Income and Deductions			
Allowance for other funds used during construction	675	2,689	2,261
Federal income tax	4,580	2,459	1,439
Fuel audit disallowance	(10,000)	—	—
Disallowed project costs	—	—	(2,100)
Other, net	6,078	4,062	8,328
Total Other Income and Deductions	1,333	9,210	9,928
Income Before Interest Charges	126,092	126,628	141,161
Interest Charges			
Long term debt	63,918	64,873	68,628
Other, net	7,082	4,593	3,115
Allowance for borrowed funds used during construction	(2,905)	(2,719)	(2,026)
Total Interest Charges	68,095	66,747	69,717
Net Income	57,997	59,881	71,444
Dividends on Preferred Stock	6,963	6,025	6,025
Earnings Applicable to Common Stock	$ 51,034	$ 53,856	$ 65,419
Weighted Average Number of Shares for Period (000's)	31,794	31,293	31,090
Earnings per Common Share	$1.60	$1.72	$2.10

Statement of Retained Earnings

(Thousands of Dollars) Year Ended December 31	1991	1990	1989
Balance at Beginning of Period	$ 62,542	$ 57,983	$ 39,710
Add			
Net Income	57,997	59,881	71,444
Total	120,539	117,864	111,154
Deduct			
Dividends declared on capital stock			
Cumulative preferred stock	6,963	6,025	6,025
Common stock	52,061	49,297	47,146
Total	59,024	55,322	53,171
Balance at End of Period	$ 61,515	$ 62,542	$ 57,983

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

BALANCE SHEET

(Thousands of Dollars) At December 31	1991	1990
ASSETS		
Utility Plant		
Electric	$2,122,248	$1,674,307
Gas	320,385	304,308
Common	116,858	104,460
Nuclear fuel	147,063	227,219
	2,706,554	2,310,294
Less: Accumulated depreciation	1,067,471	628,571
Nuclear fuel amortization	111,178	184,423
	1,527,905	1,497,300
Construction work in progress	76,848	82,663
Net Utility Plant	1,604,753	1,579,963
Current Assets		
Cash and cash equivalents	1,488	544
Accounts receivable, net of allowance for doubtful accounts: 1991—$411; 1990—$591	84,053	79,280
Unbilled revenue receivable	55,921	49,172
Materials and supplies, at average cost		
Fossil fuel	10,766	18,272
Construction and other supplies	12,539	12,224
Gas stored underground	7,057	—
Prepayments	17,185	16,553
Total Current Assets	189,009	176,045
Deferred Debits		
Unamortized debt expense	9,611	8,943
Deferred finance charges—Nine Mile project	25,586	35,578
Deferred ice storm charges	36,431	—
Other	88,406	63,930
Total Deferred Debits	160,034	108,451
Total Assets	$1,953,796	$1,864,459
CAPITALIZATION AND LIABILITIES		
Capitalization		
Long term debt—mortgage bonds	$ 530,422	$ 579,712
—promissory notes	141,900	141,900
Preferred stock redeemable at option of Company	67,000	67,000
Preferred stock subject to mandatory redemption	60,000	30,000
Common shareholders' equity		
Common stock	529,339	516,388
Retained earnings	61,515	62,542
Total Common Shareholders' Equity	590,854	578,930
Total Capitalization	1,390,176	1,397,542
Long Term Liability—Department of Energy	63,626	59,989
Current Liabilities		
Long term debt due within one year	96,750	40,250
Short term debt	59,500	42,400
Accounts payable	53,983	47,069
Dividends payable	15,555	14,235
Taxes accrued	12,050	10,606
Interest accrued	16,313	14,591
Pension costs accrued	13,515	5,780
Other	13,450	14,569
Total Current Liabilities	281,116	189,500
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes	162,955	153,874
Deferred finance charges—Nine Mile project	25,586	35,578
Other	30,337	27,976
Total Deferred Credits and Other Liabilities	218,878	217,428
Commitments and Other Matters (Note 10)		
Total Capitalization and Liabilities	$1,953,796	$1,864,459

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

Statement of Cash Flows

(Thousands of Dollars) Year Ended December 31	1991	1990	1989
Cash Flow from Operations			
Net income	$ 57,997	$ 59,881	$ 71,444
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation and amortization	84,181	77,767	75,063
Amortization of nuclear fuel	23,606	25,573	21,923
Deferred fuel—electric	4,122	(477)	(3,287)
Deferred income taxes	9,124	16,682	19,847
Allowance for funds used during construction	(3,580)	(5,408)	(4,287)
Disallowed project costs—Nine Mile plant	—	—	2,100
Unbilled revenue, net	(8,931)	(2,818)	(37,542)
Ice storm costs deferred	(36,431)	—	—
Decommissioning fund	(15,581)	(3,640)	—
Changes in certain current assets and liabilities:			
Accounts receivable	(4,773)	1,519	(17,071)
Materials and supplies—fossil fuel	7,506	(5,183)	(4,869)
—construction and other supplies	(315)	(1,246)	(1,800)
Taxes accrued	1,444	(2,805)	7,419
Accounts payable	6,914	(6,077)	13,802
Interest accrued	1,722	(690)	(371)
Other current assets and liabilities, net	7,143	(1,906)	(3,542)
Other, net	(14,701)	920	1,071
Total Operating	$ 119,447	$ 152,092	$ 139,900
Cash Flow from Investing Activities			
Utility Plant			
Plant additions	$(114,579)	$(123,887)	$(112,034)
Nuclear fuel additions	(13,058)	(8,297)	(12,901)
Less: Allowance for funds used during construction	3,580	5,408	4,287
Additions to Utility Plant	(124,057)	(126,776)	(120,648)
Sterling project property loss	—	—	(1,604)
Other, net	(685)	(98)	683
Total Investing	$(124,742)	$(126,874)	$(121,569)
Cash Flow from Financing Activities			
Proceeds from:			
Sale of common stock	$ 13,446	$ 3,058	$ 8,761
Sale of preferred stock	30,000	—	—
Sale of long term debt, mortgage bonds	100,000	—	—
Short term borrowings	17,100	42,400	—
Retirement of long term debt	(92,334)	(28,000)	(37,833)
Capital stock expense	(495)	(230)	(108)
Discount and expense of issuing long term debt	(3,310)	—	(237)
Dividends paid on preferred and common stock	(57,704)	(54,787)	(52,525)
Other, net	(464)	908	244
Total Financing	$ 6,239	$ (36,651)	$ (81,698)
Increase (decrease) in cash and cash equivalents	$ 944	$ (11,433)	$ (63,367)
Cash and cash equivalents at beginning of year	$ 544	$ 11,977	$ 75,344
Cash and cash equivalents at end of year	$ 1,488	$ 544	$ 11,977

Supplemental Disclosure of Cash Flow Information

(Thousands of Dollars) Year Ended December 31	1991	1990	1989
Cash Paid During the Year			
Interest paid (net of capitalized amount)	$ 63,848	$ 64,851	$ 67,716
Income taxes paid	$ 20,399	$ 17,516	$ 10,996

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. The subsidiary activity has to date remained insignificant to the Company's financial position and results of operation.

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

RATES AND REVENUE

Revenue is recorded on the basis of meters read. In addition, beginning in July 1988, as part of a PSC rate decision, the Company commenced recording an estimate of unbilled revenue for service rendered subsequent to the meter-read date through the end of the accounting period. Pursuant to the 1988, 1990 and 1991 rate orders, $2.2 million, $13.8 million and $20.5 million was amortized to earnings in lieu of cash rate relief in 1991, 1990 and 1989, respectively. Approximately $2.4 million will be similarly amortized subsequent to 1991.

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 an 80%/20% basis up to a $2.6 million cumulative, after-tax, 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 net revenues on sales to electric utilities be shared on the same 80%/20% basis.

In addition, there is a similar 80%/20% 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.

In December 1991, the Company recognized a non-cash charge against earnings of $10 million for refunds to be made to customers in connection with a PSC fuel procurement audit. This refund will occur in 1992.

DEFERRED FUEL COSTS

The Company practices fuel cost deferral accounting as prescribed by the PSC under the electric and gas cost adjustment clauses included in the tariff schedules of the Company. 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 reflected 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 3.3%, 3.5% and 3.4% per annum of average depreciable property in 1991, 1990 and 1989, respectively. Amortization includes $.3 million in 1991, $2.2 million in 1990 and $7.3 million in 1989 related to the Sterling project property loss.

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 in June 1985. The Company estimates the fees, including accrued interest, owed to the DOE to be $63.6 million at December 31, 1991. The Company is allowed by the PSC to recover in rates these costs. The estimated fees are classified as a long-term liability and interest is accrued at the current three-month Treasury bill rate, adjusted quarterly. The Act also requires the DOE to provide for the disposal of nuclear fuel irradiated after April 6, 1983, for a charge of one mill ($.001) per KWH generated at nuclear plants. 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 $134.7 million, and those for the Company's 14% share of Unit 2's decommissioning costs are estimated to be approximately $30.6 million (1991 dollars). Through December 31, 1991, the Company has accrued and recovered in rates $42.8 million for this purpose and is currently accruing for decommissioning costs at a rate of approximately $10.1 million per year based on the use of a combination of internal and external sinking funds. (See Note 10.)

The decommissioning costs, which form the basis for current accruals, were derived from the record of the Company's prior rate proceeding (PSC Opinion 91-13, issued June 1991).

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 gross rates approved by the PSC for purposes of computing AFUDC were: 7.1% effective July 1, 1991; 8.6% effective February 1, 1991 through June 30, 1991; 9.6% effective July 1, 1990 through January 31, 1991; and 10.25% effective January 1, 1988 through June 30, 1990.

(Note 1 continued on page 34)

NOTES TO FINANCIAL STATEMENTS

(continued from page 33)

Effective July 16, 1984, pursuant to PSC authorization, the Company discontinued accruing AFUDC on $50 million of construction work in progress related to its investment in Unit 2 for which a cash return was being allowed through its inclusion in rate base. An additional $150 million and $230 million were included in rate base, effective July 9, 1985 and July 14, 1986, respectively, as authorized by the PSC, and AFUDC accruals were likewise discontinued. The PSC also ordered in 1984 that amounts be 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 would be available to reduce future revenue requirements over a period substantially shorter than the life of Unit 2, and the balance in the deferred debit account would then be collected from customers over a longer period of time. In July 1988, in accordance with PSC Opinion 88-21, the Company eliminated by offset one-half of the deferred debit and credit balances in connection with the unused portion of customer prepaid financing costs associated with Unit 2, reducing the cumulative balance to $44.7 million. The balances of $25.6 million at December 31, 1991, if not used by mid-1994, may be offset against each other pursuant to PSC directives. In connection with the Company's 1991 rate case decision, $2.5 million will be amortized through the Statement of Income during the year commencing July 1, 1991.

FEDERAL INCOME TAX

For income tax purposes, depreciation is 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. The cumulative balance of tax deductions not offset by provisions for deferred income taxes through 1991 is approximately $415 million.

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

SFAS-96, Accounting for Income Taxes (as amended by SFAS-108), has not yet been adopted by the Company. SFAS-96 requires adoption in calendar year 1993 and 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. The Company presently believes the impact for SFAS-96 to be immaterial.

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. The Company recognizes the costs of providing these benefits as a current expense.

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 will adopt this accounting practice in the first quarter of 1992.

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)	1991	1990	1989
Charged to operating expense:			
Current	$28,766	$20,660	$20,509
Deferred	5,493	13,830	17,330
Total	34,259	34,490	37,839
Charged (Credited) to other income:			
Current	(8,211)	(5,311)	(3,956)
Deferred	3,631	2,852	2,517
Total	(4,580)	(2,459)	(1,439)
Total Federal income tax expense	$29,679	$32,031	$36,400

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)	1991		1990		1989	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
Net Income	$57,997		$59,881		$ 71,444	
Add: Federal income tax expense	29,679		32,031		36,400	
Income before Federal income tax	$87,676		$91,912		$107,844	
Computed tax expense	$29,810	34.0	$31,250	34.0	$ 36,667	34.0
Increases (decreases) in tax resulting from:						
Difference between tax depreciation and amount deferred	5,606	6.4	4,127	4.5	3,646	3.4
Investment tax credit	(2,432)	(2.8)	(2,752)	(3.0)	(2,853)	(2.6)
Miscellaneous items, net	(3,305)	(3.7)	(594)	(0.7)	(1,060)	(1.0)
Total Federal income tax expense	$29,679	33.9	$32,031	34.8	$ 36,400	33.8

A summary of the deferred amounts charged or (credited) to income is as follows:

(Thousands of Dollars)	1991	1990	1989
Investment tax credit	$ (4,235)	$ (2,414)	$ (1,448)
Depreciation	24,158	22,906	25,473
Fuel costs	205	1,180	338
Sterling abandonment	512	(796)	(3,179)
Deferred ice storm charges	9,666	—	—
Accrued revenue	(353)	1,596	4,416
Disallowed project costs	—	—	(1,077)
Alternative Minimum Tax	(13,768)	(2,475)	(5,016)
Revenues Deferred—Nine Mile Two	(2,413)	1,028	4,604
Pension	(2,721)	(2,729)	(898)
Other items	(1,927)	(1,614)	(3,366)
Total	$ 9,124	$16,682	$19,847

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. 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)	1991	1990
Accumulated benefit obligation, including vested benefits of $237.4 in 1991 and $207.1 in 1990	$251.9*	$219.7*
Projected benefit obligation for service rendered to date	$359.7*	$311.9*
Less—Plan assets at fair value, primarily listed stocks and bonds	433.3	357.1
	(73.6)	(45.2)
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions	98.0	62.7
Less—Prior service cost not yet recognized in net periodic pension cost	5.5	5.8
Less—Unrecognized net obligation at December 31	5.4	5.9
Pension liability recognized on the balance sheet	$ 13.5	$ 5.8

*Actuarial present value

Net pension cost included the following components:

(Millions)	1991	1990	1989
Service cost—benefits earned during the period	$ 7.1	$ 7.3	$ 6.4
Interest cost on projected benefit obligation	26.4	25.3	23.7
Actual return on plan assets	(58.6)	(9.0)	(63.5)
Net amortization and deferral	33.1	(15.1)	43.1
Net periodic pension cost	$ 8.0	$ 8.5	$ 9.7

The projected benefit obligation at December 31, 1991 and 1990 assumed discount rates of 7¾ percent and 8½ percent, respectively, and a long-term rate of increase in future compensation levels of 6½ percent and 7 percent, respectively. The assumed long-term rate of return on plan assets at December 31, 1991 and 1990 was 8½ percent. The unrecognized net obligation is being amortized over 15 years beginning January 1986.

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits for retired employees and health care coverage for surviving spouses of retirees (see Note 1). The cost of providing these benefits was approximately $3.0 million in 1991, $2.5 million in 1990, and $2.2 million in 1989.

During the first quarter of 1992, the Company will adopt SFAS-106 "Accounting for Postretirement Benefits Other than Pensions". The Company estimates that the net periodic cost for postretirement benefits at the time of adoption will be approximately $6.6 million based on accrual accounting required by SFAS-106. The net periodic cost includes approximately $2.2 million amortization of the unrecognized transition obligation (the accumulated postretirement benefit obligation at adoption), currently estimated at $45 million and to be amortized over twenty years. In accordance with its latest rate proceeding (PSC Opinion 91-13), the Company has been provided revenues in rates equal to the expenses to be accrued.

NOTE 4. DEPARTMENTAL FINANCIAL INFORMATION

The Company's records are maintained by operating departments, in accordance with PSC accounting policies, giving effect to the rate-making 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)	1991	1990	1989
ELECTRIC			
Operating Information			
Operating revenues	$ 617,542	$ 594,395	$ 581,124
Operating expenses, excluding provision for income taxes	478,101	464,478	445,539
Pretax operating income	139,441	129,917	135,585
Provision for income taxes	31,390	30,670	29,887
Net operating income	$ 108,051	$ 99,247	$ 105,698
Other Information			
Depreciation and amortization	$ 72,746	$ 67,302	$ 65,287
Nuclear fuel amortization	$ 23,606	$ 25,573	$ 21,923
Capital expenditures	$ 97,294	$ 101,024	$ 98,646
Investment Information			
Identifiable assets (a)	$1,607,210	$1,557,176	$1,522,334
GAS			
Operating Information			
Operating revenues	$ 235,728	$ 236,496	$ 264,573
Operating expenses, excluding provision for income taxes	216,151	214,505	231,086
Pretax operating income	19,577	21,991	33,487
Provision for income taxes	2,869	3,820	7,952
Net operating income	$ 16,708	$ 18,171	$ 25,535
Other Information			
Depreciation and amortization	$ 11,435	$ 10,465	$ 9,776
Capital expenditures	$ 26,763	$ 25,752	$ 22,002
Investment Information			
Identifiable assets (a)	$ 325,451	$ 291,088	$ 284,511

(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)	
Plant in Service Balance 12/31/91	$95.5	$868.2
Accumulated Provision for Depreciation 12/31/91	$28.6	$420.8
Plant Under Construction 12/31/91	$ 3.0	$ 9.7

The Plant in Service and Accumulated Provision for Depreciation balances for Nine Mile Point Nuclear Unit No. 2 shown above have been increased by 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 1991	1990
4½	T	Nov. 15, 1991	$ —	$ 15,000
4¾	U	Sept. 15, 1994	16,000	16,000
5.3	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	Y	Aug. 15, 1999	30,000	30,000
9¼	Z	Sept. 1, 2000	30,000	30,000
9¼	BB	June 15, 2006	50,000	50,000
8¾	CC	Sept. 15, 2007	50,000	50,000
9½	DD	Dec. 1, 2003	40,000	40,000
6½	EE	Aug. 1, 2009	10,000	10,000
10.95	FF	Feb. 15, 2005	27,500	33,000
12¼	HH	May 15, 2012	10,500	10,500
13¾	JJ	June 15, 1999	20,000	22,500
11¼	KK	May 15, 1995	—	49,334
8.6	LL	Aug. 1, 1993	75,000	75,000
8¾	MM	May 1, 1992	75,000	75,000
11¾	NN	June 15, 1993	—	20,000
8¾	OO	Dec. 1, 2028	25,500	25,500
9¾	PP	Apr. 1, 2021	100,000	—
			627,500	619,834
Net bond (discount) premium			(328)	128
Less: Due within one year			96,750	40,250
Total			$530,422	$579,712

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 1990 and 1991 requirements were met by certification of additional property.

The Series EE, Series HH and Series OO 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 B and Series C, respectively (Rochester Gas and Electric Corporation Projects) issued by the New York State Energy Research and Development Authority through a participation agreement with the Company. 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.

The Series FF First Mortgage Bonds are subject to a mandatory sinking fund of $2.75 million annually which began on February 15, 1986 and will continue each February 15, with the noncumulative option to double the payment in any year up to a maximum of 5 years. Annually, since 1988, the Company exercised this option and redeemed an additional $2.75 million of Series FF Bonds in each year and the Company expects to exercise this option to redeem an additional $2.75 million in February 1992. On February 18, 1992 the Company will exercise its option to redeem $16.5 million principal amount of these bonds at a price of 105.48%.

The Series JJ First Mortgage Bonds are subject to a mandatory sinking fund of $2.5 million annually, which began on June 15, 1990, and will continue each June 15 thereafter.

The Series LL and MM First Mortgage Bonds are not redeemable prior to maturity.

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

(Thousands)	1992	1993	1994	1995	1996
Series FF	$19,250*	$ 2,750	$ 2,750	$ 2,750	
Series JJ	2,500	2,500	2,500	2,500	$ 2,500
Series MM	75,000				
Series LL		75,000			
Series U			16,000		
Series V					18,000
	$96,750*	$80,250	$21,250	$ 5,250	$20,500

* Includes planned redemption of $16.5 million of Series FF on February 18, 1992.

PROMISSORY NOTES

		(Thousands) December 31	
Issued	Due	1991	1990
November 15, 1984	October 1, 2014	$ 51,700	$ 51,700
December 5, 1985	November 15, 2015	40,200	40,200
July 22, 1987	July 15, 2027	50,000	50,000
Total		$141,900	$141,900

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 below. These obligations are supported by certain Bank Letters of Credit discussed below. Any amounts advanced under such Letters of Credit must be repaid, with interest, by the Company.

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 4.32% for 1991, 5.55% for 1990 and 6.14% for 1989. The interest rate will be adjusted monthly unless converted to a fixed rate.

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, 1994. The annual interest rate was adjusted to 5.90% effective November 15, 1988, to 6.15% effective November 15, 1989, to 5.70% effective November 15, 1990 and to 4.50% effective November 15, 1991. The interest rate will be adjusted annually unless converted to a fixed rate.

The $50.0 million Promissory Note was issued in connection with NYSERDA's Adjustable Rate Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), Series 1987. This obligation is supported by an irrevocable Letter of Credit expiring July 31, 1994. This Promissory Note bore interest at 5⅞% per annum through July 14, 1990. The annual interest rate was adjusted to 6.30% effective July 15, 1990 and to 5.50% effective July 15, 1991. The interest rate will be adjusted annually unless converted to a fixed rate.

NOTE 7. PREFERRED AND PREFERENCE STOCK

Type, by Order of Seniority	Par Value	Shares Authorized	Shares Outstanding
Preferred Stock (cumulative)	$100	2,000,000	1,270,000*
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, 1991	(Thousands) December 31 1991	1990	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, 1991	(Thousands) December 31 1991	1990	Optional Redemption (per share)
8.25	R	300,000	$30,000	$30,000	$108.25 Before 3/1/92+
7.45	S	100,000	10,000	—	Not applicable
7.55	T	100,000	10,000	—	Not applicable
7.65	U	100,000	10,000	—	Not applicable
Total		600,000	$60,000	$30,000	

+Thereafter at lesser rates

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 commences 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.

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.

NOTE 8. COMMON STOCK

At December 31, 1991, there were 50,000,000 shares of $5 par value Common Stock authorized, of which 32,101,139 were outstanding. No shares of Common Stock are reserved for options, warrants, conversions, or other rights. There were 793,503 shares of Common Stock reserved and unissued for shareholders under the Automatic Dividend Reinvestment and Stock Purchase Plan and 163,326 shares reserved and unissued for employees under the RG&E Savings Plus Plan.

COMMON STOCK:

	Per Share	Shares Outstanding	Amount (Thousands)
Balance, January 1, 1989		30,785,811	$504,907
Automatic Dividend Reinvestment and Stock Purchase Plan	17.288–20.913	472,157	8,761
Capital Stock Expense			(108)
Balance, December 31, 1989		31,257,968	$513,560
Automatic Dividend Reinvestment and Stock Purchase Plan	18.600–19.288	134,828	2,513
Savings Plus Plan	18.625–19.750	28,472	545
Capital Stock Expense			(230)
Balance, December 31, 1990		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

NOTE 9. SHORT TERM DEBT

At December 31, 1991 and December 31, 1990, the Company had short term debt outstanding of $59.5 million and $42.4 million, respectively. The weighted average interest rate on short term debt outstanding at year end 1991 was 5.09% and was 6.43% for borrowings during the year. For 1990, the weighted average interest rate on short term debt outstanding at year end was 8.85% and was 8.54% for borrowings during the year.

On December 1, 1988 the Company renewed its $90 million revolving credit facility for a period of three years. The commitment termination date has been extended to December 31, 1994. Commitment fees related to this facility amounted to $149,000 in 1991, $164,000 in 1990 and $168,000 in 1989.

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, 1991, the Company would be able to incur $5.2 million of 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.

In addition, 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, 1992, are secured by the Company's accounts receivable.

NOTE 10. COMMITMENTS AND OTHER MATTERS

CAPITAL EXPENDITURES

The Company's 1992 construction expenditures program is currently estimated at $145 million, including $10 million of carrying charges. The Company has entered into certain commitments for purchase of materials and equipment in connection with that program.

(Note 10 continued on page 42)

NOTES TO FINANCIAL STATEMENTS

(continued from page 41)

SEVERE ICE STORM AND STORM PLAN

In its filing for new electric rates in August 1991 and in a separate petition to the PSC, the Company is seeking full recovery of costs it incurred as a result of the March 1991 ice storm. Through December 31, 1991, the Company incurred incremental storm damage repair costs of approximately $36.4 million, none of which are reimbursable through insurance coverage. That amount is reflected on the balance sheet under deferred debits and a portion of such amount (estimated at 20%) is expected to be capitalized as plant additions. The Company has requested recovery of deferred storm-related costs, other than capital additions, over a period of 25 years. That request is under review in the Company's pending rate cases where Staff of the PSC and intervenors are urging various disallowances of the Company's storm damage repair costs. The Company believes those costs to be prudent and, therefore, recoverable in rates, but it cannot predict what action the PSC may ultimately take regarding the Company's rate request, including the recovery of storm-related costs.

The Company in 1991 upgraded its procedures for responding to storm emergencies and included them in the Company's storm emergency plan. The plan, which reflects improvements stemming from both the Company's self-assessment and a report prepared by the staff of the PSC, was filed with the PSC in 1991. The electric rates authorized for the Company in the PSC's June 1991 rate order are subject to a refund of $4 million contingent upon the filing with the PSC of a revised storm emergency plan. The Company believes its plan satisfies PSC requirements, but the plan is subject to further revision resulting from the Company's own and PSC review.

The Company has resolved substantially all of the claims for damages resulting from the ice storm and storm restoration efforts and believes that the amount required to satisfy all such claims will not be material.

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 Company has collected approximately $42.8 million through December 31, 1991.

In June 1988, the NRC issued new regulations establishing criteria for various facets of decommissioning including acceptable alternative methods, planning, funding and environmental review. The NRC regulations establish a minimum external funding level determined by formula. The NRC minimum represents only the cost of removing the radioactive plant structures. The Company's depreciation rates reflect a 5% cost of removal factor for Ginna non-radioactive plant structures; however, they do not currently reflect a cost of removal factor for the Company's 14% share of Nine Mile Two non-radioactive plant structures. Since March 1990, the Company has deposited $18.5 million to external decommissioning trust funds. In July 1990, the Company, in compliance with the NRC regulations, submitted a funding plan to the NRC.

In connection with the Company's rate case completed in June 1991, the PSC approved the collection during the rate year ending June 30, 1992 of an aggregate $10.1 million for decommissioning, covering both nuclear units. The amount allowed in rates is based on estimated ultimate decommissioning costs of $134.7 million for Ginna and $30.6 million for the Company's 14% share of Nine Mile Two (1991 dollars). 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.

In August 1991, the NRC approved the Company's application for an amendment to the Ginna Nuclear Plant operating license extending the license expiration date from April 25, 2006 to September 18, 2009. As a result, the annual expense accrual required to fully fund the external decommissioning trust funds will be reduced by approximately $1.4 million each year commencing with the rate year beginning July 1, 1992.

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. Amendments to the Act in 1988 increased the public liability limit to approximately

$7.4 billion, expanded coverage to include precautionary evacuations and extended the Act's effectiveness 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 $63 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. The Company's interests in two nuclear units could thus expose it to a current potential payment for each accident of $71.8 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 $3.2 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, 1991, 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 $1.25 billion in the NEIL II Property Insurance Program. 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 $167 million as a sublimit for this coverage at the Ginna Nuclear Power Plant. The owners at Nine Mile Two have selected the maximum available sublimit of $200 million. 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 $5.3 million and $6.9 million in the event of losses under the replacement power and property damage coverages, respectively.

ENVIRONMENTAL MATTERS

In 1985, the New York State Department of Environmental Conservation (NYSDEC) identified property in the vicinity of the Lower Falls of the Genesee River in Rochester as an inactive hazardous waste disposal site (the Site). The Company owns, and was the prior owner or operator of, a number of locations within the Site. In mid-1991 NYSDEC advised the Company that it delisted the Site, i.e., removed it from its Registry of Inactive Hazardous Waste Sites. The effect of delisting is to terminate the Company's status as a potentially responsible party for the Site, to discontinue the pending NYSDEC review of a joint Company/City of Rochester proposal for a limited further investigation of the Site, and to defer (and perhaps end) the prospect of Site remedial action and 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 procedures under which such individual sites will be compared to new hazardous waste criteria. The Company and its predecessors formerly owned and operated coal gasification facilities within the Site and, in September 1991, the Company voluntarily initiated a study of subsurface conditions in the vicinity of those retired facilities. The Company is unable to predict what further listing action NYSDEC may take, but regards the delisting as a positive development.

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 material does not appear to be linked to the Site. The Company undertook an investigation to determine the extent of contamination. The study found that some soil and ground water contamination existed on-site, but there was no evidence that the contamination 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

(Note 10 continued on page 44)

(continued from page 43)

review. If the NYSDEC requires remediation of this location, the Company may be fully or partially responsible for the costs of investigation and any site remediation. The Company cannot at this time predict what may result from the NYSDEC review of information on the material from the boring, what future studies may be performed, what remediation measures may be directed and what share of any such activities the Company may be asked to assume.

On a portion of the Company's property in the Site, 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 the Company granted the County, certain retention ponds which were reportedly used to recover 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 in recovering 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.

In the letter announcing the Site delisting, NYSDEC indicated an intention to pursue appropriate closure of the County's former retention pond area, suggesting that it may be treated as a separate hazardous waste site. The Company is unable to assess what implications the NYSDEC letter may have for the County's claim against it.

GAS COST RECOVERY

Throughout the late 1970's and early 1980's, many interstate natural gas pipelines signed long-term gas sales contracts with producers under which the pipelines were obligated to take delivery of a specified percentage of maximum contract volumes of natural gas or, if such quantities were not taken, to pay for them ("take-or-pay"). As a result of reduced demand, many pipelines subsequently experienced a significant reduction in sales, leading to substantial take-or-pay liability to their producers. The FERC has adopted an approach which requires pipelines to absorb substantial portions of their take-or-pay costs and requires the pipelines' customers to develop consensus methodologies to allocate the remaining costs among customers. These are being developed in individual pipeline rate cases at this time.

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. That proceeding is ongoing, and the issues raised include the legal authority of the PSC to deny recovery of such costs. However, in October 1989 the PSC approved a settlement between the Staff of the PSC and the Company providing for the Company to recover in rates 87.5% of the first $12 million of the pipeline take-or-pay costs imposed upon it. The recovery of any take-or-pay costs incurred in excess of $12 million would be subject to future determination.

In addition, the FERC is in the process of developing policies and rules which will enable natural gas purchasers, such as the Company, to choose their gas suppliers and receive non-discriminatory services from the interstate pipelines. A major component of this policy direction permits natural gas purchasers to convert their purchase contracts with interstate pipelines into transportation contracts. These conversions will require the pipelines to reduce their purchase commitments to natural gas producers. The costs of such reductions will be allocated among the pipelines' customers. The allocation methodologies are being developed in individual rate cases at this time.

The Company is presently unable to estimate the amount of take-or-pay or transition costs which may ultimately be included in its pipeline suppliers' charges to it. As of December 31, 1991 the Company had been billed for $10.8 million of take-or-pay costs and has thus far recovered $7.4 million from its customers.

OTHER MATTERS

The Company has a contract 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 DOE-furnished enrichment for a future year upon giving ten years' notice. Consistent with that provision, the Company has terminated its commitment to DOE for the years 2000 and 2001. The Company has secured the remaining 30% of its Ginna requirements for the reload years 1992 through 1995 under different arrangements with DOE. The Company plans to meet its enrichment requirements for years beyond those already committed by making further arrangements with DOE or by contracting with third parties. The cost of DOE enrichment services utilized for the next seven reload years (priced at the most current rate) ranges from $4 million to $7 million per year.

In late 1986 and early 1987, the Secretary of the Company corresponded with attorneys who were threatening to bring a shareholders' derivative action on behalf of the Company against officers and directors responsible for Company activities related to the Company's participation in Nine Mile Point Unit 2. Neither the directors nor Company officers have received further communications from this party on this matter in the intervening five years. The same attorneys commenced a stockholder derivative suit in federal district court against directors and officers of Niagara alleging certain claims regarding Unit 2 and, when that suit was dismissed, commenced a similar suit in October 1990 against the same defendants in State Supreme Court, Onondaga County. On July 12, 1991, the judge hearing the latter suit approved a settlement from which no party has appealed. The Company is unable to predict whether the threats received by it will lead to litigation similar to that in which Niagara was involved.

REPORT OF INDEPENDENT ACCOUNTANTS

Price Waterhouse

1900 Lincoln First Tower
Rochester, New York 14604
January 27, 1992

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

In our opinion, the accompanying balance sheets and the related statements of income, retained earnings and cash flows present fairly, in all material respects, the financial position of Rochester Gas and Electric Corporation at December 31, 1991 and 1990, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1991, in conformity with generally accepted accounting principles. 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.

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 45.

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, 1991, the Company maintained an effective system of internal control over the preparation of its published financial statements.

Roger W. Kober

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

Robert C. Henderson

Robert C. Henderson
Senior Vice President, Controller and Chief Financial Officer

January 27, 1992

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)				
Quarter Ended	Operating Revenues	Operating Income	Net Income	Earnings on Common Stock	Earnings per Common Share (in dollars)
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**
December 31, 1990	$ 220,360	$ 32,878	$ 18,136	$ 16,630	$.53
September 30, 1990	187,508	30,218	15,593	14,087	.45
June 30, 1990	182,216	16,541	2,068	562	.01
March 31, 1990	240,807	37,781	24,084	22,578	.72
December 31, 1989	$ 233,001	$ 37,991	$ 21,627	$ 20,121	$.64
September 30, 1989	183,209	31,698	18,420	16,914	.54
June 30, 1989	184,553	18,579	3,282	1,776	.05
March 31, 1989	244,933	42,965	28,114	26,608	.86

*Includes recognition of $6.6 million net-of-tax fuel audit disallowance

COMMON STOCK AND DIVIDENDS

Earnings	1991	1990	1989
Earnings per weighted average share	**$1.60**	$1.72	$2.10

Shares	1991	1990	1989
Number of shares (000's)			
Weighted average	**31,794**	31,293	31,090
Actual number at December 31	**32,101**	31,421	31,258

TAX STATUS OF CASH DIVIDENDS

Cash dividends paid in 1991, 1990 and 1989 were 100 percent taxable for Federal income tax purposes.

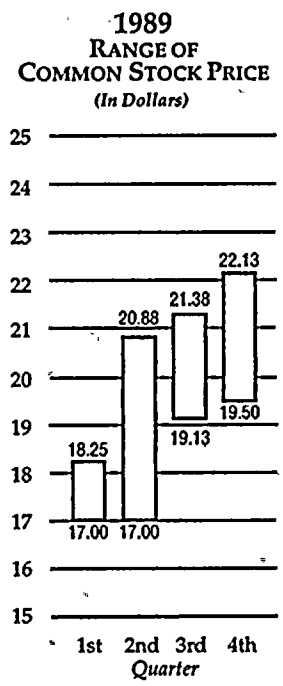
DIVIDEND POLICY

The Company has paid cash dividends quarterly on its Common Stock without interruption since it became publicly held in 1949. The Company intends to strive to achieve a common stock dividend payout equal to 8.5 to 9.0 percent of common stock book value. However, 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 1992, the Company paid a cash dividend of $.42 per share on its Common Stock, up $.015 from the prior quarterly dividend payment of $.405. The January 1992 dividend payment is equivalent to $1.68 on an annual basis.

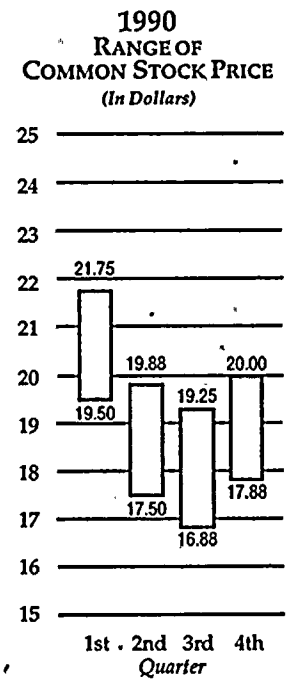
COMMON STOCK TRADING

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



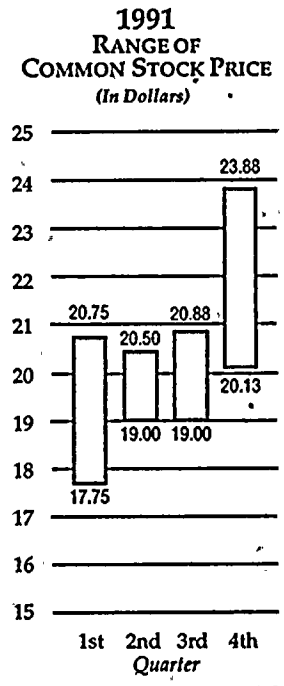
DIVIDENDS PAID PER SHARE, 1989 PER QUARTER
(In Dollars)

0.375 0.375 0.375 0.375



DIVIDENDS PAID PER SHARE, 1990 PER QUARTER
(In Dollars)

0.39 0.39 0.39 0.39



DIVIDENDS PAID PER SHARE, 1991 PER QUARTER
(In Dollars)

0.405 0.405 0.405 0.405

SELECTED FINANCIAL DATA

(Thousands of Dollars) Year Ended December 31	1991	1990	1989	1988	1987	1986
SUMMARY OF OPERATIONS						
Operating Revenues						
Electric	$588,930	$551,930	$543,096	$514,637	$ 489,366	$463,841
Gas	235,728	236,496	264,573	231,217	218,408	257,982
	824,658	788,426	807,669	745,854	707,774	721,823
Electric sales to other utilities	28,612	42,465	38,028	29,966	26,215	20,465
Total Operating Revenues	853,270	830,891	845,697	775,820	733,989	742,288
Operating Expenses						
Fuel Expenses						
Electric fuels	65,105	76,420	75,873	65,787	61,443	49,531
Purchased electricity	27,683	34,264	39,645	30,299	26,467	30,144
Gas purchased for resale	129,779	132,512	152,623	129,596	124,086	157,198
Total Fuel Expenses	222,567	243,196	268,141	225,682	211,996	236,873
Operating Revenues Less Fuel Expenses	630,703	587,695	577,556	550,138	521,993	505,415
Other Operating Expenses						
Operations excluding fuel expenses	208,440	194,594	173,764	159,689	159,170	148,340
Maintenance	65,415	62,391	64,316	52,575	46,124	44,767
Depreciation and Amortization	84,181	77,767	75,063	69,703	55,530	52,072
Taxes—local, state and other	113,649	101,035	95,341	88,635	82,869	84,590
Federal income tax—current	28,766	20,661	20,509	20,363	32,781	22,521
—deferred	5,493	13,829	17,330	20,299	23,144	37,304
Total Other Operating Expenses	505,944	470,277	446,323	411,264	399,618	389,594
Operating Income	124,759	117,418	131,233	138,874	122,375	115,821
Other Income and Deductions						
Allowance for other funds used during construction	675	2,689	2,261	2,047	5,030	32,828
Federal income tax	4,580	2,459	1,439	1,683	17,520	13,880
Fuel audit disallowance	(10,000)	—	—	—	—	—
Disallowed project costs	—	—	(2,100)	—	(55,860)	—
Other, net	6,078	4,062	8,328	6,901	8,831	6,725
Total Other Income and Deductions	1,333	9,210	9,928	10,631	(24,479)	53,433
Income before Interest Charges	126,092	126,628	141,161	149,505	97,896	169,254
Interest Charges						
Long term debt	63,918	64,873	68,628	72,270	73,489	74,571
Short term debt	2,623	1,070	—	—	129	68
Other, net	4,459	3,523	3,115	2,898	2,685	2,074
Allowance for borrowed funds used during construction	(2,905)	(2,719)	(2,026)	(1,777)	(2,696)	(11,978)
Total Interest Charges	68,095	66,747	69,717	73,391	73,607	64,735
Income from Continuing Operations, Before Cumulative Effect of Accounting Change	57,997	59,881	71,444	76,114	24,289	104,519
Cumulative Effect for Years Prior to 1987 of Accounting Change for Disallowed Costs	—	—	—	—	(193,000)	—
Net Income (Loss)	57,997	59,881	71,444	76,114	(168,711)	104,519
Dividends on Preferred Stock, at required rates	6,963	6,025	6,025	7,348	8,147	8,058
Earnings (Loss) Applicable to Common Stock	$ 51,034	$ 53,856	$ 65,419	$ 68,766	$(176,858)	$ 96,461
Weighted Average Number of Shares Outstanding in Each Period (000's)	31,794	31,293	31,090	30,513	29,728	28,927
Earnings (Loss) per Common Share—Total	$1.60	$1.72	$2.10	$2.25	$ (5.95)	$3.33
Earnings per Common Share—Continuing Operations	$1.60	$1.72	$2.10	$2.25	$ 0.54	$3.33
Cash Dividends Paid per Common Share	$1.62	$1.56	$1.50	$1.50	$2.025	$2.20

CONDENSED BALANCE SHEET

(Thousands of Dollars) At December 31	1991	1990	1989	1988	1987	1986
ASSETS						
Utility Plant	$2,706,554	$2,310,294	$2,208,158	$2,122,922	$1,559,848	$1,531,019
Less: Accumulated depreciation and amortization	1,178,649	812,994	730,621	653,876	586,840	571,022
	1,527,905	1,497,300	1,477,537	1,469,046	973,008	959,997
Construction work in progress	76,848	82,663	68,784	41,044	501,738	768,905
Net utility plant	1,604,753	1,579,963	1,546,321	1,510,090	1,474,746	1,728,902
Current Assets	189,009	176,045	190,321	213,626	184,472	141,344
Deferred Debits	160,034	108,451	102,729	102,015	131,526	114,340
Total Assets	$1,953,796	$1,864,459	$1,839,371	$1,825,731	$1,790,744	$1,984,586
CAPITALIZATION AND LIABILITIES						
Capitalization						
Long term debt	$ 672,322	$ 721,612	$ 764,627	$ 792,976	$ 845,326	$ 773,082
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	60,000	30,000	30,000	30,000	50,797	43,485
Common shareholders' equity						
Common stock	529,339	516,388	513,560	504,907	494,018	479,704
Retained earnings	61,515	62,542	57,983	39,710	17,617	249,505
Total common shareholders' equity	590,854	578,930	571,543	544,617	511,635	729,209
Total Capitalization	1,390,176	1,397,542	1,433,170	1,434,593	1,474,758	1,612,776
Long Term Liability—Department of Energy	63,626	59,989	55,502	51,016	47,773	44,950
Current Liabilities	281,116	189,500	138,983	128,546	90,667	118,470
Deferred Credits and Other Liabilities	218,878	217,428	211,716	211,576	177,546	208,390
Total Capitalization and Liabilities	$1,953,796	$1,864,459	$1,839,371	$1,825,731	$1,790,744	$1,984,586

FINANCIAL DATA

At December 31	1991	1990	1989	1988	1987	1986
Capitalization Ratios(a) (percent)						
Long term debt	50.6	53.6	55.1	56.8	58.7	49.3
Preferred stock	8.7	6.7	6.5	6.5	7.7	6.7
Common shareholders' equity	40.7	39.7	38.4	36.7	33.6	44.0
Total	100.0	100.0	100.0	100.0	100.0	100.0
Book Value per Common Share—Year End	$18.41	$18.42	$18.28	$17.69	$16.98	$24.93
Rate of Return on Average Common Equity (percent)	8.60	9.29	11.56 (b)	12.68	12.45 (b)	13.38
Embedded Cost of Senior Capital (percent)						
Long term debt	8.32	8.59	8.74	8.71	8.90	9.36
Preferred stock	6.97	6.72	6.72	6.72	7.09	7.20
Effective Federal Income Tax Rate (percent)	33.9	34.8	33.8	33.9	61.3	30.5
Depreciation Rate (percent)—Electric	3.05	3.33	3.25	3.56	3.50	3.50
—Gas	2.94	2.94	2.96	2.96	2.98	2.99
Interest Coverages(b)(c)						
Before federal income taxes (incld. AFUDC)	2.38	2.32	2.53	2.53	2.55	2.96
(excld. AFUDC)	2.33	2.25	2.47	2.48	2.45	2.38
After federal income taxes (incld. AFUDC)	1.91	1.86	2.02	2.01	1.93	2.36
(excld. AFUDC)	1.86	1.78	1.96	1.96	1.83	1.78

(a) Includes Company's long term liability to the Department of Energy. Excludes amounts due or redeemable within one year.
(b) Excludes disallowed Nine Mile Two plant costs written off in 1989 and 1987.
(c) AFUDC included in interest coverages for 1986 has not been restated to reflect the disallowance of certain Nine Mile Two plant costs recognized by the Company in 1987. The recognition by the Company in 1991 of a fuel procurement audit approved by the New York State Public Service Commission has been excluded from 1991 coverages.

ELECTRIC DEPARTMENT STATISTICS

Year Ended December 31	1991	1990	1989	1988	1987	1986
Electric Revenue (000's)						
Residential	$212,327	$197,612	$191,732	$188,451	$178,933	$166,664
Commercial	181,561	165,445	155,076	149,663	146,138	137,077
Industrial	141,001	130,012	124,634	120,490	118,479	116,321
Other (Includes Unbilled Revenue)	54,041	58,861	71,654	56,033	45,816	43,779
Electric revenue from our customers	588,930	551,930	543,096	514,637	489,366	463,841
Other electric utilities	28,612	42,465	38,028	29,966	26,215	20,465
Total electric revenue	617,542	594,395	581,124	544,603	515,581	484,306
Electric Expense (000's)						
Fuel used in electric generation	65,105	76,420	75,873	65,787	61,443	49,531
Purchased electricity	27,683	34,264	39,645	30,299	26,467	30,144
Other operation	168,610	155,289	137,458	124,871	126,320	113,497
Maintenance	57,032	53,880	55,915	44,060	37,641	36,573
Depreciation and Amortization	72,746	67,302	65,287	60,444	46,776	43,753
Taxes—local, state and other	86,925	77,323	71,361	66,426	61,504	61,314
Total electric expense	478,101	464,478	445,539	391,887	360,151	334,812
Operating Income before Federal Income Tax	139,441	129,917	135,585	152,716	155,430	149,494
Federal income tax	31,390	30,670	29,887	34,093	48,788	52,051
Operating Income from Electric Operations (000's)	$108,051	$99,247	$105,698	$118,623	$106,642	$97,443
Electric Operating Ratio %	51.6	53.8	53.2	48.7	48.9	47.4
Electric Sales—KWH (000's)						
Residential	2,085,429	2,075,072	2,072,047	2,051,808	1,970,345	1,890,293
Commercial	1,928,730	1,897,583	1,832,521	1,792,162	1,732,939	1,657,606
Industrial	1,917,796	1,931,633	1,906,429	1,869,417	1,782,223	1,775,722
Other	507,765	490,077	491,905	483,730	463,256	452,756
Total billed	6,439,720	6,394,365	6,302,902	6,197,117	5,948,763	5,776,377
Unbilled sales	7,657	(25,421)	33,406	—	—	—
Total customer sales	6,447,377	6,368,944	6,336,308	6,197,117	5,948,763	5,776,377
Other electric utilities	1,034,370	1,316,379	1,255,282	1,149,900	1,047,654	925,318
Total electric sales	7,481,747	7,685,323	7,591,590	7,347,017	6,996,417	6,701,695
Electric Customers at December 31						
Residential	298,440	296,110	293,418	290,037	285,988	281,630
Commercial	28,856	28,804	28,386	27,888	27,383	26,865
Industrial	1,388	1,428	1,422	1,392	1,381	1,368
Other	2,558	2,553	2,512	2,326	2,281	2,266
Total electric customers	331,242	328,895	325,738	321,643	317,033	312,129
Electricity Generated and Purchased—KWH (000's)						
Fossil	2,146,664	2,505,110	2,578,006	2,214,588	1,877,922	1,491,167
Nuclear	4,391,480	4,016,721	3,659,185	3,884,884	3,793,021	3,603,116
Hydro	174,239	244,539	175,085	169,002	223,958	235,175
Pumped storage	240,206	269,966	290,582	292,305	246,925	237,663
Less energy for pumping	(364,520)	(405,966)	(429,895)	(430,401)	(387,546)	(353,735)
Other	1,269	20,408	54,893	2,195	4,554	1,850
Total generated—Net	6,589,338	6,650,778	6,327,856	6,132,573	5,758,834	5,215,236
Purchased	1,451,208	1,498,089	1,757,413	1,705,755	1,703,411	1,945,586
Total electric energy	8,040,546	8,148,867	8,085,269	7,838,328	7,462,245	7,160,822
System Net Capability—KW at December 31						
Fossil	541,000	541,000	541,000	541,000	541,000	510,000
Nuclear	622,000	621,000	621,000	621,000	470,000	470,000
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	354,000	356,000	369,000	360,000	363,000	356,000
Total system net capability	1,593,000	1,594,000	1,607,000	1,598,000	1,450,000	1,412,000
Net Peak Load—KW	1,297,000	1,208,000	1,249,000	1,275,000	1,205,000	1,100,000
Annual Load Factor—Net %	61.7	64.6	62.4	59.7	60.8	64.7

GAS DEPARTMENT STATISTICS

Year Ended December 31	1991	1990	1989	1988	1987	1986
Gas Revenue (000's)						
Residential	$ 6,354	$ 6,508	$ 6,770	$ 6,439	$ 6,436	$ 7,694
Residential spaceheating	157,458	159,501	165,832	150,383	138,552	156,120
Commercial	40,196	43,534	46,897	44,781	43,311	52,653
Industrial	6,761	9,674	9,371	9,859	10,842	28,800
Municipal and other (Includes Unbilled Revenue)	24,959	17,279	35,703	19,755	19,267	12,715
Total gas revenue	235,728	236,496	264,573	231,217	218,408	257,982
Gas Expense (000's)						
Gas purchased for resale	129,779	132,512	152,623	129,596	124,086	157,198
Other operation	39,830	39,307	36,306	34,818	32,850	34,843
Maintenance	8,383	8,510	8,401	8,515	8,483	8,194
Depreciation	11,435	10,465	9,776	9,259	8,754	8,319
Taxes—local, state and other	26,724	23,711	23,980	22,209	21,365	23,276
Total gas expense	216,151	214,505	231,086	204,397	195,538	231,830
Operating Income before Federal Income Tax	19,577	21,991	33,487	26,820	22,870	26,152
Federal income tax	2,869	3,820	7,952	6,569	7,137	7,774
Operating Income from Gas Operations (000's)	$ 16,708	$ 18,171	$ 25,535	$ 20,251	$ 15,733	$ 18,378
Gas Operating Ratio %	75.5	76.3	74.6	74.8	75.7	77.6
Gas Sales—Therms (000's)						
Residential	9,068	9,644	10,321	10,374	10,255	11,382
Residential spaceheating	253,655	262,458	277,267	267,697	244,655	253,101
Commercial	71,509	77,617	84,152	86,413	83,167	92,864
Industrial	13,000	18,536	17,873	20,174	22,033	56,621
Municipal	10,580	13,350	12,319	15,514	17,985	23,405
Total billed	357,812	381,605	401,932	400,172	378,095	437,373
Unbilled sales	3,291	(22,840)	20,320	—	—	—
Total gas sales	361,103	358,765	422,252	400,172	378,095	437,373
Transportation of customer-owned gas	109,835	101,985	105,303	83,594	67,496	24,589
Total gas sold and transported	470,938	460,750	527,555	483,766	445,591	461,962
Gas Customers at December 31						
Residential	21,448	22,410	23,321	24,139	24,834	25,865
Residential spaceheating	222,918	219,242	215,120	210,710	206,458	201,227
Commercial	18,151	17,920	17,677	17,213	16,771	16,330
Industrial	921	960	1,095	1,042	1,035	1,015
Municipal	983	984	1,067	1,039	1,026	1,009
Transportation	423	401	367	270	147	46
Total gas customers	264,844	261,917	258,647	254,413	250,271	245,492
Gas—Therms (000's)						
Purchased for resale	384,643	366,684	426,941	408,044	381,632	439,381
Gas storage, net	39,859	—	—	—	—	—
Other	1,140	2,525	1,764	1,967	2,317	5,996
Total gas available	425,642	369,209	428,705	410,011	383,949	445,377
Cost of gas per therm (excluding gas storage, net)	33.43¢	36.03¢	35.74¢	31.76¢	32.51¢	35.82¢
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	3,539,260	3,539,820	3,719,050	3,744,500	3,443,240	3,499,640
Degree Days (Calendar Month)						
For the period	6,146	5,924	7,109	6,862	6,423	6,621
Percent colder (warmer) than normal	(8.4)	(11.8)	5.9	1.6	(4.3)	(1.4)

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

BOARD OF DIRECTORS (as of February 1, 1992)

Theodore J. Altier
Former Chairman of the Board and
Chief Executive Officer,
Altier & Sons Shoes, Inc.

Keith W. Amish
Former Vice Chairman of the Board,
Rochester Gas and Electric Corporation

William Balderston III
Vice Chairman,
Chase Lincoln First Bank, N.A.
and Executive Vice President,
The Chase Manhattan Corporation

Paul W. Briggs
Chairman of the Executive and
Finance Committee,
Rochester Gas and Electric Corporation

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

Natacha P. Dykman
Former Chairman of the
Board of Trustees,
Center for Governmental Research, Inc.

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

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
President,
Rochester Institute of Technology

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

William G. vonBerg
Executive Director,
Executive Service Corps of
Rochester, Inc.

COMMITTEES OF THE BOARD OF DIRECTORS

EXECUTIVE AND FINANCE
Keith W. Amish
William Balderston III
Paul W. Briggs*
Roger W. Kober
Cornelius J. Murphy
Arthur M. Richardson
Harry G. Saddock
William G. vonBerg

AUDIT
Paul W. Briggs
Allan E. Dugan
Natacha P. Dykman
William F. Fowble
Theodore L. Levinson
Constance M. Mitchell
M. Richard Rose
William G. vonBerg*

COMMITTEE ON MANAGEMENT
William Balderston III
Paul W. Briggs*
William F. Fowble
Cornelius J. Murphy
M. Richard Rose
William G. vonBerg

NOMINATING
Theodore J. Altier
William Balderston III
Natacha P. Dykman
Constance M. Mitchell
Arthur M. Richardson*
Harry G. Saddock

*Chairman

OFFICERS (as of February 1, 1992)

Roger W. Kober
Chairman of the Board, President and
Chief Executive Officer
Age 58, Years of Service, 26

Robert C. Henderson
Senior Vice President,
Controller and Chief Financial Officer
Age 51, Years of Service, 28

David K. Laniak
Senior Vice President, Gas, Electric,
Distribution and Customer Services
Age 56, Years of Service, 37

Robert E. Smith
Senior Vice President,
Production and Engineering
Age 54, Years of Service, 32

David C. Helligman
Vice President,
Secretary and Treasurer
Age 51, Years of Service, 28

Robert C. Mecredy
Vice President,
Ginna Nuclear Production
Age 46, Years of Service, 20

Wilfred J. Schrouder, Jr.
Vice President,
Employee Relations, Public Affairs and
Materials Management
Age 50, Years of Service, 29

Daniel J. Baler
Assistant Controller
Age 45, Years of Service, 8

John M. Kuebel
Auditor
Age 56, Years of Service, 27

Alan A. Lohrmann
Assistant Treasurer
Age 52, Years of Service, 30

Thomas S. Richards
General Counsel
Age 48, Years of Service*

*Appointed General Counsel effective October 1, 1991

Printed on recycled paper.

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 IO-K Annual Report
Shareholders may obtain a copy of the Company's 1991 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
(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 (outside
Massachusetts)
(800) 827-1446 (in Massachusetts)

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 (outside
Massachusetts)
(800) 827-1446 (in Massachusetts)

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
(212) 250-6000

RGE

Docket # 50-220
Accession # 9205280191
Date. 5/20/92 of Ltr
~~Regulatory Docket File~~

-NOTICE-

THE ATTACHED FILES ARE OFFICIAL RECORDS OF THE INFORMATION & REPORTS MANAGEMENT BRANCH. THEY HAVE BEEN CHARGED TO YOU FOR A LIMITED TIME PERIOD AND MUST BE RETURNED TO THE RECORDS & ARCHIVES SERVICES SECTION P1-22 WHITE FLINT. PLEASE DO NOT SEND DOCUMENTS CHARGED OUT THROUGH THE MAIL. REMOVAL OF ANY PAGE(S) FROM DOCUMENT FOR REPRODUCTION MUST BE REFERRED TO FILE PERSONNEL.

-NOTICE-

Rochester Gas and Electric Corporation
89 East Avenue, Rochester, N.Y. 14649
(716) 546-2700
An Equal Opportunity Employer