ROCHESTER GAS & ELECTRIC CORPORATION

Annual Report

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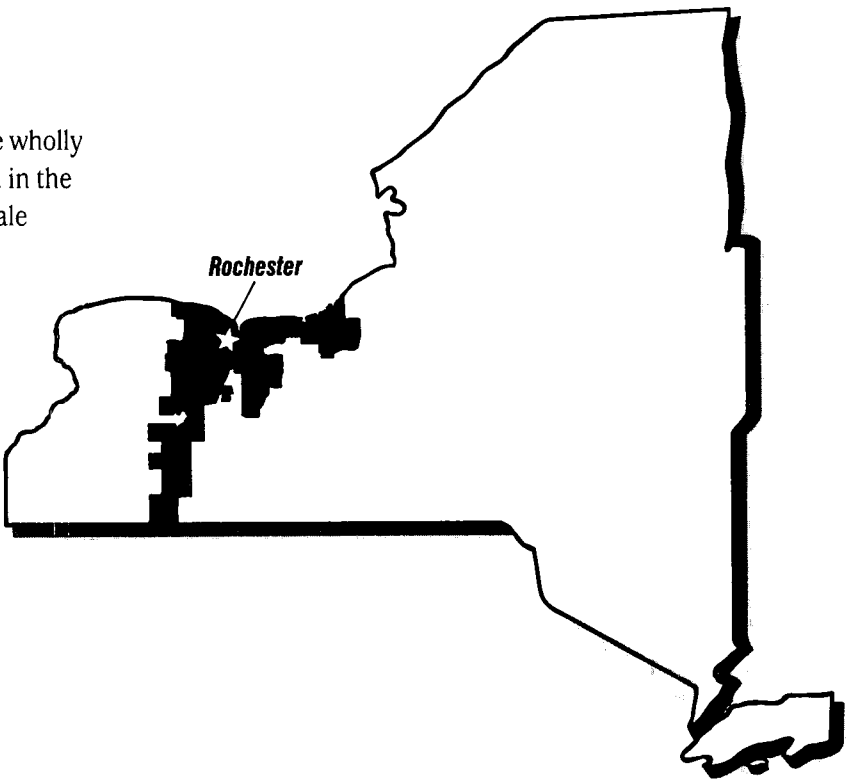
RG&E Service Area/Business

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 900,000, 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.



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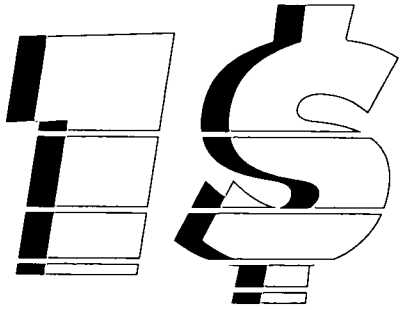
Where The 1990 Revenue Dollar Came From and How It Was Used



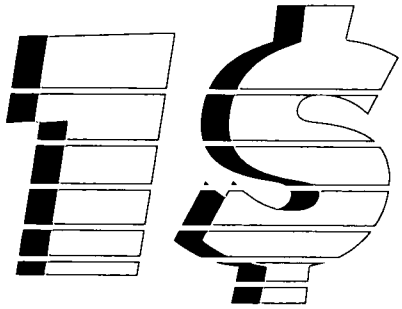
44¢ Residential (24¢ Electric, 20¢ Gas)

25¢ Commercial (20¢ Electric, 5¢ Gas)

17¢ Industrial (16¢ Electric, 1¢ Gas)

9¢ Other (7¢ Electric, 2¢ Gas)

5¢ Electric Sales to Other Utilities



29¢ Cost of Fuel (13¢ Electric Fuel and Purchased Electricity, 16¢ Purchased Gas)

16¢ Taxes

16¢ Other Operations

14¢ Wages and Benefits

10¢ Depreciation & Amortization

8¢ Interest

7¢ Dividends & Reinvested Earnings

FINANCIAL HIGHLIGHTS

	1990	1989	% Change
Financial Data (Dollars in thousands)			
Operating revenues: Electric	$ 594,395	$ 581,124	2
Gas	$ 236,496	$ 264,573	(11)
Operating expenses	$ 713,473	$ 714,464	–
Operating income	$ 117,418	$ 131,233	(11)
Net income	$ 59,881	$ 71,444	(16)
Earnings applicable to common stock	$ 53,856	$ 65,419	(18)
Rate of return on average common equity*	9.29%	11.56%	(20)
Common Stock Data			
Weighted average number of shares outstanding (thousands)	31,293	31,090	1
Per common share:			
Earnings	$1.72	$2.10	(18)
Dividends	$1.56	$1.50	4
Book Value (year end)	$18.42	$18.28	1
Year-end market price	$19.50	$21.50	(9)
Shareholders at year end	36,977	38,762	(5)
Operating Data			
Sales (thousands)			
Kilowatt-hours to customers	6,368,944	6,336,308	1
Kilowatt-hours to other utilities	1,316,379	1,255,282	5
Therms of gas sold and transported	460,750	527,555	(13)
Customers (year end)			
Electric	328,895	325,738	1
Gas	261,516	258,280	1
Construction expenditures, less allowance for funds used during construction (thousands)	$ 126,776	$ 120,648	5
Employees (year end)	2,759	2,666	3

*Excludes net disallowed Nine Mile Two costs of $1.4 million written off in 1989.

TO OUR SHAREHOLDERS

Last year in our letter to you in the annual report we said that we entered the new decade in pretty good shape, all things considered. In 1991 we are still maintaining that, all things considered, our financial condition is improving despite earnings that were lower than a year ago.

Revenues and Earnings

Total revenues for 1990 were $831 million, down $15 million from 1989. Earnings were off 18 percent from the previous year, or $54 million compared with $65 million. Earnings per share on common stock for the year amounted to $1.72, down 38 cents from the $2.10 per share earned in 1989.

The major cause of the decline in earnings was the weather in 1990. That year was 12 percent warmer than normal, 17 percent warmer than 1989 and is recorded as the third warmest year in our region since the year 1900. Since rates are based on sales forecasts that assume normalized weather, any deviation from a "normal" year's weather can produce revenues higher or lower than projected. In 1990, the elements worked against us. Most of the decline in earnings per share is attributed to weather that was warmer than normal in the heating season and cooler than normal in the air conditioning season.

Retained Earnings and Dividends

Our retained earnings have grown from $18 million at the end of 1987 to $63 million by the end of 1990. Consistent with our stated policy to achieve a common stock dividend payout of 8.5 to 9.0 percent of common stock book value, your board of directors raised the quarterly dividend rate. In December 1990 the board approved an increase of 1.5 cents in the quarter's common stock dividend rate effective in January 1991. That brings the annual common stock dividend rate to $1.62 as compared with the $1.56 paid in 1990.

Sales

Total kilowatt-hour sales of electricity to customers in 1990 were up only one-half of one percent over 1989 while electric sales to other utilities were up 4.9 percent from the previous year. Therm sales of natural gas to customers in 1990, including gas transported for customers, were off 12.7 percent from 1989. The small growth in electric kilowatt-hour sales and the decline in therm sales of gas is mainly attributable to the near-record warm year overall and a summer that had less cooling requirements than the previous year.

Aside from the unusually warm weather, growth in the number of electric and gas customers continues to be strong. In 1990 we added 3,200 electric customers and a similar number of gas customers.

Electric Operations

Our Ginna nuclear power plant again had another excellent year of operation with an availability factor of 84 percent for 1990. That means the plant, which produces half of our own customers' electric requirements, was available for operation 307 days out of a possible 365 including the planned shutdown for annual refueling, maintenance and inspection. That level of availability compares very favorably with that of other nuclear power plants in the country, as does the plant's capacity factor for 1990 which was also 84 percent. Capacity factor is the percentage of actual electric production measured against the maximum rated potential.

Along with excellent production levels at our Ginna nuclear power plant, we are very pleased that inspections and reviews at that plant by the Federal Nuclear Regulatory Commission (NRC) in 1990 found improvement in many areas of operation – improvement on an already good record. The NRC review cited improvements in all areas, particularly maintenance, surveillance, security and emergency preparedness.

Harry G. Saddock (l.) Roger W. Kober

Our fossil-fueled power plants also recorded another excellent year. In 1990 our Russell and Beebee coal-fired power plants achieved 87 percent and 90 percent availability factors respectively. These indicators of reliability and performance are well above the national average for comparable power plants.

In the area of system reliability we continue to upgrade our distribution systems and procedures to maintain our high level of system dependability. In 1990 we committed $27 million of capital expenditures to electric distribution system upgrades, and we have projected $26 million for system upgrades in 1991.

Nine Mile Two

The performance of the Nine Mile Two nuclear power plant in 1990 has fallen short of our expectations. The 1,080,000-kilowatt plant had an availability factor of only 54 percent.

In spite of two encouraging, sustained operating runs of about 100 days each in 1990, the plant was not always able to operate at full capacity. The planned shutdown for inspection, maintenance and refueling in September of 1990 was extended through January 30, 1991, for a total of 21 weeks. Since the plant is not scheduled for another refueling shutdown until February of 1992, there is an opportunity for the plant to establish itself this year from an operating standpoint.

While the Nine Mile Two plant performance falls short of our expectations, the progress of the four non-operating owners in working with and assisting Niagara Mohawk as a result of a joint operating agreement is proving beneficial. That agreement has been extended through

February, 1992. We believe that the Nine Mile Two plant has an opportunity in 1991 to achieve the levels of performance that we all expect, and we remain dedicated to that goal.

On January 30, 1991, the New York Public Service Commission (PSC) finalized approval of a settlement agreement resolving all open issues with regard to the construction of Nine Mile Two and its operation through January 19, 1990. The written order is expected to be received in February. The settlement provides for equal sharing, between shareholders and customers, of the net proceeds recovered by the Nine Mile Two owners as a result of litigation against plant contractors and vendors. The settlement also provided for a refund of $2.9 million to electric customers.

This settlement brings the lengthy and costly Nine Mile Two issues to a close. We do not expect to incur any further write-offs attributable to our Nine Mile Two investment or the plant's initial operation.

Gas Operations

As with the electric side of our business, we are devoting corporate resources to the upgrading of natural gas delivery systems to maintain our already excellent reliability record. Our expansion of the gas franchise into the Livonia area south of Rochester is bringing new business as expected.

We reported last year that we were having discussions with Empire State Pipeline regarding its proposed pipeline project to run from Niagara Falls, NY to Syracuse, NY. The construction of that pipeline has been approved and is expected to be in operation late this year. This additional source of natural gas bolsters our supply and cost options.

Since the proposed gas pipeline will cross our service territory, we believed there was an opportunity to consider whether some degree of participation by RG&E in the project could be advantageous for our customers and shareholders. We have a petition pending before the PSC and we expect a favorable decision. Being a partner in the project will give us the potential for additional earnings beyond those derived from gas sales strictly within our franchise territory.

Rates

In July of 1990, the PSC ruled on our request for additional electric and gas revenues that was filed nearly a year earlier. We were allowed an additional $36.1 million in annual electric revenues and $4.3 million in gas revenues. That amounts to an average percentage increase of 6.6 percent in electric rates and 1.7 percent in gas rates. The decision came following an agreement we made with the PSC in June of 1988 to freeze electric rates at the January 1988 level and gas rates as of January 1987 until the summer of 1990.

In August of 1990 we petitioned the PSC for additional electric and gas revenues. A decision by the PSC is not expected before June of 1991. We requested an increase in annual electric revenues of $39.8 million and $5.7 million for gas. If granted in full, the rates would represent a combined increase of four percent to the typical residential electric customer who heats with gas.

Consumer Awareness

Our commitment to promote consumer awareness of RG&E energy and customer service programs is going forward with increasing momentum. Through public information campaigns, advertising, marketing communications, bill inserts and communications with our employees, we are promoting safety and the many services and energy information programs available.

Demand Side Management and New Generation Deferral

We are continuing to commit resources to programs that are intended to promote energy efficiency and help forestall the need for investments in new power plants through electric demand side management and third-party generation. The programs now underway for residential, commercial, and industrial customers, as well as independent power producers, are consistent with New York State energy policies.

RG&E supports these programs and shares their objectives of increased energy efficiency and avoidance of premature, potentially difficult and costly construction of new power plants. Our Demand Side Management Department is currently coordinating ten active programs and is considering two additional programs.

We are also seeking proposals from potential new suppliers of electricity to provide electric capacity and energy to RG&E under long-term, firm contracts. If these proposals are consistent with RG&E's system requirements and performance objectives, and they are less expensive than other alternatives, they will defer the need for RG&E to construct new power plants. Preliminary expressions of interest in this program have been strong and RG&E expects to have a significant number of proposals from which to choose.

Capital Requirements

Capital requirements in 1990 were $158 million, of which $28 million was used to satisfy sinking fund obligations. Capital requirements in 1991 are estimated to be $191 million. Of that amount, construction requirements are anticipated to total $151 million, with $45 million being spent at the Company's Ginna nuclear power plant and another $44 million to upgrade and expand electric and gas distribution facilities. Most of the funds required for the Company's 1991 construction program are expected to be generated internally with some interim financing in the form of short-term debt being required. The Company expects to seek long-term financing during the first half of 1991 to pay off outstanding short-term debt and to satisfy maturing securities and sinking fund obligations which total $40 million in 1991.

Outlook

There seems to be general acceptance of the fact that the country is and has been in a recession for several months. The severity of the economic downturn can only be speculated at this time, particularly in light of international uncertainties.

From strictly a local view, the Rochester area has historically been more resistant to economic downturns than other regions. The mix of our commercial and industrial resources presents a good balance that is resilient to disturbance.

That's not to say that our area is immune from national economic conditions. There have been local layoffs and the housing starts are down with little hope of quick recovery. But, some important economic indicators locally are holding up comparatively well.

The Rochester Index of Business Activity, a measure of the total output of goods and services, remained relatively stable through the end of the year. Also encouraging is the fact that our area continues to see increases in non-manufacturing employment. Rochester accounts for 40 percent of all exports in New York State and 60 percent in the upstate region.

It's been predicted by some that the recession will be short lived. If that's the case, then we don't expect any severe economic effect in our service area.

We continue to rely heavily on our employees. They are doing a fine job and they continue to look for ways to improve their effectiveness and efficiency.

Despite economic uncertainties, we believe we will see an improved financial condition in 1991.

Harry G. Saddock
Chairman of the Board
and Chief Executive Officer

Roger W. Kober
President
and Chief Operating Officer

February 1, 1991

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.

Nine Mile Two

The Company has a 14 percent ownership in the Nine Mile Two facility, a 1,080,000 kilowatt nuclear electric generating unit (the Unit or Nine Mile Two) located near Oswego, New York. The Unit was constructed by Niagara Mohawk Power Corporation (Niagara Mohawk) and commenced commercial operation in the Spring of 1988.

Although Niagara Mohawk is the operator of Nine Mile Two, an interim operating agreement provides for management oversight of the Unit to February 1992 by the four non-operating owners. During this period, the owners will continue to explore alternative operating arrangements, including the possible formation of a separate operating company.

In September 1990 Nine Mile Two began its first refueling outage. Following a series of scheduled shut down activities, this outage was completed on January 30, 1991. Nine Mile Two during 1990 had two sustained periods of routine operation of approximately 100 days each but with the first refueling outage, the Unit's 1990 capacity factor was only 44 percent. The Company believes the operating performance of Nine Mile Two will improve consistent with industry experience, although no assurance of future operating performance can be made. The next scheduled major refueling outage for the Unit is planned for February 1992.

Operations at Nine Mile Two have been and continue to be closely observed by the Nuclear Regulatory Commission (NRC). Since December 1988, Nine Mile Two has been on the NRC's list of nuclear plants which require "close monitoring" by it, a category of plants identified by the NRC as having weaknesses warranting such attention.

On January 30, 1991 the New York State Public Service Commission (PSC) finalized approval of 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. Issuance of a written order is expected in February. A number of issues had remained unresolved following an October 1986 PSC Order (the 1986 Settlement Agreement) which limited to $585 million (less prepaid financing charges approximating $97 million) the amount of Nine Mile Two construction costs which could be included in the Company's rate base. The Company's full investment in allowable Nine Mile Two capital costs, assuming an April 15, 1988 commercial operation date, was reflected in rate base effective with the rate year beginning August 1, 1988. 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. The 1990 Settlement Agreement also provides that any cash 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 requires the Company to refund to its electric customers $2.9 million and such amount will be applied as a credit during 1991 against fuel costs incurred by these customers.

In 1987 the Company wrote off $262 million (net of tax) in connection with the 1986 Settlement Agreement and the net impact of the 1990 Settlement Agreement ($1.4 million net of tax) was recorded by the Company in December 1989 in anticipation of that agreement with the PSC. The Company does not anticipate being required to write off any further Nine Mile Two investment or sustain any further disallowance of expenses for the Unit's initial operation.

Refer to Note 10 of the Notes to Financial Statements for additional information regarding the Company's investment in Nine Mile Two.

Liquidity and Capital Resources

Providing funds for construction expenditures and the retirement of long-term debt reduced the Company's cash and cash equivalents during 1990 (see Statement of Cash Flows, page 23). For the first time since 1987, the Company during 1990 began short-term borrowing of funds to finance a portion of its capital requirements. At December 31, 1990 the Company had $42.4 million of short-term debt outstanding. Additional external financing during 1991 is anticipated by the Company primarily to satisfy 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 1988 to 1990 and the current estimate of capital requirements through 1993 are summarized in the table below.

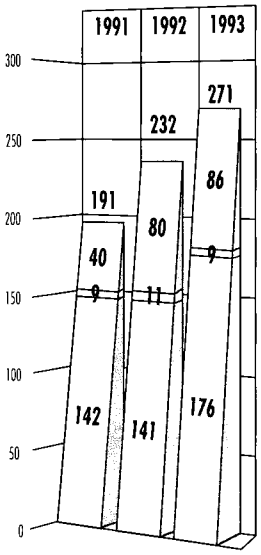
Capital Requirements

	Actual			Projected		
Type of Facilities	1988	1989	1990	1991	1992	1993
	(Millions of Dollars)					
Electric Property:						
Production	$ 39	$ 48	$ 47	$ 55	$ 55	$ 75
Transmission and Distribution	28	28	31	35	34	41
Street Lighting and Other	1	2	2	2	2	2
Subtotal	68	78	80	92	91	118
Nuclear Fuel	17	12	7	18	15	21
Total Electric	85	90	87	110	106	139
Gas Property	15	17	20	18	18	18
Common Property	7	12	15	14	17	19
Total	107	119	122	142	141	176
Carrying Costs:						
Allowance for Funds Used During Construction (AFUDC)	4	4	5	6	9	9
Deferred Financing Charges Included in Other Income	1	2	3	3	2	–
Total Construction Requirements	112	125	130	151	152	185
Securities Redemptions, Maturities and Sinking Fund Obligations*	69	38	28	40	80	86
Total Capital Requirements	$181	$163	$158	$191	$232	$271

*Excludes prospective refinancings.

Projected Capital Requirements

(millions of dollars)



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

For the period 1991 to 1993, the Company anticipates construction requirements to average approximately $163 million per year. Expenditures made at the Company's nuclear facilities to improve operating efficiency and comply with regulatory requirements are a significant component of production plant costs over the period. In addition to its construction expenditures, the Company has securities maturities and sinking fund obligations totaling approximately $206 million over the three-year period 1991 to 1993 as shown by the graph to the left. Excluded from the capital requirements table on page 7 are payments by the Company to an external nuclear decommissioning trust and any expenditures which may be required to comply with the Clean Air Act Amendments of 1990 (see Projected Capital and Other Requirements for a discussion of these subjects).

The AFUDC amounts included in the table on page 7 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 below under Rate Base and Regulatory Policies.

◊ ***1990 Capital Requirements***

Electric production plant expenditures, including AFUDC, in 1990 included $36 million of expenditures made at the Company's Ginna nuclear plant and $7 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 $27 million in 1990. Other Electric Department capital expenditures during the year included $5 million for fuel at the Ginna nuclear plant and $3 million at Nine Mile Two, including AFUDC.

In the Gas Department, the replacement of older cast iron mains with longer-lasting and less expensive plastic pipe, the relocation of gas mains for highway improvement, and the installation of gas services for new load resulted in construction expenditures of $20 million, including AFUDC, in 1990.

Capital requirements in 1990 also included sinking fund redemptions totaling $28 million, of which $20 million was spent to satisfy the 1990 sinking fund requirement of the Series NN First Mortgage Bonds.

◊ ***Projected Capital and Other Requirements***

The Company has no current plans to install additional baseload generation through at least the mid-1990s. The Company has instituted a supply side management program, one objective of which is to arrange to acquire modest new supplies of electric generation from outside sources. Much of this new generation will come from independent power producers through competitive bidding, with such open bidding being required by the PSC. The Company is currently soliciting bids for the addition of 50 megawatts of peaking capacity by 1994. Also, over the next three to four years, approximately 55 megawatts of capacity is currently expected to be supplied by a cogenerator under contract with the Company.

The Company will continue to make generating plant modifications and its construction program will focus on the need to serve new customers, to provide for the replacement of obsolete or inefficient utility property and to modify facilities consistent with the most current environmental and safety regulations. Nuclear plant expenditures to satisfy regulatory requirements, industry standards, and the Company's commitment to maintain a high level of nuclear safety and performance are reflected in its projected 1991 construction program. Construction requirements for 1991 also include additional expenditures to be made at the Company's fossil-fueled and hydro generating plants.

In addition to its projected capital requirements, the Company is making deposits to an external decommissioning trust in satisfaction of certain funding requirements established by the NRC to meet the eventual decommissioning costs of nuclear plants. In March 1990 the Company established an external decommissioning trust fund with initial funding of $3.5 million. Deposits to this external trust fund have been approved by the PSC and are reflected in current rates. Further information about the Company's external decommissioning trust fund can be found in Notes 1 and 10 of the Notes to Financial Statements.

Excluded from the capital requirements table on page 7 are any expenditures which may be made in connection with the Clean Air Act Amendments of 1990 (Amendments), which became law in November 1990. The Amendments will affect air emissions and quality control measures primarily at the Company's fossil-fueled electric generating facilities. The Company has not fully assessed the ultimate cost impact of the Amendments on Company operations; however, based on a preliminary analysis, the Company believes that the Amendments will not result in significant capital expenditures at the Company's generating stations. The Company believes that the costs to comply with the Amendments will be recoverable in rates, but no assurance can be given as to what costs may be approved by the PSC for rate recovery. Additional discussion of the Amendments and their effect on Company operations can be found in Note 10 of the Notes to Financial Statements.

The Company has requested PSC approval to purchase 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, with an in-service date currently projected as November 1, 1991. The Company has filed for permission from the PSC to form a wholly-owned subsidiary which will invest in the pipeline. The investment in Empire, which is not expected to exceed $20 million, is excluded from the capital expenditures table on page 7, as is $7.9 million for additional gas inventory. Following the construction of Empire, the Company expects to participate in a project debt financing of approximately 75 percent of its investment in Empire. The PSC Staff has proposed that only 50 percent of the Company's Empire investment be reflected in rate base so risks and benefits would be shared equally between customers and shareholders. Construction of the pipeline was approved by the PSC on January 30, 1991. See Energy Costs—Gas for additional information on the Company's participation in Empire.

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.

Liquidity, Financing and Capital Structure

Capital requirements in 1990 were satisfied by a combination of internally generated funds, proceeds provided from the redemption of temporary cash investments, and short-term borrowings. The Company had no public issuance of securities in 1990; however, it did raise $2.5 million through its Automatic Dividend Reinvestment and Stock Purchase Plan (ADR Plan), as discussed below.

The Company believes that an average of approximately 85 percent to 90 percent of the funds required per year for its 1991 to 1993 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 1991 to 1993. Although the Company expects to issue securities during 1991, 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. The Company's financing program is under continuous review and may be revised depending upon the level of construction, market conditions, rate relief, cost of capital and other factors.

◊ ***Financing***

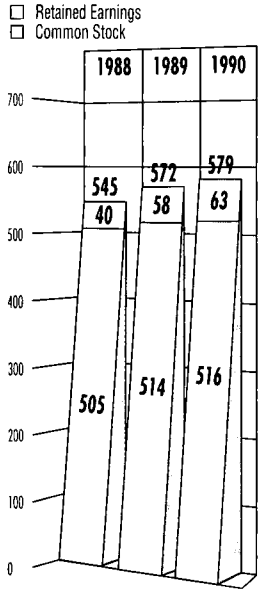
Interim financing is available from certain domestic banks in the form of short-term borrowings under a $90 million revolving credit agreement which continues until December 31, 1993 and may be extended annually. Borrowings under this agreement are secured by a subordinate mortgage. In addition, since 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 was extended to December 31, 1991, are secured by the Company's accounts receivable. At December 31, 1990 the Company had $42.4 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 mid-January 1991 was unable to issue unsecured debt. Interim financing capability remains available, however, with secured borrowings under the Company's credit agreements, as discussed above.

In early December 1990 the Company filed a registration statement with the Securities and Exchange Commission to permit the issuance of up to $200 million of First Mortgage Bonds on terms to be determined at the time of sale. This registration statement became effective December 21, 1990 and allows the Company financing flexibility regarding the timing of new issues. As financial market conditions warrant, the Company may, from time to time, issue securities to permit the early redemption of higher-cost senior securities.

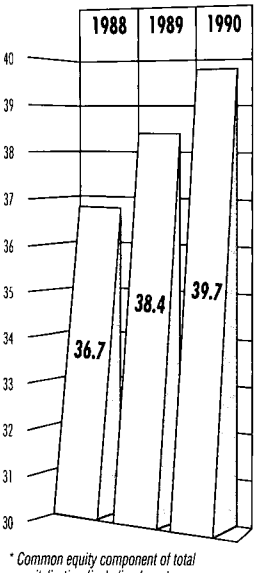
Effective October 1, 1990, the Company's ADR Plan was amended to allow shares acquired for participating shareholders to be either newly-issued shares purchased from the Company or outstanding shares purchased on the open market. Prior to that time, all shares for the ADR Plan had been purchased entirely on the open market since October 1989. As amended, the Plan will allow the Company the opportunity to obtain funds to finance a portion of its capital expenditures program and to raise additional equity capital. From October 1990 to year-end, the Company issued approximately 135,000 new shares of Common Stock through its ADR Plan, providing approximately $2.5 million to help finance its capital expenditures program. New shares issued in 1990 through the ADR Plan were purchased from the Company at a market price above the book value per share at the time of purchase.

Common Shareholders Equity
(millions of dollars)



Growth in common shareholders equity during 1990 was achieved primarily through increased retained earnings

Common Equity Ratio*
(percent at year end)



** Common equity component of total capitalization (including long-term liability to Department of Energy)*

Growth in retained earnings, along with the redemption of long-term debt, strenghtened this ratio during 1990

◊ ***Capital Structure***

The Company continued to experience a growth in retained earnings during 1990 as illustrated by the graph to the upper left. The Company's retained earnings at December 31, 1990 were $62.5 million, an increase of approximately $4.5 million compared with December 31, 1989. Increased retained earnings, coupled with debt redemptions, in 1990 helped to boost common equity to 39.7 percent of capitalization at December 31, 1990, as illustrated by the graph to the lower left. The balance of such capitalization was comprised of 6.7 percent preferred equity and 53.6 percent long-term debt, and includes the Company's long-term liability to the federal 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.

Rate Base and Regulatory Policies

The Company is subject to regulation of rates, service, and sale of securities, among other matters, by the PSC. Following a two-year negotiated rate moratorium reached in June 1988 with the PSC (the 1988 Rate Settlement), the Company was granted authority to increase its rates for electric and gas service effective July 1990. These new rates are based on a forecasted test year for the twelve months ending June 30, 1991. The Company has filed a request with the PSC to increase base rates for electric and gas service effective July 1991. A final decision from the PSC, however, is not expected before June 1991; and, the Company is unable to predict what action the PSC may ultimately take.

◊ ***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 12. Although the July 1990 authorized return on common equity and rate base is a reduction from the previously allowed returns under the 1988 Rate Settlement, the PSC has concluded that the July 1990 rate increases should, for the twelve months ending June 1991, allow the Company to achieve approximately a 2.5 times pretax interest coverage, exclusive of AFUDC and the amortization of deferred Nine Mile Two customer prepaid financing costs (see below). In addition to the amounts indicated in the table on page 12, the July 1990 PSC rate order authorized the amortization of certain non-cash rate moderators (primarily deferred Nine Mile Two financing costs and unbilled gas revenues) totaling approximately $4.0 million in the Electric Department and $4.7 million in the Gas Department. The July 1990 rate order also provides that in subsequent rate filings by the Company, the normal authorized return on equity may be increased by up to 50 basis points based on a share of the actual net resource savings resulting from the Company's approved demand side management program (see Operating Revenues and Sales). Conversely, return on equity may be decreased by up to 50 basis points for inadequate demand side management performance.

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 2, 1987	$ 1,223*	0.2%	10.75%	12.60%
	July 17, 1987	16,198	3.4	10.48	13.20
	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
Gas	January 2, 1987	458*	0.2	10.75	12.60
	July 17, 1987	–	–	10.48	13.20
	July 26, 1988	–	–	10.39**	13.40
	July 12, 1990	4,250	1.7	9.91	12.10

*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, 1990	$39,787	6.6%	10.26%	12.75%
Gas	August 2, 1990	5,684	2.2	10.26	12.75

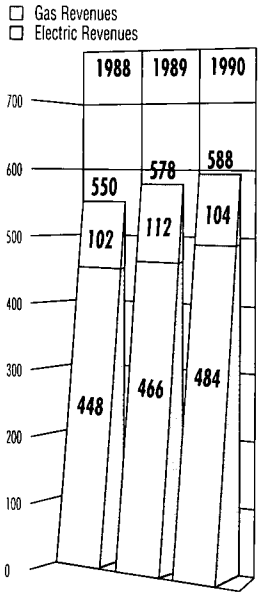
*As amended.

In a series of rate orders preceding the commercial operation of Nine Mile Two, the PSC permitted most of the Company's $488 million of allowed Nine Mile Two investment to be reflected in rates. 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. The 1990 Settlement Agreement also provides an allowance for certain Nine Mile Two operation and maintenance costs through July 1991. The PSC approved the 1990 Settlement Agreement at a meeting in October 1990 and finalized that approval at a meeting on January 30, 1991. Issuance of a written order is expected in February.

As indicated above, 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 1990, the Company started amortizing $2.5 million of these deferred credits to Other Income as permitted by the PSC's July 1990 rate order. Amortization of these deferred credits to Other Income has aggregated $16.4 million through December 31, 1990. The July 1990 rate order also authorized the Company to write off $11.2 million of deferred expenses as an offset to these deferred credit balances. If not used prior to July 31, 1994 as non-cash earnings for rate moderation purposes, both the remaining deferred credit and deferred debit balances (estimated to be $29.1 million at June 30, 1991) would be eliminated by offset as permitted by the PSC. In its 1990 rate filing (see below), the Company has proposed to amortize an additional $2.8 million of such deferred credits over the rate year ending June 30, 1992.

Operating Revenues less Fuel Expenses

(millions of dollars)



Revenues in 1990 reflect a rate increase, customer growth, and milder weather

In August 1990 the Company filed rate requests with the PSC as summarized under the heading "Pending" in the table on page 12. The higher rates have been requested to cover those increases in capital and operating costs projected for the rate year ending June 30, 1992 that are neither adequately provided for in present rates nor expected to be offset by increased revenues from sales. The staff of the PSC and intervenors have proposed lower rate increases than those sought by the Company. The Company is unable to predict what, if any, rate changes may be approved by the PSC. A decision on this filing is not expected before June 1991.

Results of Operations

The following financial review identifies the causes of significant changes in the amounts of revenues and expenses, comparing 1990 to 1989 and 1989 to 1988. The Notes to Financial Statements on pages 24 to 37 of this report contain additional information. Commencing with the commercial operation of Nine Mile Two in April 1988, the Company began to record operating revenues and operating expenses associated with the plant's operation.

Operating Revenues and Sales

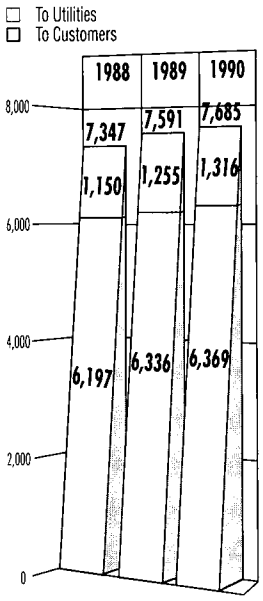
Following a nine percent increase in 1989, operating revenues in 1990 were down two percent compared with a year earlier. Increased electric revenues from the sale of energy to customers and other electric utilities were more than offset by a decline in gas revenues due to the impact of mild weather over most of the heating months during 1990. Reflecting a drop in purchased energy expenses, operating revenues less fuel expenses, however, were up in 1990 as illustrated by the graph to the left. Details of the revenue changes are presented in the table below.

Operating Revenues

Increase or (Decrease) from Prior Year (Thousands of Dollars)	Electric Department 1990	Electric Department 1989	Gas Department 1990	Gas Department 1989
Customer Revenues (Estimated) from:				
Rate Increases	$ 15,452	$ 87	$ 1,644	$ –
Unbilled Revenues, Net	(13,956)	13,954	(22,458)	17,068
Fuel Clause Adjustments	(378)	4,787	(298)	14,937
Weather Effects (Heating)	(1,233)	272	(17,291)	4,513
Customer Consumption	5,202	13,819	4,469	6,624
Transportation Gas, Net Effect	–	–	(334)	(5,299)
Other	3,747	(4,460)	6,191	(4,487)
Total Change in Customer Revenues	8,834	28,459	(28,077)	33,356
Electric Sales to Other Utilities	4,437	8,062	–	–
Total Change in Operating Revenues	$ 13,271	$36,521	$(28,077)	$33,356

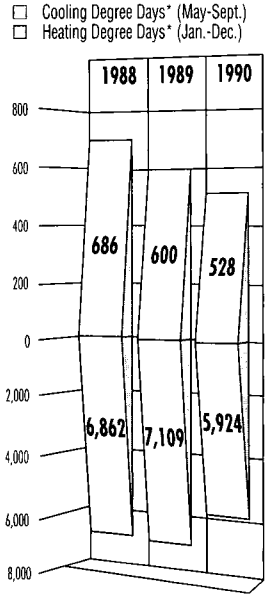
For the 1990 comparison period, estimated customer revenues derived from rate increases, as shown in the table above, reflect new rates for electric and gas service effective July 1990. Prior to that time, base rates had been maintained at their June 1988 level pursuant to the terms of the 1988 Rate Settlement.

Electric Sales
(thousands of mwh)



Increased sales to other electric utilities helped to boost electric energy sales in 1990

Degree Day Variations



** 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*

Beginning in July 1988 as part of the 1988 Rate Settlement, the PSC approved the Company's request to start recording unbilled revenue. 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 the change in accounting to recognize unbilled revenues was amortized to income during the period July 1988 to July 1990, and the July 1990 rate decision authorized the amortization of an additional $1.5 million over the twelve-month period ending June 1991. The Company in its August 1990 rate filing has requested that the balance of unbilled revenues associated with this change in accounting, approximately $3.7 million of unbilled gas revenues, be amortized over the rate year beginning July 1991. In accordance with the 1988 Rate Settlement, the Company commenced recording monthly accruals for unbilled revenues at December 31, 1988. The Company's Statement of Income reflects net unbilled revenues of $10.4 million in 1988, $41.4 million in 1989, and $5.0 million in 1990. Quarterly earnings comparisons to periods prior to 1989 are less meaningful because of the adoption of this accounting method. However, for quarterly periods subsequent to the beginning of 1989 and for calendar years, this change in accounting will have no significant effect on earnings comparisons. Primarily as a result of the seasonal nature of our 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 reduced $3.7 million in 1989 and increased $2.2 million in 1990, primarily reflecting actual experience in both electric fuel costs and generation mix compared with rate assumptions. In addition, fuel clause revenues beginning in September 1990 include the recovery of energy conservation dollar-savings (revenues less incremental cost of fuel) not currently provided for in base rates which result from the implementation of the Company's demand side management program (discussed below).

In January 1989, the Audit Section of the PSC began an audit of the Company's fuel procurement practices. In August 1990 the Company responded to certain findings in an interim report prepared by the Audit Section which was critical of senior management's oversight of the Company's fuel procurement process during the 1980s. The Company believes its fuel procurement practices have been and continue to be sound. PSC Staff and the Company are currently discussing Staff recommendations for improved procedures and management oversight, at the conclusion of which Staff is expected to present its major conclusions in a final report. The Company is unable to predict what action the PSC may ultimately take; however, if the PSC were to accept the Audit Section's interim report as presently written, the Company's earnings and financial position could be adversely affected. The degree of any such effects could also be influenced by the time period over which the cost of PSC-directed remedial action would be recognized.

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 suggested by the graph to the left, the Company's service area experienced unseasonably mild weather during the 1990 heating months. The first quarter of 1990 was the warmest first quarter since 1921. The weather as measured on a calendar month

degree day basis for all of 1990 was 16.7 percent warmer than 1989. Conversely, weather for all of 1989 was 3.6 percent colder than 1988 as measured on a similar basis. During 1989, the Company's service area also experienced a cool summer compared with the prior year and this pattern continued in 1990 with weather during the summer months being even cooler, as measured on a cooling degree day basis, than the comparable period a year earlier.

Kilowatt-hour sales of energy to customers was up less than one percent in 1990, following a 2.2 percent increase in 1989 as shown by the graph on the top of page 14. The growth in electric energy sales in 1990 and 1989 was inhibited by the impact of cooler weather during the summer months on air conditioning usage. Kilowatt-hour sales of energy in 1990, however, were strengthened by the impact of nearly 3,200 new customers added during the year. Electric sales to commercial customers led the increase in sales to all major customer groups both in 1990 and 1989.

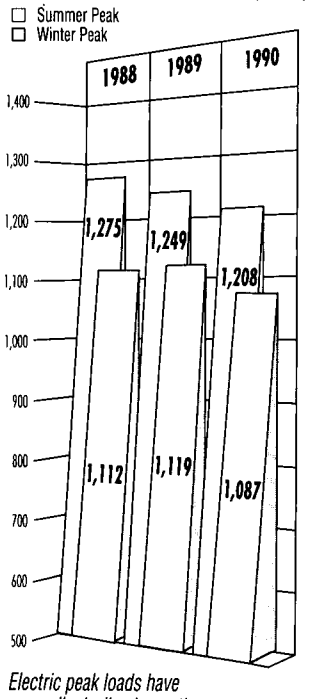
Like most electric utilities, the Company is encouraging energy efficiency through demand side management (DSM) programs. Objectives of the DSM programs include increasing the efficiency with which electricity is used and shifting electric load from peak to non-peak times, thus helping to save energy and delay the need to add new generating capacity. To the left is a graph which shows electric peak loads incurred by the Company over the last three years. 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. Energy conservation dollar-savings (revenues less incremental cost of fuel) resulting from the implementation of DSM projects are estimated and recovered in rates.

Fluctuations in revenues from electric sales to other utilities are generally related to the Company's retail customer energy requirements, New York Power Pool energy market conditions and the availability of electric generation from Company facilities. The 1990 increase in electric sales to other utilities also reflects the impact of higher contract sales of energy. The availability of power from Nine Mile Two, along with generation from the Ginna nuclear plant, allows the Company to sell more fossil-fueled generation to other utilities while retaining lower incremental-cost, nuclear-generated energy for the Company's own electric customers.

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, excluding Company use, amounted to 9.9 million dekatherms in 1990 and 9.8 million dekatherms in 1989. These purchases have caused decreases in customer revenues, as shown in the table on page 13, 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.

After increasing by 9.1 percent in 1989, total therms of gas sold and transported, including unbilled sales, decreased by 12.7 percent in 1990 as illustrated 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, residential gas sales would have increased approximately 2.4 percent in 1990 over 1989, while nonresidential sales in 1990 would have been up by approximately 2.2 percent compared with a year earlier. Despite the weather conditions, therm sales to industrial customers increased in 1990 due to supplemental gas sales to industrial transportation customers who periodically were unable to obtain gas from their normal suppliers and the more consistent use of gas during the year by some major dual-fuel industrial customers. Having a positive effect on therms of gas sold and

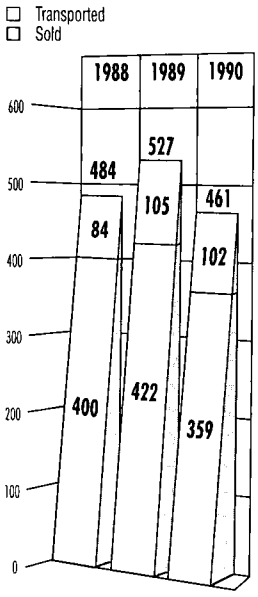
Net Peak Electric Load (MW)



Electric peak loads have generally declined over the past two years

Gas Sold and Transported

(millions of therms)

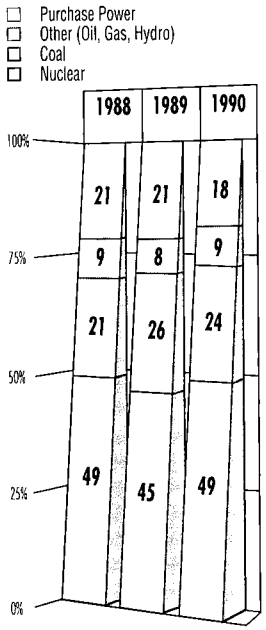


A decline in weather-sensitive gas spaceheating sales led to a decrease in total therms sold and transported in 1990

transported was the growth in the number of gas customers over the past three years. Also, in November 1989 the Company began serving a new gas franchise area around Livonia, New York, with annual sales and transportation over the next few years expected to reach approximately 1.5 million therms.

For the 1990 comparison periods, the increase in "Other" customer revenues shown in the table on page 13 is largely the result of more customer consumption (billing) days in 1990 compared with a year earlier, revenues associated with a recent New York State surtax (see Taxes), and increased miscellaneous gas revenues.

Sources of Electric Generation by Fuel Type (percent)



Fuel diversity provides the Company with a more reliable energy supply

Operating Expenses

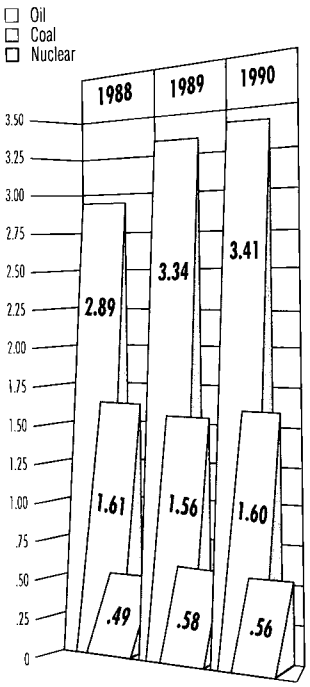
Compared with a year earlier, operating expenses were nearly unchanged in 1990 after rising twelve percent in 1989. The increase in 1989 operating expenses over 1988 was due to higher energy costs and increased maintenance expense at the Company's Ginna nuclear plant in connection with an extensive ten-year inspection required by the NRC. Operating expenses in 1989 also reflect the recognition of Nine Mile Two expenses for a full year, in contrast to approximately nine months beginning with commercial operation in 1988. At December 31, 1990 the Company had deferred $6.7 million of Nine Mile Two operating expenses (recorded on the Company's Balance Sheet as a deferred asset) pursuant to the terms of the 1988 Rate Settlement. Pending receipt of the PSC order approving the 1990 Settlement Agreement, the Company will offset $5.2 million of such deferred expense against customer prepaid Nine Mile Two financing costs as authorized by the Company's July 1990 rate order. A summary of the change in operating expenses for the 1990 and 1989 comparison periods is presented in the table below.

Operating Expenses

Increase or (Decrease) from Prior Year (Thousands of Dollars)	1990	1989
Fuel for Electric Generation	$ 547	$10,086
Purchased Electricity	(5,381)	9,346
Gas Purchased for Resale	(20,111)	23,027
Other Operation	20,830	14,075
Maintenance	(1,925)	11,741
Depreciation and Amortization	2,704	5,360
Taxes Charged to Operating Expenses	2,345	3,883
Total Change in Operating Expenses	$ (991)	$77,518

Fuel Costs per Million BTU's

(in dollars)



The cost of nuclear fuel continues to have an advantage over the cost of fossil fuel.

◇ Energy Costs – Electric

The 1990 increase in fuel expenses for electric generation was relatively less than the increase in generation, the result of an electric generation mix favoring less expensive nuclear fuel over the cost of coal and oil. To the left are graphs which present the Company's electric generation mix by fuel type and the cost per million BTU's for the Company's major electric generation fuels. For the 1989 comparison period, increased generation from the Company's fossil-fueled units was largely responsible for the increase in fuel expenses for electric generation.

The decrease in purchased electricity expense for the 1990 comparison period resulted from a reduction in kilowatt-hours purchased. Compared with 1988, increasing average rates caused purchased electricity expense to increase in 1989 and average rates continued to increase in 1990.

◊ *Energy Costs – Gas*

The gas procurement practices of the Company reflect an open-market approach that allows the Company and many of its large-consumption gas customers to take advantage of favorable spot market purchases. These purchases, together with contract purchases, allow the Company flexibility to respond to price variations and provide a diversity of supply. The Company's proposed contracts with Empire (see Projected Capital and Other Requirements) will allow it to diversify its natural gas supply opportunities and improve its ability to transport natural gas into central and western New York. Participation in the project will open up new storage and transportation capabilities, but no significant change in the operation of the Company's gas system is currently anticipated. The Company has negotiated a new contract with its present major supplier of natural gas for a ten-year period through the year 2001. This contract is subject to approval by the Federal Energy Regulatory Commission and a final decision is expected before June 1991. In general, the contract recognizes the Company's right to obtain service from alternative pipelines, if available, and provides for a combination of bundled and unbundled (storage capacity, upstream and downstream firm transportation capacity) services from the Company's present supplier.

The cost of gas purchased was down in 1990 due to a decrease in the volume of gas purchased. Increased average costs were the primary reason for higher purchased gas costs in 1989 and the average rate for gas purchased continued to rise in 1990.

◊ *Operating Expenses, Excluding Fuel*

Excluding the effect of accounting procedures to recognize certain deferred Nine Mile Two revenues and expenses, other operation expenses as summarized in the table on page 16, increased $17 million in 1990 and $18 million in 1989. Payroll costs, including benefits, increased $4.7 million in 1990 and $6.9 million in 1989 due, in part, to increased personnel requirements to support the Company's nuclear operations and to help ensure regulatory compliance. Other operation expenses also reflect additional expenses of $5.6 million in 1990 and $5.2 million in 1989 associated with the Company's share of Nine Mile Two operation expenses. Increasing other operation expenses in 1990 by $2.9 million were higher transmission wheeling charges on purchased electricity and increased nuclear fuel storage expenses. In 1989, other operation expenses were reduced by an accounting procedure to reverse prior Nine Mile Two revenue deferrals as determined in the ratemaking process and the discontinuance of this accounting procedure increased other operation expenses in 1990 compared with a year earlier.

In December 1990 the Financial Accounting Standards Board (FASB) issued a Statement of Financial Accounting Standards entitled "Accounting for Postretirement Benefits Other than Pensions" (SFAS-106). Among other things, SFAS-106 requires accrual accounting for postretirement benefits other than pensions. The Company presently records the cost for such benefits on a current basis. When adopted by the Company, SFAS-106 will increase the Company's annual expense for postretirement benefits. The Company believes, however, that the effects will not materially impact the Company's financial position or results of operations since it anticipates ratemaking recognition. The impact on the Company's expenses is moderated by the defined-dollar nature of its benefits. SFAS-106 is effective for fiscal years beginning after December 15, 1992.

Fluctuation of maintenance expense in both comparison periods was due largely to additional expense associated with an intensive ten-year inspection in 1989 at the Company's Ginna nuclear plant during the plant's annual outage for refueling.

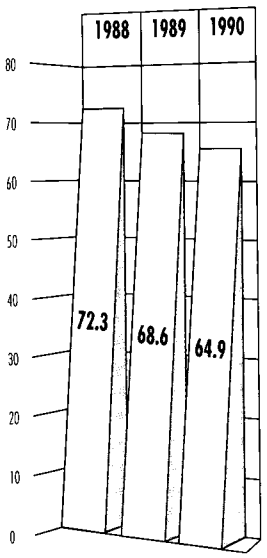
Depreciation expense includes an accrual for future nuclear plant decommissioning expenses and, for 1990, reflects an increase in such accrued expenses. Amortization expense in 1990 was reduced as a result of a reduction in the amortization of the Sterling project property loss. This amortization will be completed in 1991. Recognition of Nine Mile Two depreciation expense commenced with the commercial operation of the facility in April 1988.

◊ *Taxes*

The increases in local, state and other taxes in both comparison periods reflect higher assessments and tax rates on property, and higher income and gross earnings taxes which are based on taxable revenues, including unbilled revenues. In addition, approximately $2.7 million of the 1990 increase in these taxes is due to a new New York State gross receipts and income surtax of 15 percent approved May 1990, to be applied retroactively to January 1, 1990. Approximately one-third of the increase in 1989 local, state and other taxes over 1988 resulted from the recognition of these taxes as operating expenses once Nine Mile Two entered commercial operation.

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 and continues to be deliberated by the FASB. The Company presently believes the impact of SFAS-96, as currently amended, to be immaterial.

Interest Charges-Long-Term Debt
(millions of dollars)



Optional redemptions, along with bond maturities and sinking fund obligations, have helped to reduce the cost of long-term debt.

Other Statement of Income Items

The Company's writeoff in 1989 of additional estimated disallowed Nine Mile Two plant costs is reported under the caption "Other Income and Deductions" on the Statement of Income.

AFUDC variances are generally related to the amount of utility plant under construction and not included in rate base. Effective July 1990, the AFUDC rate was lowered to 9.60 percent from 10.25 percent.

Other Income includes $3.3 million of non-cash earnings in 1990 and $1.7 million in 1989 associated with the amortization of certain 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 both comparison periods reflects a change in interest income received from temporary cash investments.

As a result of both the mandatory and optional redemption of certain higher-cost first mortgage bonds, long-term debt interest expense over the three-year period 1988-1990 has declined, despite the issuance of additional long-term debt during this period. A graph of long-term debt interest expense is presented to the upper left.

Earnings/Summary

Presented below 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.

In December 1989 the Company announced a quarterly dividend increase from $.375 to $.39 per share of Common Stock payable in January 1990. Subsequently, on December 19, 1990 the Company announced a new quarterly dividend rate of $.405 per share payable in January 1991. Future dividend payments are dependent on future earnings, financial requirements and other factors.

Earnings Summary

	Earnings (Thousands of Dollars)	Shares[1] (Thousands)	Earnings per Share
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
1988			
As Reported	$68,766	30,513	$2.25

[1]Weighted average shares outstanding.
[2]Reported earnings modified to exclude disallowed Nine Mile Two costs written off in 1989. See Note 10 of the Notes to Financial Statements.

NEW APPOINTMENTS

Board of Directors Appointment

William F. Fowble was elected to the board of directors on May 16, 1990. He is group vice president and general manager, Photographic Services at Eastman Kodak Company. Mr. Fowble replaces Walter A. Fallon, former chairman of the board and chief executive officer of Eastman Kodak Company. Mr. Fallon served as a director of RG&E for 18 years.

Management Appointment

On August 1, 1990 the board of directors elected Robert C. Mecredy, Ph. D. as vice president, Ginna nuclear production. Dr. Mecredy earned his doctoral degree in nuclear engineering from the University of Michigan and joined RG&E in 1971 as a nuclear engineer.

FINANCIAL REPORTS

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STATEMENT OF INCOME

(Thousands of Dollars) Year Ended December 31	1990	1989	1988
Operating Revenues			
Electric	$551,930	$543,096	$514,637
Gas	236,496	264,573	231,217
	788,426	807,669	745,854
Electric sales to other utilities	42,465	38,028	29,966
Total Operating Revenues	830,891	845,697	775,820
Operating Expenses			
Fuel Expenses			
Fuel for electric generation	76,420	75,873	65,787
Purchased electricity	34,264	39,645	30,299
Gas purchased for resale	132,512	152,623	129,596
Total Fuel Expenses	243,196	268,141	225,682
Operating Revenues Less Fuel Expenses	587,695	577,556	550,138
Other Operating Expenses			
Operations excluding fuel expenses	194,594	173,764	159,689
Maintenance	62,391	64,316	52,575
Depreciation and amortization	77,767	75,063	69,703
Taxes – local, state and other	101,035	95,341	88,635
Federal income tax	34,490	37,839	40,662
Total Other Operating Expenses	470,277	446,323	411,264
Operating Income	117,418	131,233	138,874
Other Income and Deductions			
Allowance for other funds used during construction	2,689	2,261	2,047
Federal income tax	2,459	1,439	1,683
Disallowed project costs	–	(2,100)	–
Other, net	4,062	8,328	6,901
Total Other Income and Deductions	9,210	9,928	10,631
Income Before Interest Charges	126,628	141,161	149,505
Interest Charges			
Long term debt	64,873	68,628	72,270
Other, net	4,593	3,115	2,898
Allowance for borrowed funds used during construction	(2,719)	(2,026)	(1,777)
Total Interest Charges	66,747	69,717	73,391
Net Income	59,881	71,444	76,114
Dividends on Preferred Stock	6,025	6,025	7,348
Earnings Applicable to Common Stock	$ 53,856	$ 65,419	$ 68,766
Weighted Average Number of Shares for Period (000's)	31,293	31,090	30,513
Earnings per Common Share	$1.72	$2.10	$2.25

STATEMENT OF RETAINED EARNINGS

(Thousands of Dollars) Year Ended December 31	1990	1989	1988
Balance at Beginning of Period	$ 57,983	$ 39,710	$ 17,617
Add			
Net Income	59,881	71,444	76,114
Total	117,864	111,154	93,731
Deduct			
Dividends declared on capital stock			
Cumulative preferred stock	6,025	6,025	7,348
Common stock	49,297	47,146	45,832
Preferred stock redemption	–	–	841
Total	55,322	53,171	54,021
Balance at End of Period	$ 62,542	$ 57,983	$ 39,710

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

BALANCE SHEET

(Thousands of Dollars) At December 31	1990	1989
Assets		
Utility Plant		
Electric	$1,674,307	$1,609,338
Gas	304,308	286,104
Common	104,460	93,794
Nuclear fuel	227,219	218,922
	2,310,294	2,208,158
Less: Accumulated depreciation	628,571	567,260
Nuclear fuel amortization	184,423	163,361
	1,497,300	1,477,537
Construction work in progress	82,663	68,784
Net Utility Plant	1,579,963	1,546,321
Current Assets		
Cash and cash equivalents	544	11,977
Accounts receivable, net of allowance for doubtful accounts: 1990 – $591; 1989 – $2,717	79,280	80,799
Unbilled revenue receivable	49,172	60,194
Materials and supplies, at average cost		
Fossil fuel	18,272	13,089
Construction and other supplies	12,224	10,978
Prepayments	16,553	13,284
Total Current Assets	176,045	190,321
Deferred Debits		
Unamortized debt expense	8,943	11,075
Deferred finance charges – Nine Mile project	35,578	42,947
Other	63,930	48,707
Total Deferred Debits	108,451	102,729
Total Assets	$1,864,459	$1,839,371
Capitalization and Liabilities		
Capitalization		
Long term debt – mortgage bonds	$ 579,712	$ 622,727
– promissory notes	141,900	141,900
Preferred stock redeemable at option of Company	67,000	67,000
Preferred stock subject to mandatory redemption	30,000	30,000
Common shareholders' equity		
Common stock	516,388	513,560
Retained earnings	62,542	57,983
Total Common Shareholders' Equity	578,930	571,543
Total Capitalization	1,397,542	1,433,170
Long Term Liability – Department of Energy	59,989	55,502
Current Liabilities		
Long term debt due within one year	40,250	25,250
Short term debt	42,400	—
Accounts payable	47,069	53,146
Dividends payable	14,235	13,700
Taxes accrued	10,606	13,411
Interest accrued	14,591	15,281
Pension costs accrued	5,780	1,084
Other	14,569	17,111
Total Current Liabilities	189,500	138,983
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes	153,874	137,192
Deferred unbilled revenue	4,744	14,123
Deferred finance charges – Nine Mile project	35,578	42,947
Other	23,232	17,454
Total Deferred Credits and Other Liabilities	217,428	211,716
Commitments and Other Matters (Note 10)		
Total Capitalization and Liabilities	$1,864,459	$1,839,371

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

STATEMENT OF CASH FLOWS

(Thousands of Dollars) Year Ended December 31	1990	1989	1988
Cash Flow from Operations			
Net income	$ 59,881	$ 71,444	$ 76,114
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation and amortization	77,767	75,063	69,703
Amortization of nuclear fuel	25,573	21,923	19,945
Deferred fuel – electric	(477)	(3,287)	(1,020)
Deferred income taxes	16,682	19,847	28,124
Allowance for funds used during construction	(5,408)	(4,287)	(3,824)
Disallowed project costs – Nine Mile plant	–	2,100	–
Unbilled revenue, net	(2,818)	(37,542)	(8,528)
Changes in certain current assets and liabilities:			
Accounts receivable	1,519	(17,071)	(10,019)
Receivable under Nine Mile cotenant agreement	–	–	40,600
Materials and supplies – fossil fuel	(5,183)	(4,869)	1,487
– construction and other supplies	(1,246)	(1,800)	1,366
Taxes accrued	(2,805)	7,419	2,569
Accounts payable	(6,077)	13,802	6,348
Interest accrued	(690)	(371)	(270)
Other current assets and liabilities, net	(1,906)	(3,542)	(3,239)
Other, net	(2,720)	1,071	(6,644)
Total Operating	$ 152,092	$ 139,900	$ 212,712
Cash Flow from Investing Activities			
Utility Plant			
Plant additions	$(123,887)	$(112,034)	$ (96,439)
Nuclear fuel additions	(8,297)	(12,901)	(17,972)
Less: Allowance for funds used during construction	5,408	4,287	3,824
Additions to Utility Plant	(126,776)	(120,648)	(110,587)
Sterling project property loss	–	(1,604)	(95)
Other, net	(98)	683	(1,056)
Total Investing	$(126,874)	$(121,569)	$(111,738)
Cash Flow from Financing Activities			
Proceeds from:			
Sale of common stock	$ 3,058	$ 8,761	$ 11,189
Sale of long term debt, mortgage bonds	–	–	25,500
Short term borrowings	42,400	–	–
Retirements of:			
Preferred stock	–	–	(22,758)
Long term debt	(28,000)	(37,833)	(45,833)
Capital stock expense	(230)	(108)	8
Discount and expense of issuing long term debt	–	(237)	(496)
Dividends paid on preferred and common stock	(54,787)	(52,525)	(53,423)
Other, net	908	244	37
Total Financing	$ (36,651)	$ (81,698)	$ (85,776)
(Decrease) increase in cash and cash equivalents	$ (11,433)	$ (63,367)	$ 15,198
Cash and cash equivalents at beginning of year	$ 11,977	$ 75,344	$ 60,146
Cash and cash equivalents at end of year	$ 544	$ 11,977	$ 75,344

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

(Thousands of Dollars) Year Ended December 31	1990	1989	1988
Cash Paid During the Year			
Interest paid (net of capitalized amount)	$ 64,851	$ 67,716	$ 71,352
Income taxes paid	$ 17,516	$ 10,996	$ 10,521

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 operations.

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 and 1990 rate orders $13.8 million, $20.5 million and $8.5 million was amortized to earnings in lieu of cash rate relief in 1990, 1989 and 1988, respectively. Approximately $4.7 million will be similarly amortized subsequent to 1990.

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 and sales to other electric utilities. 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.

In addition, there is a similar 80%/20% sharing process of variances from forecasted revenues derived from sales to large gas customers that can use alternate fuels. The gas department tariffs also provide a separate but equivalent rate, excluding the cost of gas, to reflect charges for the transportation of privately owned gas through the Company's facilities.

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. See Note 10 for discussion of Nine Mile Point Nuclear Plant Unit No. 2 (Unit 2). 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 3.5%, 3.4% and 3.6% per annum of average depreciable property in 1990, 1989 and 1988, respectively. Amortization includes $2.2 million in 1990, $7.3 million in 1989 and $8.6 million in 1988 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 $60.0 million at December 31, 1990. The Company is allowed by the PSC to recover in rates these costs. The estimated fees are classified as a long-term liability and interest is accrued at the current three-month Treasury bill rate, adjusted quarterly. The Act also requires the DOE to provide for the disposal of nuclear fuel irradiated after April 6, 1983, for a charge of one mill ($.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 by the PSC to be approximately $246.5 million in the year 2006 when the permanent license expires, and those for the Company's 14% share of Unit 2's decommissioning costs are estimated by the PSC to be approximately $124.1 million at license expiration in the year 2026. Through December 31, 1990, the Company has accrued and recovered in rates $32.7 million for this purpose and is currently accruing for decommissioning costs at a rate of approximately $10.2 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 90-17, issued July, 1990).

Allowance for Funds Used During Construction

The Company capitalizes an Allowance for Funds Used During Construction (AFUDC) based upon the net 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.

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 (See Note 10), reducing the cumulative balance to $44.7 million. The balances of $35.6 million at December 31, 1990, if not used by July 31, 1994, may be offset against each other pursuant to PSC directives. In connection with the Company's 1990 rate case decision, $2.5 million will be amortized through the Statement of Income during the year commencing July 1, 1990.

The gross rates approved by the PSC for purposes of computing AFUDC were: 9.6% effective July 1, 1990; and 10.25%, effective January 1, 1988 through June 30, 1990. AFUDC on the Unit 2 major construction project, however, was applied in 1988 at a reduced rate which was net of the income tax effect of the interest portion of AFUDC. The net-of-tax rate did not apply to any projects in 1989 or 1990. The net-of-tax rate used on this project for 1988 was 8.55%.

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 1990 is approximately $415 million.

(Note 1 continued on page 26)

(continued from page 25)

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

SFAS-96, Accounting for Income Taxes (as amended by SFAS-103), was issued in December of 1987 and has not yet been adopted by the Company. SFAS-96 requires adoption in calendar year 1992 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. Additionally, the Company may also be required to provide deferred taxes for the effect of taxes previously flowed through the Statement of Income. The Company presently believes the impact of 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. When adopted, SFAS-106 will increase the Company's annual expense for postretirement benefits. The impact on the Company's expenses is limited however, due to the defined-dollar nature of its benefits. The Company believes that the effects of adopting SFAS-106 will be recognized in rate making and will not materially impact the Company's financial position or results of operations.

Earnings Per Share

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

Note 2. Federal Income Taxes

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

(Thousands of Dollars)	1990	1989	1988
Charged to operating expense:			
Current	$20,660	$20,509	$20,363
Deferred	13,830	17,330	20,299
Total	34,490	37,839	40,662
Charged (Credited) to other income:			
Current	(5,311)	(3,956)	(9,508)
Deferred	2,852	2,517	7,825
Total	(2,459)	(1,439)	(1,683)
Total Federal income tax expense	$32,031	$36,400	$38,979

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)	1990		1989		1988	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
Net Income	$59,881		$ 71,444		$ 76,114	
Add: Federal income tax expense	32,031		36,400		38,979	
Income before Federal income tax	$91,912		$107,844		$115,093	
Computed tax expense	$31,250	34.0	$ 36,667	34.0	$ 39,132	34.0
Difference between tax depreciation and amount deferred	4,127	4.5	3,646	3.4	1,626	1.4
Investment tax credit	(2,752)	(3.0)	(2,853)	(2.6)	(3,763)	(3.2)
Miscellaneous items, net	(594)	(0.7)	(1,060)	(1.0)	1,984	1.7
Total Federal income tax expense	$32,031	34.8	$ 36,400	33.8	$ 38,979	33.9

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

(Thousands of Dollars)	1990	1989	1988
Investment tax credit	$ (2,414)	$ (1,448)	$ (3,763)
Depreciation	22,906	25,473	29,519
Fuel costs	1,180	338	2,681
Sterling abandonment	(796)	(3,179)	585
Capitalized overheads	–	(1,805)	(265)
Accrued revenue	1,596	4,416	(442)
Disallowed project costs	–	(1,077)	–
Alternative Minimum Tax	(2,475)	(5,016)	(1,513)
Revenues Deferred – Nine Mile II	1,028	4,604	3,685
Pension	(2,729)	(898)	(1,949)
Other items	(1,614)	(1,561)	(414)
Total	$16,682	$19,847	$28,124

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)	1990	1989
Accumulated benefit obligation, including vested benefits of $207.1 in 1990 and $200.5 in 1989	$219.7*	$212.5*
Projected benefit obligation for service rendered to date	$311.9*	$305.2*
Less – Plan assets at fair value, primarily listed stocks and bonds	357.1	362.2
	(45.2)	(57.0)
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions	62.7	64.8
Less – Prior service cost not yet recognized in net periodic pension cost	5.8	.2
Less – Unrecognized net obligation at December 31	5.9	6.5
Pension liability recognized on the balance sheet	$ (5.8)	$ (1.1)

*Actuarial present value

Net pension cost included the following components:

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

The projected benefit obligation at December 31, 1990 and 1989 assumed discount rates of 8½ percent and 8¼ percent, respectively, and a long-term rate of increase in future compensation levels of 7 percent. The assumed long-term rate of return on plan assets at December 31, 1990 and 1989 was 8½ percent and 8 percent, respectively. The changes in these assumptions were based on market interest rates and did not materially impact Company costs. The unrecognized net obligation is being amortized over 15 years beginning January, 1986.

Pension cost for 1990, 1989, and 1988 was $8.5 million, $9.7 million and $10.8 million, respectively.

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 $2.5 million in 1990, $2.2 million in 1989, and $1.8 million in 1988.

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)	1990	1989	1988
Electric			
Operating Information			
Operating revenues	$ 594,395	$ 581,124	$ 544,603
Operating expenses, excluding provision for income taxes	464,478	445,539	391,887
Pretax operating income	129,917	135,585	152,716
Provision for income taxes	30,670	29,887	34,093
Net operating income	$ 99,247	$ 105,698	$ 118,623
Other Information			
Depreciation and amortization	$ 67,302	$ 65,287	$ 60,444
Nuclear fuel amortization	$ 25,573	$ 21,923	$ 19,945
Capital expenditures	$ 101,024	$ 98,646	$ 91,941
Investment Information			
Identifiable assets (a)	$1,557,176	$1,522,334	$1,469,571
Gas			
Operating Information			
Operating revenues	$ 236,496	$ 264,573	$ 231,217
Operating expenses, excluding provision for income taxes	214,505	231,086	204,397
Pretax operating income	21,991	33,487	26,820
Provision for income taxes	3,820	7,952	6,569
Net operating income	$ 18,171	$ 25,535	$ 20,251
Other Information			
Depreciation and amortization	$ 10,465	$ 9,776	$ 9,259
Capital expenditures	$ 25,752	$ 22,002	$ 18,646
Investment Information			
Identifiable assets (a)	$ 291,088	$ 284,511	$ 257,200

(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. Allowance for funds used during construction has been excluded from the construction costs presented below (Oswego Unit No. 6 $16.7 million and Nine Mile Point Nuclear Unit No. 2 $244.3 million). 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)	
RG&E's actual construction costs		
– 1989	$ 0.7	$ 1.0
– 1990	1.1	(0.8)
Expended by RG&E in prior years	78.0	588.0
	$79.8	$588.2

For further information regarding Nine Mile Point Nuclear Plant Unit No. 2 refer to Note 10. Construction costs in 1990 were reduced by approximately $1.0 million of credits arising from spare parts being transferred to Niagara Mohawk material and supplies inventory. Pursuant to Statement of Financial Accounting Standards No. 90, the Company, during 1987 and 1989, recognized disallowances of a portion of the Nine Mile Nuclear Plant Unit No. 2 facility (Total $379.1 million). These disallowances are not included in this table. Also not included are Company costs for nuclear fuel loading ($20.9 million), common facilities ($23.3 million), operating spare parts, transmission facilities, post-in-service additions ($15.9 million), and Company direct costs.

Note 6. Long Term Debt

First Mortgage Bonds

%	Series	Due	(Thousands) Principal Amount December 31 1990	1989
4½	T	Nov. 15, 1991	$ 15,000	$ 15,000
4⅝	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
9⅛	Z	Sept. 1, 2000	30,000	30,000
9¼	BB	June 15, 2006	50,000	50,000
8⅜	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	33,000	38,500
12¼	HH	May 15, 2012	10,500	10,500
13⅞	JJ	June 15, 1999	22,500	25,000
11¼	KK	May 15, 1995	49,334	49,334
8.6	LL	Aug. 1, 1993	75,000	75,000
8⅞	MM	May 1, 1992	75,000	75,000
11¾	NN	June 15, 1993	20,000	40,000
8⅜	OO	Dec. 1, 2028	25,500	25,500
			619,834	647,834
Net bond premium			128	143
Less: Due within one year			40,250	25,250
Total			$579,712	$622,727

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 1989 requirement was met with funds deposited with the Trustee, and these funds were used for redemption of outstanding bonds of Series KK. The 1990 requirement was 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. In February 1988, 1989 and 1990, the Company exercised this option and redeemed an additional $2.75 million of Series FF Bonds in each year.

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.

(Note 6 continued on page 30)

(continued from page 29)

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

(Thousands)	1991	1992	1993	1994	1995
Series NN	$20,000				
Series FF	2,750	$2,750	$2,750	$2,750	$2,750
Series JJ	2,500	2,500	2,500	2,500	2,500
Series T	15,000				
Series MM		75,000			
Series LL			75,000		
Series U				16,000	
Series KK					49,334
	$40,250	$80,250	$80,250	$21,250	$54,584

Promissory Notes

Issued	Due	(Thousands) December 31 1990	1989
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 5.55% for 1990, 6.14% for 1989 and 5.22% for 1988. The interest rate will be adjusted monthly or may be 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, 1993. This Promissory Note bore interest at 6½% per annum through November 14, 1988. The annual interest rate was adjusted to 5.90% effective November 15, 1988, to 6.15% effective November 15, 1989, and to 5.70% effective November 15, 1990. The interest rate will be adjusted annually or may be 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, 1993. 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. The interest rate will be adjusted annually or may be 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	970,000*
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, 1990	(Thousands) December 31 1990	1989	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, 1990	(Thousands) December 31 1990	1989	Redemption (per share)+
8.25	R	300,000	$30,000	$30,000	$108.25 Before 3/1/92

+Thereafter at lesser rates

Mandatory redemption of 60,000 shares per year commences on March 1, 1993 for Series R. 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.

Note 8. Common Stock

At December 31, 1990, there were 50,000,000 shares of $5 par value Common Stock authorized, of which 31,421,268 were outstanding. No shares of Common Stock are reserved for options, warrants, conversions, or other rights. There were 1,365,172 shares of Common Stock reserved and unissued for shareholders under the Automatic Dividend Reinvestment and Stock Purchase Plan and 271,528 shares reserved and unissued for employees under the RG&E Savings Plus Plan. Net loss resulting from the reacquisition of Series P preferred stock in 1988 is shown as Reacquired Capital Stock.

Common Stock:

	Per Share	Shares Outstanding	Amount (Thousands)
Balance, January 1, 1988		30,121,375	$494,018
Automatic Dividend Reinvestment and Stock Purchase Plan	15.963–18.013	619,172	10,440
Savings Plus Plan	16.000–17.188	45,264	749
Capital Stock Expense			8
Reacquired Capital Stock			(308)
Balance, December 31, 1988		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

Note 9. Short Term Debt

At December 31, 1990, the Company had short term debt outstanding of $42.4 million. The weighted average interest rate on short term debt outstanding at year end 1990 was 8.85% and was 8.54% for borrowings during the year. There were no borrowings in 1989.

On December 1, 1988 the Company renewed its $90 million revolving credit facility for a period of three years. In December 1989 and December 1990 the Company requested and was granted a one-year extension of the commitment termination date to December 31, 1992 and December 31, 1993, respectively. Commitment fees related to this facility amounted to $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, 1990, the Company would not be able to incur 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, 1991, are secured by the Company's accounts receivable.

Note 10: Commitments and Other Matters

Capital Expenditures

The Company's 1991 construction expenditures program is currently estimated at $151 million, including $9 million of carrying charges. The Company has entered into certain commitments for purchase of materials and equipment in connection with that program. The above amounts exclude the planned investment in Empire State Pipeline, approval for which is pending before the PSC. If such approval is granted, the Company expects to spend an additional $24.9 million.

Nine Mile Point Nuclear Plant

Nine Mile Point Nuclear Plant Unit No. 2 (Unit 2), a nuclear generating unit in Oswego County, New York, with an electrical capability of 1,080 megawatts, was completed and entered commercial service in Spring 1988. Its construction and initial operation presented a number of complex financial and regulatory issues, resulting in substantial write-offs for the Company. Although Unit 2 operating performance, regulatory relationships and budgetary considerations continue to demand its attention, the Company anticipates a period of more routine contribution of Unit 2 energy to meeting the electrical requirements of Company customers. Current Unit 2 developments of note are briefly recounted below.

Niagara Mohawk Power Corporation (Niagara) is operating Unit 2 on behalf of all owners pursuant to a full power operating license which the Nuclear Regulatory Commission (NRC) issued on July 2, 1987 for a 40-year term beginning October 31, 1986. Under arrangements dating from September 1975, ownership, output, and cost of Unit 2 are shared by five owners: the Company (14%), Niagara (41%), Long Island Lighting Company (18%), New York State Electric & Gas Corporation (18%) and Central Hudson Gas & Electric Corporation (9%). An interim operating agreement for the Unit, superseding the original 1975 version, was adopted by the owners in 1989, approved by the PSC in September 1990 and is effective until February 1992. Under the revised agreement, Niagara continues as operator of Unit 2, but all five owners share certain policy, budget and managerial oversight functions. The owners are continuing to discuss alternative operating arrangements at Nine Mile Point and part of that effort is an ongoing evaluation of the feasibility of establishing a separate operating entity there.

As it had earlier done in the case of Nine Mile Point Nuclear Unit No. 1 (Unit 1) – an adjoining facility entirely owned by Niagara, the NRC in December 1988 announced that it was undertaking close monitoring of Unit 2. Plants in this category have been identified as having weaknesses that warrant increased NRC attention. The agency has continued Units 1 and 2 in that status at each ensuing semi-annual review of licensed nuclear plants. The spring 1990 NRC systematic assessment of licensee performance (SALP), which also generally treats Units 1 and 2 together, found limited progress in certain of the seven categories evaluated, but for the most part continued to assign ratings from which the owners had been striving to improve. Such efforts continue and a new SALP report is expected in the spring.

In summer 1990, the Institute of Nuclear Power Operations (INPO), an industry-sponsored oversight group, performed an evaluation of Units 1 and 2. INPO identified deficiencies in key areas related to monitoring devices and supervision of maintenance practices, as it had in 1989, as well as the enforcement of accountability and control of special tests.

Unit 2 resumed operation on January 30, 1991 after completing its initial refueling outage. Unit 2 operating performance in 1990 improved, with two sustained periods of routine operation of approximately 100 days each. The Company believes that Unit 2 operating performance will continue to improve consistent with industry experience.

The next scheduled refueling outage for Unit 2 is expected to begin on February 29, 1992. However, an indication on a pipe weld was discovered to have increased in size during an inspection conducted by Niagara during the initial refueling outage. Based upon the results of this inspection, the NRC has notified Niagara that it must reinspect the weld within five to nine months of returning Unit 2 to service after completion of the initial refueling outage, or provide justification to the NRC for waiting to conduct the reinspection until the next refueling outage. Performing this inspection would require shutdown of Unit 2 for approximately ten days. Niagara intends to provide justification to the NRC for continued operation until the next refueling outage; however, no assurance can be provided that the NRC will accept Niagara's justification.

Although Unit 2 cost substantially more to build, a 1986 Settlement which the owners reached with the PSC Staff, and which the PSC approved, provided that, whatever the final construction cost of Unit 2, the aggregate amount allowed in the owners' rate bases would be $4.16 billion, reduced by prepaid financing costs. In a series of rate orders preceding commercial operation of Unit 2, the PSC permitted most of the Company's $488 million allowed investment (its 14% share of $4.16 billion, less prepaid financing charges) to be reflected in its rates. The

(Note 10 continued on page 34)

(continued from page 33)

Company also benefitted from a $40.6 million payment by Niagara to induce the Company to enter into the 1986 Settlement.

Despite the 1986 Settlement and the PSC order approving it, the owners and PSC Staff disagreed on its implementation and interpretation in several separate proceedings. The owners ultimately sought judicial review of PSC rulings upholding the PSC Staff's position, while other parties separately sought review of the PSC's approval of the 1986 Settlement itself.

Negotiations among the Unit 2 owners, the PSC Staff, and certain other parties to resolve the outstanding issues noted in the preceding paragraph resulted in a Settlement Agreement filed with the PSC in June 1990. The PSC approved the Settlement Agreement at a meeting in October 1990 and finalized that approval at a meeting on January 30, 1991. Issuance of a written order is expected in February. The Settlement Agreement resolved all open Unit 2 ratemaking issues with respect to its construction and its operation through January 19, 1990, including both a petition by the State Attorney General seeking disallowance of some utility replacement power costs associated with the 1988-89 mid-cycle outage and pending judicial review proceedings noted above. The net impact upon the Company of this Settlement Agreement was an estimated write-off, additional to that recognized in Calendar 1987 ($262 million), of $1.4 million, net of tax effects, which was recognized in December 1989, including a refund to the Company's electric customers of $2.9 million commencing upon formal PSC approval of the Settlement Agreement. The foregoing write-off reflected the current recognition of all benefits to which the Company is entitled under the owners' settlement with General Electric Company (see below).

In May 1990 all parties agreed to a settlement in the owners' lawsuit against three companies involved in furnishing the Unit 2 reactor's original main steam isolation valves. In a second lawsuit, commenced in 1988 against both the firm furnishing architect engineering and construction-management services and a company which fabricated and erected piping, the owners are seeking damages arising from the breach of certain obligations in the contractual arrangements with the defendants, which actions led to redesign, reconstruction and higher cost for the completed work. Discovery procedures are continuing. The Company cannot predict whether that suit will be successful or the amount of damages, if any, which may be recovered. The owners had earlier settled a dispute with General Electric Company relating to the Nuclear Steam Supply System. The accounting treatment for the proceeds from, and the expenses in the prosecution of, these claims was included in the now approved 1990 Settlement Agreement discussed above.

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 Unit 2. Neither the directors nor Company officers have received further communications from this party on this matter in nearly four years. Certain litigation involving Niagara and commenced by the same attorneys was dismissed from federal court in 1989 without further judicial activity to date. The same parties involved in the federal action against Niagara commenced similar action against Niagara in state court in late 1990. The Company is unable to predict whether the threats received by it will lead to litigation similar to that in which Niagara has been involved.

PSC Fuels Audit

During 1989, the PSC's Utility Operational Audit Section (Staff) audited the Company's fuel procurement practices, reviewing documents, interviewing Company personnel and visiting Company and vendor facilities. An interim report of Staff's findings, which is critical of senior management's oversight of the fuel procurement process and of various practices in that area during the 1980's, was received by the Company in May 1990. The Company's receipt of the interim report initiated a period of Company review and the preparation by it of a root cause analysis report submitted to Staff in August.

The Company and Staff have been discussing an accommodation of their differing views on several of the Staff's findings, at the conclusion of which Staff is expected to present its major conclusions in a final report. The PSC may initiate a proceeding in which it could ultimately disallow Company-incurred fuel costs, thereby either preventing their recovery in rates or requiring their refund, as appropriate.

The Company is unable to predict the outcome of the iterative procedure described above and what, if any, disallowance action the PSC may take on any matters that cannot be resolved. The Company believes its fuel procurement practices have been and continue to be prudent. Despite the Company's serious objections to many of the significant observations contained in the Staff interim report, if the PSC were to accept the interim report as presently written, the Company's earnings and financial position could be adversely affected. The degree of any such effects could be influenced by the time period over which the cost of PSC-directed remedial action would be recognized.

Environmental Matters

Operations of the Company's facilities are subject to various federal, state and local environmental standards.

In November 1990 the President signed into law the 1990 Clean Air Act Amendments. New York State is also considering changes to its air regulations. The Clean Air Act changes are expected to affect, and State action could additionally affect, the quality and cost of fuel burned in the Company's electric generating facilities and related air emission and quality control measures. Since the federal action has only recently been taken, and the State regulatory process is at an early stage, the Company is not in a position to identify the control measures and associated technology the Act will require, nor to assess their ultimate cost impact on Company operations. Based, however, on a preliminary analysis and applying various assumptions, the costs, including fuel, it would incur in order to achieve and maintain compliance could approximate $73 million (in 1990 dollars) for the eleven-year period 2000 to 2011. The Company believes that such costs would be recoverable in rates.

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 NYSDEC conducted an investigation with which the Company as an owner of a portion of the property cooperated and, in March 1988, released a report entitled "Expanded Phase I Investigation – Genesee River Gorge (Lower Falls)". That report includes an assessment of the adequacy of available data, makes recommendations for additional phased investigations and identifies property owners. The Company is included in the list of property owners and on a subsequently-developed list of potentially responsible parties, which list may be supplemented. The site has been assigned Classification 2, "significant threat to the public health or environment – action required", in the NYSDEC's registry of inactive waste sites. In May 1989, the Company and the City of Rochester agreed to conduct an additional, limited investigation at the site and to share its costs. The Company anticipates that such investigatory work would take two or more years to complete once regulatory authorities have approved the work plan. Cleanup of certain areas of the site may be ordered by the NYSDEC. In the absence of an agreed upon work plan, it is impossible at this time to determine the cost to the Company for those investigations or any subsequent remedial action.

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 Lower Falls 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 risk assessment information for its review.

If the NYSDEC requires remediation of these sites by virtue of ownership and/or past site disposal activity, 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 outcome will be reached in the Lower Falls site investigation, and, with respect to either location, 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 the Company's property in the Lower Falls site noted above, the County of Monroe has installed and operates sewer lines. During sewer installation, the County constructed 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 have 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. The County claims to have expended approximately $1.5 million in disposing of the materials. The Company has had discussions with the County on this matter. If the Company were to be found liable therefor, it could experience costs as yet undetermined.

(Note 10 continued on page 36)

(continued from page 35)

During 1990, a mollusk new to this area, called the "zebra mussel", extended its range throughout the Rochester area of Lake Ontario and of the Genesee River and is now present at all of the Company's electric generating stations. Although not yet an operational problem, this organism has the potential to cause substantial biofouling problems within the water use systems of the Company's facilities, as it could restrict water flows through pumps, condensers and piping. Current zebra mussel control consists of chlorination conducted within the limits of the State Pollution Discharge Elimination System permits. Modifications to existing chlorination systems are currently being designed and/or implemented in order to increase the effectiveness of these treatments. Overall, zebra mussel control will require additional maintenance efforts and the installation of additional control equipment. At this time, the costs of these control efforts are expected to be approximately three million dollars in capital expenditures and over $150,000/year in operation and maintenance costs. The Company believes that any costs associated with such efforts to control zebra mussels would be fully recoverable in rates. The Company is also involved in utility organizations researching both short-term and long-term control technologies designed to minimize operational impacts of the zebra mussel.

Nuclear Plant Decommissioning

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 $32.7 million through December 31, 1990.

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. According to the formula, the Company estimates that minimum funding level pursuant to the NRC regulation to be approximately $124.1 million for Ginna and $25.3 million for the Company's 14% share of Nine Mile Two (1990 dollars). The NRC minimum represents only the cost of removing the radioactive plant structures. In March 1990, the Company established an external decommissioning trust fund with initial funding of $3.5 million. 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 1990, the PSC approved the collection of $10.2 million for decommissioning during the rate year ending June 30, 1991. The amount allowed in rates is based on estimated ultimate decommissioning costs of $131.6 million for Ginna and $29.1 million for the Company's 14% share of Nine Mile Two (1989 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.

Nuclear-Related Insurance

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. Effective November 15, 1990, Nuclear

Electric Insurance Limited expanded coverage under its property insurance program to include 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 $170 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 $3.8 million and $7.3 million in the event of losses under the replacement power and property damage coverages, respectively.

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 Federal Energy Regulatory Commission (FERC) had previously developed an approach which required pipelines to absorb substantial portions of their take-or-pay costs and allocated the remainder among the pipelines' customers in proportion to past purchases. However, that approach was struck down by the courts, and the treatment of these costs at the pipeline level is uncertain even though interim collection of the costs is permitted.

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.

The Company is presently unable to estimate the amount of take-or-pay costs which may ultimately be included in its pipeline suppliers' charges to it. As of December 31, 1990 the Company had been billed for $5.3 million of take-or-pay costs and has recovered $4.9 million from its customers.

Other Matters

The Company's contract with the federal Department of Energy (DOE) for nuclear fuel enrichment services 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. The Company has secured the remaining 30% of its Ginna requirements under additional arrangements with DOE for the reload years 1991 through 1995. The remaining 30% of its Ginna requirements for the 1990 reload year were purchased on the spot market. The cost of DOE enrichment services utilized for the three most recent reload years and that estimated for the next seven reload years (priced at the most current rate) range from $4 million to $7 million per year.

REPORT OF INDEPENDENT ACCOUNTANTS

Price Waterhouse

1900 Lincoln First Tower
Rochester, New York 14604
January 31, 1991

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, 1990 and 1989, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1990, 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

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. The Nine Mile Two disallowed project costs and related write-off during 1989 are discussed in Note 10 of the Notes to the Financial Statements.

	(Thousands)				
Quarter Ended	Operating Revenues	Operating Income	Net Income	Earnings on Common Stock	Earnings Per Common Share (in dollars)
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
December 31, 1988	$193,465	$26,454	$10,577	$ 9,071	$.29
September 30, 1988	175,111	37,879	21,979	20,079	.65
June 30, 1988	163,016	28,396	12,517	10,546	.34
March 31, 1988	244,227	46,145	31,042	29,071	.96

COMMON STOCK AND DIVIDENDS

Tax Status of Cash Dividends

Cash dividends paid in 1990, 1989 and 1988 were 100 percent taxable for Federal income tax purposes.

Earnings and Dividends

	1990	1989	1988
Earnings per weighted average share	$1.72	$2.10	$2.25
Number of shares (000's)			
Weighted average	31,293	31,090	30,513
Actual number at December 31	31,421	31,258	30,786
Number of shareholders at December 31	36,977	38,762	41,834
Cash dividends paid			
1st quarter	$.39	$.375	$.375
2nd quarter	.39	.375	.375
3rd quarter	.39	.375	.375
4th quarter	.39	.375	.375

Common Stock Trading

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

	1990	1989	1988
Common Stock – Price Range			
High			
1st quarter	21¼	18¼	17½
2nd quarter	19⅞	20⅞	18¼
3rd quarter	19¼	21⅜	18¼
4th quarter	20	22⅛	17⅞
Low			
1st quarter	19½	17	14¾
2nd quarter	17½	17	15¾
3rd quarter	16⅞	19⅛	16⅜
4th quarter	17⅞	19½	16¾
At December 31	19½	21½	17¼

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.

Quarterly dividends on Common Stock are generally paid on the twenty-fifth day of January, April, July and October. In January 1991, the Company paid a cash dividend of $.405 per share on its Common Stock, up $.015 from the prior quarterly dividend payment of $.39. The January 1991 dividend payment is equivalent to $1.62 on an annual basis.

SELECTED FINANCIAL DATA

(Thousands of Dollars) Year Ended December 31	1990	1989	1988	1987	1986	1985
Summary of Operations						
Operating Revenues						
Electric	$551,930	$543,096	$514,637	$ 489,366	$463,841	$435,846
Gas	236,496	264,573	231,217	218,408	257,982	270,623
	788,426	807,669	745,854	707,774	721,823	706,469
Electric sales to other utilities	42,465	38,028	29,966	26,215	20,465	44,103
Total Operating Revenues	830,891	845,697	775,820	733,989	742,288	750,572
Operating Expenses						
Fuel Expenses						
Electric fuels	76,420	75,873	65,787	61,443	49,531	71,172
Purchased electricity	34,264	39,645	30,299	26,467	30,144	27,804
Gas purchased for resale	132,512	152,623	129,596	124,086	157,198	175,705
Total Fuel Expenses	243,196	268,141	225,682	211,996	236,873	274,681
Operating Revenues Less Fuel Expenses	587,695	577,556	550,138	521,993	505,415	475,891
Other Operating Expenses						
Operations excluding fuel expenses	194,594	173,764	159,689	159,170	148,340	129,273
Maintenance	62,391	64,316	52,575	46,124	44,767	42,518
Depreciation and Amortization	77,767	75,063	69,703	55,530	52,072	46,716
Taxes – local, state and other	101,035	95,341	88,635	82,869	84,590	81,983
Federal income tax – current	20,661	20,509	20,363	32,781	22,521	12,974
– deferred	13,829	17,330	20,299	23,144	37,304	44,978
Total Other Operating Expenses	470,277	446,323	411,264	399,618	389,594	358,442
Operating Income	117,418	131,233	138,874	122,375	115,821	117,449
Other Income and Deductions						
Allowance for other funds used during construction	2,689	2,261	2,047	5,030	32,828	38,393
Federal income tax	2,459	1,439	1,683	17,520	13,880	13,344
Disallowed project costs	–	(2,100)	–	(55,860)	–	–
Other, net	4,062	8,328	6,901	8,831	6,725	3,899
Total Other Income and Deductions	9,210	9,928	10,631	(24,479)	53,433	55,636
Income before Interest Charges	126,628	141,161	149,505	97,896	169,254	173,085
Interest Charges						
Long term debt	64,873	68,628	72,270	73,489	74,571	70,373
Short term debt	1,070	–	–	129	68	–
Other, net	3,523	3,115	2,898	2,685	2,074	2,227
Allowance for borrowed funds used during construction	(2,719)	(2,026)	(1,777)	(2,696)	(11,978)	(14,339)
Total Interest Charges	66,747	69,717	73,391	73,607	64,735	58,261
Income from Continuing Operations, Before Cumulative Effect of Accounting Change	59,881	71,444	76,114	24,289	104,519	114,824
Discontinued Steam Operations	–	–	–	–	–	(6,356)
Cumulative Effect for Years Prior to 1987 of Accounting Change for Disallowed Costs	–	–	–	(193,000)	–	–
Net Income (Loss)	59,881	71,444	76,114	(168,711)	104,519	108,468
Dividends on Preferred and Preference Stock, at required rates	6,025	6,025	7,348	8,147	8,058	9,467
Earnings (Loss) Applicable to Common Stock	$ 53,856	$ 65,419	$ 68,766	$(176,858)	$ 96,461	$ 99,001
Weighted Average Number of Shares Outstanding in Each Period, (000's)	31,293	31,090	30,513	29,728	28,927	27,641
Earnings (Loss) per Common Share – Total	$1.72	$2.10	$2.25	$ (5.95)	$3.33	$3.58
Earnings per Common Share – Continuing Operations	$1.72	$2.10	$2.25	$ .54	$3.33	$3.81
Cash Dividends Paid per Common Share	$1.56	$1.50	$1.50	$2.025	$2.20	$2.20

Condensed Balance Sheet

(Thousands of Dollars) At December 31	1990	1989	1988	1987	1986	1985
Assets						
Utility Plant	$2,310,294	$2,208,158	$2,122,922	$1,559,848	$1,531,019	$1,446,916
Less – Accumulated depreciation and amortization	812,994	730,621	653,876	586,840	571,022	532,947
	1,497,300	1,477,537	1,469,046	973,008	959,997	913,969
Construction work in progress	82,663	68,784	41,044	501,738	768,905	710,194
Net utility plant	1,579,963	1,546,321	1,510,090	1,474,746	1,728,902	1,624,163
Current Assets	176,045	190,321	213,626	184,472	141,344	144,381
Deferred Debits	108,451	102,729	102,015	131,526	114,340	82,092
Total Assets	$1,864,459	$1,839,371	$1,825,731	$1,790,744	$1,984,586	$1,850,636
Capitalization and Liabilities						
Capitalization						
Long term debt	$ 721,612	$ 764,627	$ 792,976	$ 845,326	$ 773,082	$ 765,511
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	30,000	30,000	30,000	50,797	43,485	45,922
Common shareholders' equity						
Common stock	516,388	513,560	504,907	494,018	479,704	461,078
Retained earnings	62,542	57,983	39,710	17,617	249,505	216,795
Total common shareholders' equity	578,930	571,543	544,617	511,635	729,209	677,873
Total Capitalization	1,397,542	1,433,170	1,434,593	1,474,758	1,612,776	1,556,306
Long Term Liability – Department of Energy	59,989	55,502	51,016	47,773	44,950	42,214
Current Liabilities	189,500	138,983	128,546	90,667	118,470	98,434
Deferred Credits and Other Liabilities	217,428	211,716	211,576	177,546	208,390	153,682
Total Capitalization and Liabilities	$1,864,459	$1,839,371	$1,825,731	$1,790,744	$1,984,586	$1,850,636

Financial Data

At December 31	1990	1989	1988	1987	1986	1985
*Capitalization Ratios** (percent)						
Long term debt	53.6	55.1	56.8	58.7	49.3	50.5
Preferred stock	6.7	6.5	6.5	7.7	6.7	7.1
Common shareholders' equity	39.7	38.4	36.7	33.6	44.0	42.4
Total	100.0	100.0	100.0	100.0	100.0	100.0
Book Value per Common Share – Year End	$18.42	$18.28	$17.69	$16.98	$24.93	$23.79
Rate of Return on Average Common Equity (percent)	9.29	11.56**	12.68	12.45**	13.38	14.93
Embedded Cost of Senior Capital (percent)						
Long term debt	8.59	8.74	8.71	8.90	9.36	9.88
Preferred stock	6.72	6.72	6.72	7.09	7.20	7.27
Effective Federal Income Tax Rate (percent)	34.8	33.8	33.9	61.3	30.5	28.0
Depreciation Rate (percent) – Electric	3.33	3.25	3.56	3.50	3.50	3.40
– Gas	2.94	2.96	2.96	2.98	2.99	2.98
*Interest Coverages****						
Before federal income taxes (incld. AFUDC)	2.32	2.53	2.53	2.55	2.96	3.08
(excld. AFUDC)	2.25	2.47	2.48	2.45	2.38	2.35
After federal income taxes (incld. AFUDC)	1.86	2.02	2.01	1.93	2.36	2.49
(excld. AFUDC)	1.78	1.96	1.96	1.83	1.78	1.77

*Includes Company's long term liability to the Department of Energy. Excludes amounts due or redeemable within one year.
**Excludes disallowed Nine Mile Two plant costs written off in 1989 and 1987.
***AFUDC included in interest coverages prior to 1987 has not been restated to reflect the disallowance of certain Nine Mile Two plant costs recognized by the Company in 1987.

ELECTRIC DEPARTMENT STATISTICS

Year Ended December 31	1990	1989	1988	1987	1986	1985
Electric Revenue (000's)						
Residential	$197,612	$191,732	$188,451	$178,933	$166,664	$155,193
Commercial	165,445	155,076	149,663	146,138	137,077	122,292
Industrial	130,012	124,634	120,490	118,479	116,321	110,135
Other (Includes Unbilled Revenue)	58,861	71,654	56,033	45,816	43,779	48,226
Electric revenue from our customers	551,930	543,096	514,637	489,366	463,841	435,846
Other electric utilities	42,465	38,028	29,966	26,215	20,465	44,103
Total electric revenue	594,395	581,124	544,603	515,581	484,306	479,949
Electric Expense (000's)						
Fuel used in electric generation	76,420	75,873	65,787	61,443	49,531	71,172
Purchased electricity	34,264	39,645	30,299	26,467	30,144	27,804
Other operation	155,289	137,458	124,871	126,320	113,497	96,194
Maintenance	53,880	55,915	44,060	37,641	36,573	35,013
Depreciation and Amortization	67,302	65,287	60,444	46,776	43,753	39,015
Taxes – local, state and other	77,323	71,361	66,426	61,504	61,314	58,867
Total electric expense	464,478	445,539	391,887	360,151	334,812	328,065
Operating Income before Federal Income Tax	129,917	135,585	152,716	155,430	149,494	151,884
Federal income tax	30,670	29,887	34,093	48,788	52,051	52,068
Operating Income from Electric Operations (000's)	$ 99,247	$105,698	$118,623	$106,642	$ 97,443	$ 99,816
Electric Operating Ratio %	53.8	53.2	48.7	48.9	47.4	48.0
Electric Sales – KWH (000's)						
Residential	2,075,072	2,072,047	2,051,808	1,970,345	1,890,293	1,846,993
Commercial	1,897,583	1,832,521	1,792,162	1,732,939	1,657,606	1,591,670
Industrial	1,931,633	1,906,429	1,869,417	1,782,223	1,775,722	1,814,460
Other	490,077	491,905	483,730	463,256	452,756	452,142
Total billed	6,394,365	6,302,902	6,197,117	5,948,763	5,776,377	5,705,265
Unbilled sales	(25,421)	33,406	–	–	–	–
Total customer sales	6,368,944	6,336,308	6,197,117	5,948,763	5,776,377	5,705,265
Other electric utilities	1,316,379	1,255,282	1,149,900	1,047,654	925,318	1,404,504
Total electric sales	7,685,323	7,591,590	7,347,017	6,996,417	6,701,695	7,109,769
Electric Customers at December 31						
Residential	296,110	293,418	290,037	285,988	281,630	277,758
Commercial	28,804	28,386	27,888	27,383	26,865	26,184
Industrial	1,428	1,422	1,392	1,381	1,368	1,362
Other	2,553	2,512	2,326	2,281	2,266	2,254
Total electric customers	328,895	325,738	321,643	317,033	312,129	307,558
Electricity Generated and Purchased – KWH (000's)						
Fossil	2,505,110	2,578,006	2,214,588	1,877,922	1,491,167	2,211,246
Nuclear	4,016,721	3,659,185	3,884,884	3,793,021	3,603,116	3,613,104
Hydro	244,539	175,085	169,002	223,958	235,175	153,636
Pumped storage	269,966	290,582	292,305	246,925	237,663	240,375
Less energy for pumping	(405,966)	(429,895)	(430,401)	(387,546)	(353,735)	(373,537)
Other	20,408	54,893	2,195	4,554	1,850	4,354
Total generated – Net	6,650,778	6,327,856	6,132,573	5,758,834	5,215,236	5,849,178
Purchased	1,498,089	1,757,413	1,705,755	1,703,411	1,945,586	1,713,481
Total electric energy	8,148,867	8,085,269	7,838,328	7,462,245	7,160,822	7,562,659
System Net Capability – KW at December 31						
Fossil	541,000	541,000	541,000	541,000	510,000	587,000
Nuclear	621,000	621,000	621,000	470,000	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	356,000	369,000	360,000	363,000	356,000	352,000
Total system net capability	1,594,000	1,607,000	1,598,000	1,450,000	1,412,000	1,485,000
Net Peak Load – KW	1,208,000	1,249,000	1,275,000	1,205,000	1,100,000	1,076,000
Annual Load Factor – Net %	64.6	62.4	59.7	60.8	64.7	65.4

GAS DEPARTMENT STATISTICS

Year Ended December 31	1990	1989	1988	1987	1986	1985
Gas Revenue (000's)						
Residential	$ 6,508	$ 6,770	$ 6,439	$ 6,436	$ 7,694	$ 8,403
Residential spaceheating	159,501	165,832	150,383	138,552	156,120	153,279
Commercial	43,534	46,897	44,781	43,311	52,653	53,568
Industrial	9,674	9,371	9,859	10,842	28,800	38,837
Municipal and other (Includes Unbilled Revenue)	17,279	35,703	19,755	19,267	12,715	16,536
Total gas revenue	236,496	264,573	231,217	218,408	257,982	270,623
Gas Expense (000's)						
Gas purchased for resale	132,512	152,623	129,596	124,086	157,198	175,705
Other operation	39,307	36,306	34,818	32,850	34,843	33,079
Maintenance	8,510	8,401	8,515	8,483	8,194	7,505
Depreciation	10,465	9,776	9,259	8,754	8,319	7,701
Taxes – local, state and other	23,711	23,980	22,209	21,365	23,276	23,116
Total gas expense	214,505	231,086	204,397	195,538	231,830	247,106
Operating Income before Federal Income Tax	21,991	33,487	26,820	22,870	26,152	23,517
Federal income tax	3,820	7,952	6,569	7,137	7,774	5,884
Operating Income from Gas Operations (000's)	$ 18,171	$ 25,535	$ 20,251	$ 15,733	$ 18,378	$ 17,633
Gas Operating Ratio %	76.3	74.6	74.8	75.7	77.6	79.9
Gas Sales – Therms (000's)						
Residential	9,644	10,321	10,374	10,255	11,382	12,296
Residential spaceheating	262,458	277,267	267,697	244,655	253,101	244,593
Commercial	77,617	84,152	86,413	83,167	92,864	93,283
Industrial	18,536	17,873	20,174	22,033	56,621	76,263
Municipal	13,350	12,319	15,514	17,985	23,405	24,848
Total billed	381,605	401,932	400,172	378,095	437,373	451,283
Unbilled sales	(22,840)	20,320	–	–	–	–
Total Gas Sales	358,765	422,252	400,172	378,095	437,373	451,283
Transportation of customer-owned gas	101,985	105,303	83,594	67,496	24,589	618
Total gas sold and transported	460,750	527,555	483,766	445,591	461,962	451,901
Gas Customers at December 31						
Residential	22,410	23,321	24,139	24,834	25,865	27,202
Residential spaceheating	219,242	215,120	210,710	206,458	201,227	196,035
Commercial	17,920	17,677	17,213	16,771	16,330	15,816
Industrial	960	1,095	1,042	1,035	1,015	1,029
Municipal	984	1,067	1,039	1,026	1,009	990
Total gas customers	261,516	258,280	254,143	250,124	245,446	241,072
Gas – Therms (000's)						
Purchased for resale	366,684	426,941	408,044	381,632	439,381	469,386
Other	2,525	1,764	1,967	2,317	5,996	14,943
Total gas available	369,209	428,705	410,011	383,949	445,377	484,329
Cost of gas per therm	36.03¢	35.74¢	31.76¢	32.51¢	35.82¢	37.53¢
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	3,539,820	3,719,050	3,744,500	3,443,240	3,499,640	3,746,980
Degree Days (Calendar Month)						
For the period	5,924	7,109	6,862	6,423	6,621	6,626
Percent colder (warmer) than normal	(11.8)	5.9	1.6	(4.3)	(1.4)	(1.3)

*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 January 1, 1991)

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Chief Executive Officer,
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Chase Lincoln First Bank, N.A.

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E. Kent Damon
Former Vice President and Secretary,
Xerox Corporation

Natacha P. Dykman
Former Chairman of the Board of Trustees,
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Goodrich & Sherwood Company

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Richardson Capital Corporation

M. Richard Rose
President,
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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*
E. Kent Damon
Roger W. Kober
Cornelius J. Murphy
Arthur M. Richardson
Harry G. Saddock
William G. vonBerg

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

Compensation
William Balderston III
Paul W. Briggs*
E. Kent Damon
Cornelius J. Murphy
M. Richard Rose
William G. vonBerg

Nominating
Theodore J. Altier
E. Kent Damon*
Natacha P. Dykman
Constance M. Mitchell
Arthur M. Richardson
Harry G. Saddock

*Chairman

OFFICERS
(as of January 1, 1991)

Harry G. Saddock
Chairman of the Board and
Chief Executive Officer
Age 61, Years of Service, 40

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President and
Chief Operating Officer
Age 57, Years of Service, 25

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Senior Vice President,
Controller and Chief Financial Officer
Age 50, Years of Service, 27

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Senior Vice President, Gas, Electric,
Distribution and Customer Services
Age 55, Years of Service, 36

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Age 53, Years of Service, 31

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Vice President,
Technical Projects,
Age 61, Years of Service, 35

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Vice President,
Secretary and Treasurer
Age 50, Years of Service, 27

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Vice President,
Ginna Nuclear Production
Age 45, Years of Service, 19

Howard E. Rowley
Vice President,
Gas and Transportation
Age 63, Years of Service, 42

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Vice President,
Electric Transmission and Distribution
Age 63, Years of Service, 45

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Vice President,
Employee Relations, Public Affairs and
Materials Management
Age 49, Years of Service, 28

Daniel J. Baier
Assistant Controller
Age 44, Years of Service, 7

John M. Küebel
Auditor
Age 55, Years of Service, 26

Alan A. Lohrmann
Assistant Treasurer
Age 51, Years of Service, 29

INVESTOR INFORMATION

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

Form 10-K Annual Report
Shareholders may obtain a copy of the Company's 1990 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.

Annual Meeting
The 1991 annual meeting of shareholders will be held on Wednesday, May 15, at 11 a.m. at the Company's Employee Center. The address is 700 Jefferson Road, Henrietta, New York.

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
1-800-442-2001

Transfer Agent and Registrar
The First National Bank of Boston
Shareholder Services Division
Mail Stop: 45-02-09
P.O. Box 644
Boston, MA 02102-0644
1-800-442-2001

First Mortgage Bond Trustee and Paying Agent
Bankers Trust Company
Attn: Security Holder Relations
P.O. Box 9006
Church Street Station
New York, NY 10249
(212) 250-6000

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