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50-410 Nine Mile Point Nuclear Station, Unit 2, Niagara Moha 05000410

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BIRD,R.J.	Rochester Gas & Electric Corp.

See Financial Rpts

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SUBJECT: Forwards complete copies of RG&E Securities & Exchange Commission Form 10-K for 1997.Form 10-K for FY97 was incomplete due to error in photocopying.

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August 18, 1998

United States Nuclear Regulatory Commission
ATTN.: Document Control Desk
Washington, D.C. 20555

RE: Docket Nos. 50-410 and 50-244
Facility Operating Licenses Nos. NPF-69 and DPR-18

Dear Commissioners:

On July 31, 1998 we submitted for filing the application of Rochester Gas and Electric Corporation ("RG&E") for the consent of the Commission to the transfer of control over RG&E as the holder of licenses for facilities as to which the Commission has issued Licenses Nos. NPF-69 and DPR-18. The transactions to which the application pertains are planned in connection with RG&E's proposed restructuring to adopt a holding company form of corporate organization as authorized by the New York State Public Service Commission.

Due to an error in photocopying, Exhibit D to RG&E's application, a copy of RG&E's Annual Report to the Securities and Exchange Commission on Form 10-K for the fiscal year ended December 31, 1997, was incomplete. Enclosed please find complete copies of RG&E's Form 10-K for 1997.

1/1

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If you should have any questions about this application, please contact counsel for RG&E in this matter, Ernest J. Ierardi, at (716) 263-1526, or at the law firm of Nixon, Hargrave, Devans & Doyle LLP at the above mailing address.

Respectfully submitted,

Robert J. Bird, Jr.

Robert J. Bird, Jr.
NIXON, HARGRAVE, DEVANS & DOYLE LLP
Attorneys for Rochester Gas and Electric Corporation

cc: Mr. Hubert J. Miller
Regional Administrator
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[illegible]

EXHIBIT D

9808200296

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

RECEIVED
FEB 20 1998
Nixon, Hargrave, Devans & Doyle LLP

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended: December 31, 1997

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ________________ to ________________

Commission file number: 1-672-2

Rochester Gas and Electric Corporation
(Exact name of registrant as specified in its charter)

New York	16-0612110
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer identification No.)

89 East Avenue, Rochester, NY 14649
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (716) 546-2700

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $5 par value	New York Stock Exchange

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

Securities registered pursuant to Section 12(g) of the Act:

Preferred Stock, $100 par value

4% Series F	4.95% Series K
4.10% Series H	4.55% Series M
4.75% Series I	
4.10% Series J	

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

On January 1, 1998 the aggregate market value of the voting stock held by nonaffiliates of the Registrant was approximately $1,312,000,000.

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

YES X NO ___

Indicate the number of shares outstanding of each of the registrant's classes of common stock as of the latest practicable date.

Common Stock, $5 par value, at January 1, 1998, 38,862,347.

Documents Incorporated by Reference	Part of Form 10-K
Definitive proxy statement in connection with annual meeting of shareholders to be held April 15, 1998.	III

ROCHESTER GAS AND ELECTRIC CORPORATION

Information Required on Form 10-K

PART I

Item 1. BUSINESS

The following are discussed under the general heading of "Business". Reference is made to the various other Items as applicable.

GENERAL

Incorporated in 1904 in the State of New York, the Company supplies electric and gas service wholly within that State. It produces and distributes electricity and distributes gas in parts of nine counties centering about the City of Rochester. At December 31, 1997 the Company had 1,958 employees.

The Company's service area has a population of approximately one million and is well diversified among residential, commercial and industrial consumers. In addition to the City of Rochester, which is the third largest city and a major industrial center in New York State, it includes a substantial suburban area with commercial growth and a large and prosperous farming area. A majority of the industrial firms in the Company's service area manufacture consumer goods. Many of the Company's industrial customers are nationally known, such as Xerox Corporation, Eastman Kodak Company, General Motors Corporation, and Bausch & Lomb Incorporated.

The business of the Company is seasonal. With respect to electricity, winter peak loads are attained due to spaceheating sales and shorter daylight hours and summer peak loads are reached due to the use of air-conditioning and other cooling equipment. With respect to gas, the greatest sales occur in the winter months due to spaceheating usage. The Company also plans to enter into unregulated businesses that will bring energy products and services to the marketplace both within and outside the Company's franchise area.

In each of the communities in which it renders service, the Company, with minor exceptions, holds the necessary municipal franchises, none of which contains burdensome restrictions. The franchises are non-exclusive, and are either unlimited as to time or run for terms of years. The Company anticipates renewing franchises as they expire on a basis substantially the same as at present.

Information concerning revenues, operating profits and identifiable assets for significant industry segments is set forth in Note 4 of the Notes to the Company's financial statements under Item 8. Information relating to the principal classes of service from which electric and gas revenues are derived and other operating data are included herein under "Operating Statistics". A discussion of the causes of significant changes in revenues is presented in Item 7 - Management's Discussion and Analysis of Financial Condition and Results of

Operations. Percentages of the Company's operating revenues derived from electric and gas operations for each of the last three years are as follows:

	1997	1996	1995
Electric	67.6%	67.1%	71.1%
Gas	32.4%	32.9%	28.9%
	100.0%	100.0%	100.0%

The Company is operating in a rapidly changing competitive marketplace for electric and gas service. This competitive environment includes a federal and State trend toward deregulation and promotion of open-market choices for consumers. In November 1997 the New York State Public Service Commission (PSC) approved a Settlement Agreement among the Company, PSC staff and other parties which sets the framework for the introduction and development of open competition in the electric energy marketplace in New York State over the next five years.

Regarding the Company's electric business, in early 1996 the Federal Energy Regulatory Commission (FERC) issued new rules to facilitate the development of competitive wholesale markets. In 1997 the Company together with other New York utilities filed with FERC a "Comprehensive Proposal to Restructure the New York Wholesale Market" and requested approval of their restructuring plan in early 1998. At the State level, the PSC endorsed a fundamental restructuring of the electric utility industry in the State in its "Competitive Opportunities Proceeding". The Company's Competitive Opportunities Settlement in 1997, including its proposed retail access program called "Energy Choice", allows for a phase-in to open electric markets while lowering customer prices and establishing an opportunity for competitive returns on shareholder investments. Although the Company is just beginning to receive applications from potential competitors under its distribution tariff, it expects more to be filed, particularly from companies with strong retailing and customer service capabilities and wholesale power trading expertise.

With the unbundling of services as directed by FERC Order 636, primary responsibility for reliable natural gas has shifted from interstate pipeline companies to local distribution companies, such as the Company. All gas customers have a choice of suppliers since November 1996, subject to certain phase-in limitations through 1998 for loss of gas commodity sales. Some of these companies are large, nationally known, publicly held marketers or suppliers. In 1997 the Company commenced negotiations with the staff of the PSC and other parties with the objective of developing a multi-year settlement of issues pertaining to the Company's gas business.

See Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations under the heading "Competition" for further information on the Competitive Opportunities Settlement and the competitive challenges the Company faces in its electric and gas business and how it is responding to those challenges.

REGULATORY MATTERS

The Company is subject to PSC regulation of rates, service, and sale of securities, among other matters. The Company is also regulated by the FERC on a limited basis, in the areas of interstate sales and exchanges of electricity, intrastate sales of electricity for resale, transmission wheeling service for other utilities, and licensing of hydroelectric facilities. As a licensee and operator of nuclear facilities, the Company is also subject to regulation by the

Nuclear Regulatory Commission (NRC). The impact of regulation is discussed throughout this report.

See Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations under the heading "Rates and Regulatory Matters" for summaries of recent PSC rate decisions and its flexible pricing tariff for major industrial and commercial electric customers.

ELECTRIC OPERATIONS

Electric System. The total net generating capacity of the Company's electric system is 1,239,000 Kw. In addition the Company purchases 120,000 Kw of firm power under contract and 35,000 Kw of non-contractual peaking power from the New York Power Authority, 150,000 Kw of a 1,000,000 Kw pumped storage plant owned by the Power Authority in Schoharie County, New York, 50,000 Kw of firm power from the Power Authority's 821,000 Kw FitzPatrick Nuclear Power Plant near Oswego, New York and 20,000 Kw of firm power from Hydro-Quebec purchased through the Power Authority. The Company's net peak load of 1,425,000 Kw occurred on August 15, 1995.

The percentages of electricity actually generated and purchased for the years 1993-1997 are as follows:

	1997	1996	1995	1994	1993
Sources of Generated Energy:					
Nuclear	61.6%	49.4%	52.8%	55.3%	57.6%
Fossil	20.0	18.2	18.6	18.1	19.5
Hydro and Other	2.7	3.0	2.0	2.7	2.6
Total Generated Net	84.3	70.6	73.4	76.1	79.7
Purchased	15.7	29.4	26.6	23.9	20.3
Total Electric Energy	100.0%	100.0%	100.0%	100.0%	100.0%

The Company, six other New York utilities and the Power Authority are members of the New York Power Pool (NYPP). The primary purposes of the NYPP are to coordinate inter-utility sales of bulk power, long range planning of generation and transmission facilities, and inter-utility operating and emergency procedures in order to better assure reliable, adequate and economic electric service throughout the State. For a discussion on potential changes to the NYPP, see Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - " FERC Open Transmission Orders and Company filings".

Generating Facilities. The Company's five major generating facilities are two nuclear units, the Ginna Nuclear Plant (Ginna Plant) and the Company's 14% share of Nine Mile Point Nuclear Plant Unit No. 2 (Nine Mile Two), and three fossil fuel generating stations, the Russell and Beebee Stations and the Company's 24% share of Oswego Unit Six. In terms of capacity these comprise 39%, 13%, 20%, 7% and 15%, respectively, of the Company's current electric generating system.

On December 1, 1997 Niagara Mohawk Power Corporation (Niagara) announced a plan to sell its fossil-fueled and hydroelectric generating stations by auction in 1998. This plan was agreed to as part of Niagara's Power Choice Settlement currently under review by the PSC. The Company intends to include its 24 percent share of Niagara's Oswego Steam Station Unit 6 (Oswego 6) for sale as part of Niagara's auction. Any gains or losses realized by the Company from the sale of its share of Oswego 6 would be treated in accordance with the terms of the Settlement under the Competitive Opportunities Proceeding. The Company would

include its share of Oswego 6 in these efforts as well. The gross and net book cost of the Company's share of Oswego 6 as of December 31, 1997 are $99 million and $58 million, respectively

On January 21, 1998 the Company decided to retire Beebee Station by mid-1999. Factors such as the plant's age, location in an area no longer consistent with the surrounding development, lack of a rail/coal delivery system and more stringent clean air regulations made the plant uneconomical in the developing competitive generation business. The retirement of Beebee Station is not expected to have a material effect on the Company's financial position or results of operations. The plant will be fully depreciated at the time of retirement. The Settlement provides that all prudently incurred incremental costs associated with the shut down and decommissioning of the plant are recoverable through the Company's distribution access tariff. The electric capability and energy currently provided by the plant is expected to be replaced by purchased power as needed.

Nine Mile Two, a nuclear generating unit in Oswego County, New York with a designed capability of 1,143 megawatts (Mw) as estimated by Niagara, was completed and entered commercial service in Spring 1988. Niagara is operating the Unit on behalf of all owners pursuant to a full power operating license which the 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 the project are shared by the Company (14%), Niagara (41%) Long Island Lighting Company (18%), New York State Electric & Gas Corporation (18%) and Central Hudson Gas & Electric Corporation (9%). Under the operating Agreement, Niagara serves as operator of Nine Mile Two, but all five cotenant owners share certain policy, budget and managerial oversight functions. The base term of the Operating Agreement is 24 months from its effective date, with automatic extension, unless terminated by written notice of one or more of the cotenant owners to the other cotenant owners; such termination becomes effective six months from the receipt of any such notice of termination by all the cotenant owners receiving such notice. The gross and net book cost of the Company's share of Nine Mile Two including $374 million of disallowed costs previously written off, as of December 31, 1997 are $879 million and $399 million, respectively.

The Company's Ginna Plant, which has been in commercial operation since July 1, 1970, provides 480 Mw of the Company's electric generating capacity. In August 1991 the NRC approved the Company's application for amendment to extend the Ginna Plant operating license expiration date from April 25, 2006 to September 18, 2009.

The gross and net book cost of the Ginna Plant as of December 31, 1997 are $560 million and $309 million, respectively. From time to time the NRC issues directives requiring all or a certain group of reactor licensees to perform analyses as to their ability to meet specified criteria, guidelines or operating objectives and where necessary to modify facilities, systems or procedures to conform thereto. Typically, these directives are premised on the NRC's obligation to protect the public health and safety. The Company reviews such directives and implements a variety of modifications based on these directives and resulting analyses. Expenditures at the Ginna Plant, including the cost of these modifications, are estimated to be $10.1 million, $10.4 million and $6.4 million for the years 1998, 1999 and 2000, respectively, and are included in the capital expenditure amounts presented under Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations.

The Company has four licensed hydroelectric generating stations with an aggregate capability of 47 megawatts. Although applications for renewal of those licenses were timely made in 1991, the FERC was unable to complete processing of many such applications by the December 31, 1993 license expiration. The FERC, therefore, issued annual licenses that essentially extend the terms of the old licenses year-to year until processing of the new ones can be completed. The

Company received final licenses for Stations 2 and 5 in February of 1996. The license for Station 26 was received in October, 1997. Overly stringent environmental conditions, governmental requirements and high property taxes have nullified the economic viability of the fourth station, number 160 (less than one megawatt net capacity). It will not be relicensed.

Joint Nuclear Operating Company. See Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations under Competition - Nuclear Operating Company regarding formation of a joint nuclear operating company to support and manage the operations of nuclear plants in New York State including Nine Mile Two and the Company's Ginna Plant described below.

Insurance. The Price-Anderson Act establishes a federal program insuring against public liability in the event of a nuclear accident at a licensed U.S. reactor. 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 $79.3 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 a surcharge for New York State premium taxes. The Company's interests in two nuclear units could thus expose it to a potential liability for each accident of $90.4 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.

As a licensee of a commercial nuclear power plant in the United States, the Company is required to have and maintain financial protection to cover radiation injury claims of certain nuclear workers. The Company purchases primary insurance to meet this requirement. On January 1, 1998, a new insurance policy was issued that applies to claims first reported on or after January 1, 1998. This policy has a limit of $200 million (reinstated annually if certain conditions are met) for radiation injury claims against the Company, or against other licensees who are insured by this policy. If these claims exceed the $200 million limit of primary coverage, the provisions of the Price-Anderson Act (discussed above) would apply. Since reserves for outstanding claims under former policies could be insufficient and certain claims may still be made under former policies due to a discovery period, the Company could be assessed under these former policies along with the other policyholders. The Company's share could be up to $3.0 million in any one year.

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. 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 $3.0 million and $10.9 million in the event of losses under the replacement power and property damage coverages, respectively.

GAS OPERATIONS

As of December 31, 1997 the Company's daily city gate resource capability is 4,380,000 therms and its daily contracted transportation capacity is 4,080,000 therms (where one Therm is equivalent to 100,000 British Thermal Units). The Company optimizes its assets by contracting for gas resources that align with its system requirements. The Company experienced on January 19, 1994, its maximum daily throughput of approximately 4,740,000 therms, (3,910,000 therms sold to retail customers and 830,000 therms delivered for transportation customers).

The Company purchases all of its required gas supply from numerous marketers and producers under contracts containing various terms and conditions.

See Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations under the caption "Energy Management and Costs - Gas" for a discussion of that topic.

The Company continues to provide new and additional gas service. Of 243,264 residential gas spaceheating customers at December 31, 1997, 2,579 were added during 1997.

Approximately 31% of the gas delivered to customers by the Company during 1997 was purchased directly by commercial, industrial and municipal customers from brokers, producers and pipelines. The Company provided the transportation of gas on its system to these customers' premises.

FUEL SUPPLY

Nuclear. Generally, the nuclear fuel cycle consists of the following: (1) the procurement of uranium concentrate (yellowcake), (2) the conversion of uranium concentrate to uranium hexafluoride, (3) the enrichment of the uranium hexafluoride, (4) the fabrication of fuel assemblies, (5) the utilization of the nuclear fuel in generating station reactors and (6) the appropriate storage or disposition of spent fuel and radioactive wastes. Arrangements for nuclear fuel materials and services for the Ginna Plant and Nine Mile Two have been made to permit operation of the units through the years indicated:

	Ginna Plant	Nine Mile Two(1)
Uranium Concentrate	2000(3)	2002(2)
Conversion	2000(4)	2002(2)
Enrichment	(5)	(6)
Fabrication	2001	2003

(1) Information was supplied by Niagara Mohawk Power Corporation.

(2) Arrangements have been made for procuring the majority of the uranium and conversion requirements through 2002, leaving the remaining portion of the requirements uncommitted.

(3) The Company has a contract under which it may procure up to 80 percent of the annual Ginna Plant uranium requirements. A second contract is in place to supply about 30% of the annual requirements for 1998 through 1999, and 100% of requirements in 2000. The remaining requirements are uncommitted.

(4) Seventy percent of the conversion requirements have been procured through 1997 under one contract. A second contract is in place covering 70% of requirements in 1998 and 1999, and 100% in 2000. Twenty percent of requirements for 1998 are covered by a contract for delivery of UF6 (uranium plus conversion). Ten percent of requirements for 1998 will be filled from inventory.

(5) The Company has a contract with United States Enrichment Corporation (USEC) for nuclear fuel enrichment services which assures provision of 70% of the Ginna Plant's requirements through 1999. A second enrichment contract is in place which assures 30% of the Ginna Plant's requirements through 1999 and 100% of requirements in 2000 and 2001.

(6) Nine Mile Two is covered for 100% of requirements through 1998 and for 75% (with an option to increase to 100%) from 1999 through 2003.

With appropriate lead times, the Company will pursue arrangements for the supply of uranium requirements and related services beyond those years for which arrangements have been made as shown above.

The average annual cost of nuclear fuel per million BTU used for electric generation for the last five years is as follows:

	1997	1996	1995	1994	1993
Ginna Plant	$.461	$.424	$.410	$.403	$.400
Nine Mile Two	$.485	$.512	$.503	$.481	$.515

See Note 10 of the Notes to Financial Statements under Item 8 for additional information regarding nuclear fuel disposal costs, nuclear plant decommissioning and DOE uranium enrichment facility decontamination and decommissioning.

Coal. The Company's 1998 coal requirements are expected to be approximately 800,000 tons. In 1997 100% of its requirements were purchased under contract. To meet the additional coal burn requirements and meet its current reserve supply of coal ranging from 30-60 days supply at maximum burn rates, it is anticipated that the Company will purchase spot market coal to supplement it contract supply.

The sulfur content of the coal utilized in the Company's existing coal-fired facilities ranges from 1.0 to 1.9 pounds per million BTU. Under existing New York State regulations, the Company's coal-fired facilities may not burn coal which exceeds 2.5 pounds per million BTU, and must average no higher than 1.7 pounds per million BTU over a 12-month period or 1.9 pounds per million BTU over a three-month period.

The average annual delivered cost of coal used for electric generation was as follows:

	1997	1996	1995	1994	1993
Per Million BTU	$1.34	$1.34	$1.31	$1.38	$1.42

FINANCING AND CAPITAL REQUIREMENTS PROGRAM

A discussion of the Company's capital requirements, financial objectives and the resources available to meet such requirements may be found in Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations. The sale of additional securities depends on regulatory approval and the Company's ability to meet certain requirements contained in its mortgage and Restated Certificate of Incorporation.

Under the New York State Public Service Law, the Company is required to secure authorization from the Public Service Commission of the State of New York (PSC) prior to issuance of any stock or any debt having a maturity of more than one year.

The Company's First Mortgage Bonds are issued under a General Mortgage dated September 1, 1918, between the Company and Bankers Trust Company, as Trustee, which has been amended and supplemented by thirty-nine supplemental indentures. Before additional First Mortgage Bonds are issued, the following financial requirements must be satisfied:

(a) The First Mortgage prohibits the issuance of additional First Mortgage Bonds unless earnings (as defined) for a period of twelve months ending not earlier than sixty days prior to the issue date of the additional bonds are at least 2.00 times the annual interest charges on First Mortgage Bonds, both those outstanding and those proposed to be outstanding. The ratio under this test for the twelve months ended December 31, 1997 was 6.99.

(b) The First Mortgage also provides that, if additional First Mortgage Bonds are being issued on the basis of property additions (as defined), the principal amount of the bonds may not exceed 60% of available property additions. As of December 31, 1997 the amount of additional First Mortgage Bonds which could be issued on that basis was approximately $398,393,000. In addition to issuance on the basis of property additions, First Mortgage Bonds may be issued on the basis of 100% of the principal amount of other First Mortgage Bonds which have been redeemed, paid at maturity, or otherwise reacquired by the Company. As of December 31, 1997, the Company could issue $321,669,000 of Bonds against Bonds that have matured or been redeemed.

The Company's Restated Certificate of Incorporation (Charter) provides that, without consent by two-thirds of the votes entitled to be cast by the preferred stockholders, the Company may not issue additional preferred stock unless in a 12-month period within the preceding 15 months: (a) net earnings applicable to payment of dividends on preferred stock, after taxes, have been at least 2.00 times the annual dividend requirements on preferred stock, including the shares both outstanding and proposed to be issued, and (b) net earnings available for interest on indebtedness, after taxes, have been at least 1.50 times the annual interest requirements on indebtedness and annual dividend requirements on preferred stock, including the shares both outstanding and proposed to be issued. For the twelve months ended December 31, 1997, the coverage ratio under (b) above (the more restrictive provision) was 2.83.

For information with respect to short-term borrowing arrangements and limitations see Item 8, Note 9 - Short-Term Debt.

The Company's Charter does not contain any financial tests for the issuance of preference or common stock.

The Company's securities ratings at December 31, 1997 were:

	First Mortgage Bonds	Preferred Stock
Standard & Poor's Corporation	BBB+	BBB
Moody's Investors Service	Baa1	baa2
Duff & Phelps	BBB+	BBB

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

ENVIRONMENTAL QUALITY CONTROL

Operations at the Company's facilities are subject to various federal, state and local environmental standards. To assure the Company's compliance with these requirements, the Company expended approximately $0.6 million on a variety of projects and facility additions during 1997.

The federal Low Level Radioactive Waste Policy Act (Act), as amended in 1985, provides for states to join compacts or individually develop their own low level radioactive waste disposal sites. The Company can provide no assurance as to what disposal arrangements, if any, New York will have in place. The State has not passed legislation that would designate a site for the disposal of low level radioactive waste. The Company has interim storage capacity at the Ginna Plant through 2002. Efforts are being pursued to extend storage capacity beyond 2002, if necessary, at this plant. A low level radioactive waste management and contingency plan is currently ongoing to provide assurance that Nine Mile Two will be properly prepared to handle interim storage of low level radioactive waste for the next ten years and beyond, if necessary.

The Company has wastewater discharge permits from NYSDEC for its Ginna, Beebee and Russell Stations, which were renewed in July 1997, February 1994, and June 1994, respectively. These permits are each effective for a period of five years. Consistent with these permits, no significant changes to the wastewater discharge treatment systems are currently required, nor anticipated.

The Company believes that additional expenditures and costs made necessary by mandated environmental protection programs will be fully allowable for ratemaking purposes under cost of service rate regulation. Capital expenditures for meeting various federal, State and local environmental standards are estimated to be $9 million for the year 1998, $2 million for the year 1999 and $1 million for the year 2000. These expenditures are included under Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations, in the table entitled "Capital Requirements".

See Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8, Note 10 - Commitments and Other Matters, with respect to other environmental matters.

RESEARCH AND DEVELOPMENT

The Company's research activities are designed to improve existing energy technologies and to develop new technologies for the production, distribution, utilization and conservation of energy while preserving environmental quality. Research and development expenditures in 1997, 1996 and 1995 were $4.5 million, $4.9 million, and $5.2 million, respectively. These expenditures represent the Company's contribution to research administered by Electric Power Research Institute, Empire State Electric Energy Research Corporation and an assessment for state government sponsored research by the New York State Energy Research and Development Authority, as well as internal research projects.

Electric Department Statistics

Year Ended December 31	1997	1996*	1995*	1994*	1993*	1992
Electric Revenue (000's)						
Residential	$ 252,464	$ 254,885	$ 256,294	$ 243,961	$ 234,866	$ 222,210
Commercial	210,643	215,763	215,696	206,545	196,100	187,262
Industrial	144,305	153,337	157,464	150,372	148,084	141,507
Municipal and Other	72,061	66,898	67,128	57,270	59,905	57,288
Electric revenue from our customers	679,473	690,883	696,582	658,148	638,955	608,267
Other electric utilities	20,856	16,885	25,883	16,605	16,361	25,541
Total electric revenue	700,329	707,768	722,465	674,753	655,316	633,808
Electric Expense (000's)						
Fuel used in electric generation	47,665	40,938	44,190	44,961	45,871	48,376
Purchased electricity	28,347	46,484	54,167	37,002	31,563	29,706
Other operation	205,058	204,746	199,524	192,360	192,749	183,118
Maintenance	41,217	41,429	44,032	47,295	52,464	53,714
Depreciation and amortization	103,395	92,615	78,812	75,211	72,326	73,213
Taxes - local, state and other	91,111	95,010	102,380	97,919	96,043	94,841
Total electric expense	516,793	521,222	523,105	494,748	491,016	482,968
Operating Income before Federal Income Tax	183,536	186,546	199,360	180,005	164,300	150,840
Federal income tax	61,837	61,901	59,500	52,842	43,845	38,046
Operating Income from Electric Operations (000's)	$ 121,699	$ 124,645	$ 139,860	$ 127,163	$ 120,455	$ 112,794
Electric Operating Ratio %	46.0	47.1	47.3	47.7	49.2	49.7
Electric Sales - KWH (000's)						
Residential	2,139,064	2,132,902	2,144,718	2,117,168	2,123,277	2,084,705
Commercial	2,118,991	2,061,625	2,064,813	2,028,611	1,986,100	1,938,173
Industrial	2,010,613	2,010,963	1,964,975	1,860,833	1,892,700	1,929,720
Municipal and Other	537,051	520,885	531,311	513,675	504,987	503,388
Total customer sales	6,805,719	6,726,375	6,705,817	6,520,287	6,507,064	6,455,986
Other electric utilities	1,218,794	994,842	1,484,196	1,021,733	743,588	1,062,738
Total electric sales	8,024,513	7,721,217	8,190,013	7,542,020	7,250,652	7,518,724
Electric Customers at December 31						
Residential	308,909	307,181	306,601	304,494	302,219	300,344
Commercial	30,940	30,620	30,426	29,984	29,635	29,339
Industrial	1,300	1,325	1,347	1,361	1,382	1,386
Municipal and Other	2,824	2,688	2,711	2,670	2,638	2,605
Total electric customers	343,973	341,841	341,085	338,509	335,874	333,674
Electricity Generated and Purchased - KWH (000's)						
Fossil	1,664,914	1,512,513	1,631,933	1,479,120	1,520,936	2,197,757
Nuclear	5,119,544	4,094,272	4,645,646	4,527,178	4,495,457	4,191,035
Hydro	227,867	248,990	171,886	218,129	199,239	278,318
Pumped storage	238,900	246,726	237,904	247,550	233,477	226,391
Less energy for pumping	(358,350)	(370,097)	(361,144)	(371,383)	(355,725)	(344,245)
Other	890	936	1,565	1,245	2,559	811
Total generated - net	6,893,765	5,733,340	6,327,790	6,100,839	6,095,943	6,550,067
Purchased	1,301,636	2,437,433	2,343,484	1,998,882	1,646,244	1,389,875
Total electric energy	8,195,401	8,170,773	8,671,274	8,099,721	7,742,187	7,939,942
System Net Capability - KW at December 31						
Fossil	526,000	529,000	529,000	532,000	541,000	541,000
Nuclear	638,000	638,000	640,000	617,000	620,000	617,000
Hydro	47,000	47,000	47,000	47,000	47,000	47,000
Other	28,000	28,000	28,000	29,000	29,000	29,000
Purchased	375,000	375,000	375,000	375,000	347,000	348,000
Total system net capability	1,614,000	1,617,000	1,619,000	1,600,000	1,584,000	1,582,000
Annual Peak Load - KW	1,421,000	1,305,000	1,425,000	1,374,000	1,333,000	1,252,000
Annual Load Factor - Net %	56.1	61.9	57.6	58.8	59.1	62.5

* Reclassified for comparative purposes.

Gas Department Statistics

Year Ended December 31	1997	1996*	1995*	1994*	1993*	1992
Gas Revenue (000's)						
Residential	$ 5,852	$ 6,010	$ 4,081	$ 5,935	$ 5,526	$ 6,456
Residential spaceheating	249,101	246,945	230,934	215,974	201,129	186,710
Commercial	51,893	52,073	51,117	49,115	46,321	44,395
Industrial	5,800	6,175	6,686	7,088	6,368	6,284
Municipal and other	23,663	35,076	1,045	47,949	34,364	17,879
Total gas revenue	336,309	346,279	293,863	326,061	293,708	261,724
Gas Expense (000's)						
Gas purchased for resale	196,579	202,297	167,762	194,390	166,884	141,291
Other operation	63,416	61,348	59,684	49,312	47,593	43,506
Maintenance	5,418	5,634	5,194	7,774	9,229	9,006
Depreciation	13,127	12,999	12,781	12,250	11,851	11,815
Taxes - local, state and other	30,685	31,858	31,514	31,859	30,849	29,411
Total gas expense	309,225	314,136	276,935	295,585	266,406	235,029
Operating Income before Federal Income Tax	27,084	32,143	16,928	30,476	27,302	26,695
Federal income tax	3,442	7,600	6,715	8,403	5,485	5,545
Operating Income from Gas Operations (000's)	$ 23,642	$ 24,543	$ 10,213	$ 22,073	$ 21,817	$ 21,150
Gas Operating Ratio %	78.9	77.8	79.2	77.1	76.2	74.1
Gas Sales - Therms (000's)						
Residential	5,773	6,455	7,167	6,535	6,871	8,780
Residential spaceheating	285,395	299,085	280,763	283,039	295,093	287,623
Commercial	65,675	70,543	68,380	72,410	78,887	78,996
Industrial	7,828	9,334	9,560	11,420	12,030	12,438
Municipal	7,331	8,086	8,219	10,230	12,188	11,41[illegible]
Total gas sales	372,002	393,503	374,089	383,634	405,069	399,247
Transportation of customer-owned gas	166,060	167,779	146,149	136,372	124,436	126,140
Total gas sold and transported	538,062	561,282	520,238	520,006	529,505	525,387
Gas Customers at December 31						
Residential	16,265	16,718	17,443	17,836	18,389	19,114
Residential spaceheating	243,264	240,685	238,267	235,313	231,937	228,096
Commercial	19,118	19,045	18,978	18,742	18,636	18,378
Industrial	829	857	879	905	924	932
Municipal	1,117	961	981	988	1,001	1,010
Transportation	836	744	655	558	466	424
Total gas customers	281,429	279,010	277,203	274,342	271,353	267,954
Gas - Therms (000's)						
Purchased for resale	274,430	279,353	237,728	262,267	347,778	360,493
Gas from storage	104,317	122,843	152,852	134,802	76,378	53,757
Other	1,410	1,082	1,800	2,959	1,039	1,061
Total gas available	380,157	403,278	392,380	400,028	425,195	415,311
Cost of gas per therm	51.70¢	52.30¢	45.80¢	50.00¢	36.79¢	35.35¢
Total Daily Capacity - Therms at December 31**	4,380,000	4,480,000	5,230,000	5,625,000	5,625,000	4,485,000
Maximum daily throughput - Therms	4,114,290	4,022,600	3,980,000	4,735,690	3,864,850	3,768,470
Degree Days (Calendar Month)						
For the period	6,921	6,998	6,535	6,699	7,044	6,981
Percent colder (warmer) than normal	2.8	3.9	(3.0)	(0.6)	4.4	3.4

* Reclassified for comparative purposes.

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

Item 2. PROPERTIES

ELECTRIC PROPERTIES

The net capability of the Company's electric generating plants in operation as of December 31, 1997 the net generation of each plant for the year ended December 31, 1997, and the year each plant was placed in service are as set forth below:

Electric Generating Plants

	Type of Fuel	Year Unit Placed in Service	Net Capability (Mw)	Net Generation thousands (kwh)
Beebee Station (Steam)	Coal	1959	80	418,139
Beebee Station (Gas Turbine)	Oil	1969	14	425
Russell Station (Steam)	Coal	1949-1957	257	1,237,958
Ginna Station (Steam)	Nuclear	1970	480	3,894,652
Oswego Unit 6[1] (Steam)	Oil	1980	189	8,817
Nine Mile Point Unit No. 2[2] (Steam)	Nuclear	1988	158	1,224,892
Station No. 9 (Gas Turbine)	Gas	1969	14	465
Station 5 (Hydro)	Water	1917	39	173,487
5 Other Stations (Hydro)	Water	1906-1960	8	54,380
				7,013,215
Pumped Storage [3]				238,900
Less: energy for pumping				(358,350)
			1,239	6,893,765

(1) Represents 24% share of jointly-owned facility.
(2) Represents 14% share of jointly-owned facility.
(3) Owned and operated by the Power Authority.

The Company owns 147 distribution substations having an aggregate rated transformer capacity of 2,149,754 Kva, of which 138, having an aggregate rated capacity of 1,970,588 Kva, were located on lands owned in fee, and nine of which, having an aggregate rated capacity of 179,166 Kva, were located on land under easements, leases or license agreements. The Company also has 72,881 line transformers with a capacity of 2,903,304 Kva. The Company also owns 24 transmission substations having an aggregate rated capacity of 3,052,017 Kva of which 23, having an aggregate rated capacity of 2,977,350 Kva, were located on land owned in fee and one, having a rated capacity of 74,667 Kva, was located on land under easements. The Company's transmission system consists of approximately 716 circuit miles of overhead lines and approximately 400 circuit miles of underground lines. The distribution system consists of approximately 16,262 circuit miles of overhead lines, approximately 3,857 circuit miles of underground lines and 353,220 installed meters. The electric transmission and distribution system is entirely interconnected and, in the central portion of the City of Rochester, is underground. The electric system of the Company is directly interconnected with other electric utility systems in New York and indirectly interconnected with most of the electric utility systems in the United States and Canada. (See Item 1 - Business, "Electric Operations".)

GAS PROPERTIES

The gas distribution systems consists of 4,257 miles of gas mains and 292,392 installed meters. (See Item 1 - Business, "Gas Operations" and "Gas Department Statistics".

OTHER PROPERTIES

The Company owns a ten-story office building centrally located in Rochester and other structures and property. The Company also leases approximately 475,000 square feet of facilities for administrative offices and operating activities in the Rochester area.

The Company has good title in fee, with minor exceptions, to its principal plants and important units, except rights of way and flowage rights, subject to restrictions, reservations, rights of way, leases, easements, covenants, contracts, similar encumbrances and minor defects of a character common to properties of the size and nature of those of the Company. The electric and gas transmission and distribution lines and mains are located in part in or upon public streets and highways and in part on private property, either pursuant to easements granted by the apparent owner containing in some instances removal and relocation provisions and time limitations, or without easements but without objection of the owners. The First Mortgage securing the Company's outstanding bonds is a first lien on substantially all the property owned by the Company (except cash and accounts receivable). A mortgage securing the Company's revolving credit agreement is also a lien on substantially all the property owned by the Company (except cash and accounts receivable) subject and subordinate to the lien of the First Mortgage. The Company has credit agreements with a domestic bank under which short-term borrowings are secured by the Company's accounts receivable.

Item 3. LEGAL PROCEEDINGS

See Item 8, Note 10 - Commitments and Other Matters.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during the fourth quarter of the fiscal year ended December 31, 1997.

Item 4-A. EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age 1/1/98	Positions, Offices and Business Experience 1993 to date
Thomas S. Richards	54	Chairman of the Board, President and Chief Executive Officer - January 1998 to date.
		President and Chief Operating Officer - March 1996 to December 1997.
		Senior Vice President, Energy Services - August 1995 to March 1996.
		Senior Vice President, Corporate Services and General Counsel - August, 1994 to August 1995.
		Senior Vice President, Finance and General Counsel - October 1993 to August, 1994.
		General Counsel - January, 1993 to October, 1993.
Michael J. Bovalino	42	President, Energetix, Inc (a wholly owned subsidiary of the Company) January 1998 to date.
		Senior Vice President, Energy Services - January 1997 to December 1997.
		Vice President, Retail Services for Plum Street Enterprises (a wholly owned subsidiary of Niagara Mohawk Power Corporation, 300 Erie Boulevard West, Syracuse, NY 13202) prior to joining the Company.
Robert E. Smith	60	Senior Vice President, Energy Operations - August 1995 to date.
		Senior Vice President, Customer Operations - August, 1994 to August, 1995.
		Senior Vice President, Production and Engineering - 1993 to August, 1994.

Name	Age 1/1/98	Positions, Offices and Business Experience 1993 to date
J. Burt Stokes	54	Senior Vice President, Corporate Services and Chief Financial Officer - January 1, 1996 to date. Chief Financial Officer and acting Chief Executive Officer for General Railway Signal Corporation, 150 Sawgrass Dr., Rochester, NY 14692 prior to joining the Company.
Michael T. Tomaino	60	Senior Vice President and General Counsel - October, 1997 to Date. Vice President, General Counsel and Secretary for Goulds Pumps, Inc., 300 Willowbrook Office Park, Fairport, NY 14450 prior to joining the Company.
William J. Reddy	50	Controller - May, 1997 to Date. Group Manager, Public Affairs Services - January 1995 to April 1997. Division Manager, Public Affairs Services - October 1994 to January 1995. Department Manager, Forecasts and Budgets - 1993 to September 1994.

The term of office of each officer extends to the meeting of the Board of Directors following the next annual meeting of shareholders and until his or her successor is elected and qualifies.

PART II

Item 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

COMMON STOCK AND DIVIDENDS

Earnings/Dividends	1997	1996	1995
Earnings per share			
- basic	$2.30	$2.32	$1.69
- diluted	$2.30	$2.32	$1.69
Dividends paid per share	$1.80	$1.80	$1.80

Shares/Shareholders	1997	1996	1995
Number of shares (000's)			
Weighted average - basic	38,853	38,762	38,113
- diluted	38,909	38,762	38,113
Actual number at December 31	38,862	38,851	38,453
Number of shareholders at December 31	31,337	33,675	35,356

TAX STATUS OF CASH DIVIDENDS

Cash dividends paid in 1997, 1996 and 1995 were 100 percent taxable for federal income tax purposes.

DIVIDEND POLICY

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

Quarterly dividends on Common Stock are generally paid on the twenty-fifth day of January, April, July and October. In January 1998, the Company paid a cash dividend of $.45 per share on its Common Stock. The January 1998 dividend payment is equivalent to $1.80 on an annual basis.

COMMON STOCK TRADING

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

Common Stock - Price Range	1997	1996	1995
High			
1st quarter	20 3/8	23 3/4	23
2nd quarter	21 7/16	21 7/8	22 5/8
3rd quarter	24 15/16	21 3/8	24 1/8
4th quarter	34 1/2	19 5/8	24 1/8
Low			
1st quarter	18 7/8	21 1/4	20 3/8
2nd quarter	18	19 7/8	20 1/8
3rd quarter	20 5/8	18	20
4th quarter	23 3/4	17 7/8	22 3/8
At December 31	34	19 1/8	22 5/8

ITEM 6 - SELECTED FINANCIAL DATA

CONSOLIDATED SUMMARY OF OPERATIONS

(Thousands of Dollars) Year Ended December 31	1997	1996*	1995*	1994*	1993*	1992
Operating Revenues						
Electric	$679,473	$690,883	$696,582	$658,148	$638,955	$608,267
Gas	336,309	346,279	293,863	326,061	293,708	261,724
	1,015,782	1,037,162	990,445	984,209	932,663	869,991
Electric sales to other utilities	20,856	16,885	25,883	16,605	16,361	25,541
Total Operating Revenues	1,036,638	1,054,047	1,016,328	1,000,814	949,024	895,532
Operating Expenses						
Fuel Expenses						
Fuel for electric generation	47,665	40,938	44,190	44,961	45,871	48,376
Purchased electricity	28,347	46,484	54,167	37,002	31,563	29,706
Gas purchased for resale	196,579	202,297	167,762	194,390	166,884	141,291
Total Fuel Expenses	272,591	289,719	266,119	276,353	244,318	219,373
Operating Revenues Less Fuel Expenses	764,047	764,328	750,209	724,461	704,706	676,159
Other Operating Expenses						
Operations excluding fuel expenses	268,474	266,094	259,207	241,672	240,342	226,624
Maintenance	46,635	47,063	49,226	55,069	61,693	62,720
Depreciation and amortization	116,522	105,614	91,593	87,461	84,177	85,028
Taxes - local, state and other	121,796	126,868	133,895	129,770	126,892	124,252
Federal income tax - current	69,812	65,757	65,368	35,658	33,453	36,101
- deferred	(4,533)	3,744	847	25,587	15,877	7,490
Total Other Operating Expenses	618,706	615,140	600,136	575,225	562,434	542,215
Operating Income	145,341	149,188	150,073	149,236	142,272	133,944
Other (Income) and Deductions						
Allowance for other funds used during construction	(351)	(684)	(585)	(396)	(153)	(164)
Federal income tax	(3,704)	(3,450)	(16,948)	(16,259)	(9,827)	(4,195)
Regulatory disallowances	-	-	26,866	600	1,953	8,215
Pension Plan Curtailment	-	-	-	33,679	8,179	-
Other, net	3,308	(712)	9,631	(923)	2,113	(6,155)
Total Other (Income) and Deductions	(747)	(4,846)	18,964	16,701	2,265	(2,299)
Interest Charges						
Long term debt	44,615	48,618	53,026	53,606	56,451	60,810
Short term debt	47	21	398	1,808	1,487	1,950
Other, net	6,629	9,307	8,658	4,758	5,220	5,228
Allowance for borrowed funds used during construction	(563)	(1,423)	(2,901)	(2,012)	(1,714)	(2,184)
Total Interest Charges	50,728	56,523	59,181	58,160	61,444	65,804
Net Income	95,360	97,511	71,928	74,375	78,563	70,439
Dividends on Preferred Stock at required rates	5,805	7,465	7,465	7,369	7,300	8,290
Earnings Applicable to Common Stock	$89,555	$90,046	$64,463	$67,006	$71,263	$62,149
Earnings per Common Share - Basic	$2.30	$2.32	$1.69	$1.79	$2.00	$1.86
Earnings per Common Share - Diluted	$2.30	$2.32	$1.69	$1.79	$2.00	$1.86
Cash Dividends Declared per Common Share	$1.80	$1.80	$1.80	$1.77	$1.73	$1.69

* Reclassified for comparative purposes.

CONDENSED CONSOLIDATED BALANCE SHEET

(Thousands of Dollars) At December 31	1997	1996	1995 *	1994 *	1993 *	1992 *
Assets						
Utility Plant	$3,234,077	$3,159,759	$3,068,103	$2,981,151	$2,890,799	$2,798,581
Less: Accumulated depreciation and amortization	1,714,368	1,569,078	1,518,878	1,423,098	1,335,083	1,253,117
	1,519,709	1,590,681	1,549,225	1,558,053	1,555,716	1,545,464
Construction work in progress	74,018	69,711	121,725	128,860	112,750	83,834
Net utility plant	1,593,727	1,660,392	1,670,950	1,686,913	1,668,466	1,629,298
Current Assets	242,371	250,461	292,596	236,519	248,589	209,621
Investment in Empire	-	-	38,879	38,560	38,560	9,846
Deferred Debits	432,191	450,623	453,726	484,962	488,527	181,434
Total Assets	$2,268,289	$2,361,476	$2,456,151	$2,446,954	$2,444,142	$2,030,199
CAPITALIZATION AND LIABILITIES						
Capitalization						
Long term debt	$587,334	$646,954	$716,232	$735,178	$747,631	$658,880
Preferred stock redeemable at option of Company	47,000	67,000	67,000	67,000	67,000	67,000
Preferred stock subject to mandatory redemption	35,000	45,000	55,000	55,000	42,000	54,000
Common shareholders' equity:						
Common stock	699,031	696,019	687,518	670,569	652,172	591,532
Retained earnings	109,313	90,540	70,330	74,566	75,126	66,968
Total common shareholders' equity	808,344	786,559	757,848	745,135	727,298	658,500
Total Capitalization	1,477,678	1,545,513	1,596,080	1,602,313	1,583,929	1,438,380
Long Term Liabilities (Department of Energy)	96,726	93,752	90,887	87,826	89,804	94,602
Current Liabilities	189,317	158,217	182,338	181,327	234,530	267,276
Deferred Credits and Other Liabilities	504,568	563,994	586,846	575,488	535,879	229,941
Total Capitalization and Liabilities	$2,268,289	$2,361,476	$2,456,151	$2,446,954	$2,444,142	$2,030,199

* Reclassified for comparative purposes.

FINANCIAL DATA

At December 31	1997	1996	1995	1994	1993	1992
Capitalization Ratios (a) (percent)						
Long-term debt	43.0	44.7	47.4	48.2	49.4	48.2
Preferred Stock	5.2	6.9	7.3	7.3	6.6	8.0
Common shareholders' equity	51.8	48.4	45.3	44.5	44.0	43.8
Total	100.0	100.0	100.0	100.0	100.0	100.0
Book Value per Common Share - Year End	$20.80	$20.24	$19.71	$19.78	$19.70	$18.92
Rate of Return on Average Common Equity (b) (percent)	11.00	11.41	8.37	8.92	10.25	9.94
Embedded Cost of Senior Capital (percent)						
Long-term debt	7.32	7.33	7.38	7.40	7.36	7.91
Preferred stock	5.80	6.26	6.26	6.26	6.69	6.98
Effective Federal Income Tax Rate (percent)	39.2	40.4	40.7	37.7	33.5	35.9
Depreciation Rate (percent) - Electric	3.12	2.99	2.76	2.69	2.62	2.69
- Gas	2.60	2.60	2.59	2.62	2.60	2.78
Interest Coverages						
Before federal income taxes (incld. AFUDC)	4.06	3.82	2.95	2.98	2.87	2.62
(excld. AFUDC)	4.04	3.79	2.90	2.94	2.84	2.58
After federal income taxes (incld. AFUDC)	2.86	2.68	2.16	2.24	2.24	2.04
(excld. AFUDC)	2.84	2.65	2.10	2.20	2.21	2.00
Interest Coverages Excluding Non-Recurring Items (c)						
Before federal income taxes (incld. AFUDC)	4.06	3.82	3.66	3.55	3.03	2.74
(excld. AFUDC)	4.04	3.79	3.61	3.51	3.00	2.70
After federal income taxes (incld. AFUDC)	2.86	2.68	2.62	2.61	2.35	2.12
(excld. AFUDC)	2.84	2.65	2.57	2.57	2.32	2.08

(a) Includes Company's long-term liability to the Department of Energy (DOE) for nuclear waste disposal. Excludes DOE long-term liability for uranium enrichment decommissioning and amounts due or redeemable within one year.

(b) The return on average common equity for 1995 excluding effects of the 1995 Gas Settlement is 12.10%. The rate of return on average common equity excluding effects of retirement enhancement programs recognized by the Company in 1994 and 1993 is 11.90% and 11.20%, respectively.

(c) Recognition by the Company in 1992 of disallowed ice storm costs as approved by the PSC has been excluded from 1992 coverages. Coverages for 1994 and 1993 exclude the effects of retirement enhancement programs recognized by the Company during each year and certain gas purchase undercharges written off in 1994 and 1993. Coverages in 1995 exclude the economic effect of the 1995 Gas Settlement ($44.2 million, pretax).

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is Management's assessment of certain significant factors affecting the financial condition and operating results of the Company. This assessment contains forward-looking statements which are subject to various risks and uncertainties. The Company's actual results could differ from those anticipated in such forward-looking statements as a result of numerous factors which may be beyond the Company's control by reason of factors such as electric and gas utility restructuring, future economic conditions, and developments in the legislative, regulatory and competitive environments in which the Company operates. Shown below is a listing of the principal items discussed.

EARNINGS SUMMARY

Despite rate reductions in July 1996 and 1997, earnings applicable to Common Stock were nearly unchanged in 1997 due, in part, to the increased availability of the Company's Ginna nuclear generating facility following the 1996 refueling and steam generator replacement outage. Increased Company generation allowed the Company to reduce purchased electric expense , while increasing available power for customer consumption and resale. A decrease in financing costs as a result of discretionary redemptions and refinancing activities during the year also helped to increase earnings. In addition to rate reductions, offsetting a gain in 1997 earnings were a warmer heating season during the first quarter of the year coupled with a cooler summer which affected air conditioning load.

Basic and dilutive earnings per share of $2.30 in 1997 are down two cents compared to a year ago. In February 1997, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 128 ("SFAS-128"), "Earnings per Share," which changes the methodology of calculating earnings per share. The Company adopted SFAS No. 128 during the fourth quarter of 1997. The impact on earnings per share for prior periods is not material. A discussion of the calculation of earnings per share is presented in Note 1 to the Notes to Financial Statements.

Basic and dilutive earnings per share of $1.69 reported in 1995 reflect a pretax reduction of $44.2 million, or $.75 per share net-of-tax, in connection

with a negotiated settlement (see 1995 Gas Settlement discussed below) reached between the Company, Staff of the New York State Public Service Commission (PSC) and other parties resolving various proceedings to review issues affecting the Company's gas costs.

The impact of developing competition in the energy marketplace will affect future earnings. The Competitive Opportunities Case Settlement (the "Settlement", see description below) allows for a phase-in to open electric markets while lowering customer prices and establishing an opportunity for competitive returns on shareholder investments. The nature and magnitude of the potential impact of the Settlement on the business of the Company will depend on the availability of qualified energy suppliers, the degree of customer participation and ultimate selection of an alternative energy supplier, the Company's ability to be competitive by controlling its operating expenses, and the Company's ultimate success in development of its unregulated business opportunities as permitted under the Settlement.

Future earnings will also be affected, in part, by the Company's degree of success in remarketing its excess gas capacity as set under the terms of the 1995 Gas Settlement and in controlling its local gas distribution costs. The Company believes it will be successful in meeting the 1995 Gas Settlement targets over the remaining year of the Settlement period, although no assurance may be given.

COMPETITION

Overview. During 1996 and 1997, the Company, the Staff of the PSC, and several other parties negotiated an agreement which was approved by the PSC in November 1997. This agreement sets the framework for the introduction and development of open competition in the electric energy marketplace and lasts through the year 2002. Over this time, the way electricity is delivered to customers will fundamentally change. In phases, the Company will open its electric system to other suppliers. The system will be fully open to competitors by July of 2001. These suppliers will compete to package and sell energy and related services to customers. The Company and its subsidiaries will be among the supplier choices. Competing suppliers will pay the Company a fee to use its electric distribution system and the Company will remain responsible for maintaining it and responding to most emergencies.

PSC COMPETITIVE OPPORTUNITIES CASE SETTLEMENT. Through its "Competitive Opportunities Proceeding," the PSC has embarked on a fundamental restructuring of the electric utility industry in the State. Among other elements, the PSC's goals included lower rates for consumers and increased customer choice in obtaining electricity and other energy services.

The Company's proceeding was completed on November 26, 1997 with the PSC approval of a Settlement Agreement among the Company, the PSC Staff and other parties. The PSC's November 26, 1997 order of approval was confirmed by a full Opinion and Order (No. 98-1) issued January 14, 1998.

Summary. The Settlement provides for a transition to competition during its five-year term (July 1, 1997 through June 30, 2002) and establishes the Company's electric rates for each annual period. A Retail Access Program will be phased in, allowing customers to purchase electricity, and later electricity and capacity commitments, from sources other than the Company. The Company will be provided a reasonable opportunity to recover prudently incurred costs, including those pertaining to generation and purchased power.

The Settlement also requires the Company to functionally separate its component operations: distribution, generation, and retailing. Any unregulated retail operations must be structurally separate from the regulated utility functions but may be funded with up to $100 million. In addition, the Company would have the option after receiving the necessary regulatory approvals to establish a holding company structure. Although the Settlement provides incentives for the sale of generating assets, it requires neither divestiture of generating or other assets, nor write off of "stranded costs" (the above-market costs, presumed to result from competition).

The Company believes that the Settlement will not adversely affect its eligibility to continue to apply Statement of Financial Accounting Standards No. 71 ("SFAS-71"), with the exception of certain "to-go costs" associated with non-nuclear generation. If, contrary to the Company's view, such eligibility were adversely affected, a material write-down of assets, the amount of which is not presently determinable, could be required.

Rate Plan. Over the five year term of the Settlement, the cumulative rate reductions will be as follows: Rate Year 1: $3.5 million; Rate Year 2: $12.8 million; Rate Year 3: $27.6 million; Rate Year 4: $39.5 million; and Rate Year 5: $64.6 million.

The Rate Plan permits the Company to offset against the foregoing total reductions certain inflation-related expenses, and certain amounts related to a power purchase agreement with Kamine/Besicorp Allegany L.P. (Kamine), including seven-eighths of any difference between Kamine costs currently included in rates and any increased amount resulting from enforcement of such agreement with any balance not recovered during the term of the Settlement subject to deferral for recovery after such term. The agreement is subject to litigation, as discussed in Note 10 of the Notes to Financial Statements. In the event of a settlement of the Kamine matter, the Settlement permits the Company to offset against rate reductions, the following amounts: Rate Year 2, $3.5 million; Rate Year 3, $8.4 million; Rate Year 4 and continuing until Settlement payments are complete or July 1, 2002, whichever is later, $10.5 million.

In the event that the Company earns a return on common equity in excess of an effective rate of 11.50 percent over the entire five-year term of the Settlement, 50 percent of such excess will be used to write down deferred costs accumulated during the term. The other 50 percent of the excess will be used to write down accumulated deferrals or investment in electric plant or Regulatory Assets (which are deferred costs whose classification as an asset on the balance sheet is permitted by SFAS-71). If certain extraordinary events occur, including a rate of return on common equity below 8.5 percent or above 14.5 percent, or a pretax interest coverage below 2.5 times, then either the Company or any other party to the Settlement would have the right to petition the PSC for review of the Settlement and appropriate remedial action.

Retail Access. RG&E's Energy Choice Program will be available to all of its customers, without regard to customer class, on an equal basis up to certain usage caps. On July 1, 1998, customers whose electric loads represent approximately 10 percent of the Company's total annual retail sales will be eligible to purchase electricity (but not capacity commitments) from alternative suppliers. On July 1, 1999, customers with 20 percent of total sales will be eligible and as of July 1, 2000, 30 percent of total sales will be eligible. As of July 1, 2001, all retail customers will be eligible to purchase energy and capacity from alternative suppliers.

During the initial, energy only stage of the Retail Access Program, the Company's distribution rate will be set by deducting 2.3 cents per kilowatt hour ("KWH") from its full service ("bundled") rates and Load Serving Entities acting as retailers in the Company's service area will be entitled to purchase electricity from the Company at a rate of 1.9 cents per KWH. During the energy and capacity stage, the rate will generally equal the bundled rate less the cost of the electric commodity and the Company's non-nuclear generating capacity. These commodity and capacity costs, generally referred to as "contestable costs," are estimated to be 3.2 cents per KWH, inclusive of gross receipts taxes.

Generating Assets. The Company will not be required to divest any of its generation facilities. To the extent that the Company sells any generating assets during the term of the Settlement, gains on such sales will be shared between the Company and customers. With regard to losses on such sales, the Settlement acknowledges an intent that the Company will be permitted to recover such losses through distribution rates during the term of the Settlement. Future rate treatment is to be consistent with the principle that the Company is to have a reasonable opportunity to recover such costs.

"To-go costs" of the Company's non-nuclear resources (i.e., capital costs incurred after February 28, 1997, operation and maintenance expenses, and property, payroll and other taxes) are to be recovered through the distribution

access tariff. The fixed portion of To-Go Costs would be recovered in full through the distribution access tariff until July 1, 1999 and subject to the market thereafter in accordance with the phase-in schedule for the Retail Access Program described above. The variable portion of non-nuclear to-go costs would also be subject to the market in accordance with the phase-in Schedule described above. Upon extension of eligibility for the Retail Access Program to all retail customers on July 1, 2001, the Company would be authorized to modify its distribution access rates, so as to hold constant the degree to which its to-go costs are at risk for recovery through the market. Thus, while the recovery of non-nuclear to-go Costs would continue to be through the market, recovery of nuclear costs would remain recoverable through regulated rates. No change in such treatment of nuclear facilities would be implemented prior to the PSC's resolution of the issues raised in its Staff Report on nuclear generation (see PSC Position Paper on Nuclear Generation). Shutdown and decommissioning costs would be recovered during the term of the Settlement in a manner consistent with past ratemaking treatment.

Pilot Program. Consistent with a PSC order issued June 23, 1997 in a separate proceeding involving establishment of pilot programs for farmers and food processors, the Settlement provides that the Company's Retail Access Program will commence on February 1, 1998 for those groups within the Company's service area.

Tariff Filing. On December 1, 1997, the Company submitted to the PSC its proposed tariffs and a Distribution Operating Agreement to establish "Energy Choice", the Company's proposed retail access program to implement the terms of the Settlement. In an order issued January 21, 1998, the PSC approved certain provisions of the December 1, 1997 tariff filing and required the Company to revise others. In late January 1998 the Company filed revisions to the tariff to incorporate the changes required by the PSC's order.

Miscellaneous. After approval of the Settlement becomes final and non-appealable, the Company will withdraw legal appeals which challenge various PSC Orders regarding the PSC Competitive Opportunities Proceeding, establishment of a pilot program pursuant to those proceedings, and certain provisions of the 1996 Electric Rate Settlement.

The present Settlement supersedes the 1996 Rate Settlement. Various incentive and penalty provisions in the 1996 Electric Rate Settlement are eliminated.

BUSINESS AND FINANCIAL STRATEGY: THE COMPANY'S RESPONSE. Under the terms of the Settlement, the Company will functionally separate its generation, distribution, and regulated energy services businesses. As permitted by the Settlement, the Company has established a separate unregulated subsidiary called Energetix which will be able to compete for energy, energy services and products both in and outside the Company's existing franchise service territory. The Company has also developed an integrated financial strategy which includes new business development initiatives and a Common Stock share repurchase program.

Energy Choice. Within the framework of the Energy Choice Program, the Company will unbundle traditional utility services. Retail electric customers in the Company's service territory will have the opportunity to purchase energy, capacity, and retailing services from competitive energy service companies, referred to as Load Serving Entities (LSEs). They may also continue to purchase fully-bundled electric service from the Company under existing retail tariffs.

General Structure. Energy Choice adopts the "single-retailer" model for the relationship between RG&E, the LSEs, and retail customers. Under the "single-retailer" model the regulated utility's customer is the LSE, whose customers are the retail customers. The relationship between the regulated utility and retail customers is substantially eliminated. The LSE assumes responsibility for providing its retail customers with bundled energy and delivery services, and for virtually all related retailing functions, including direct contact and communications with retail customers. With the exception of transmission and distribution service, the LSE will procure for its customers, or will itself create and provide them with, all necessary components of fully bundled service on a competitive basis.

Throughout the term of the Settlement, RG&E will continue to provide regulated and fully bundled electric service under its retail service tariff to customers who choose to continue with or return to such service, and to customers to whom no competitive alternative is offered.

Until the development of a wholesale market for generating capacity, there will be no suitable mechanism for the reallocation, from the regulated utility to the LSE, of responsibility for ensuring adequate installed reserve capacity. Accordingly, during the initial "Energy Only" stage of the Energy Choice Program (July 1, 1998 to July 1, 1999), LSEs will be able to choose their own sources of energy supply, while RG&E will provide to LSEs, and will be compensated for, the generating capacity (installed reserve) needed to serve their retail customers reliably. During the "Energy and Capacity" stage commencing July 1, 1999, the LSEs will be able to select, and will be responsible for procuring, generating capacity, as well as energy, to serve the loads of their retail customers, and distribution charges will be accordingly reduced as hereinafter described. If by July 1, 1998 there is not a functioning Statewide energy and capacity market (see discussion under FERC Open Transmission Orders), the Company may petition the PSC for deferral of the scheduled commencement of the Energy and Capacity stage.

Summary. The availability of LSEs to serve eligible customers and how quickly they decide to become involved cannot be determined. Likewise, the Company is not able to predict the number of customers that may chose to no longer be served under the Company's regulated tariffs.

The proposed tariffs for Energy Choice as filed by the Company are expected to become effective February 1, 1998 for the pilot program. The PSC has not set a decision-making date for the full-scale program. The Company is unable to predict what final rules or regulations will ultimately be adopted by the PSC for this program.

Unregulated Energy Services Company. It is part of the Company's financial strategy to stimulate growth by entering into unregulated businesses. The first step in this direction was the formation and operation of Energetix effective January 1, 1998. Energetix is an unregulated subsidiary of the Company that will bring energy products and services to the marketplace both within and outside the Company's franchise area.

The Settlement approved by the PSC in November allows for the investment of up to $100 million in unregulated businesses during the next five years. During 1998, the Company expects to determine the actual level of the initial investments to be made in unregulated business opportunities.

On July 1, 1997 the Company and Energetix filed with the Federal Energy Regulatory Commission (FERC) seeking authorization to engage in the wholesale sale of electric energy and capacity at market-based rates. These applications were accepted by FERC on September 12, 1997. The Company must seek separate authorization in order to sell electric energy to Energetix at market-based rates.

Stock Repurchase Plan. In December 1997 the Company's Board of Directors approved a Stock Repurchase Plan. This plan, which is subject to approval by the PSC, provides for the repurchase over the next three years of up to 4.5 million shares of Common Stock, representing approximately 11.5 percent of the Company's outstanding shares of Common Stock at December 31, 1997. The Company expects a PSC decision in early 1998.

Nuclear Operating Company. In October 1996, the Company and Niagara Mohawk Power Corporation (Niagara) announced plans to establish a nuclear operating company to be known as the New York Nuclear Operating Company (NYNOC). Since that time NYNOC has been organized as a New York Limited Liability Company and the Consolidated Edison Company of New York and New York Power Authority have announced their desire to move forward with the Company and Niagara with plans to implement NYNOC. It is envisioned that NYNOC would eventually assume responsibility for operation of all the nuclear plants in New York State, including the Company's totally owned Ginna Nuclear Plant and jointly owned Nine Mile Two. The Company believes that NYNOC could contribute to maintaining a high level of operational performance, contribute to continued satisfactory Nuclear

Regulatory Commission (NRC) compliance, provide opportunities for continued cost reduction and provide the basis for satisfactory economic regulation by the PSC. Various groups are now involved in the detailed studies and analyses required before a definitive decision to proceed with NYNOC can be made. The organizing utilities have submitted comments on the PSC Staff position paper on nuclear generation (discussed below under the heading PSC Position Paper on Nuclear Generation) noting that the Staff proposal would nullify the potential benefits of NYNOC.

PSC POSITION PAPER ON NUCLEAR GENERATION. On August 27, 1997, the PSC requested comments from interested parties on a PSC Staff position paper concerning the treatment of nuclear generation after a transition period. The Staff paper concludes that (1) nuclear generation should operate on a competitive basis, (2) sale of generation plants at auction to third parties is the preferred means of determining market value and offers the greatest potential for mitigation of stranded costs and the elimination of anti-competitive subsidies, and (3) where third party sales are not feasible, "to-go" costs (fuel, labor and other operating costs, prospective capital additions, property taxes and insurance) must be recovered in the wholesale market price of power.

On October 15, 1997, the Company and four other utilities jointly responded to the PSC. The utilities believe that the inherent operating characteristics of nuclear generation and the implications of NRC regulation require that nuclear plants have access to an adequate revenue stream and that such plants should be treated for dispatch purposes as baseload, must run units. The utilities urge the PSC to adopt a process that would enable all parties to fully develop the necessary facts and analyses and to invite the NRC to participate in addressing the future of nuclear generation in New York State. Certain other parties have filed comments on the position paper, some of which oppose full recovery of "stranded costs" that could result from sales of plants at less than book costs. The Company is unable to predict the outcome of the PSC's consideration.

FERC OPEN TRANSMISSION ORDERS AND COMPANY FILINGS. In early 1996 FERC issued new rules to facilitate the development of competitive wholesale markets by requiring electric utilities to offer "open-access" transmission service on a non-discriminatory basis in tariffs. The Company filed its required transmission service tariff on July 9, 1996. The new tariff would apply to wholesale purchases and sales made by the Company and the financial impact will depend on prevailing energy prices in the wholesale market. The near-term impacts of this tariff are not expected to be significant. On March 6, 1997, the Company reached a settlement in principle with the other parties respecting rate issues. FERC approval of the settlement was granted on June 25, 1997.

On January 31, 1997, the utilities filed a "Comprehensive Proposal To Restructure the New York Wholesale Electric Market" with the FERC. As proposed, the existing New York Power Pool (NYPP) will be dissolved and an independent system operator (ISO) will administer a state-wide open access tariff and provide for the short-term reliable operation of the bulk power system in the state. In addition to proposing a FERC-endorsed ISO, the proposal calls for creation of a New York Power Exchange and a New York State Reliability Council. An additional supplemental filing with FERC was made on December 19,1997 which lays out a specific timeframe for the implementation of a competitive wholesale electricity market in New York State. The utilities have requested FERC approval of their restructuring plan no later than March 31, 1998, which would allow the ISO to be operational by June 30, 1998. The timetable for retail competition will be determined for each utility in accordance with individual settlements in the Competitive Opportunities Proceeding.

Significant changes to pricing procedures now in effect within NYPP are expected, but it is unclear what effect these changes may have once other regulatory changes in New York State are implemented. At the present time, the Company cannot predict what effects regulations ultimately adopted by FERC will have, if any, on future operations or the financial condition of the Company.

GAS RESTRUCTURING AND PSC NEGOTIATIONS. In March 1996 the PSC issued an Order and approved utility restructuring plans designed to open up the local

natural gas market to competition and thereby allow residential, small business and commercial/industrial users the same ability to purchase their gas supplies from a variety of sources, other than the local utility, that larger industrial customers already have. During a three-year phase-in period the State's gas utilities would be permitted to require customers converting from sales service to take associated pipeline capacity for which the utilities had originally contracted. The PSC has indicated that it will address the issue of how the costs of such capacity would be recovered after the three-year period during the third year of the phase-in period. The PSC Staff has recently issued a position paper on The Future of the Natural Gas Industry in which the Staff proposes that local distribution companies (such as the Company) exit the merchant function in five years. Treatment of existing pipeline capacity contracts and Provider of Last Resort responsibilities are substantial issues to be worked out between the PSC, the local gas distribution companies and other stakeholders. See Note 10 of the Notes to Financial Statements for further information about the PSC gas restructuring proceedings and the PSC Staff position paper.

Gas customers have had a choice of suppliers since November 1, 1996. Under separate transportation tariffs, the Company distributes the gas and charges for the distribution as well as associated services. The Company believes its position in the market is such that it will maintain its distribution system margins. Under a phase-in limitation, loss of gas commodity sales may be limited to five percent of the Company's annual gas volume the first year, and then five additional percent for each of the following two years. The phase-in will be reviewed as experience is gained with the program. The Company anticipates that the use of transportation gas service will increase. Through December 31, 1997, 150 customers were being served under this service.

In July 1997, the Company commenced negotiations with the PSC Staff and other parties with the objective of developing a multi-year settlement of issues pertaining to the Company's gas business that would take effect upon expiration of the current 1995 Gas Settlement (see Rates and Regulatory Matters) on June 30, 1998. A further objective of these negotiations is to maximize the efficiencies of the entire business by structuring a settlement that will be as consistent as possible with the provisions of the Settlement in the Competitive Opportunities Proceeding, as discussed earlier. Negotiations are at an early stage; accordingly, the Company can make no prediction as to their outcome.

COMPETITION AND THE COMPANY'S PROSPECTIVE FINANCIAL POSITION. With PSC approval, the Company has deferred certain costs rather than recognize them on its books when incurred. Such deferred costs are then recognized as expenses when they are included in rates and recovered from customers. Such deferral accounting is permitted by SFAS-71. These deferred costs are shown as Regulatory Assets on the Company's Balance Sheet and a discussion and summarization of such Regulatory Assets is presented in Note 10 of the Notes to Financial Statements.

In a competitive electric market, strandable assets would arise when investments are made in facilities, or costs are incurred to service customers, and such costs are not fully recoverable in market-based rates. Estimates of such strandable assets are highly sensitive to the competitive wholesale market price assumed in the estimation. In a competitive natural gas market, strandable assets would arise where customers migrate away from dependence on the Company for full service, leaving the Company with surplus pipeline and storage capacity, as well as natural gas supplies, under contract. A discussion of strandable assets is presented in Note 10 of the Notes to Financial Statements.

At December 31, 1997 the Company believes that its regulatory and strandable assets, if any, are not impaired and are probable of recovery. The Settlement in the Competitive Opportunities Proceeding does not impair the opportunity of the Company to recover its investment in these assets. However, the PSC has published a Staff paper to address issues surrounding nuclear generation, including the determination of fair market value for facilities after a five year restructuring transition period. It appears that the PSC may seek to apply similar principles to other types of generating facilities. A determination in this proceeding could have an impact on strandable assets.

RATES AND REGULATORY MATTERS

1996 ELECTRIC RATE SETTLEMENT. The PSC approved a Settlement Agreement (1996 Rate Settlement) among the Company, PSC Staff and several other parties which set rates for a three-year period commencing July 1, 1996. The Competitive Opportunities Settlement (Settlement) supersedes the 1996 Rate Settlement. A rate reduction for the first rate year under the Settlement of 0.5 percent ($3.5 million) commencing July 1, 1997 is equal to the previously approved planned reduction under the 1996 Rate Settlement. After approval of the Settlement becomes final and non-appealable, the Company will terminate its petition seeking judicial review of the 1996 Rate Settlement.

1995 GAS SETTLEMENT. In October of 1995, a settlement of various gas rate and management issues was finalized (the 1995 Gas Settlement). This settlement affects the rate treatment of various gas costs through October 31, 1998.

Highlights of the 1995 Gas Settlement are:

- The Company will forego, for three years ending in mid-1998, gas rate increases exclusive of the cost of natural gas and certain cost increases imposed by interstate pipelines.
- The Company has agreed not to charge customers for pipeline capacity costs in 1996, 1997 and 1998 of $22.5 million, $24.5 million, and $27.2 million, respectively. The Company may sell its excess transportation capacity in the market under FERC rules.
- The Company agreed to write off excess gas pipeline capacity and other costs incurred through 1995.

The economic effect of the 1995 Gas Settlement on the Company's 1995 results of operations was to reduce earnings by $.75 per share.

The Company has entered into several agreements to help manage its pipeline capacity costs and has successfully met settlement targets for capacity remarketing for the twelve months' periods ending October 31, 1997 and October 31, 1996, thereby avoiding negative financial impacts for those periods. The Company believes that it will also be successful in meeting the Settlement targets in the remaining year of the Settlement period, although no assurance may be given.

FLEXIBLE PRICING TARIFF. Under its flexible pricing tariff for major industrial and commercial electric customers, the Company may negotiate competitive electric rates at discount prices to compete with alternative power sources, such as customer-owned generation facilities. Pursuant to the terms of the Settlement under the Competitive Opportunities Proceeding, the Company will absorb, as it has done since the inception of these rates, the difference between the discounted rates paid under these individual contracts and the rates that would otherwise apply. Approximately 27 percent of all electric sales (KWHs) to customers are made under long-term contracts, primarily to large industrial customers. These contracts represent approximately 42 percent of the Company's revenues from its commercial and industrial customers. The Company has not experienced any significant customer loss due to competitive alternative arrangements. Certain provisions of a flexible rate contract with the University of Rochester have been challenged by the Antitrust Division of the United States Department of Justice as discussed in Note 10 to the Financial Statements under the heading Litigation.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow, mainly from operations, provided the funds for construction expenditures, debt reductions, redemption of Preferred Stock and the payment of dividends during 1997 (see Consolidated Statement of Cash Flows).

CAPITAL AND OTHER REQUIREMENTS. The Company's capital requirements relate primarily to expenditures for energy delivery, including electric transmission and distribution facilities and gas mains and services as well as nuclear fuel, electric production and the repayment of existing debt. In 1996 the Company completed replacement of the two steam generators at the Ginna Nuclear Plant which resulted in improved plant efficiency. The Company spent approximately $46 million on this project in 1996 and $29 million in 1995. The Company has no plans to install additional baseload generation.

Purchased Power Requirement. Under federal and New York State laws and regulations, the Company is required to purchase the electrical output of unregulated cogeneration facilities which meet certain criteria (Qualifying Facilities). The Company was compelled by regulators to enter into a contract with Kamine for approximately 55 megawatts of capacity, the circumstances of which are discussed in Note 10 of the Notes to Financial Statements. The Company has no other long-term obligations to purchase energy from Qualifying Facilities.

Year 2000 Computer Issues. As the year 2000 approaches many companies face a potentially serious information systems (computer) problem because most software application and operational programs written in the past will not properly recognize calendar dates beginning with the year 2000. At this time, the Company believes that the problem is being addressed properly to prevent any adverse operational or financial impacts. The Company believes it will incur approximately $15 million of costs through January 1, 2000, associated with making the necessary modifications identified to date. Total costs incurred in 1997 were approximately $1.4 million.

ENVIRONMENTAL ISSUES. The production and delivery of energy are necessarily accompanied by the release of by-products subject to environmental controls. The Company has taken a variety of measures (e.g., self-auditing, recycling and waste minimization, training of employees in hazardous waste management) to reduce the potential for adverse environmental effects from its energy operations. A more detailed discussion concerning the Company's environmental matters, including a discussion of the federal Clean Air Act Amendments, can be found in Note 10 of the Notes to Financial Statements.

REDEMPTION OF SECURITIES. In addition to first mortgage bond maturities and mandatory sinking fund obligations over the past three years, discretionary redemption of securities totaled $1 million in 1995, $49 million in 1996, and approximately $152 million in 1997. Included in discretionary redemptions for 1997 were nearly $102 million of tax-exempt securities which were refinanced with new multi-mode tax-exempt bonds as discussed under Financing.

CAPITAL REQUIREMENTS - SUMMARY. Capital requirements for the three-year period 1995 to 1997 and the current estimate of capital requirements through 2000 are summarized in the Capital Requirements table.

The Company's capital expenditures program is under continuous review and could be revised for any number of issues. The Company also may consider, as conditions warrant, the redemption or refinancing of certain outstanding long-term securities.

Capital Requirements

Type of Facilities	Actual 1995	1996	1997	Projected 1998	1999	2000
	(Millions of Dollars)					
Electric Property						
Production	$ 48	$ 57	$ 9	$ 19	$ 17	$ 13
Energy Delivery	25	23	28	43	32	28
Subtotal	73	80	37	62	49	41
Nuclear Fuel	17	16	19	15	16	27
Total Electric	90	96	56	77	65	68
Gas Property	14	17	22	23	17	18
Common Property	4	6	9	24	18	6
Total	108	119	87	124	100	92
Carrying Costs						
Allowance for Funds Used During Construction	3	2	1	1	1	1
Total Construction Requirements	111	121	88	125	101	93
Securities Redemptions, Maturities and Sinking Fund Obligations*	1	67	182	40	10	30
Total Capital Requirements	$112	$188	$270	$165	$111	$123

* Excludes prospective refinancings.

FINANCING. Capital requirements in 1997, including the discretionary redemption of $49.7 million of securities, were satisfied primarily with internally generated funds. In addition, the Company at its option refinanced $101.9 million of outstanding tax-exempt securities with the proceeds from the sale on August 19, 1997 of $101.9 million of New York State Energy Research and Development Authority (NYSERDA) multi-mode tax-exempt bonds due August 1, 2032. Interest rates on these bonds may be set weekly or may be set for varying periods based on market conditions at the time. The weighted average interest rate on these bonds was 3.65 percent for 1997.

On September 16, 1997, the Company completed arrangements for the delivery in September 1998 of $25.5 million of 5.95% NYSERDA tax-exempt bonds due September 1, 2033. Proceeds will be used to redeem an issue of tax-exempt first mortgage bonds which is not redeemable until December 1998.

Under the Company's Performance Stock Option Plan, options for 403,605 shares of Common Stock became exercisable due to Common Stock market price performance during 1997. During 1997, Common Stock shares outstanding increased by 10,883 shares as a result of those options which were actually exercised during the year. These were the only shares of Common Stock issued by the Company during 1997.

The Company foresees modest near-term financing requirements. With an increasingly competitive environment, the Company believes maintaining a high degree of financial flexibility is critical. In this regard, the Company's long-term objective is to control capital expenditures. Moreover, in 1998 the Company may begin funding a stock repurchase program and investments in unregulated businesses as discussed under Competition.

Capital and other cash requirements during 1998 are anticipated to be satisfied primarily from a combination of internally generated funds and the use of short-term credit arrangements. The Company may refinance maturing long-term debt and Preferred Stock obligations during 1998 depending on prevailing financial market conditions.

The Company anticipates utilizing its credit agreements and unsecured lines of credit to meet any interim external financing needs prior to issuing any long-term securities. For information with respect to short-term borrowing arrangements and limitations, see Note 9 of the Notes to Financial Statements. As financial market conditions warrant, the Company may also, from time to time, redeem higher cost senior securities.

RESULTS OF OPERATIONS

The following financial review identifies the causes of significant changes in the amounts of revenues and expenses, comparing 1997 to 1996 and 1996 to 1995. The Notes to Financial Statements contain additional information.

OPERATING REVENUES AND SALES. Operating revenues in 1997 were lower than 1996 with the effect of electric base rate decreases in July 1996 and 1997 and lower therm sales of gas due to milder weather than last year partially offset by higher customer electric kilowatt-hour sales resulting from increased customers and higher electric sales to other utilities. Despite lower operating revenues, operating revenues less fuel expenses were nearly unchanged reflecting primarily a decline in purchased electricity expense as a result of increased availability of the Company's generating facilities.

The effect of weather variations on operating revenues is most measurable in the Gas Department, where revenues from spaceheating customers comprise about 90 to 95 percent of total gas operating revenues. Compared to a year earlier, weather in the Company's service area was 9.0 percent warmer during the first three months of 1997 and 1.1 percent warmer for the entire year on a calendar month heating degree day basis. In contrast, weather during 1996 was 7.1 percent colder than 1995 on a calendar month heating degree day basis. With elimination of a weather normalization clause in the Company's gas tariff effective November 1, 1995, abnormal weather variations may have a more pronounced effect on gas revenues. Cooler than normal summer weather during 1997 and 1996 hampered the demand for air conditioning usage, with a more pronounced effect in 1997 with the 1997 weather being approximately 27 percent cooler than 1996.

Compared with a year earlier, kilowatt-hour sales of energy to retail customers were up 1.2 percent in 1997, following a 0.3 percent increase in 1996. Sales to commercial customers achieved the largest gain in 1997. Sales to industrial customers led the increase in 1996 compared to a year earlier and were driven by one large industrial customer who purchased more electric power as an alternative to power produced at its own plant. Decreased electric demand for air conditioning usage caused by cooler summer weather had an impact on kilowatt-hour sales in 1996 and 1997.

Fluctuations in revenues from electric sales to other utilities are generally related to the Company's customer energy requirements, the wholesale energy market, availability of transmission, and the availability of electric generation from Company facilities. Revenues from electric sales to other utilities rose in 1997 due to increased sales resulting from greater availability of our combined nuclear and fossil generation, a favorable wholesale market in the second half of the year, and increased marketing of available capacity. In contrast to 1997, revenues from sales to other electric utilities declined in 1996 reflecting decreased kilowatt-hour sales to such utilities and less generation from the Company's Ginna Nuclear Plant.

The transportation of gas for large-volume customers who are able to purchase natural gas from sources other than the Company is an important component of the Company's marketing mix. Company facilities are used to distribute this gas, which amounted to 16.6 million dekatherms in 1997 and 16.8 million dekatherms in 1996. These purchases by eligible customers have caused decreases in Company revenues, with offsetting decreases in purchased gas

expenses and, in general, do not adversely affect earnings because transportation customers are billed at rates which, except for the cost of buying and transporting gas to the Company's city gate, approximate the rates charged the Company's retail gas service customers. Gas supplies transported in this manner are not included in Company therm sales, depressing reported gas sales to non-residential customers.

Therms of gas sold and transported were down 4.1 percent in 1997, after increasing nearly eight percent in 1996. These changes reflect, primarily, the effect of weather variations on therm sales to customers with spaceheating. If adjusted for normal weather conditions, residential gas sales would have decreased about 1.5 percent in 1997 over 1996, while non-residential sales, including gas transported, would have increased approximately two percent in 1997. The average use per residential gas customer, when adjusted for normal weather conditions, showed a modest decrease in 1996 and 1997.

FOSSIL UNIT RATINGS AND STATUS. Several of the Company's fossil-fueled generating units have been temporarily derated since February 1997 to maintain acceptable opacity levels while the Company investigates additional engineering solutions to address the opacity of the Units' emissions (see Note 10 of the Notes to Financial Statements under the heading "Environmental Matters, Opacity Issue"). The financial impact of the deratings includes the lost opportunity associated with energy sales and, at times, the need to make additional purchases to meet system requirements. While the deratings have decreased earnings, and will continue to do so, the amount is not expected to be material.

The NYPP is in the process of evaluating new rules for its system load regulation. Opacity limitations are expected to reduce the ability of the Company to react to changes in load and provide system load regulation services when called upon by the NYPP, resulting in additional costs. Depending on the new NYPP requirements, and whether the deratings remain in effect, the revised rules could result in the Company having to purchase additional regulation services which may cost between $500,000 and $2,500,000 annually. The Company intends to make a $2.7 million capital upgrade to the precipitator of one of its fossil-fueled generating units which is expected to remove a substantial portion of the opacity exceedance which led to the derating.

On January 21, 1998 the Company decided to retire Beebee Station by mid-1999. Factors such as the plant's age, location in an area no longer consistent with the surrounding development, lack of a rail/coal delivery system and more stringent clean air regulations made the plant uneconomical in the developing competitive generation business. The retirement of Beebee Station is not expected to have a material effect on the Company's financial position or results of operations. The plant will be fully depreciated at the time of retirement. The Settlement provides that all prudently incurred incremental costs associated with the shut down and decommissioning of the plant are recoverable through the Company's distribution access tariff. The electric capability and energy currently provided by the plant is expected to be replaced by purchased power as needed.

On December 1, 1997 Niagara announced a plan to sell its fossil-fueled and hydroelectric generating stations by auction in 1998. This plan was agreed to as part of Niagara's Power Choice Settlement currently under review by the PSC. The Company intends to include its 24 percent share of the Oswego Steam Station Unit 6 (Oswego 6) for sale as part of Niagara's auction. Any gains or losses realized by the Company from the sale of its share of Oswego 6 would be treated in accordance with the terms of the Settlement under the Competitive Opportunities Proceeding.

OPERATING EXPENSES

Energy Costs - Electric. Higher fuel expense for electric generation in 1997 compared with a year earlier reflects increased generation from both fossil and nuclear-fueled plants. Total Company electric generation was up approximately 21 percent in 1997 over 1996. For the 1996 comparison period, lower electric fuel costs resulted from less electric generation. The fuel cost adjustment clause has been eliminated effective July 1, 1996. Company

shareholders will assume the full benefits and detriments realized from actual electric fuel costs and generation mix compared with PSC-approved forecast amounts.

The Company normally purchases electric power to supplement its own generation when needed to meet load or reserve requirements, and when such power is available at a cost lower than the Company's production cost. Increased availability and efficiencies following the 1996 installation of new steam generators at the Ginna nuclear plant resulted in lower kilowatt-hour purchases of electricity in 1997 which led to a decline in purchased electric power expense. Despite an increase in kilowatt-hours purchased in 1996, electric purchased power expense was also down in 1996 reflecting, in part, lower purchases from the higher-cost Kamine facility as discussed below.

Under a contract with Kamine, the Company has been required to purchase unneeded energy at uneconomical rates (see Note 10 of the Notes to Financial Statements). The Company purchased 337 thousand megawatt-hours of energy from Kamine at a total price of $16.6 million in 1995. The Kamine facility has been out of service since the middle of February 1996 which helped to lower the unit cost for purchased electricity in 1996 compared to 1995.

Energy Management and Costs - Gas. The Company acquires gas supply and transportation capacity based on its requirements to meet peak loads which occur in the winter months. The Company is committed to transportation capacity on the Empire State Pipeline (Empire) and the CNG Transmission Corporation (CNG) pipeline systems, as well as to upstream pipeline transportation and storage services. The combined CNG and Empire transportation capacity is adequate to meet the Company's current requirements.

For the 1997 comparison period, gas purchased for resale expense declined driven by a reduced volume of purchased gas resulting from a warmer heating season. Higher commodity costs and increased volumes of purchased gas caused an increase in gas purchased for resale expense in 1996 compared to 1995.

Operations Excluding Fuel Expenses. For the 1997 comparison period, the increase in operations excluding fuel expenses reflects mainly higher outside services expenses, recognition of obsolete and unproductive materials inventory, storm costs, and regulatory compliance costs partially offset by lower payroll costs and decreased expense associated with uncollectible accounts. For the 1996 comparison period, the increase in operations excluding fuel expenses reflects mainly higher payroll costs and an increase in amortization expense beginning July 1, 1996 for customer information system enhancements. Higher payroll costs for this period reflects amortization of additional early retirement costs for programs concluded in October 1994 and greater employee redeployment/outplacement costs. An additional expense accrual for doubtful accounts increased operating expenses by $15.0 million in 1995.

The Company is continuing to take aggressive steps to improve its collection efforts. Uncollectible expense in 1997 was $18 million, compared with $20 million in 1996. In 1995, uncollectible expense was $23 million.

For both comparison periods, the increase in depreciation expense reflects primarily results from depreciation of the new Ginna nuclear plant steam generators (approximately $800,000 additional expense per month) and recovery of increased nuclear decommissioning expense of approximately $3.2 million per quarter beginning July 1, 1996.

Taxes Charged To Operating Expenses. Local, state and other taxes decreased in 1997 reflecting mainly lower property taxes due to decreases in assessments and/or rates and lower revenue taxes due to decreases in revenues and the New York State revenue tax surcharge rate. The decrease in these taxes for 1996 reflects mainly lower property taxes due to decreases in assessments.

The decrease in federal income tax in 1997 reflects mainly the reversal of a prior provision for the in-service date of Nine Mile Two as a result of an agreement reached with the Internal Revenue Service.

OTHER STATEMENT OF INCOME ITEMS. For the 1996 comparison period, the variation in non-operating federal income tax reflects mainly accounting adjustments related to regulatory disallowances.

Recorded under the caption Other Income and Deductions is the recognition of regulatory disallowances in connection with the 1995 Gas Settlement (see Rates and Regulatory Matters).

Other (Income) and Deductions, Other--net decreased in 1997 due mainly to recognition of expense associated with management performance awards and the Company's Performance Stock Option Plan. For the 1996 comparison period, Other (Income) and Deductions, Other -- net increased mainly due to the elimination in 1996 of two accrued expenses in 1995 related to depreciation expense for the Empire State Pipeline and amortization of certain employee early retirement costs.

Both mandatory redemptions and the optional redemptions of certain higher-cost long-term debt have helped to reduce long-term debt interest expense over the three-year period 1995-1997. Compared to the prior year, the average short-term debt outstanding was up slightly in 1997 following a decrease in 1996.

Preferred Stock dividends decreased in 1997 due to the Company's discretionary redemption in April of its 7.50% Preferred Stock, Series N and the mandatory sinking fund redemption of its 7.45% Preferred Stock, Series S in September.

DIVIDEND POLICY. The level of future cash dividend payments on Common Stock will be dependent upon the Company's future earnings, its financial requirements, and other factors. The Company's Certificate of Incorporation provides for the payment of dividends on Common Stock out of the surplus net profits (retained earnings) of the Company.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. FINANCIAL STATEMENTS

Report of Independent Accountants

Consolidated Statement of Income for each of the three years ended December 31, 1997.

Consolidated Statement of Retained Earnings for each of the three years ended December 31, 1997.

Consolidated Balance sheet at December 31, 1997 and 1996.

Consolidated Statement of Cash Flows for each of the three years ended December 31, 1997.

Notes to Consolidated Financial Statements.

Financial Statement Schedules:

The following Financial Statement Schedule is submitted as part of Item 14, Exhibits, Financial Statement Schedules and Reports on Form 8-K, of this Report. (All other Financial Statement Schedules are omitted because they are not applicable, or the required information appears in the Financial Statements or the Notes thereto.)

Schedule II - Valuation and Qualifying Accounts.

B. SUPPLEMENTARY DATA

Interim Financial Data.

REPORT OF INDEPENDENT ACCOUNTANTS

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

In our opinion, the consolidated financial statements listed under Item 8A in the index appearing on the preceding page present fairly, in all material respects, the financial position of Rochester Gas and Electric Corporation and its subsidiaries at December 31, 1997 and 1996, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1997 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.

/s/ PRICE WATERHOUSE LLP
PRICE WATERHOUSE LLP

Rochester, New York
January 23, 1998

CONSOLIDATED STATEMENT OF INCOME

(Thousands of Dollars) Year Ended December 31	1997	1996	1995
Operating Revenues			
Electric	$679,473	$690,883	$696,582
Gas	336,309	346,279	293,863
	1,015,782	1,037,162	990,445
Electric sales to other utilities	20,856	16,885	25,883
Total Operating Revenues	1,036,638	1,054,047	1,016,328
Operating Expenses			
Fuel Expenses			
Fuel for electric generation	47,665	40,938	44,190
Purchased electricity	28,347	46,484	54,167
Gas purchased for resale	196,579	202,297	167,762
Total Fuel Expenses	272,591	289,719	266,119
Operating Revenues Less Fuel Expenses	764,047	764,328	750,209
Other Operating Expenses			
Operations excluding fuel expenses	268,474	266,094	259,207
Maintenance	46,635	47,063	49,226
Depreciation and amortization	116,522	105,614	91,593
Taxes - local, state and other	121,796	126,868	133,895
Federal income tax	65,279	69,501	66,215
Total Other Operating Expenses	618,706	615,140	600,136
Operating Income	145,341	149,188	150,073
Other (Income) and Deductions			
Allowance for other funds used during construction	(351)	(684)	(585)
Federal income tax	(3,704)	(3,450)	(16,948)
Regulatory disallowances	-	-	26,866
Other, net	3,308	(712)	9,631
Total Other (Income) and Deductions	(747)	(4,846)	18,964
Interest Charges			
Long term debt	44,615	48,618	53,026
Other, net	6,676	9,328	9,056
Allowance for borrowed funds used during construction	(563)	(1,423)	(2,901)
Total Interest Charges	50,728	56,523	59,181
Net Income	95,360	97,511	71,928
Dividends on Preferred Stock	5,805	7,465	7,465
Earnings Applicable to Common Stock	$89,555	$90,046	$64,463
Earnings per Common Share - Basic	$2.30	$2.32	$1.69
Earnings per Common Share - Diluted	$2.30	$2.32	$1.69

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(Thousands of Dollars) Year Ended December 31	1997	1996	1995
Balance at Beginning of Period	$90,540	$70,330	$74,566
Add			
Net Income	95,360	97,511	71,928
Adjustment Associated with Stock Redemption	(846)	-	-
Total	185,054	167,841	146,494
Deduct			
Dividends declared on capital stock			
Cumulative preferred stock - at required rates	5,805	7,465	7,465
Common Stock	69,936	69,836	68,699
Total	75,741	77,301	76,164
Balance at End of Period	$109,313	$90,540	$70,330
Cash Dividends Declared per Common Share	$1.80	$1.80	$1.80

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

CONSOLIDATED BALANCE SHEET

(Thousands of Dollars) At December 31	1997	1996
Assets		
Utility Plant		
Electric	$2,439,108	$2,413,881
Gas	416,989	391,231
Common	134,938	129,946
Nuclear fuel	243,042	224,701
	3,234,077	3,159,759
Less: Accumulated depreciation	1,510,074	1,381,908
Nuclear fuel amortization	204,294	187,170
	1,519,709	1,590,681
Construction work in progress	74,018	69,711
Net Utility Plant	1,593,727	1,660,392
Current Assets		
Cash and cash equivalents	25,405	21,301
Accounts receivable, net of allowance for doubtful accounts: 1997 - $ 26,926; 1996 - $ 17,502	104,781	112,908
Unbilled revenue receivable	48,438	53,261
Materials, supplies and fuels	39,929	39,888
Prepayments	23,818	23,103
Total Current Assets	242,371	250,461
Deferred Debits		
Nuclear generating plant decommissioning fund	132,540	91,195
Nine Mile Two deferred costs	30,309	31,360
Unamortized debt expense	16,943	14,820
Other deferred debits	20,411	28,759
Regulatory assets	231,988	284,489
Total Deferred Debits	432,191	450,623
Total Assets	$2,268,289	$2,361,476
Capitalization and Liabilities		
Capitalization		
Long term debt - mortgage bonds	$485,434	$555,054
- promissory notes	101,900	91,900
Preferred stock redeemable at option of Company	47,000	67,000
Preferred stock subject to mandatory redemption	35,000	45,000
Common shareholders' equity:		
Common stock	699,031	696,019
Retained earnings	109,313	90,540
Total Common Shareholders' Equity	808,344	786,559
Total Capitalization	1,477,678	1,545,513
Long Term Liabilities (Department of Energy)		
Nuclear waste disposal	83,261	79,057
Uranium enrichment decommissioning	13,465	14,695
Total Long Term Liabilities	96,726	93,752
Current Liabilities		
Long term debt due within one year	30,000	20,000
Preferred stock redeemable within one year	10,000	10,000
Short term debt	20,000	14,000
Accounts payable	53,195	49,462
Dividends payable	18,791	19,349
Taxes accrued	5,041	4,694
Interest accrued	8,593	10,317
Other	43,697	30,395
Total Current Liabilities	189,317	158,217
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes	344,969	370,028
Pension costs accrued	67,361	69,806
Other	92,238	124,160
Total Deferred Credits and Other Liabilities	504,568	563,994
Commitments and Other Matters	-	-
Total Capitalization and Liabilities	$2,268,289	$2,361,476

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

ROCHESTER GAS AND ELECTRIC CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS

(Thousands of Dollars) Year Ended December 31	1997	1996	1995
CASH FLOW FROM OPERATIONS			
Net income	$ 95,360	$ 97,511	$ 71,928
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation and amortization	133,942	121,824	109,575
Deferred fuel	489	(6,501)	3,432
Deferred income taxes	(10,064)	6,391	(8,047)
Allowance for funds used during construction	(914)	(2,107)	(3,486)
Unbilled revenue, net	4,823	10,908	(9,899)
Stock option plan	2,399	-	-
Nuclear generating plant decommissioning fund	(20,331)	(11,732)	(8,837)
Pension costs accrued	(3,398)	(2,494)	6,280
Post employment benefit internal reserve	6,189	6,626	4,636
Regulatory disallowance	-	-	26,866
Provision for doubtful accounts	5,078	4,987	14,893
Changes in certain current assets and liabilities:			
Accounts receivable	3,049	3,228	(25,599)
Materials, supplies and fuels	(41)	(1,238)	6,837
Taxes accrued	347	(13,944)	15,167
Accounts payable	3,733	(3,116)	9,644
Other current assets and liabilities, net	7,344	(5,186)	9,639
Other, net	6,847	(3,931)	28,762
Total Operating	234,852	201,226	251,791
CASH FLOW FROM INVESTING ACTIVITIES			
Net additions to utility plant	(84,068)	(114,274)	(109,547)
Other, net	(1)	9,204	11,124
Total Investing	(84,069)	(105,070)	(98,423)
CASH FLOW FROM FINANCING ACTIVITIES			
Proceeds from:			
Sale/Issuance of common stock	272	8,612	17,074
Issuance of long term debt	101,900	-	-
Short term borrowings, net	6,000	14,000	(51,600)
Retirement of long term debt	(151,568)	(67,332)	(1,000)
Retirement of preferred stock	(30,000)	-	-
Dividends paid on preferred stock	(6,366)	(7,465)	(7,465)
Dividends paid on common stock	(69,933)	(69,657)	(68,347)
Other, net	3,016	2,866	(719)
Total Financing	(146,679)	(118,976)	(112,057)
Increase (Decrease) in cash and cash equivalents	$ 4,104	$ (22,820)	$ 41,311
Cash and cash equivalents at beginning of year	$ 21,301	$ 44,121	$ 2,810
Cash and cash equivalents at end of year	$ 25,405	$ 21,301	$ 44,121

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

(Thousands of Dollars) Year Ended December 31	1997	1996	1995
Cash Paid During the Year			
Interest paid (net of capitalized amount)	$ 50,681	$ 55,545	$ 56,592
Income taxes paid	$ 70,500	$ 76,890	$ 43,500

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

NOTES TO FINANCIAL STATEMENTS

Note 1. SUMMARY OF ACCOUNTING PRINCIPLES

GENERAL. The Company supplies electric and gas services wholly within the State of New York. It produces and distributes electricity and distributes gas in parts of nine counties centering about the City of Rochester. 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 ratemaking and accounting practices and policies of the PSC.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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

PRINCIPLES OF CONSOLIDATION. The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries Roxdel (now "Energetix") and Energyline. All intercompany balances and transactions have been eliminated.

Energyline was formed as a gas pipeline corporation to fund the Company's investment in the Empire State Pipeline project. In late 1996, Energyline sold its investment in the Empire State Pipeline.

The Roxdel (now "Energetix") activity is insignificant to the Company's financial position and results of operation.

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

Through June 30, 1996, tariffs for electric service included fuel cost adjustment clauses which adjusted the rates monthly to reflect changes in the actual average cost of fuels. Beginning July 1, 1996, the electric fuel adjustment clause was eliminated in connection with a rate settlement agreement with the PSC.

In prior years, retail customers who used gas for spaceheating were subject to a weather normalization adjustment to reflect the impact of variations from normal weather on a billing month basis for the months of October through May, inclusive. On January 25, 1995, the Company suspended the weather normalization adjustment in an effort to mitigate high billings due to the warm weather, and the suspension became permanent. This decreased 1995 pre-tax earnings from gas operations by $5.8 million.

The Company continues to use gas cost deferral accounting. 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 period.

UTILITY PLANT, DEPRECIATION AND AMORTIZATION. The cost of additions to utility plant and replacement of retirement units of property is capitalized. Cost includes labor, material, and similar items, as well as indirect charges such as engineering and supervision, and is recorded at original cost. The Company capitalizes an Allowance for Funds Used During Construction (AFUDC) approximately equivalent to the cost of capital devoted to plant under construction that is not included in its rate base. AFUDC is segregated into two components and classified in the Consolidated Statement of Income as Allowance for Borrowed Funds Used During Construction, an offset to Interest Charges, and

Allowance for Other Funds Used During Construction, a part of Other Income. The rate approved by the PSC for purposes of computing AFUDC was 5.0% during the three-year period ended December 31, 1997. 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.

CASH AND CASH EQUIVALENTS. Cash and cash equivalents consist of cash and short-term commercial paper. These investments have original maturity not exceeding three months. Such investments are stated at cost, which approximates fair value, and are considered cash equivalents for financial statement purposes.

INVESTMENTS IN DEBT AND EQUITY SECURITIES. The Company's accounting policy, as prescribed by the PSC, with respect to its nuclear decommissioning trusts is to reflect the trusts' assets at market value and reflect unrealized gains and losses as a change in the corresponding accrued decommissioning liability.

GAS SUPPLY. The Company periodically enters into agreements to minimize price risks for natural gas in storage. Gains or losses resulting from these agreements are deferred until the corresponding gas is withdrawn from storage and delivered to customers.

RESEARCH AND DEVELOPMENT COST. Research and Development costs were charged to expense as incurred. Expenditures for the years 1997, 1996, and 1995 were $4.5 million, $4.9 million and $5.2 million respectively.

ENVIRONMENTAL REMEDIATION COSTS. The Company accrues for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study.

Such accruals are adjusted as further information develops or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value.

MATERIALS SUPPLIES AND FUELS. Materials and supplies inventories are valued at the lower of cost or market using the first-in, first-out method. Fuel inventories are valued at average cost. The Company periodically enters into agreements to minimize price risks for natural gas in storage. Gains or losses resulting from these agreements are deferred until the corresponding gas is withdrawn from storage and delivered to customers.

STOCK-BASED COMPENSATION. Financial Accounting Standards Board Statement No. 123 (SFAS-123), Accounting for Stock-Based Compensation, was adopted by the Company in the first quarter of 1996. It recommends the use of a fair value based method of accounting for compensation costs associated with stock-based compensation. The Company currently has Stock Appreciation Rights plans covering certain employees and directors. For these plans, the Company's accounting policy has been to use a fair value method of computing periodic compensation expense. SFAS-123 was applied to the valuation of the 1996 Performance Stock Option Plan (PSOP), which became effective on January 22, 1997. The aggregate amount charged to expense as a result of these plans approximates $1.0 million annually in 1996 and 1995, and approximates $8.2 million in 1997. Additional information on the PSOP is included in Note 8.

RECLASSIFICATIONS. Certain amounts in the prior years' financial statements were reclassified to conform with current year presentation.

EARNINGS PER SHARE. SFAS-128, Earnings Per Share, was adopted by the Company in the fourth quarter of 1997. This statement replaces the presentation of primary Earnings Per Share with Basic Earnings Per Share, and also requires presentation of Diluted Earnings Per Share. Basic Earnings Per Share (EPS) is computed by dividing income available to common shareholders by the weighted average number of common shares outstanding for the period. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue

common stock were exercised or converted into common stock or resulted in the issuance of common stock that then shared in the earnings of the Company.

The following table illustrates the calculation of both Basic and Diluted EPS for the year ended December 31, 1997:

	Income (Numerator)	Shares (Denominator)	Per-Share Amount
Basic EPS:			
Net Income	$95,360		
Less:			
Preferred Stock Dividends	(5,805)		
Income available to Common Shareholders	89,555	38,853	$2.30
Diluted EPS:			
Effect of Dilutive Securities Stock Option Plan		56	
Income available to Common Shareholders plus assumed conversions	$89,555	38,909	$2.30

As there were no dilutive shares in prior years, basic and dilutive earnings per share were the same for 1996 and 1995.

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)		
	1997	1996	1995
Charged (Credited) to operating expense:			
Current	$ 69,812	$ 65,757	$ 65,368
Deferred	(4,533)	3,744	847
Total	65,279	69,501	66,215
Charged (Credited) to other income:			
Current	1,828	(6,097)	(9,996)
Deferred	(3,100)	5,079	(4,520)
Deferred investment tax credit	(2,432)	(2,432)	(2,432)
Total	(3,704)	(3,450)	(16,948)
Total federal income tax expense	$ 61,575	$ 66,051	$ 49,267

The following is a reconciliation of the difference between the amount of federal income tax expense reported in the Consolidated Statement of Income and the amount computed at the statutory tax rate of 35%.

	(Thousands of Dollars)		
	1997	1996	1995
Net Income	$ 95,360	$ 97,511	$ 71,928
Add: federal income tax expense	61,575	66,051	49,267
Income before federal income tax	$156,935	$163,562	$121,195
Computed tax expense at statutory tax rate	$ 54,927	$ 57,247	$ 42,418
Increases (decreases) in tax resulting from:			
Difference between tax depreciation and amount deferred	10,772	10,796	7,197
Deferred investment tax credit	(2,432)	(2,432)	(2,432)
Miscellaneous items, net	(1,692)	440	2,084
Total federal income tax expense	$ 61,575	$ 66,051	$ 49,267

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

	(Thousands of Dollars)		
	1997	1996	1995
Nuclear decommissioning	$(20,807)	$(17,880)	$(14,797)
Accelerated depreciation	216,704	213,907	197,952
Deferred investment tax credit	27,981	29,562	31,143
Depreciation previously flowed through	157,538	169,562	183,077
Pension	(23,166)	(24,570)	(24,241)
Other	(13,281)	(553)	4,518
Total	$344,969	$370,028	$377,652

SFAS-109 "Accounting for Income Taxes" requires that a deferred tax liability must be recognized on the balance sheet for tax differences previously flowed through to customers. Substantially all of these flow-through adjustments relate to property, plant and equipment and related investment tax credits and will be amortized consistent with the depreciation of these accounts. The net amount of the additional liability at December 31, 1997 and 1996 was $160 million and $175 million, respectively. In conjunction with the recognition of this liability, a corresponding regulatory asset was also recognized.

Note 3. PENSION PLAN AND OTHER POST EMPLOYMENT 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. The Company's funding policy is to contribute annually an amount consistent with the requirements of the Employee Retirement Income Security Act and the Internal Revenue Code. These contributions are intended to provide for benefits attributed to service to date and for those expected to be earned in the future.

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

	(Millions)	
	1997	1996
Accumulated benefit obligation, including vested benefits of $384.7 in 1997 and $374.6 in 1996	$(404.0)*	$(392.6)*
Projected benefit obligation for service rendered to date	$(499.3)*	$(480.2)*
Less: Plan assets at fair value, primarily listed stocks and bonds	638.4	567.1
Plan assets in excess of projected benefits	139.1	86.9
Unrecognized net loss (gain) from past experience different from that assumed and effects of changes in assumptions	(219.0)	(170.7)
Prior service cost not yet recognized in net periodic pension cost	10.7	11.6
Unrecognized net obligation at December 31	1.8	2.4
Pension costs accrued	$(67.4)	$(69.8)

* Actuarial present value.

Net pension cost included the following components:

	(Millions)		
	1997	1996	1995
Service cost - benefits earned during the period	$ 6.2	$ 7.4	$ 6.0
Interest cost on projected benefit obligation	33.0	33.4	35.4
Actual return on plan assets	(104.3)	(80.8)	(101.1)
Net amortization and deferral	63.1	39.0	56.1
Net periodic pension (credit) cost	$ (2.0)	$ (1.0)	$ (3.6)

The projected benefit obligation at December 31, 1997 and December 31, 1996 assumed discount rates of 6.75% and 7.25%, respectively, and a long-term rate of increase in future compensation levels of 5.00%. The assumed long-term rate of return on plan assets was 8.50%. The unrecognized net obligation is being amortized over 15 years beginning January 1986.

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits to retired employees and health care coverage for surviving spouses of retirees. Substantially all of the Company's employees are eligible provided that they retire as employees of the Company. In

1997, the health care benefit consisted of a contribution of up to $200 per retiree per month towards the cost of a group health policy provided by the Company. The life insurance benefit consists of a Basic Group Life benefit, covering substantially all employees, providing a death benefit equal to one-half of the retiree's final pay. In addition, certain employees and retirees, employed by the Company at December 31, 1982, are entitled to a Special Group Life benefit providing a death benefit equal to the employee's December 31, 1982 pay.

SFAS-106, "Accounting for Postretirement Benefits Other than Pensions", allows the Company to amortize the initial unrecognized, unfunded Accumulated Postretirement Benefit Obligation at January 1992 estimated at $56 million over twenty years. The Company intends to continue funding these benefits as the benefit becomes due.

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

	(Millions)	
	1997	1996
Accumulated postretirement benefit obligation:		
Retired employees	$(73.9)	$(65.6)
Active employees	(15.1)	(13.5)
	$(89.0)	$(79.1)
Less - Plan assets at fair value	0.0	0.0
Accumulated postretirement benefit obligation (in excess of) less than fair value of assets	(89.0)	(79.1)
Unrecognized net loss (gain) from past experience different from that assumed and effects of changes in assumptions	8.4	3.7
Prior service cost not yet recognized in net periodic pension cost	8.9	7.1
Unrecognized net obligation at December 31	39.5	42.3
Accrued postretirement benefit cost	$(32.2)	$(26.0)

Net periodic postretirement benefit cost included the following components:

	(Millions)	
	1997	1996
Service cost - benefits attributed to the period	$ 0.9	$ 1.0
Interest cost on accumulated postretirement benefit obligation	5.8	5.4
Actual return on plan assets	0.0	0.0
Net amortization and deferral	3.5	4.2
Net periodic postretirement benefit cost	$ 10.2	$10.6

The Accumulated Postretirement Benefit Obligation at December 31, 1997 and 1996 assumed discount rates of 6.75% and 7.25%, respectively, and long-term rate of increase in future compensation levels of 5.00%.

SFAS-112, "Employers' Accounting for Postemployment Benefits", requires the Company to recognize the obligation to provide postemployment benefits to former or inactive employees after employment but before retirement. The Company has been allowed to recover this cost in rates.

Note 4. DEPARTMENTAL FINANCIAL INFORMATION

The Company's records are maintained by operating departments, in accordance with PSC accounting policies. 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 Consolidated Statement of Income.

	(Thousands of Dollars)		
	1997	1996	1995
Electric			
Operating Information			
Operating revenues	$ 700,329	$ 707,768	$ 722,465
Operating expenses, excluding provision for income taxes	516,793	521,222	523,105
Pretax operating income	183,536	186,546	199,360
Provision for income taxes	61,837	61,901	59,500
Net operating income	$ 121,699	$ 124,645	$ 139,860
Other Information			
Depreciation and amortization	$ 103,395	$ 92,615	$ 78,812
Nuclear fuel amortization	$ 17,419	$ 16,209	$ 17,982
Capital expenditures	$ 58,522	$ 95,334	$ 93,634
Investment Information, Identifiable assets (a)	$1,783,825	$1,877,224	$1,913,762
Gas			
Operating Information			
Operating revenue	$ 336,309	$ 346,279	$ 293,863
Operating expenses, excluding provision for income taxes	309,225	314,136	276,935
Pretax operating income	27,084	32,143	16,928
Provision for income taxes	3,442	7,600	6,715
Net operating income	$ 23,642	$ 24,543	$ 10,213
Other Information			
Depreciation	$ 13,127	$ 12,999	$ 12,781
Capital expenditures	$ 25,546	$ 18,940	$ 15,913
Investment Information Identifiable assets (a)	$ 441,849	$ 447,865	$ 477,758

(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 Consolidated Statement of Income. Various modifications will be made throughout the lives of these plants to increase operating efficiency or reliability, and to satisfy changing environmental and safety regulations.

	Oswego Unit No. 6	Nine Mile Point Nuclear Unit No. 2
Net megawatt capability (summer)	788	1,128
RG&E's share - megawatts	189	158
- percent	24	14
Year of completion	1980	1988

	(Millions of Dollars) December 31, 1997	
Plant In Service Balance	$ 98.9	$879.3
Accumulated Provision For Depreciation	$ 41.4	$478.7
Plant Under Construction	$ 0.6	$ 3.3

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

Note 6. LONG-TERM DEBT

FIRST MORTGAGE BONDS

%	Series	Due	(Thousands of Dollars) Principal Amount December 31 1997	1996
6 1/4	W	Sept. 15, 1997	$ -	$ 20,000
6.7	X	July 1, 1998	30,000	30,000
8.00	Y	Aug. 15, 1999	-	29,668
6 1/2	EE	Aug. 1, 2009	-	10,000
8 3/8	OO[a]	Dec. 1, 2028	25,500	25,500
9 3/8	PP	Apr. 1, 2021	100,000	100,000
8 1/4	QQ[b]	Mar. 15, 2002	100,000	100,000
6.35	RR[a]	May 15, 2032	10,500	10,500
6.50	SS[a]	May 15, 2032	50,000	50,000
7.00	(b)(c)	Jan. 14, 2000	30,000	30,000
7.15	(b)(c)	Feb. 10, 2003	39,000	39,000
7.13	(b)(c)	Mar. 3, 2003	1,000	1,000
7.64	(c)	Mar. 15, 2023	33,000	33,000
7.66	(c)	Mar. 15, 2023	5,000	5,000
7.67	(c)	Mar. 15, 2023	12,000	12,000
6.375	(b)(c)	July 30, 2003	40,000	40,000
7.45	(c)	July 30, 2023	40,000	40,000
			$516,000	$575,668
Net bond discount			(566)	(614)
Less: Due within one year			30,000	20,000
Total			$485,434	$555,054

(a) The Series OO, Series RR and Series SS First Mortgage Bonds equal the principal amount of and provide for all payments of principal, premium and interest corresponding to the Pollution Control Revenue Bonds, Series C, and Pollution Control Refunding Revenue Bonds, Series 1992 A, Series 1992 B (Rochester Gas and Electric Corporation Projects), respectively, issued by the New York State Energy Research and Development Authority (NYSERDA) through a participation agreement with the Company. Payments of the principal of, and interest on the Series 1992 A and Series 1992 B Bonds are guaranteed under a Bond Insurance Policy by MBIA Insurance Corporation.

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

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

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

Sinking and improvement fund requirements aggregate $333,540 per annum under the First Mortgage, excluding mandatory sinking funds of individual series. Such requirements may be met by certification of additional property or by depositing cash with the Trustee. The 1997 and 1996 requirements were met with funds deposited with the Trustee, and these funds were used for redemption of outstanding bonds of Series Y.

On May 1, 1997 the Company redeemed all its outstanding First Mortgage 8% Bonds, Series Y, due August 15, 1999 and all its outstanding First Mortgage 6¼% Bonds, Series W, due September 15, 1997. On October 15, 1997, the Company redeemed all its outstanding First Mortgage 6½% Bonds, Series EE.

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

(Thousands of Dollars)

	1998	1999	2000	2001	2002
Series X	$30,000				
7% Series			$30,000		
Series QQ					$100,000
	$30,000	$ -	$30,000	$ -	$100,000

PROMISSORY NOTES

Issued	Due	(Thousands of Dollars) December 31 1997	1996
November 15, 1984[d]	October 1, 2014	$ -	$51,700
December 5, 1985[e]	November 15, 2015	-	40,200
August 19, 1997[f]	August 1, 2032	101,900	-
Total		$101,900	$91,900

(d) 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. On October 1, 1997, the Company redeemed all the outstanding Series 1984 Bonds. The average interest rate was 3.43% through September 30, 1997, 3.38% for 1996 and 3.68% for 1995.

(e) 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. On November 15, 1997 the Company redeemed all the outstanding Series 1985 Bonds. The annual interest rate was adjusted to 3.60% effective November 15, 1996 and to 3.75% effective November 15, 1995.

(f) Multi-mode pollution control notes totaling the principal amount of $101.9 million were issued in connection with NYSERDA's Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), $34,000,000 1997 Series A, $34,000,000 1997 Series B and $33,900,000 1997 Series C. The Multi-mode Revenue Bonds have a structure that enables the Company to optimize the use of short-term rates by allowing for the interest rates to be based on a daily rate, a weekly rate, a commercial paper rate, an auction rate or a multi-year fixed rate. Payment of the principal of, and interest on the Multi-mode Revenue Bonds is guaranteed under Bond Insurance Policies by MBIA Insurance Corporation. At December 31, 1997, the Multi-mode Revenue Bonds bore interest at the weekly rate and the average annual interest rate for all three series was 3.65%.

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 NYSERDA as described above.

Based on an estimated borrowing rate at year-end 1997 of 6.62% for long-term debt with similar terms and average maturities (13 years), the fair value of the Company's long-term debt outstanding (including Promissory Notes as described above) is approximately $655 million at December 31, 1997.

Based on an estimated borrowing rate at year-end 1996 of 7.30% for long-term debt with similar terms and average maturities (13 years), the fair value of the Company's long-term debt outstanding (including Promissory Notes as described above) is approximately $670 million at December 31, 1996.

On September 16, 1997, the Company completed arrangements for the delivery in September 1998 of $25.5 million of 5.95% NYSERDA tax-exempt bonds due September 1, 2033. Proceeds are expected to be used to redeem the Series OO, tax-exempt, first mortgage bonds which are not redeemable until December 1998.

Note 7. PREFERRED AND PREFERENCE STOCK

Type by Order of Seniority	Par Value	Shares Authorized	Shares Outstanding
Preferred Stock (cumulative)	$100	2,000,000	920,000*
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, 1997	(Thousands) December 31, 1997	1996	Optional Redemption (per share) #
4	F	120,000	$12,000	$12,000	$105
4.10	H	80,000	8,000	8,000	101
4 3/4	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	-	-	20,000	102
Total		470,000	$47,000	$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. The Series N were redeemed on April 22, 1997.

B. PREFERRED STOCK, SUBJECT TO MANDATORY REDEMPTION:

%	Series	Shares Outstanding December 31, 1997	(Thousands) December 31, 1997	1996	Optional Redemption (per share)
7.45	S	-	$ -	$10,000	Not applicable
7.55	T	100,000	10,000	10,000	Not applicable
7.65	U	100,000	10,000	10,000	Not applicable
6.60	V	250,000	25,000	25,000	Not Before 3/1/04+
Total		450,000	$45,000	$55,000	
Less: Due within one year		100,000	10,000	10,000	
Total		350,000	$35,000	$45,000	

+ Thereafter at $100.00

MANDATORY REDEMPTION PROVISIONS

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

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

Series V. The Series V is subject to a mandatory sinking fund sufficient to redeem on each March 1 beginning in 2004 to and including 2008, 12,500 shares at $100 per share and on March 1, 2009, the balance of the outstanding shares. The Company has the option to redeem up to an additional 12,500 shares on the same terms and dates as applicable to the mandatory sinking fund.

Based on an estimated dividend rate at year-end 1997 of 5.67% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (5.92 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $48 million at December 31, 1997.

Based on an estimated dividend rate at year-end 1996 of 6.50% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (5.66 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $57 million at December 31, 1996.

Note 8. COMMON STOCK AND STOCK OPTIONS

In December 1997, the Board of Directors of the Company authorized the repurchase of up to 4.5 million shares of the Company's Common Stock on the open market. None of the shares were purchased prior to year end.

At December 31, 1997, there were 50,000,000 shares of $5 par value Common Stock authorized, of which 38,862,347 were outstanding. No shares of Common Stock are reserved for warrants, conversions, or other rights. There were 1,445,141 shares of Common Stock reserved for employees under the 1996 Performance Stock Option Plan, as further described below. There were 1,026,840 shares of Common Stock reserved and unissued for shareholders under the Automatic Dividend Reinvestment and Stock Purchase Plan and 129,664 shares reserved and unissued for employees under the RG&E Savings Plus Plan.

COMMON STOCK

	Shares Outstanding	Amount (Thousands)
Balance, January 1, 1995	37,669,963	$670,569
Shares Issued through Stock Plans	783,200	17,074
Decrease (Increase) in Capital Stock Expense		(125)
Balance, December 31, 1995	38,453,163	$687,518
Shares Issued through Stock Plans	398,301	8,612
Decrease (Increase) in Capital Stock Expense		(111)
Balance, December 31, 1996	38,851,464	$696,019
Shares Issued through Stock Plans	10,883	272
Additional Paid in Capital		2,399
Decrease (Increase) in Capital Stock Expense		341
Balance, December 31, 1997	38,862,347	699,031

PERFORMANCE STOCK OPTION PLAN

Effective January 22, 1997, the Company adopted a Performance Stock Option Plan which provides for the granting of options to purchase up to 2,000,000 authorized but unissued shares or treasury shares of $5 par value Common Stock to executive officers and other key employees. No participant shall be granted options for more than 200,000 shares of Common Stock during any calendar year. The options would be exercisable for a period to be determined by the Committee on Management (the Committee). The Committee may in its sole discretion grant the right to receive a cash payment upon any exercise of an option equal to the quarterly dividend payment per share of Common Stock paid from the date the option was granted to the date of exercise.

In 1997, the Board of Directors granted 504,700 options at an exercise price of $19.0625 per share. These options are vested at 50% when the stock closes at $25 per share, 75% at $30 per share and 100% at $35 per share.

Also in 1997, the Board of Directors granted 50,159 options at an exercise price of $24.75 per share. These options are vested at 25% when the stock closes

at $25 per share, 50% at $30 per share, 75% at $35 per share, and 100% at $40 per share.

In order for the options to become vested, the closing prices must be sustained at or above the levels indicated above for a minimum of five consecutive trading days.

Since the Company adopted FAS 123, compensation expense associated with the options granted is reflected in 1997 net income. For calendar 1997, the compensation expense recorded was $2.4 million. In applying FAS 123, the fair value of each option granted is estimated on the date of the grant using the Black-Scholes option pricing model with the following assumptions: risk-free rate of return ranging between 6.39% and 6.56%, expected dividend yield of 9.44%, and expected stock volatility of 17%.

A summary of the Company's stock option activity is presented below:

	Options	Weighted Average Price
Options granted 1997	554,859	$19.577
Options exercised	(10,883)	$19.063
Outstanding at 12/31/97	543,976	$19.587
Vested at 12/31/97	392,722	$19.426
Available for future grant at 12/31/97	1,445,141	

Note 9. SHORT-TERM DEBT

On December 31, 1997, the Company had short-term debt outstanding of $20.0 million. At December 31, 1996 the Company had short-term debt outstanding of $14.0 million. The weighted average interest rate in 1997 on short-term debt outstanding at year end was 6.64% and was 6.07% for borrowings during the year. The weighted average interest rate on short-term debt borrowed during 1996 was 5.86%.

In December 1997 the Company's $90 million revolving credit agreement was amended extending its term to five years, terminating December 31, 2002. Commitment fees related to this facility amounted to $113,000 in 1997 and 1996, and $165,000 in 1995.

The Company's Charter provides that 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. As of December 31, 1997, the Company would be able to incur approximately $103.8 million of additional unsecured debt under this provision. The Company has unsecured lines of credit totaling $27 million available from several banks, at their discretion.

In order to be able to use its $90 million 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, the Company has a Loan and Security Agreement to provide for borrowings up to $10 million for the exclusive purpose of financing Federal Energy Regulatory Commission Order 636 transition costs(636 Notes) and up to $30 million as needed from time to time for other working capital needs. Borrowings under this agreement, which can be renewed annually, are secured by a lien on the Company's accounts receivable.

At December 31, 1997, borrowings outstanding were $4.34 million of 636 Notes (recorded on the Balance Sheet as a liability under Deferred Credits and Other Liabilities).

Note 10. COMMITMENTS AND OTHER MATTERS

COMPETITION

OVERVIEW. The PSC, through its Competitive Opportunities Proceeding, has embarked on a fundamental restructuring of the electric utility industry in the state. Among other elements, the PSC's goals included lower rates for consumers and increased customer choice in obtaining electricity and other energy services. During 1996 and 1997, the Company, the Staff of the PSC, and several other parties negotiated a Settlement Agreement (the "Settlement") which was approved by the PSC in November 1997. The Settlement sets the framework for the introduction and development of open competition in the electric energy marketplace.

PSC COMPETITIVE OPPORTUNITIES CASE SETTLEMENT. The Settlement provides for a transition to competition during its five year term (July 1, 1997 to June 30, 2002) and establishes the Company's electric rates for each annual period. A Retail Access Program will be phased in, allowing customers to purchase electricity, and later electricity and capacity commitments, from sources other than the Company. The Company will be given a reasonable opportunity to recover prudently incurred costs, including those pertaining to generation and purchased power. The Settlement also requires the Company to functionally separate its component operations: distribution, generation, and retailing. Any unregulated retail operations must be structurally separate from the regulated utility functions but may be funded with up to $100 million. Although the Settlement provides incentives for the sale of generating assets, it requires neither divestiture of generating or other assets nor write off of stranded costs. The Company believes that the Settlement will not adversely affect its eligibility to continue to apply SFAS 71 with the exception of certain to-go costs associated with non-nuclear generation. If, contrary to the Company's view, such eligibility were adversely affected, a material write-down of assets, the amount of which is not presently determinable, could be required.

Rate Plan. Over the five year term of the Settlement, cumulative rate reductions will be: Rate Year 1: $3.5 million; Rate Year 2: $12.8 million; Rate Year 3: $27.6 million; Rate Year 4: $39.5 million; and Rate Year 5: $64.6 million. The Rate Plan permits the Company to offset against the foregoing reductions certain inflation-related expenses and certain amounts related to a purchase power agreement with Kamine. In the event that the Company earns a return on common equity in excess of 11.50% over the entire five year term of the Settlement, 50% of such excess will be used to write down deferred costs accumulated during the term, and 50% will be used to write down accumulated deferrals or investment in electric plant or regulatory assets.

Retail Access. The Company's Energy Choice Program will be available to all of its customers on an equal basis up to certain usage caps. On July 1, 1998, customers whose electric loads represent approximately 10% of the Company's total annual retail sales will be eligible to purchase electricity (but not capacity commitments) from alternative suppliers. On July 1, 1999, the percent of total sales moves to 20%, and customers would purchase both electricity and capacity commitments. On July 1, 2000, the percent moves to 30%, and on July 1, 2001, all retail customers will be eligible to purchase energy and capacity from alternative suppliers.

During the initial, energy only stage of the Retail Access Program, the Company's distribution rate will be set by deducting 2.3 cents per kilowatt hour ("KWH") from its full service ("bundled") rates and Load Serving Entities acting as retailers in the Company's service area will be entitled to purchase electricity from the Company at a rate of 1.9 cents per KWH. During the energy and capacity stage, the rate will generally equal the bundled rate less the cost of the electric commodity and the Company's non-nuclear generating capacity. These commodity and capacity costs, generally referred to as "contestable costs," are estimated to be 3.2 cents per KWH, inclusive of gross receipts taxes.

Generating Assets. The Company will not be required to divest any of its generation facilities. To the extent that the Company sells any generating

assets during the term of the Settlement, gains on such sales will be shared between the Company and customers. With regard to losses on such sales, the Settlement acknowledges an intent that the Company will be permitted to recover such losses through distribution rates during the term of the Settlement. Future rate treatment is to be consistent with the principle that the Company is to have a reasonable opportunity to recover such costs.

"To-go costs" of the Company's non-nuclear resources (i.e., capital costs incurred after February 28, 1997, operation and maintenance expenses, and property, payroll and other taxes) are to be initially recovered through distribution rates. The fixed portion of to-go costs would be recovered in full until July 1, 1999, and be subject to the market thereafter in accordance with the phase-in schedule for the Retail Access program. The variable portion of non-nuclear to-go costs would also be subject to the market in accordance with the phase-in schedule. Under the Settlement, nuclear costs would remain recoverable through regulated rates.

Miscellaneous. The present Settlement supersedes the 1996 Rate Settlement. Various incentive and penalty provisions in the 1996 Rate Settlement are eliminated.

EITF ISSUE 97-4 - DEREGULATION OF THE PRICING OF ELECTRICITY. In July, 1997, the Financial Accounting Standards Board's Emerging Issues Task Force (EITF) reached a consensus on accounting rules for utilities' transition plans for moving to more competitive environments and provided guidance on when utilities with transition plans will need to discontinue the application of SFAS-71, "Accounting for the Effects of Certain Types of Regulation".

The major EITF consensus was that the application of SFAS-71 to a segment (e.g. generation) which is subject to a deregulation transition plan should cease when the legislation or enabling rate order contains sufficient detail for the utility to reasonably determine what the transition plan will entail. The EITF also concluded that a decision to continue to carry some or all of the regulatory assets (including stranded costs) and liabilities of the separable portion of the business that is discontinuing the application of SFAS-71 should be determined on the basis of where the regulated cash flows to realize and settle them will be derived. If a transition plan provides for a non-bypassable fee for the recovery of stranded costs, there may not be any significant write-off if SFAS-71 is discontinued for a segment.

The Company's application of the EITF 97-4 consensus has not affected its financial position or results of operations because any above-market generation costs, regulatory assets and regulatory liabilities associated with the generation portion of its business will be recovered by the regulated portion of the Company through its distribution rates, given the Settlement provisions. The Settlement provides for recovery of all prudently incurred sunk costs (all investment in electric plant and electric regulatory assets) as of March 1, 1997 by inclusion in rates charged pursuant to the Company's distribution access tariff. The Settlement also states that "the Parties intend that the provisions of this Settlement will allow the Company to continue to recover such costs, during the term of the Settlement, under SFAS-71", and that "such treatment shall be consistent with the principle that the Company shall have a reasonable opportunity beyond July 1, 2002 to recover all such costs". As noted previously, the fixed portion of the non-nuclear generation to-go costs after July 1, 1999 and the variable portion of the non-nuclear generation to-go costs after July 1, 1998 are subject to market forces and would no longer be able to apply SFAS-71. The Company's net investment at December 31, 1997 in nuclear generating assets is $698.4 million and in non-nuclear generating assets is $122.0 million.

REGULATORY AND STRANDABLE ASSETS

With PSC approval the Company has deferred certain costs rather than recognize them on its books when incurred. Such deferred costs are then recognized as expenses when they are included in rates and recovered from customers. Such deferral accounting is permitted by SFAS-71. These deferred costs are shown as Regulatory Assets on the Company's Balance Sheet. Such cost

deferral is appropriate under traditional regulated cost-of-service rate setting, where all prudently incurred costs are recovered through rates. In a purely competitive pricing environment, such costs might not have been incurred and could not have been deferred. Accordingly, if the Company's rate setting was changed from a cost-of-service approach, and it was no longer allowed to defer these costs under SFAS-71, these assets would be adjusted for any impairment to recovery (pursuant to SFAS-121). In certain cases, the entire amount could be written off.

SFAS-121 requires write-down of assets whenever events or circumstances occur which indicate that the carrying amount of a long-lived asset may not be fully recoverable.

Below is a summarization of the Regulatory Assets as of December 31, 1997 and 1996:

	(Millions of Dollars) 1997	1996
Income Taxes	$159.6	$174.6
Uranium Enrichment Decommissioning Deferral	16.4	17.7
Deferred Ice Storm Charges	11.5	14.0
FERC 636 Transition Costs	11.0	32.3
Demand Side Management Costs Deferred	4.4	8.4
Gas Deferred Fuel	7.1	7.7
Other, net	22.0	29.8
Total - Regulatory Assets	$232.0	$284.5

- Income Taxes: This amount represents the unrecovered portion of tax benefits from accelerated depreciation and other timing differences which were used to reduce tax expense in past years. The recovery of this deferral is anticipated over the remaining life of the related property when the effect of the past deductions reverses in future years.

- Uranium Enrichment Decommissioning Deferral: The Energy Policy Act of 1992 requires utilities to contribute such amounts based on the amount of uranium enriched by DOE for each utility. This amount is mandated to be paid to DOE through the year 2007. The recovery of these costs is through base rates of fuel.

- Deferred Ice Storm Charges: These costs result from the non-capital storm damage repair costs following the March 1991 ice storm. The recovery of these costs has been approved by the PSC through the year 2002.

- FERC 636 Transition Costs: These costs are payable to gas supply and pipeline companies which are passing various restructuring and other transition costs on to the Company, as ordered by FERC. The majority of these costs will be recovered through the Company's gas cost adjustment by the year 2000.

- Demand Side Management Costs Deferred: These costs are Demand Side Management costs which relate to programs initiated to increase efficiency with which electricity is used. These costs are recoverable by the Company through the year 2002.

- Gas Deferred Fuel: These costs result from a PSC-approved annual reconciliation of recoverable gas costs with gas revenues in which the excess or deficiency is refunded to or recovered from customers during a subsequent period.

In a competitive electric market, strandable assets would arise when investments are made in facilities, or costs are incurred to service customers, and such costs are not fully recoverable in market-based rates. Examples include purchase power contracts (e.g., the Kamine/Besicorp Allegany L.P. contract), or

high cost generating assets. Estimates of strandable assets are highly sensitive to the competitive wholesale market price assumed in the estimation. The amount of potentially strandable assets at December 31, 1997 depends on market prices and the competitive market in New York State which is still under development and subject to continuing changes which are not yet determinable, but could be significant. Strandable assets, if any, could be written down for impairment of recovery in the same manner as deferred costs discussed above.

In a competitive natural gas market, strandable assets would arise where customers migrate away from dependence on the Company for full service, leaving the Company with surplus pipeline and storage capacity, as well as natural gas supplies, under contract. The Company has been restructuring its transportation, storage and supply portfolio to reduce its potential exposure to strandable assets. Regulatory developments discussed under " GAS RESTRUCTURING PROCEEDING," below, may affect this exposure; but whether and to what extent there may be an impact on the level and recoverability of strandable assets cannot be determined at this time.

At December 31, 1997 the Company believes that its regulatory and strandable assets, if any, are not impaired and are probable of recovery. The settlement approved in the Competitive Opportunities proceeding does not impair the opportunity of the Company to recover its investment in these assets. However, the PSC has published a Staff paper to address issues surrounding nuclear generation, including the determination of fair market value for facilities after a five year restructuring transition period. It appears that the PSC may seek to apply similar principles to other types of generating facilities. A determination in this proceeding could have an impact on strandable assets.

CAPITAL EXPENDITURES

The Company's 1998 construction expenditures program is currently estimated at $124 million. The Company has entered into certain commitments for purchase of materials and equipment in connection with that program.

NUCLEAR-RELATED MATTERS

DECOMMISSIONING TRUST. The Company is collecting amounts in its electric rates for the eventual decommissioning of its Ginna Plant and for its 14% share of the decommissioning of Nine Mile Two. The operating licenses for these plants expire in 2009 and 2026, respectively.

Under accounting procedures approved by the PSC, the Company has collected decommissioning costs of approximately $116.1 million through December 31, 1997 and is authorized to collect approximately $22 million annually through June 30, 2002 for decommissioning, covering both nuclear units. The amount allowed in rates is based on estimated ultimate decommissioning costs of $296.3 million for Ginna and $112.8 million for the Company's 14% share of Nine Mile Two (1995 dollars). These estimates are based on site specific cost studies for each plant completed in 1995. Site specific studies of the anticipated costs of actual decommissioning are required to be submitted to the NRC at least five years prior to the expiration of the license.

The NRC requires reactor licensees to submit funding plans that establish minimum NRC external funding levels for reactor decommissioning. The Company's plan, filed in 1990, consists of an external decommissioning trust fund covering both its Ginna Plant and its Nine Mile Two share. Since 1990, the Company has contributed $86.4 million to this fund and, including realized and unrealized investment returns, the fund has a balance of $132.5 million as of December 31, 1997. The amount attributed to the allowance for removal of non-contaminated structures is being held in an internal reserve. The internal reserve balance as of December 31, 1997 is $29.7 million.

The NRC is currently considering proposals which may impact financial funding requirements for decommissioning of nuclear power plants. Under current

NRC regulations electric utilities provide for decommissioning funds annually over the estimated life of a plant. If state regulatory authorities were to adopt a program to remove electric generation (including nuclear plants) from cost-based rate regulation, an action which the New York PSC is currently considering, such plants would operate in a competitive electric market and would have no assured source of revenue from energy sales. Under current regulations, the NRC can require the owners of nuclear plants lacking such assured revenue streams to provide assurance that the full estimated cost of decommissioning will ultimately be available through some guarantee mechanism.

The NRC is seeking public comment on a number of questions, including the likely timetable for utility restructuring and deregulation and to what extent costs will be recoverable if a large baseload plant is deemed to be non-competitive because of high construction costs and what funding sources will be used to shut down a plant prematurely and safely.

The NRC has released for comments a notice of proposed rulemaking (NOPR) modifying certain aspects of the financial assurance requirements for decommissioning nuclear power reactors. The NOPR includes, among other things, changes to the definition of "electric utility" for the purposes of providing financial assurance for decommissioning as well as new reporting requirements regarding each licensee's progress on external funding. The Company does not anticipate a material impact from the application of these rules in their proposed form; however it cannot predict the impact of these rules as resolution of stranded asset issues proceed in New York.

The PSC in August 1997 issued for comment a report by its staff proposing norms by which nuclear plants in the state would relate to the competitive electricity market following the period covered by electric utility restructuring agreements then pending before the PSC. Among other things, the report envisioned the sale of these plants at auction, but with the selling utilities remaining responsible for ultimate decommissioning as well as for disposal of certain spent fuel. Recognizing that bidders may not be attracted to certain units -- which could include both the Company's Ginna plant and the Nine Mile Two plant in which it has a 14% interest, the report contemplated their early shutdown unless they could compete with other forms of generation. In Fall 1997, the Company and others commented on these and other facets of the report. Through mid- January 1998, the PSC had taken no action on the report and comments.

The Staff of the Financial Accounting Standards Board are studying the recognition, measurement and classification of decommissioning costs for nuclear generating stations in the financial statements of electric utilities. If current accounting practices for such costs were changed, the annual provisions for decommissioning costs could increase, the estimated cost for decommissioning could be reclassified as a liability rather than as accumulated depreciation, the liability accounts and corresponding plant asset accounts could be increased and trust fund income from the external decommissioning trusts could be reported as investment income rather than as a reduction to decommissioning expense.

If annual decommissioning costs increased, the Company would expect to defer the effects of such costs pending disposition by the PSC.

URANIUM ENRICHMENT DECONTAMINATION AND DECOMMISSIONING FUND. Under the National Energy Act, utilities with nuclear generating facilities are assessed an annual fee payable over 15 years for the decommissioning of federally owned uranium enrichment facilities. The assessments for Ginna and the Company's share of Nine Mile Two are estimated to total $22.1 million, excluding inflation and interest. Installments aggregating approximately $9.4 million have been paid through 1997. A liability has been recognized on the financial statements along with a corresponding regulatory asset. For the two facilities the Company's liability at December 31, 1997 is $15.1 million ($13.4 million as a long-term liability and $1.7 million as a current liability). The Company is recovering costs through base rates of fuel.

In July 1996, the Company joined other utilities in a civil action against the U.S. Department of Energy (DOE), concerning these assessments. After a favorable initial decision in a parallel case, the Court of Appeals for the Federal Circuit in May 1997 reversed the lower court and held that the federal

government could assess licensees for the clean-up of these federal facilities. In January 1998, the U.S. Supreme Court refused to hear the case, effectively upholding the dismissal of the utility claims.

NUCLEAR FUEL DISPOSAL COSTS. The Nuclear Waste Policy Act (Nuclear Waste Act) of 1982, as amended, requires the 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 proposing to establish an interim storage facility which may allow it to take title to and possession of nuclear waste prior to the establishment of a permanent repository. In December 1996 the DOE notified the Company that the DOE will not start acceptance of Ginna spent fuel in 1998. In January 1997 the DOE released a draft request for proposal outlining a process for private firms to accept and transport waste from reactors until a federal facility is operational. The Nuclear Waste Act provides for a determination of the fees collectible by the DOE for the disposal of nuclear fuel irradiated prior to April 7, 1983 and for three payment options. The option of a single payment to be made at any time prior to the first delivery of fuel to the DOE was selected by the Company in June 1985. The Company estimates the fees, including accrued interest, owed to the DOE to be $83.3 million at December 31, 1997. The Company is allowed by the PSC to recover these costs in rates. The estimated fees are classified as a long-term liability and interest is accrued at the current three-month Treasury bill rate, adjusted quarterly. The Nuclear Waste Act also requires the DOE to provide for the disposal of nuclear fuel irradiated after April 6, 1983, for a charge of approximately one mill ($.001) per KWH of nuclear energy generated and sold. This charge (approximately $3.6 million per year) 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.

There are presently no facilities in operation in the United States available for the reprocessing of spent nuclear fuel from utility companies. In the Company's determination of nuclear fuel costs it has taken into account that nuclear fuel would not be reprocessed and has provided for disposal costs in accordance with the Nuclear Waste Act. The Company has completed a conceptual study of alternatives to increase the capacity for the interim storage of spent nuclear fuel at the Ginna Plant. The preferred alternative, based on cost and safety criteria, is to install high-capacity spent fuel racks in the existing area of the spent fuel pool. The additional storage capacity, scheduled to be implemented prior to September 2000, would allow interim storage of all spent fuel discharged from the Ginna Plant through the end of its Operating License in the year 2009.

ENVIRONMENTAL MATTERS

The following tables list various sites where past waste handling and disposal has or may have occurred that are discussed below:

TABLE I - COMPANY-OWNED SITES

Site Name	Location	Estimated Company Cost
West Station*	Rochester, NY	Ultimate costs have not been determined. The Company has incurred aggregate costs for these sites through December 31, 1997 of $4.3 million.
East Station	Rochester, NY	
Front Street*	Rochester, NY	
Brewer Street	Rochester, NY	
Brooks Avenue	Rochester, NY	
Canandaigua	Canandaigua, NY	

* Voluntary agreement signed.

TABLE II - SUPERFUND AND NON-OWNED OTHER SITES

Site Name	Location	Estimated Company Cost
Quanta Resources*	Syracuse, NY	Ultimate costs have not been determined. The Company has incurred aggregate costs for these sites through December 31, 1997 of less than $1.0 million.
Frontier Chemical-Pendleton*	Pendleton, NY	
Maxey Flats*	Morehead, KY	
Mexico Milk	Mexico, NY	
Byron Barrel and Drum	Bergen, NY	
Fulton Terminals*	Oswego, NY	
PAS of Oswego*	Oswego, NY	

* Orders on consent signed.

COMPANY-OWNED WASTE SITE ACTIVITIES. As part of its commitment to environmental excellence, the Company is conducting proactive Site Investigation and/or Remediation (SIR) efforts at six Company-owned sites where past waste handling and disposal may have occurred. Remediation activities at four of these sites are in various stages of planning or completion and the Company is conducting a program to restore the other two sites. The Company has recorded a total liability of approximately $13.6 million, $12.8 million of which it anticipates spending on SIR efforts at the six Company-owned sites listed in Table I above. Concurrently, the Company recorded a similar amount in its Regulatory Assets.

In mid-1995, the New York State Department of Environmental Conservation (NYSDEC) developed a listing of sites called "The Hazardous Substance Site Inventory". Under current New York State law, unless a site, which is determined to pose a public health or environmental risk, contains hazardous wastes, State "Superfund" monies cannot be used to assist in the cleanup. The State wanted to have some sense of the scale of this problem before the legislature considered other avenues of legal and financial redress than those currently available. The NYSDEC's "Hazardous Substance Waste Disposal Site Study" was developed to assess the number of and cost to remediate sites where hazardous chemicals, but not hazardous wastes are present. Of the six Company-owned sites listed in Table I above, three are listed in this inventory. These are East Station, Front Street and Brooks Avenue. In addition to these three sites, the inventory includes Ambrose Yard and Lindberg Heat Treating. The Company does not believe that additional SIR work for which the Company is responsible is required at either site, however the Company is unable to predict what action will be necessitated as a result of the listing.

The Company and its predecessors formerly owned and operated three manufactured gas facilities in the Rochester area. They are included in Table I. Cleanup activities which were previously suspended, resumed on a portion of the West Station site and were concluded in July 1996 under a voluntary agreement with the NYSDEC. The Company received release from future liability and a covenant not to sue from the NYSDEC for this work. There remain other portions of the property where additional remedial work is expected, however, only a preliminary scope and schedule have been determined. At the second of the three manufactured gas plant sites known as East Station, an interim remedial action was undertaken in late 1993. Ground water monitoring wells were also installed to assess the quality of the ground water at this location. The Company has informed the NYSDEC of the results of the samples taken. Subsequent data evaluation indicate a wider array of potential sources of coal gasification related materials than previously thought suggesting significant remedial work may be required.

At the third Rochester area property owned by the Company (Front Street) where gas manufacturing took place, a boring placed in the Fall of 1988 for a

sewer system project showed a layer containing a black viscous material. The study of the layer found that some of the soil and ground water on-site had been adversely impacted. The matter was reported to the NYSDEC and, in September 1990, the Company also provided the agency with a risk assessment. The report of the results of this study and the NYSDEC's response to the recommendations made therein will influence the future remediation costs. The Company has signed a voluntary agreement to perform limited additional investigation at the site to determine whether certain remedial actions are necessary prior to development.

Another property owned by the Company where gas manufacturing took place is located in Canandaigua, New York. Limited investigative work performed there during the summer of 1995 has shown evidence of both the former gas manufacturing operations and leakage from fuel tanks. The NYSDEC was informed; the fuel tanks removed; and additional investigative work continues. The SIR costs associated with these actions are included in Table I. The NYSDEC has not taken any action against the Company as a result of these findings.

On another portion of the Company's property (Brewer Street), the County of Monroe has installed and operates sewer lines. During sewer installation, the County constructed over Company property certain retention ponds which reportedly received from the sewer construction area certain fossil-fuel-based materials (the materials) found there. In July 1989, the Company received a letter from the County asserting that activities of the Company left the County unable to effect a regulatorily-approved closure of the retention pond area. The County's letter takes the position that it intends to seek reimbursement for its additional costs incurred with respect to the materials once the NYSDEC identifies the generator thereof and that any further cleanup action which the NYSDEC may require at the retention pond site is the Company's responsibility. In a November 1997 letter, the County has claimed that the Company was the original generator of the materials. It asserts that it will hold the Company liable for 50% of all County costs -- presently estimated at a total of approximately $5 million -- associated both with the materials' excavation, treatment and disposal and with effecting a regulatorily-approved closure of the retention pond area. The Company could incur costs as yet undetermined if it were to be found liable for such closure and materials handling, although provisions of an existing easement afford the Company rights which may serve to offset all or a portion of any such County claim. To date, the Company has agreed to pay a 20% share of the County's 1995 investigation of this area, which is estimated to cost no more than $150,000, but no commitment has been made toward any subsequent investigations or remedial measures which may be recommended by the investigations.

Monitoring wells installed at another Company facility (Brooks Avenue) in 1989 revealed that an undetermined amount of leaded gasoline had reached the ground water. The Company has continued to monitor free product levels in the wells, and has begun a modest free product recovery project. It is estimated that further investigative work into this problem may cost up to $100,000. While the cost of corrective actions cannot be determined until investigations are completed, preliminary estimates are not expected to exceed $500,000.

SUPERFUND AND NON-OWNED OTHER SITES. The Company has been or may be associated as a potentially responsible party (PRP) at seven sites not owned by it. The Company has signed orders on consent for five of these sites and recorded estimated liabilities totaling approximately $.8 million.

In one site, known as the Quanta Resources Site, the Company signed a consent order with the Environmental Protection Agency (EPA) and paid its $27,500 share of remedial cost. The Company was again contacted by EPA in late August, 1996. The EPA informed the Company that it believed certain additional work was required, including a study to determine the extent to which additional removal of waste materials was required. The EPA's list of PRPs had grown to about 80. The Company, along with most of those PRPs, has agreed (through an Administrative Order on Consent) to conduct the required study. The Company anticipates its obligation through this phase will be less than $10,000. On May 12, 1997, the Company signed an Administrative Order on Consent with the NYSDEC. This agreement served to obligate the respective parties to pay NYSDEC's past costs at the Site, the Company's share of which was determined to be $1,500. There is as yet, no information on which to determine the cost to design and conduct at the

site any remedial measures which federal or State authorities may require, the Company does not expect its additional costs to exceed $150,000.

On May 21, 1993, the Company was notified by NYSDEC that it was considered a PRP for the Frontier Chemical Pendleton Superfund Site located in Pendleton, NY. The Company has signed, along with other participating parties, an Administrative Order on Consent with NYSDEC. The Order on Consent obligates the parties to implement a work plan and remediate the site. The PRPs have negotiated a work plan for site remediation and have retained a consulting firm to implement the work plan. Preliminary estimates indicate the Company's share of additional site remediation costs are not expected to exceed $350,000. The Company is participating with the group to allocate costs among the PRPs. Subsequent work has indicated that the final cost is likely to be lower.

The Company is involved in the investigation and cleanup of the Maxey Flats Nuclear Disposal Site in Morehead, Kentucky and has signed various consent orders to that effect. The Company has contributed to a study of the site and estimates that its share of the additional costs of investigation and remediation is not expected to exceed $250,000.

The Company has been named as a PRP at three other sites and has been associated with another site for which the Company's share of total additional projected costs is not expected to exceed $71,000. Actual Company expenditures for these sites are dependent upon the total cost of investigation and remediation and the ultimate determination of the Company's share of responsibility for such costs as well as the financial viability of other identified responsible parties.

FEDERAL CLEAN AIR ACT AMENDMENTS. The Company is developing strategies responsive to the federal clean air act amendments of 1990 (Amendments) which will primarily affect air emissions from the Company's fossil-fueled generating facilities. The strategy being developed is a combination of hardware solutions which have a capital and operation and maintenance (O&M) component and allowance trading solutions which have strictly an O&M impact. The most recent strategic developments still envision this combination of efforts as the most cost effective means of proceeding although State legislative activity could impact the Company's ability to rely upon the emission allowance market to meet some of its environmental commitments. The Company cannot predict the outcome of these proceedings in the Legislature and, as a result, the Company's projections are based solely on the combination strategy. A range of capital costs between $2.9 and $3.5 million has been estimated for the implementation of several potential alterations for meeting the foreseeable nitrogen oxide, opacity and sulfur dioxide requirements of the Amendments, as well as $1.0 to $1.5 million per year in operating expenses. These capital costs would be incurred between 1998 and 2000. The O&M expenses would be for the year 1999. For the year 2000 and beyond, the Company estimates that the annual operating expenses would rise to between $2.4 million and $3.7 million. Any additional post-2000 capital costs and operating expense cannot be predicted until resolution of State and federal legislative activity enables the Company to finalize its compliance strategy.

OPACITY ISSUE. In May 1997, the Company commenced negotiations with the NYSDEC to resolve allegations of past opacity violations at the Company's Beebee and Russell Stations. The opacity standard is a regulation which limits the density of the smoke emitted from the Stations' smokestacks. The Company believes that it will reach an agreement with NYSDEC on this issue and that the amount of any civil penalty will likely include both cash and environmental benefit project components which, in the aggregate, will not be material. In addition, the Stations have been temporarily derated since February 1997 to maintain acceptable opacity levels while the Company investigates additional engineering solutions to address opacity emissions. The financial impact of the deratings includes the lost opportunity associated with energy sales and, at times, the need to make additional purchases to meet system requirements. While the deratings have decreased earnings, and will continue to do so, the Company does not expect the amount to be material. Finally, the New York Power Pool (NYPP) is in the process of evaluating new rules for its system load regulation. The current Station deratings for opacity reasons would reduce the ability of the Company to react to changes in load and provide regulation services when called

upon by the NYPP, resulting in additional costs. Depending on the new NYPP requirements, and whether the deratings remain in effect, the revised rules could result in the Company having to purchase additional regulation services which may cost between $500,000 and $2,500,000 annually.

GAS COST RECOVERY

GAS RESTRUCTURING PROCEEDING. In the PSC's Proceeding on Restructuring the Emerging Competitive Natural Gas Market, the PSC established a three-year period (ending March 28, 1999) during which the State's local distribution companies (LDCs) would be permitted to require customers converting from sales service to take associated pipeline capacity for which the LDCs had originally contracted. Prior to the beginning of the third year, the LDCs would be required to demonstrate their efforts to dispose of "excess" capacity. On September 4, 1997, the PSC issued an Order clarifying the March 28, 1996 Order. The September 4 Order requires, among other things, that the LDCs (a) assess strandable costs; (b) evaluate and pursue options to address strandable costs, including exploration of alternative uses and quantification of market values for the capacity that could be stranded by converting customers; (c) actively encourage competition including collaboration with marketers to expand the number of customers taking transportation service from the LDC and to provide customer education; and (d) to the extent LDCs cannot shed all their capacity as contracts expire, to continue to seek lower cost options and more flexibility and shorter contract terms, where cost-effective. LDCs are required to file plans addressing the foregoing issues by April 1, 1998. Pursuant to the PSC's Orders, the cost of capacity defined as "excess" may not be fully recoverable in rates. Accordingly, the Company's ability to avoid absorbing this cost will depend on the success of remarketing and portfolio structuring efforts and, if such efforts do not result in eliminating all "excess" capacity, on a satisfactory explanation as to why all such capacity could not be eliminated. The Company is engaged in negotiations with the Staff of the PSC and other parties to address these and other issues related to the future provision of gas service. At this time, no assessment of the potential impact of these requirements on the Company can be made.

On September 4, 1997, the PSC also issued for comment a Staff position paper which proposes that LDCs exit their merchant function, i.e., cease to supply the natural gas commodity to their existing customers, within five years and that they eliminate or restructure transportation and storage capacity contracts extending beyond five years so as to eliminate obligations beyond that point, except where capacity is required to fulfill operational requirements or the LDC's obligations as the "supplier of last resort" to customers having no competitive alternative. If adopted by the PSC, the Staff proposal could require the Company to remarket more capacity and to do so more rapidly than currently contemplated. The comment period concluded on December 20, 1997, and no prediction can be made as to whether the Staff proposal will be adopted or, if so, the extent of its potential impact on the Company.

1995 GAS SETTLEMENT. The Company has entered into several agreements to help manage its pipeline capacity costs and has successfully met Settlement targets for capacity remarketing for the twelve months ending October 31, 1997, thereby avoiding negative financial impacts for that period. The Company believes that it will also be successful in meeting the Settlement targets in the remaining year of the Settlement period, although no assurance may be given.

The FERC approved a change in rate design for the Great Lakes Gas Transmission Limited Partnership (Great Lakes) on which the Company holds transportation capacity. This change resulted in a retroactive surcharge by Great Lakes to the Company in the amount of approximately $8 million, including interest. Under the terms of the 1995 Gas Settlement, the Company may recover approximately one-half of the surcharge in rates charged to customers; but the remainder may not be passed through and has been previously reserved. The Company, which paid the Great Lakes assessment under protest, vigorously contested it before the FERC, but on April 25, 1996, the FERC upheld this determination that the charge to the Company is proper. The Company's petition to the U.S. Court of Appeals was denied on January 16, 1998. The Company is evaluating its next steps.

LEASE AGREEMENTS

The Company leases five properties for administrative offices and operating activities. The total lease expense charged to operations was $4.2 million, $3.9 million and $2.4 million in 1997, 1996 and 1995, respectively. For the years 1998, 1999, 2000, 2001 and 2002 the estimated lease expense charged to operations will be $4.1 million, $2.4 million, $2.4 million, $2.4 million and $2.4 million, respectively. Commitments under capital leases were not significant to the accompanying financial statements.

LITIGATION

SPENT NUCLEAR FUEL LITIGATION. The Nuclear Waste Act (Act) obligates the DOE to accept for disposal spent nuclear fuel (SNF) starting in 1998. Since the mid-1980s the Company and other nuclear plant owners and operators have paid substantial fees to the DOE to fund its obligations under the Nuclear Waste Act. DOE has indicated that it will not be in a position to accept SNF in 1998. In 1994, Northern States Power Company and other owners and operators of nuclear power plants filed suit against DOE and the U.S. in the U.S. Court of Appeals for the District of Columbia Circuit seeking a declaration that DOE's course of action was in violation of its obligations under the Act, and requesting other relief. In a July 1996 decision, the court upheld the utilities' position that DOE is obligated to accept and dispose of the utilities' SNF beginning not later than January 31, 1998. DOE had contended in effect that it could defer the disposal until the availability of a suitable SNF repository. The court rejected this DOE reading of the Nuclear Waste Act, but stopped short of providing the utilities a remedy since DOE has not yet defaulted on its obligations. By letter dated December 17, 1996, DOE invited the parties to the proceeding to provide written comments on how DOE's anticipated inability to meet its January 31, 1998 obligation to begin accepting SNF could "best be accommodated". The Company and a number of other parties responded to that invitation. By Joint Petition for Review, dated January 31, 1997, the Company and a number of other nuclear utilities petitioned the United States Court of Appeals for the District of Columbia Circuit for a declaration that the Petitioners were relieved of the obligation to pay fees into the Nuclear Waste Fund, and authorized to place those fees into escrow when and until DOE commences disposing of SNF. The Petition further requested that DOE be ordered to develop a program that would enable it to begin acceptance of SNF by January 31, 1998. By Order dated November 14, 1997, the D. C. Circuit held that DOE could not exercise delay in accepting fuel on grounds that it lacked an SNF repository, and that the utilities had a "clear right to relief". Rather than grant funding relief and order the DOE to move fuel, however, the Court referred the utilities to the remedies set forth in their contracts with the DOE. The Company is pursuing such remedies.

DEPARTMENT OF JUSTICE LAWSUIT. On June 24, 1997, the Antitrust Division of the United States Department of Justice filed a civil complaint against the Company in the United States District Court for the Western District of New York. The complaint follows a Civil Investigative Demand investigation. That investigation included a broad look at the Company's activities in the electric power industry including initially, the Company's power purchase agreement with an independent power producer. The investigation then focused primarily upon the flexible rate long term contracts entered between the Company and a number of its large customers under a tariff approved by the PSC. The tariff and the PSC policies it implemented recognized that if large customers took their electrical load off the system, the rates for remaining customers would have to increase to cover the fixed costs of operation.

The Division in its complaint has challenged only certain provisions of one flexible rate contract, the contract with the University of Rochester. The Complaint alleges that those provisions in that contract violate Section 1 of the Sherman Act by restricting the customer's right to compete with the Company in the sale of electricity and seeks an injunction prohibiting the Company from enforcing that contract and from entering other agreements that limit competition in the sale of electricity to other customers.

The Company believes that the investigation and the Complaint reflect the desire by the Antitrust Division to become involved in the deregulation of electric utilities, but that the proper way to do that is in the proceedings before the PSC in the Competitive Opportunities Case.

On September 3, 1997, the Company filed its answer which denied the material allegations of the Complaint. At the same time, the Company filed a Motion for Summary Judgment asking the Court to dismiss the action with prejudice on the grounds that the Company's actions are immune from antitrust liability under the State action exemption, that the Company's actions did not injure competition and that the Department of Justice's claims are speculative. On November 3, 1997, the Department of Justice filed its opposition to the Company's Motion for Summary Judgment and filed its own Motion for Summary Judgement. The Company's response to the Justice Department motion was filed on December 5, 1997.

These Motions for Summary Judgment were argued on December 19, 1997. In Court, the parties agreed to a resolution of the dispute, suggested by the Judge which, in the Company's opinion, would not have any material effect on its contract with the University. The Antitrust Division, however, has expressed its unwillingness to agree to a Consent Decree based on the agreement reached in Court and the matter is still pending.

LITIGATION WITH CO-GENERATOR. Under federal and New York State laws and regulations, the Company is required to purchase the electrical output of unregulated cogeneration facilities which meet certain criteria (Qualifying Facilities). Under these statutes, a utility is required to pay for electricity from Qualifying Facilities at a rate that equals the cost to the utility of power it would otherwise produce itself or purchase from other sources (Avoided Cost). With the exception of one contract which the Company was compelled by regulators to enter into with Kamine/Besicorp Allegany L.P. (Kamine) for approximately 55 megawatts of capacity, the Company has no long-term obligations to purchase energy from Qualifying Facilities.

Under State law and regulatory requirements in effect at the time the contract with Kamine was negotiated, the Company was required to agree to pay Kamine a price for power that is substantially greater than the Company's own cost of production and other purchases. Since that time the State "six-cent" law mandating a minimum price higher than the Company's own costs has been repealed and PSC estimates of future costs on which the contract was based have declined dramatically.

In September 1994, the Company commenced a lawsuit in New York State Supreme Court, Monroe County, seeking to void or, alternatively, to reform a Power Purchase Agreement with Kamine for the purchase of the electrical output of a cogeneration facility in the Town of Hume, Allegany County, New York, for a term of 25 years. The contract was negotiated pursuant to the specific pricing requirement of a State statute that was later repealed, as well as estimates of Avoided Costs by the PSC that subsequently were drastically reduced. As a result, the contract requires the Company to pay prices for Kamine's electrical output that dramatically exceed current Avoided Costs and current projections of Avoided Costs. The Company's lawsuit seeks to avoid payments to Kamine that exceed actual and currently projected Avoided Costs. Kamine answered the Company's complaint, seeking to force the Company to take and pay for power at the higher rates called for in the contract and claiming damages in an unspecified amount alleged to have been caused by the Company's conduct. The Company received test generation from the Kamine facility during the last quarter of 1994. Kamine contends that the facility went into commercial operation in December 1994 and that the Company is obligated to pay the full contract rate for it. The Company disputes this contention and refuses to pay the full contract rate. During 1995 Kamine filed a Motion for Summary Judgment dismissing the Company's complaint and directing it to perform the Power Purchase Agreement. The court denied that motion and Kamine appealed. After argument of that appeal Kamine filed for protection under the Bankruptcy laws and sent to the Appellate Division a notice that all further proceedings were stayed.

In addition, Kamine has filed a related complaint in the United States District Court for the Western District of New York alleging that the conduct which is the subject of the State court action violates the federal antitrust

laws. The complaint seeks damages in the amount of $420,000,000, when trebled, as well as preliminary and permanent injunctions. Subsequently, Kamine filed a motion for a preliminary injunction in the federal action to enjoin the Company from refusing to accept and purchase electric power from Kamine and enjoining the Company from terminating during the pendency of this lawsuit its performance under the contract. In November 1995, the Court issued a decision denying Kamine's motion for a preliminary injunction, finding, among other things, that Kamine had not established the necessary likelihood of success on the merits of its action. Kamine filed a notice of appeal from that decision but has subsequently announced that it is withdrawing that appeal.

During 1995 the PSC invited the Company to file a petition requesting, among other things, that the Commission commence an investigation to determine whether at the time of claimed commercial operation the Hume plant was a cogeneration facility under New York law as required by the Power Purchase Agreement. The Company filed such a petition and Kamine filed papers in opposition.

During 1995 Kamine filed a petition before the FERC to waive certain requirements for federal Qualified Facility status for 1994. The Company and the PSC filed in opposition to the request. Subsequently FERC issued an order granting the waiver request and the Company's motion for rehearing was denied. The Company filed a petition for review with the U.S. Court of Appeals for the District of Columbia Circuit but that court denied the request for review.

In November 1995 Kamine filed in Newark, New Jersey for protection under the Bankruptcy laws and filed a complaint in an adversary proceeding, seeking, among other things, specific performance of the Agreement. Kamine filed a motion to compel the Company to pay what would be due under Kamine's view of the terms of the Agreement during the pendency of the Adversary Proceeding. After hearing, the Bankruptcy Court denied that motion. The Court also denied various motions made by the Company to change the venue of the proceedings to New York State and to lift the automatic stay of the pending New York State action. On appeal the Bankruptcy Court was reversed and the case sent back to the Bankruptcy Court to decide where the contract issues in the Adversary Proceeding should be adjudicated. As of June 16, 1997, the Company filed a Second Amended Complaint in the State Court action asserting additional claims based on subsequent occurrences.

On March 19, 1997, the Bankruptcy Court stayed the Adversary Proceeding pending resolution of the contract issues in the New York State court trial. Kamine has indicated it will not appeal this action.

On June 26, 1997, the defendants filed a Joint Notice of Removal of Action, removing the action to the United States District Court for the Western District of New York. There have been no further proceedings to date.

Numerous other procedural motions have been presented in the Bankruptcy Court, some of which may now be considered by the New York State court. While these proceedings are pending, the Company would pay approximately two cents per kilowatt hour when the plant operates. It is not operating at the present time.

GENERAL ELECTRIC CAPITAL CORPORATION LAWSUIT. On July 3, 1997, General Electric Capital Corporation (GECC) filed a complaint against the Company in the United States District Court for the Western District of New York in connection with the Kamine project in Hume, New York, for which GECC provided financing. The complaint asserts that the Company violated the antitrust laws in its dealings with Kamine and seeks injunctive relief, treble damages and alleged actual damages of not less than $100,000,000. The claims made in the complaint filed are substantially similar to the claims made by Kamine in the same court under Kamine's version of the terms of the Power Purchase Agreement for the Hume project. The court denied Kamine's motion for a preliminary injunction on grounds which included Kamine's failure to establish a likelihood of success on the merits of its claims. Kamine had filed a notice of appeal from a decision denying Kamine's motion for a preliminary injunction. Kamine subsequently withdrew the appeal. The Company believes the complaint by GECC is also without merit and intends to defend the action.

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 sum of the quarterly earnings per share may not equal the fiscal year earnings per share due to rounding.

(Thousands of Dollars)

Quarter Ended	Operating Revenues	Operating Income	Net Income	Earnings on Common Stock	Earnings per Common Share (in dollars) Basic	Diluted
December 31, 1997	$271,039	$24,406	$14,031	$12,726	$ .32	$ .32
September 30, 1997	221,335	34,616	21,724	20,419	.52	.52
June 30, 1997	229,419	31,125	18,172	16,681	.42	.42
March 31, 1997	314,845	55,194	41,433	39,729	1.02	1.02
December 31, 1996[1]	$274,431	$33,048	$22,228	$20,362	$0.52	$ .52
September 30, 1996	234,843	36,159	21,062	19,196	0.49	.49
June 30, 1996	235,577	23,115	11,732	9,866	0.25	.25
March 31, 1996	309,195	56,866	42,489	40,623	1.05	1.05
December 31, 1995[1,2]	$270,518	$32,324	$ (387)	$(2,253)	$(.05)	$(.05)
September 30, 1995	245,145	41,738	26,934	25,068	.65	.65
June 30, 1995	219,546	29,454	14,861	12,995	.34	.34
March 31, 1995	281,119	46,557	30,520	28,653	.75	.75

[1] Reclassified for comparative purposes.
[2] Includes recognition of $28.7 million net-of-tax gas settlement adjustment.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by Item 10 of Form 10-K relating to directors who are nominees for election as directors at the Company's Annual Meeting of Shareholders to be held on April 15, 1998, will be set forth under the heading "Election of Directors" in the Company's Definitive Proxy Statement for such Annual Meeting of Shareholders.

The information required by Item 10 of Form 10-K with respect to executive officers is, pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, set forth in Part I as Item 4-A of this Form 10-K under the heading "Executive Officers of the Registrant".

Item 11. EXECUTIVE COMPENSATION

The information required by Item 11 of Form 10-K will be set forth under the headings "Report of the Committee on Management on Executive Compensation", "Executive Compensation" and "Pension Plan Table" in the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by Item 12 of Form 10-K will be set forth under the headings "General" and "Security Ownership of Management" in the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by Item 13 of Form 10-K will be set forth under the heading "Election of Directors" in the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders.

Pursuant to General Instruction G(3) to Form 10-K, Items 10 through 13 have not been answered because, within 120 days after the close of its fiscal year, the Registrant will file with the Commission a definitive proxy statement pursuant to Regulation 14A which involves the election of directors. Registrant's definitive proxy statement dated March 3, 1998 will be filed with the Securities and Exchange Commission prior to April 30, 1998. The information required in Items 10 through 13 under the headings set forth above is incorporated by reference herein by this reference thereto. Except as specifically referenced herein the proxy statement in connection with the annual meeting of shareholders to be held April 15, 1998 is not deemed to be filed as part of this Report.

PART IV

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. The financial statements listed below are shown under Item 8 of this Report.

Report of Independent Accountants.

Consolidated Statement of Income for each of the three years ended December 31, 1997.

Consolidated Statement of Retained Earnings for each of the three years ended December 31, 1997.

Consolidated Balance sheet at December 31, 1997 and 1996.

Consolidated Statement of Cash Flows for each of the three years ended December 31, 1997.

Notes to Consolidated Financial Statements.

(a) 2. Financial Statement Schedules - Included in Item 14 herein:

For each of the three years ended December 31, 1997.

Schedule II - Valuation and Qualifying Accounts.

(a) 3. Exhibits - See List of Exhibits.

(b) Reports on Form 8-K

The Company filed a Form 8-K dated December 5, 1997, reporting under Item 5, Other Events, approval by the PSC of the Company's Competitive Opportunities Case Settlement with the PSC staff and other parties with respect to the restructuring of the electric utility industry in New York State.

ROCHESTER GAS AND ELECTRIC CORPORATION

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

(Thousands of Dollars)

FOR THE YEAR ENDED DECEMBER 31, 1995

Descriptions	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged To Other Accounts	Deductions	Balance at End of Period
Reserves for:					
Uncollectible accounts	$950	$14,893		$3,893	$11,950
Materials and supplies obsolescence	0	736			736

FOR THE YEAR ENDED DECEMBER 31, 1996

Descriptions	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged To Other Accounts	Deductions	Balance at End of Period
Reserves for:					
Uncollectible accounts	$11,950	$4,987	$565		$17,502
Materials and supplies obsolescence	736	(375)			361

FOR THE YEAR ENDED DECEMBER 31, 1997

Descriptions	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged To Other Accounts	Deductions	Balance at End of Period
Reserves for:					
Uncollectible accounts	$17,502	$5,078	$4,346		$26,926
Materials and supplies obsolescence	361	2,839			3,200

Beginning in 1992 the Company no longer charges uncollectible expenses through the uncollectible reserve. The total amount written off directly to expense in 1995 was $8,170, in 1996 was $15,039 and in 1997 was $12,912.

LIST OF EXHIBITS

Exhibit 3-1*	Restated Certificate of Incorporation of Rochester Gas and Electric Corporation under Section 807 of the Business Corporation Law filed with the Secretary of State of the State of New York on June 23, 1992. (Filed in Registration No. 33-49805 as Exhibit 4-5 in July 1993)
Exhibit 3-2*	Certificate of Amendment of the Certificate of Incorporation of Rochester Gas and Electric Corporation Under Section 805 of the Business Corporation Law filed with the Secretary of State of the State of New York on March 18, 1994. (Filed as Exhibit 4 in May 1994 on Form 10-Q for the quarter ended March 31, 1994, SEC File No. 1-672.)
Exhibit 3-3*	By-Laws of the Company, as amended to date. (Filed as Exhibit 3-1 in May 1996 on Form 10-Q for the quarter ended March 31, 1996, SEC File No. 1-672)
Exhibit 4-1*	Restated Certificate of Incorporation of Rochester Gas and Electric Corporation under Section 807 of the Business Corporation Law filed with the Secretary of State of the State of New York on June 23, 1992. (Filed in Registration No. 33-49805 as Exhibit 4-5 in July 1993)
Exhibit 4-2*	Certificate of Amendment of the Certificate of Incorporation of Rochester Gas and Electric Corporation Under Section 805 of the Business Corporation Law filed with the Secretary of State of the State of New York on March 18, 1994. (Filed as Exhibit 4 in May 1994 on Form 10-Q for the quarter ended March 31, 1994, SEC File No. 1-672.)
Exhibit 4-3*	By-Laws of the Company, as amended to date. (Filed as Exhibit 3-1 in May 1996 on Form 10-Q for the quarter ended March 31, 1996, SEC File No. 1-672)
Exhibit 4-4*	General Mortgage to Bankers Trust Company, as Trustee, dated September 1, 1918, and supplements thereto, dated March 1, 1921, October 23, 1928, August 1, 1932 and May 1, 1940. (Filed as Exhibit 4-2 in February 1991 on Form 10-K for the year ended December 31, 1990, SEC File No. 1-672-2)
Exhibit 4-5*	Supplemental Indenture, dated as of March 1, 1983 between the Company and Bankers Trust Company, as Trustee (Filed as Exhibit 4-1 on Form 8-K dated July 15, 1993, SEC File No. 1-672)
Exhibit 10-1*	Basic Agreement dated as of September 22, 1975 among the Company, Niagara Mohawk Power Corporation, Long Island Lighting Company, New York State Electric & Gas Corporation and Central Hudson Gas & Electric Corporation. (Filed in Registration No. 2-54547, as Exhibit 5-P in October 1975.)
Exhibit 10-2*	Letter amendment modifying Basic Agreement dated September 22, 1975 among the Company, Central Hudson Gas & Electric Corporation, Orange and Rockland Utilities, Inc. and Niagara Mohawk Power Corporation. (Filed in Registration No. 2-56351, as Exhibit 5-R in June 1976.)

Exhibit 10-3*		Agreement dated September 25, 1984 between the Company and the United States Department of Energy, as amended. (Filed as Exhibit 10-3 in February 1995 on Form 10-K for the year ended December 31, 1994, SEC File No. 1-672-2)
Exhibit 10-4*		Agreement dated February 5, 1980 between the Company and the Power Authority of the State of New York. (Filed as Exhibit 10-10 in February 1990 on Form 10-K for the year ended December 31, 1989, SEC File No. 1-672-2)
Exhibit 10-5*		Agreement dated March 9, 1990 between the Company and Mellon Bank, N.A. (Filed as Exhibit 10-1 in May 1990 on Form 10-Q for the quarter ended March 31, 1990, SEC File No. 1-672)
Exhibit 10-6*		Basic Agreement dated September 22, 1975 as amended and supplemented between the Company and Niagara Mohawk Power Corporation. (Filed as Exhibit 10-11 in February 1993 on Form 10-K for the year ended December 31, 1992, SEC File No. 1-672-2)
Exhibit 10-7*		Operating Agreement effective January 1, 1993 among the owners of the Nine Mile Point Nuclear Plant Unit No. 2. (Filed as Exhibit 10-12 in February 1993 on Form 10-K for the year ended December 31, 1992, SEC File No. 1-672-2)
Exhibit 10-8*	(A)	Rochester Gas and Electric Corporation Deferred Compensation Plan. (Filed as Exhibit 10-14 in February 1994 on Form 10-K for the year ended December 31, 1993, SEC File No. 1-672-2)
Exhibit 10-9*	(A)	Rochester Gas and Electric Corporation Long Term Incentive Plan, Restatement of January 1, 1994. (Filed as Exhibit 10-10 in February 1995 on Form 10-K for the year ended December 31, 1994, SEC File No. 1-672-2)
Exhibit 10-10*	(A)	Rochester Gas and Electric Corporation Deferred Stock Unit Plan for Non-Employee Directors, effective as of December 31, 1995. (Filed as Exhibit 10-1 in May 1996 on Form 10-Q for the quarter ended March 31, 1996, SEC File No. 1-672)
Exhibit 10-11*	(A)	1996 Performance Stock Option Plan. (Filed as Exhibit 10-10 in February 1995 on Form 10-K for the year ended December 31, 1994, SEC File No. 1-672-2)
Exhibit 10-12*	(A)	Rochester Gas and Electric Corporation Executive Incentive Plan, Restatement of January 1, 1995. (Filed as Exhibit 10-11 in February 1996 on Form 10-K for the year ended December 31, 1995, SEC File No. 1-672-2)
Exhibit 10-13*	(A)	RG&E Unfunded Retirement Income Plan Restatement as of July 1, 1995. (Filed as Exhibit 10-12 in February 1996 on Form 10-K for the year ended December 31, 1995, SEC File No. 1-672-2)
Exhibit 10-14	(A)	Change of Control Agreement dated January 1, 1998 between the Company and Thomas S. Richards, Chairman of the Board, President and Chief Executive Officer.

Exhibit 10-15*	(A)	Change of Control Agreement dated August 17, 1995 between the Company and Robert E. Smith, Senior Vice President, Energy Operations. (Filed as Exhibit 10-15 in February 1996 on Form 10-K for the year ended December 31, 1995, SEC File No. 1-672-2)
Exhibit 10-16*	(A)	Change of Control Agreement dated January 2, 1996 between the Company and J. Burt Stokes, Senior Vice President, Corporate Services and Chief Financial Officer. (Filed as Exhibit 10-16 in February 1996 on Form 10-K for the year ended December 31, 1995, SEC File No. 1-672-2)
Exhibit 10-17*	(A)	Change of Control Agreement dated January 2, 1997 between the Company and Michael J. Bovalino, Senior Vice President, Energy Services. (Filed as Exhibit 10-18 in February 1997 on Form 10-K for the year ended December 31, 1996, SEC File No. 1-672-2)
Exhibit 10-18		Amended and Restated Settlement Agreement dated October 23, 1997 between the Company the Staff of the New York Public Service Commission (PSC), and certain other parties (Filed as Exhibit 10-4 on Form 10-Q for the quarter ended September 30, 1997, SEC File No. 1-672) as amended pursuant to an order of the PSC issued January 14, 1998 (excluding Appendices) filed herewith.
Exhibit 10-19*	(A)	Form of Rochester Gas and Electric Corporation 1996 Performance Stock Option Plan Agreement. (Filed as Exhibit 10-1 in November 1997 on Form 10-Q for the quarter ended September 30, 1997, SEC File No. 1-672)
Exhibit 10-20*	(A)	Agreement, dated October 1, 1997, between the Company and Michael T. Tomaino, Senior Vice President and General Counsel. (Filed as Exhibit 10-2 in November 1997 on Form 10-Q for the quarter ended September 30, 1997, SEC File No. 1-672)
Exhibit 10-21*		Agreement dated as of September 23,1997 between the Company and International Business Machines Corporation. (Filed as Exhibit 10-3 in November 1997 on Form 10-Q for the quarter ended September 30, 1997, SEC File No. 1-672)
Exhibit 23		Consent of Price Waterhouse LLP, independent accountants
Exhibit 27		Financial Data Schedule, pursuant to Item 601(c) of Regulation S-K.

*   Incorporated by reference.
(A) Denotes executive compensation plans and arrangements.

The Company agrees to furnish to the Commission, upon request, a copy of all agreements or instruments defining the rights of holders of debt which do not exceed 10% of the total assets with respect to each issue, including the Supplemental Indentures under the General Mortgage and credit agreements in connection with promissory notes as set forth in Note 6 of the Notes to Financial Statements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ROCHESTER GAS AND ELECTRIC CORPORATION

By: /S/ THOMAS S. RICHARDS
Thomas S. Richards
Chairman of the Board,
President and
Chief Executive Officer

DATE: February 11, 1998

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated.

SIGNATURE	TITLE	DATE
Principal Executive Officer:		
/S/ THOMAS S. RICHARDS (Thomas S. Richards)	Chairman of the Board, President and Chief Executive Officer	February 11, 1998
Principal Financial Officer:		
/S/ J. B. STOKES (J. Burt Stokes)	Senior Vice President Corporate Services and Chief Financial Officer	February 11, 1998
Principal Accounting Officer:		
/S/ WILLIAM J. REDDY (William J. Reddy)	Controller	February 11, 1998

SIGNATURE	TITLE	DATE
Directors:		
/S/ WILLIAM BALDERSTON III (William Balderston III)	Director	February 11, 1998
/S/ ANGELO J. CHIARELLA (Angelo J. Chiarella)	Director	February 11, 1998
/S/ ALLAN E. DUGAN (Allan E. Dugan)	Director	February 11, 1998
(Mark B. Grier)	Director	February , 1998
/S/ SUSAN R. HOLLIDAY (Susan R. Holliday)	Director	February 11, 1998
/S/ JAY T. HOLMES (Jay T. Holmes)	Director	February 11, 1998
/S/ SAMUEL T. HUBBARD,JR (Samuel T. Hubbard,Jr.)	Director	February 11, 1998
/S/ ROGER W. KOBER (Roger W. Kober)	Director	February 11, 1998
/S/ CONSTANCE M. MITCHELL (Constance M. Mitchell)	Director	February 11, 1998
/S/ CORNELIUS J. MURPHY (Cornelius J. Murphy)	Director	February 11, 1998
/S/ CHARLES I. PLOSSER (Charles I.Plosser)	Director	February 11, 1998
/S/ THOMAS S. RICHARDS (Thomas S. Richards)	Director	February 11, 1998