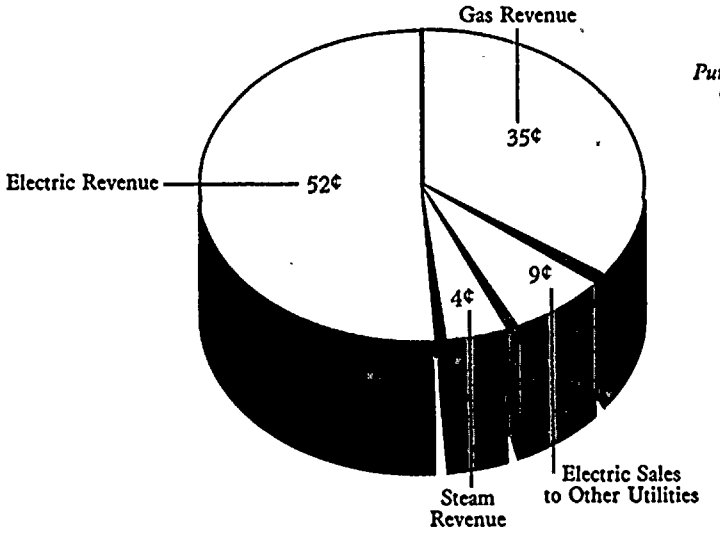
FINANCIAL HIGHLIGHTS

Annual Report 1981
for the Year Ended December 31

Source of 1981 Revenue Dollar (In Cents)



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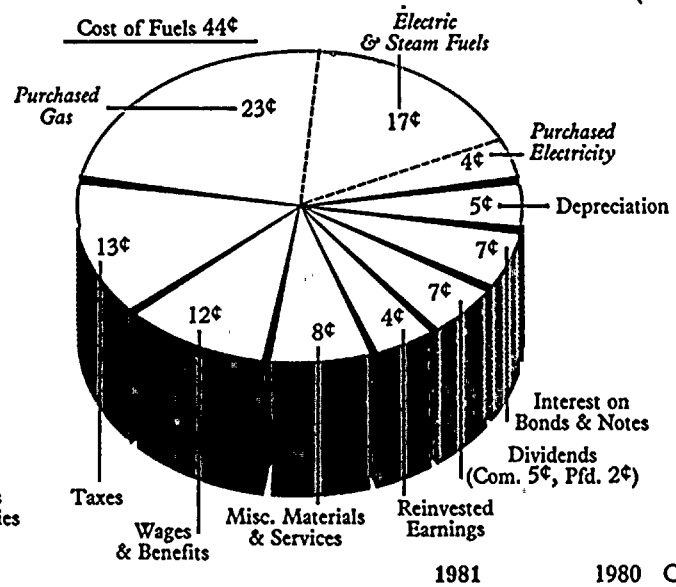

	1981	1980	% Change
Sales, Revenues and Earnings (Thousands, Except Per Share Amounts)			
Electricity to customers			
Kilowatt-hours	5,314,630	5,186,423	2
Revenue	$ 320,325	$245,005	31
Electricity to other utilities			
Kilowatt-hours	1,371,077	1,620,929	(15)
Revenue	$ 54,302	$ 52,786	3
Gas (See Note 1)			
Therms	479,503	434,492	10
Revenue	$ 212,553	$181,046	17
Steam			
Pounds	2,146,556	2,413,879	(11)
Revenue	$ 26,361	$ 23,589	12
Total operating revenues	$ 613,541	$502,426	22
Total operating expenses	$ 533,739	$442,894	21
Operating income	$ 79,802	$ 59,532	34
Net income	$ 65,750	$ 43,652	51
Earnings applicable to common stock	$ 55,212	$ 34,725	59
Rate of return on average common equity	13.91%	9.86%	41
Weighted average number of common stock shares outstanding	18,826	16,966	11
Earnings per common share	$2.93	$2.04	44
Cash dividends per common share, adjusted for stock dividends	$1.53	$1.44	6
Stock dividend paid (See Note 2)	3%	3%	
Utility Plant (Thousands)			
Capital expenditures, less allowance for funds used during construction	$ 117,764	$ 87,742	34
Net utility plant at December 31	$1,031,193	$950,474	8
Number of Customers at December 31			
Electric	290,086	285,470	2
Gas	227,953	213,157	7
Steam	234	271	(14)
Number of Common Stock Shareholders at December 31	50,538	50,416	
Number of Employees at December 31	2,785	2,691	3

Notes: (1) Figures reflect the merger of the Pavilion Natural Gas Company for the entire year of 1981. See Note 1 to the Notes to Financial Statements.
(2) A 3% stock dividend was also paid February 25, 1982.

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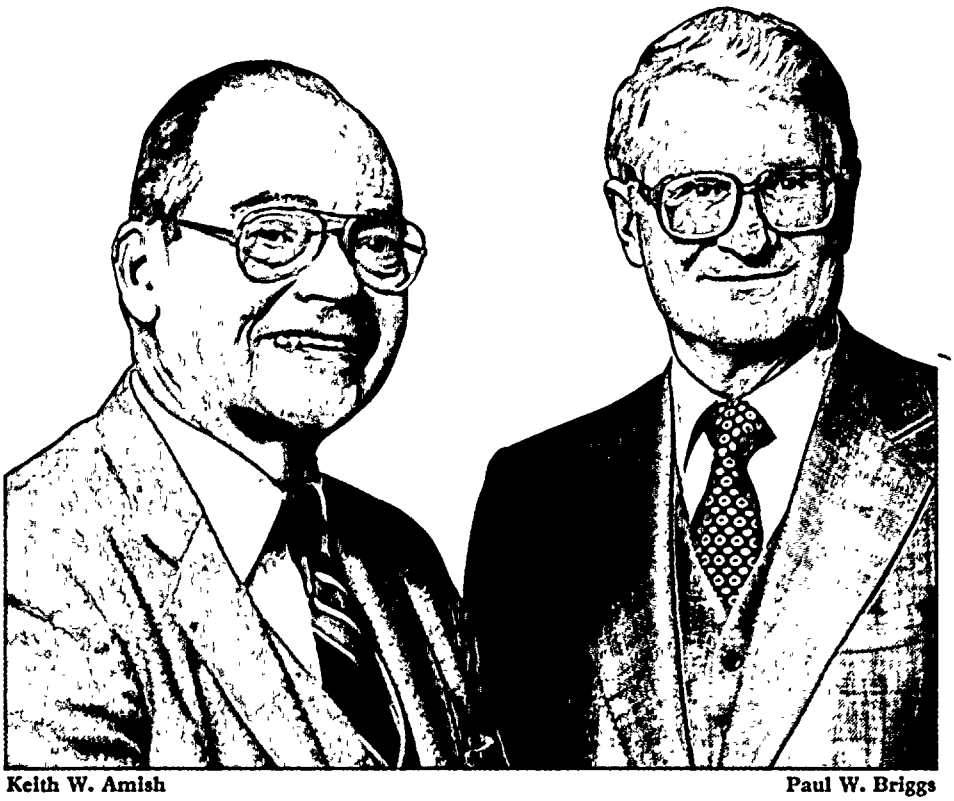


Keith W. Amish Paul W. Briggs

From a financial standpoint, 1981 was a record year for RG&E as earnings applicable to common stock rose to $55.2 million, an increase of 59 percent over 1980. Earnings per common share were $2.93; nearly 90 cents more than the 1980 per-share earnings of $2.04. Rate of return on common equity improved, moving up to nearly 14 percent, although it was still a little less than the 14.7 percent average of the returns that were authorized for the period by the New York State Public Service Commission (PSC) in the company's last two rate decisions.

Total combined revenues of $614 million represented a 22 percent increase over 1980 revenues. The rate increases granted by the PSC in July 1980 and in July 1981 were, by far, the most significant influence on the increased revenues. It was also most encouraging that we experienced fairly good growth in electric and gas sales to customers during 1981. Increases in kilowatt-hour sales of electricity to customers and sales of natural gas in therms were 2.5 percent and 10.4 percent respectively.

Operating expenses rose 21 percent in 1981 to $534 million. A major contributing factor to higher operating costs continues to be inflation which adversely affects expenses for fuels, materials, labor and services. The cost of capital for necessary construction to provide adequate, reliable energy and quality service to our customers also rose.

The rate increases granted by the PSC in July 1981 were estimated to produce additional annual revenues of $42.1 million for electric sales and $7.0 million for gas sales; an annual total of $49.1 million. A month later, in August, as part of our ongoing effort to keep pace with inflationary influences, we requested electric and gas rate increases totalling an additional $84.8 million in annual revenue. In this current rate case, which is expected to be decided in July 1982, we are seeking an authorized 18 percent rate of return on equity that more accurately reflects returns on investment required in today's financial markets.

In January 1982, the PSC rendered a favorable decision concerning the method of recovery of capital invested in the Sterling nuclear power plant project which was terminated in January 1980. That project had to be abandoned when the New York State Board for Electric Generation Siting and the Environment revoked its earlier certification for construction of the 1,150,000 kilowatt power plant. Following nearly 24 months of hearings, the PSC approved RG&E's request for amortization of its investment in the Sterling nuclear power plant project. Company costs, prior to tax saving, are $38.6 million. The cost will be amortized on a levelized basis over a five-year period beginning with the decision in the current rate case, with an allowance for carrying costs on the unamortized balance.

Intensive regulatory hearings and review in 1981 and early 1982 concerning the viability of the Nine Mile Point #2 nuclear power plant under construction near Oswego, New York have culminated with approval to proceed with the project. In expressing approval that the plant should be completed, the PSC outlined a novel regulatory plan which will provide for incentives for lower-cost completion of the plant, and penalties for higher costs. Details of any such plan, or whether there should be any plan at all, are still under consideration.

RG&E became one of five cotenants in the Nine Mile Point #2 project in 1975 when we contracted with Niagara Mohawk Power Corporation for a 14 percent share in the ownership of the plant's 1,084,000 kilowatt capacity, or 152,000 kilowatts. We viewed our participation as a necessary component of our plans for providing economical electric energy to our customers in meeting projected load growth in our service territory.

Due to reassessments of technical issues concerning the plant, additional regulatory requirements and reductions in annual electric load growth rates across the State, the projected operational date for the plant was extended to late 1986. The cost of the project escalated as a result of the delays and modifications. As of December 31, 1981, our investment in the project was $191 million. Based on the presently projected operational date it is estimated that this investment will be approximately $559 million. Given adequate rate relief, we anticipate no major problems in meeting the financial commitment. Construction of the Nine Mile Point #2 plant was more than one-third complete by year-end and work at the site continues.

New York State law requires that a thorough, independent audit of an investor-owned utility's management

and operations be conducted every five years. In 1981 RG&E was audited by the firm of Cresap, McCormick and Paget. Quoting from the published conclusion of the report, "Rochester Gas and Electric Corporation possesses a number of significant strengths including a tradition of providing outstanding customer service, a management that is unusually sensitive to employee interests, and technical accomplishments in areas such as power plant performance that have yielded direct benefits for ratepayers." A few of the technical accomplishments are highlighted in this annual report.

Of course, there were areas where the consultants found room for improvement. This is the real purpose and value of a management audit. In all, 86 recommendations were made. We agreed with many of the recommendations and have already begun implementing them. We disagreed with some recommendations and believed in other cases that the estimated cost-saving was overstated in the audit's conclusions.

On January 25, 1982, world attention focused on RG&E when a steam generator tube failure forced an emergency shutdown of the Ginna nuclear power plant. The ruptured tube allowed pressurized, radioactive water to flow from the plant's primary system to the non-radioactive water and steam in the secondary system. There were releases of small amounts of radioactive steam into the atmosphere which, under U.S. Nuclear Regulatory Commission (NRC) procedures, led our plant management to declare a site area emergency. RG&E radiological monitoring teams, covering a ten-mile radius around the plant, found no indication of any radioactive levels that would endanger the public. Our highly-qualified control room operators acted quickly and prudently in bringing the problem in the plant under control. The RG&E recovery team brought the reactor to cold shutdown by Tuesday, January 26 when clean-up and inspection began.

The actions of RG&E employees and the conservative procedures used drew favorable public recognition from the U.S. Nuclear Regulatory Commission. Even some vocal critics of nuclear power commended RG&E's handling of the accident.

There was an ample and constant flow of timely, accurate information from RG&E to the more than 140 newspeople who came to the company's Joint Emergency Information Center. Favorable comments were made by many news organizations concerning the availability of good information and RG&E's openness during the accident.

The accident was, of course, unfortunate, but we believe our actions demonstrated that nuclear power plants are safe. The job was then to thoroughly inspect the plant and analyze the problem. We are now making repairs to get the plant back in operation and to once again provide our customers with the economical electric energy that nuclear power produces. In an effort to minimize the shutdown period, we have advanced the scheduled April shutdown for refueling, maintenance, inspection and modifications to run concurrently with the downtime for steam generator repairs. We expect the plant to return to service early in May, subject to NRC concurrence.

In January 1982 your board of directors authorized the payment of a three percent stock dividend and raised the cash dividend by ten percent. It was also announced that this would be the last year for which a stock dividend would be considered. A prime advantage of stock dividends was the shareholders' ability to defer income taxes on the shares until the time they are sold. Under the Economic Recovery Tax Act of 1981, shareholders are provided a similar tax advantage within prescribed limitations by reinvestment of their cash dividends through the company's Automatic Dividend Reinvestment Plan. The availability of this compensatory tax advantage, the abundance of high-yielding investment alternatives, and the belief that the payment of stock dividends has had a dilutive effect on the market price of the company's common stock, prompted the board's decision. We believe that the change in dividend policy is in the best interest of our shareholders.

In our last annual report we described an expansion in the structure of our top management where two senior vice-president positions were added. The intent was to form a five-member senior management team in which diverse backgrounds and professional expertise would be complementary. That restructuring has already proved its worth in more effectively meeting the many-faceted challenges that confront today's electric and gas companies.

Response to the challenges represents phase one of the five-member team concept. We have begun to address the next phase of the plan by directing more disciplined and intensive efforts to strategic planning for RG&E's future. Planning has always been dominant at RG&E, but we recognize the need for more formalized, coordinated efforts led by a corporate planning group. We intend to have this organization in place by the end of the year.

RG&E's management could not meet the challenges of the business or accomplish any of its planning objectives without the fine work of our more than 2,700 employees. We commend our employees and thank them for their dedication.

As for the future, we expect moderate growth to continue in 1982. Our projections estimate a 2.3 percent increase in kilowatt-hour electric sales and a 4.5 percent increase in gas therm sales. Our capital requirements for the year are estimated at $152.7 million and will be partially financed through the issuance of long-term debt and common stock. We consider RG&E to be in good financial condition and we believe that the economic environment in our service territory will improve during the year.

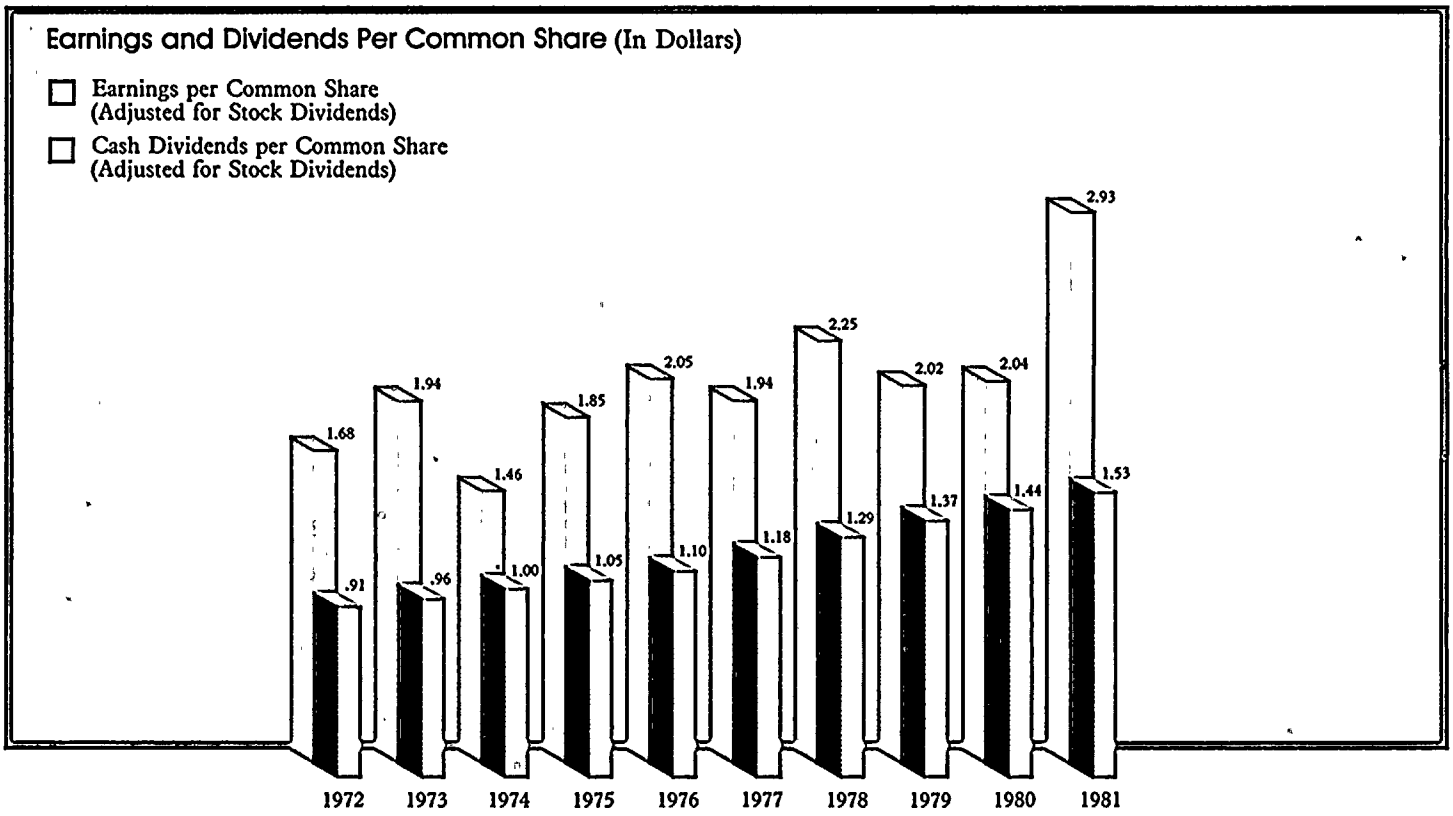
Paul W. Briggs
Chairman of the Board and
Chief Executive Officer

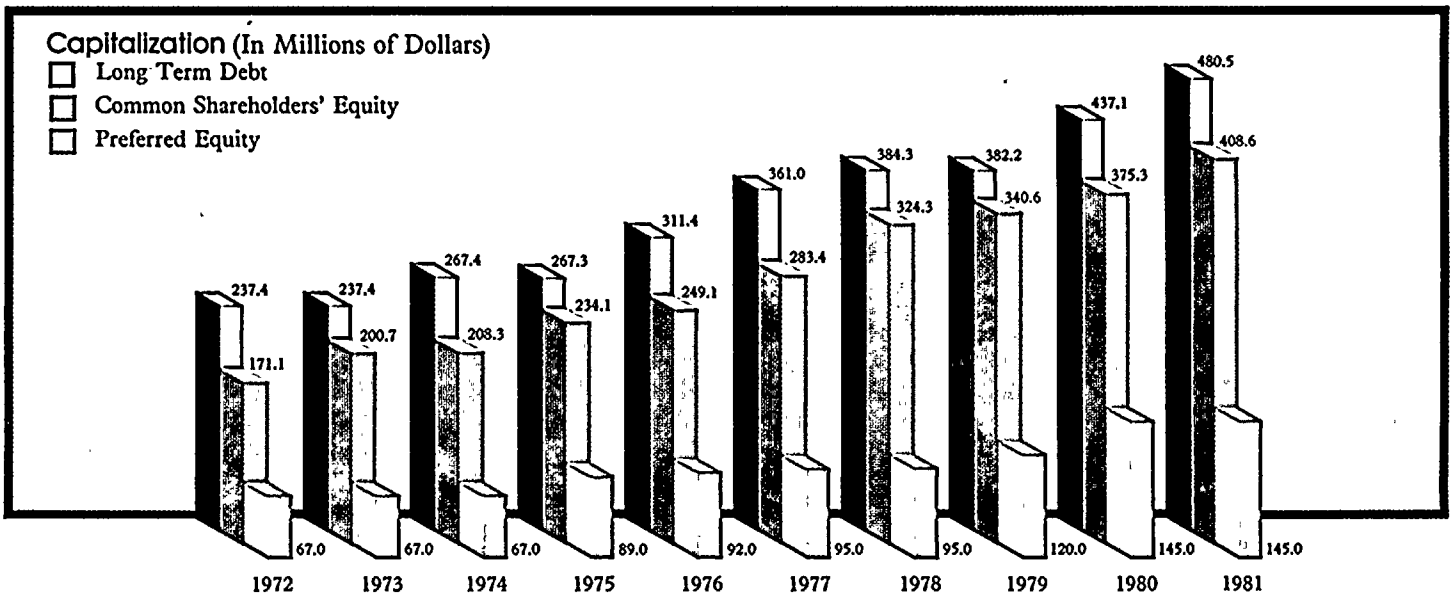
Keith W. Amish
President and
Chief Operating Officer

March 2, 1982

Of particular concern to investor-owned electric and gas companies is the ability to acquire capital to meet the heavy financial demands made on the industry. No other industry is as capital-intensive as the electric and gas utility business. We have little choice with regard to the amounts of money we need for construction programs. Customers have to be offered reliable service and adequate energy supplies regardless of the additional pressure placed on our capital requirements.

The capital market is extremely competitive and at times restrictive in the types of financing available. We have maintained a traditional approach to financing by issuing the conventional types of securities, namely first mortgage bonds, preferred and preference stocks and common stock. This we have done with the objective of having a conservative capital structure comprised of approximately 47% debt, 13% preferred and preference stocks, and 40% common stock equity. We feel our

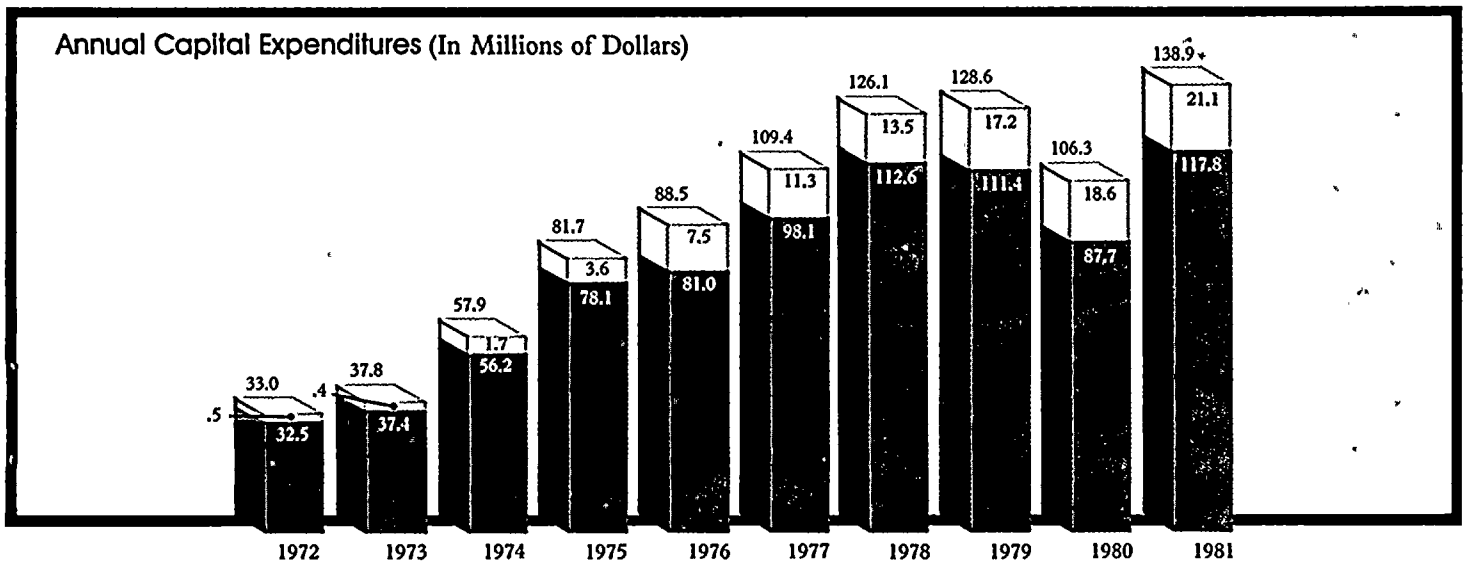




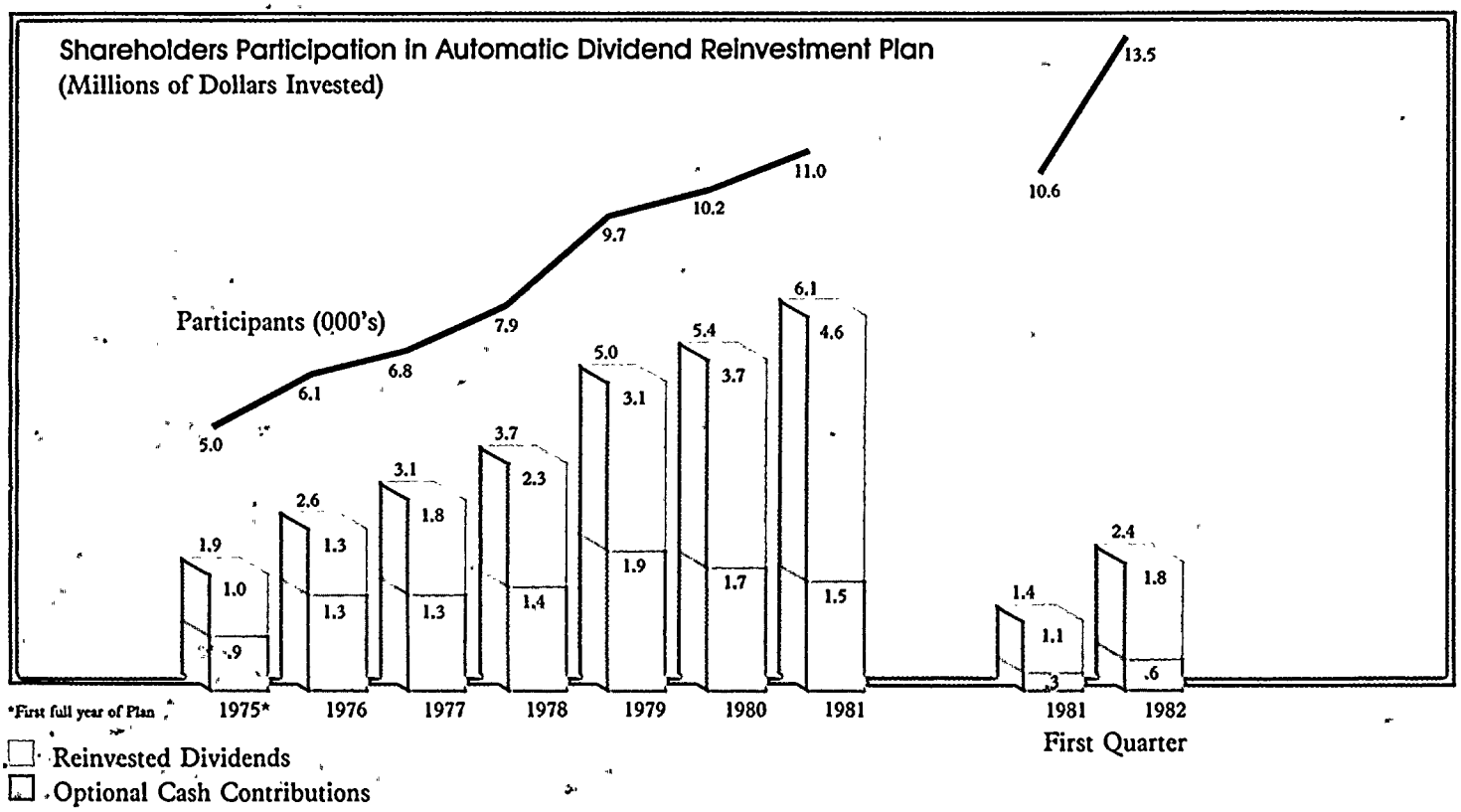
financing program over the past ten years has been completed in a timely, efficient and cost-effective manner. In that ten-year period we have expended $908 million, including Allowance for Funds Used During Construction, for capital expenditures of which $534 million has been financed externally by issuing $285 million of long term debt and $249 million of equity.

The company's Automatic Dividend Reinvestment Plan continues to be a popular vehicle for shareholders to purchase additional shares of common stock without having to pay brokerage fees or other costs. The new federal income tax law also permits Plan participants to elect to exclude from taxable income up to an aggregate of $750 per year ($1,500 for a joint return) of reinvested dividends. Currently, 26.7% of our shareholders, representing 21.2% of outstanding shares, are participants in the Plan.

The charts on these pages reflect some useful information on our financing activities over the past ten years. ◻



☐ Allowance for Funds Used During Construction
■ Capital expenditures, excluding Allowance for Funds Used During Construction

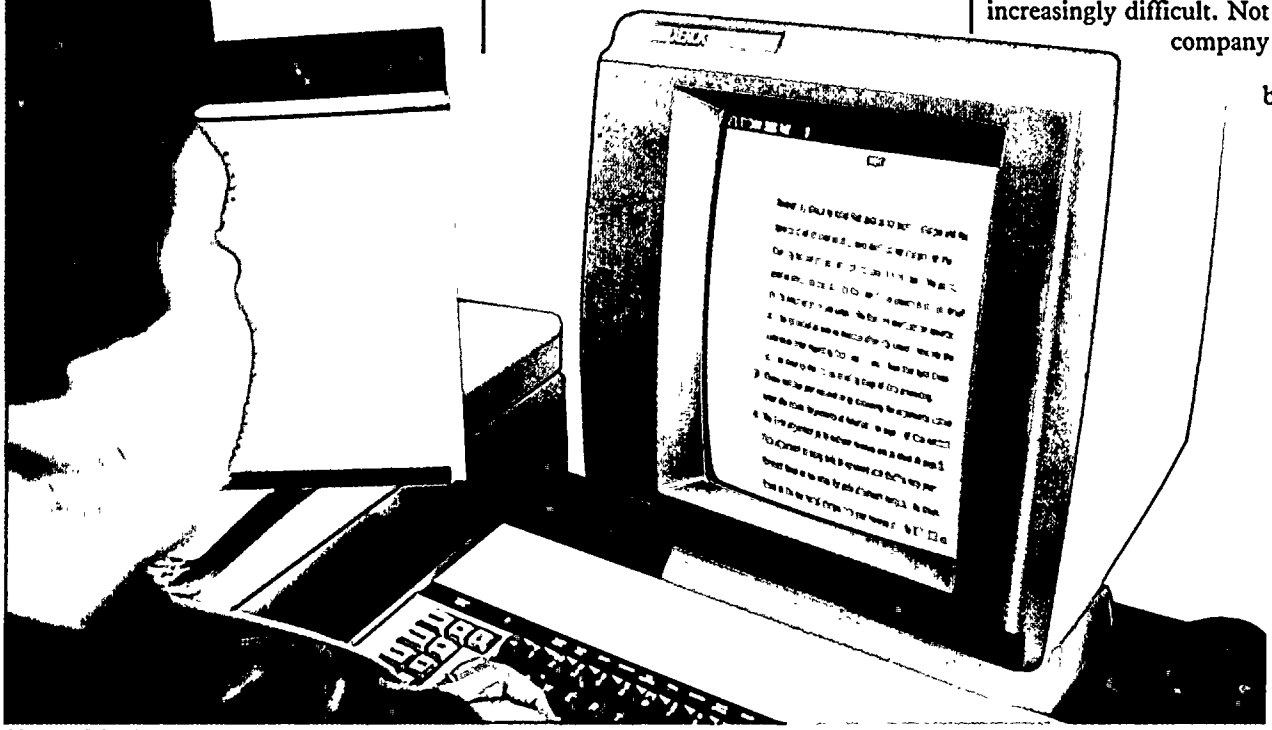


☐ Reinvested Dividends
☐ Optional Cash Contributions

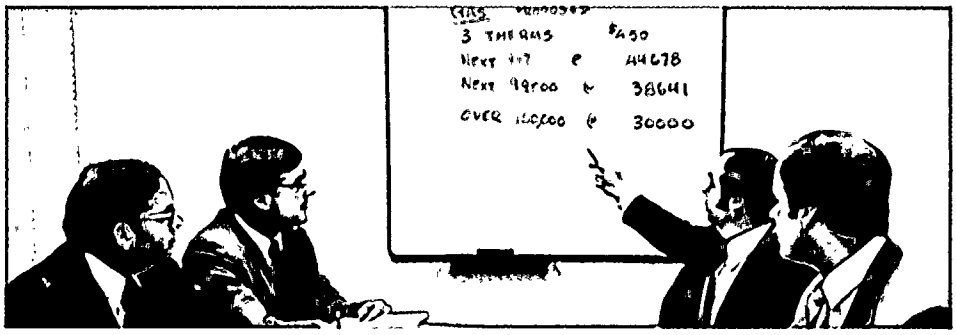
Prior to 1970, RG&E had gone 23 years without having to ask for a gas rate increase and 13 years without seeking an electric rate increase.

The last decade has brought dramatic changes in the Country's economy. Inflation, the Oil Embargo, higher construction costs, rising lending rates and lower customer demand meant that prices had to go up. Since 1970, RG&E has filed for nine electric rate increases, eight gas increases and six steam increases in trying to keep up with the rising cost of doing business. Seeking higher rates is nothing RG&E relishes, but it is quite necessary.

The preparation of a rate case is one of the responsibilities of the Rate and Economic Research Department. Over the last ten years, RG&E has attempted the task of trying to achieve rates which could sustain operations and meet financial obligations. That task has become increasingly difficult. Not only must the company file each year for rate relief, but the amount of information required



Above—Word processors help organize the voluminous paperwork that goes into rate case filings. Below left—In the foreground two volumes that represent the current rate case filing stand above the thin volume from a 1970 rate case. Below right top—One of many meetings that compile and review data for a rate case. Below right bottom—One of the many public sessions held during the rate case process.



for each filing has also increased.

The size of the filing in number of pages has nearly doubled since 1970. There has been a five-fold increase in the number of company witnesses required for the rate case process, and a drastic increase in the number of exhibits required. The latest filing, which was based on a 12-month forecast period, required five months to prepare and consisted of nearly 1000 pages of testimony and exhibits.

The regulatory agency in Albany, the New York State Public Service Commission, has the responsibility of working on behalf of consumers' interests, while setting rates which sustain the financial health of a company. Over the series of requests for rate increases, RG&E has seldom been allowed returns and rates that adequately reflect the actual costs of doing business.

With the continuing pressures of inflation and a limit on setting rates for only a 12-month forecast period, the necessity of rate increases and the filing of rate cases have become a continuous process which is expensive for the consumer and the company. As unpopular as rate increase requests may be with consumers, they are essential in maintaining reliable energy and quality service. □

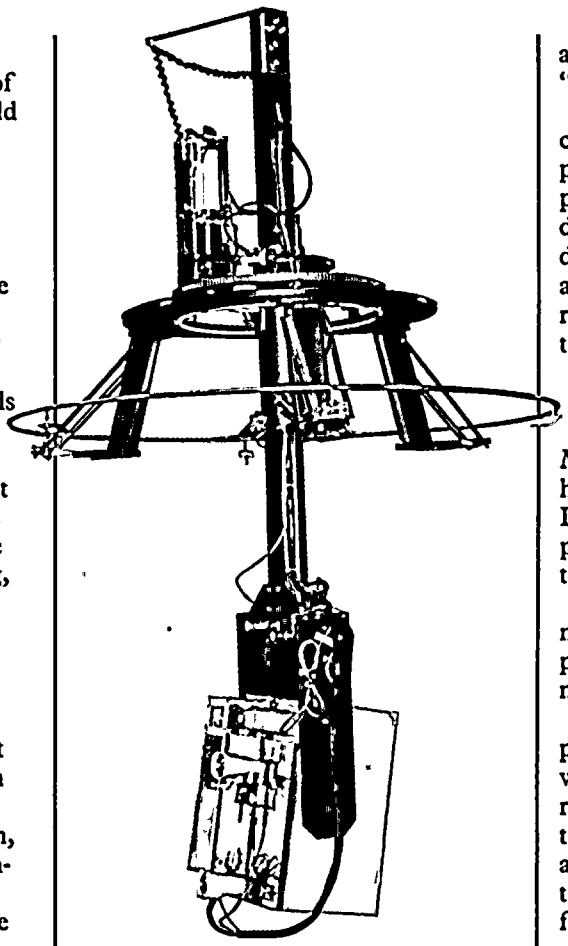
Year	Class	Effective Date	Increase Allowed		Authorized Rate Of Return On	
			Amount	%	Rate Base	Equity
			$000's	%	%	%
1970	E					
	G					
	S	11/20	1,157	21.0	4.32	
1971	E	3/25	5,900	7.5	7.72	12.0
	G					
	S					
1972	E	10/25	10,144	11.5	7.96	12.00
	G	4/28	3,676	6.8	7.77	12.00
	S	5/11	897	11.4	6.48	
1973	E					
	G					
	S	11/12	500	5.1	7.25	
1974	E	10/23	17,990	16.0	8.83	13.19
	G	10/23	4,854	7.6	8.42	12.09
	S					
1975	E					
	G					
	S	4/15	2,475	12.0	8.69	
1976	E	4/20	11,406	8.2	9.35	13.50
	G	4/20	4,983	6.3	9.35	13.50
	S					
1977	E	11/11	10,186	5.8	9.31	12.80
	G	11/11	2,536	2.4	9.31	12.80
	S					
1978	E	2/18	3,000	1.6	9.31	12.80
	G	2/2	678	.6	9.31	12.80
	S					
1979	E	5/2	17,699	8.2	9.89	13.40
	G	5/2	8,109	6.6	9.89	13.40
	S	12/15	2,895	15.0	4.37	
1980	E	7/26	38,398	15.9	10.32	13.80
	G	7/26	9,639	5.1	10.32	13.80
	S					
1981	E	7/18	42,078	14.1	11.52	16.00
	G	7/18	6,966	3.1	11.52	16.00
	S	2/18	3,550	18.2	6.49	
1982	E	Pending	75,700(a)	19.1	12.90	18.00
	G	Pending	9,100(a)	3.2	12.90	18.00
	S					

(a) Request filed August 21, 1981

E = Electric
G = Gas
S = Steam

Nuclear power plant owners have been faced with the baffling problem of finding a way to accurately inspect weld seams in the reactor coolant pumps. The pumps at the Ginna plant are 30 feet tall, weigh 99 tons each and are each designed to cool the reactor by circulating 88,000 gallons of 550°F pressurized water a minute through the reactor. The big problem facing the inspection procedure was that the only way to examine the highly-radioactive 8½- to 11-inch-thick pump casing welds was with a high-energy x-ray machine. The small opening in the top of the pumps couldn't allow even the smallest x-ray units access to the interior where the welds are exposed to a more severe environment. Radiography, or x-raying, was the only option, but no compact system had ever been developed that could deliver the high energy source and maneuverability required for the job.

In 1978, RG&E made a commitment to the Nuclear Regulatory Commission to develop a workable inspection system. Following three years of design, fabrication and testing, RG&E, Schoenberg Radiation Company and Electric Power Research Institute developed the answer; a high energy x-ray head called "MINAC."



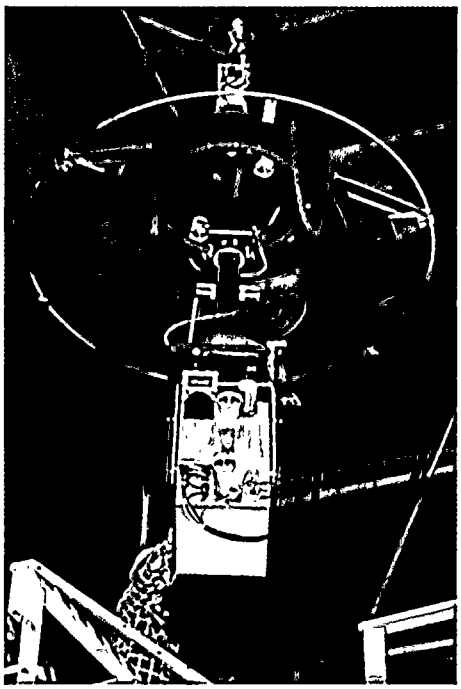
MINAC/manipulator

MINAC is a highly-flexible and compact radiographic device that was put to its first real use at the Ginna plant during the 1981 scheduled shutdown. It was gratifying that not only did the MINAC/manipulator perform as designed, but that the results of the radiographs showed that the welds in the pump had experienced no changes over the 11 years the plant had been in operation.

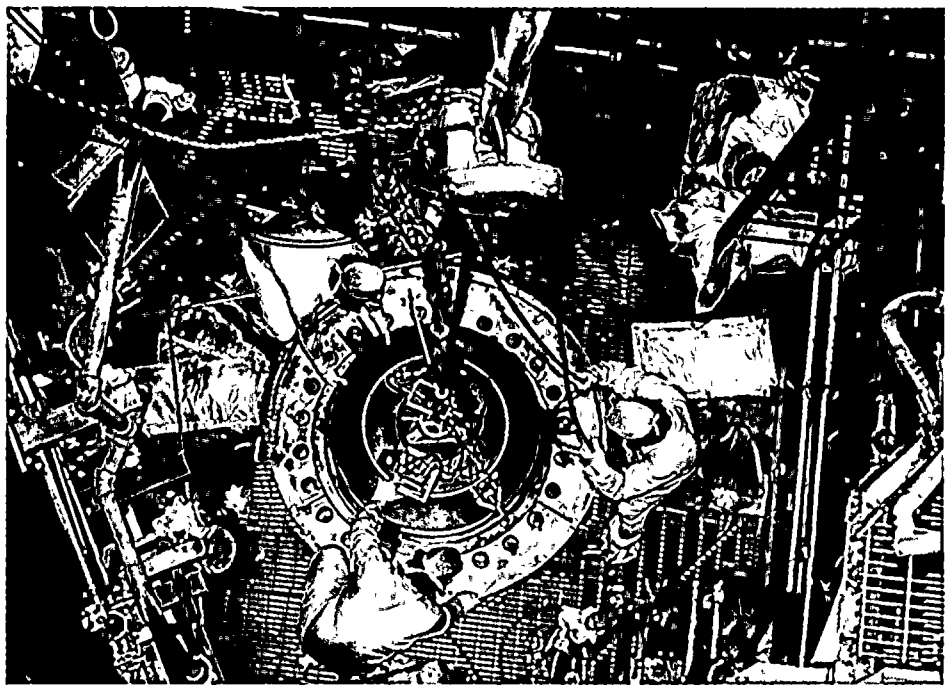
The nuclear industry declared MINAC an unqualified success. RG&E has sold the equipment to the Electric Power Research Institute, and the sale price recovered RG&E's investment in the development of the system.

This nuclear research and development project has solved major technical problems not only for RG&E, but the nuclear industry as a whole.

Another critical area of nuclear power plant maintenance and inspection in which RG&E has assumed a leadership role is the repair of steam generator tubes. Each of the two steam generators at the Ginna power plant contains 3,260 tubes that carry the reactor-heated water from the primary system through the



The MINAC/manipulator is lowered into position during mock-up training.



The MINAC/manipulator is set in place on top of the reactor coolant pump.

At RG&E's steam generator mock-up, trainees practice procedures used in the innovative tube-sleeving process.

secondary system, creating steam that drives the turbine generator. Over time, some of the tubes experience wear and may have to be "plugged" to prevent leakage of water from the primary system into the secondary system. Plugging renders the tubes permanently inoperable.

The prospects of future reduced capacity or an expensive, lengthy shutdown prompted RG&E to undertake this research program. An innovative procedure that reinforces and restores weakened generator tubes was developed by RG&E and Babcock & Wilcox and tested in a November 1980 shutdown at the Ginna nuclear power plant.

The process involves inserting a sleeve into the weakened lower part of the tube. The top of the tube sleeve is expanded and brazed, then the lower end is fused to the old tube with an explosive weld.

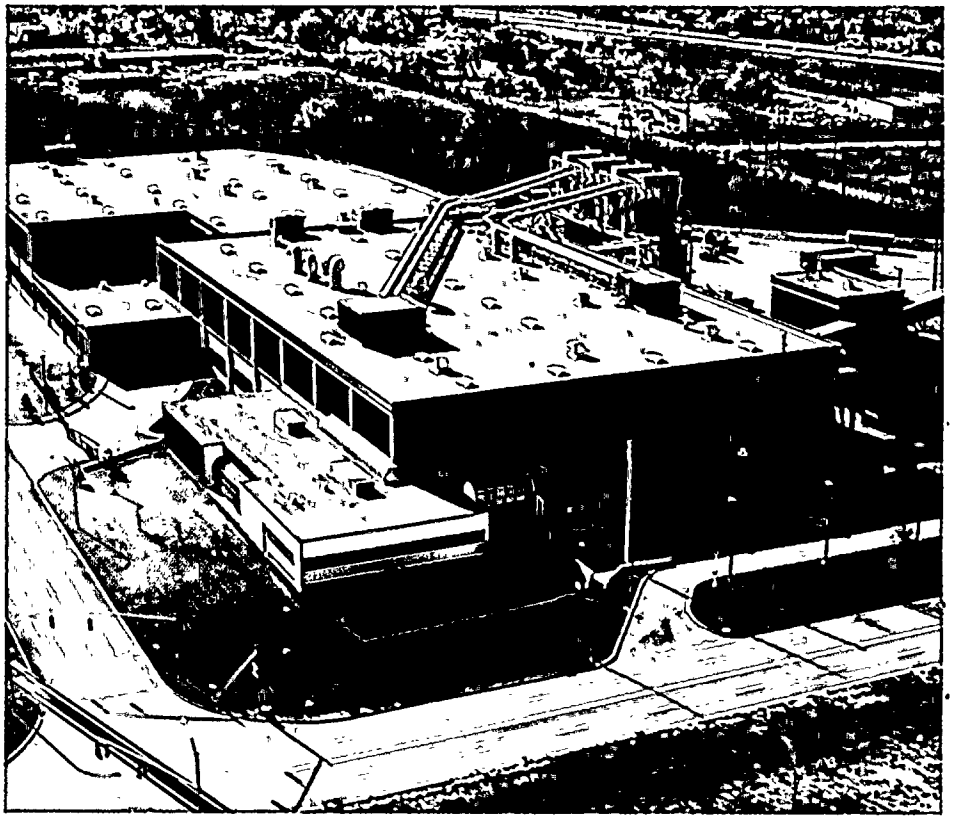
In 1980 five tubes were restored with the new method at the Ginna plant. During the 1981 shutdown, 16 tubes were restored. None of the sleeved tubes was involved in the accident of January 25, 1982. The tube-sleeving equipment and technology that was developed at RG&E is now also being employed by other reactor owners. RG&E's nuclear technology contributions are providing benefits today and will for years to come to the industry and the industry's consumers. □

Our 1976 annual report told of an agreement signed by RG&E and Monroe County for mutual support in developing a fuel system where RG&E's 260,000-kilowatt, coal-fired Russell Station could burn refuse derived fuel (RDF) produced at the County's planned refuse recovery facility. If workable, the proposed system would produce benefits for the County, its residents and for fuel conservation with no detrimental effects on customers or shareholders.

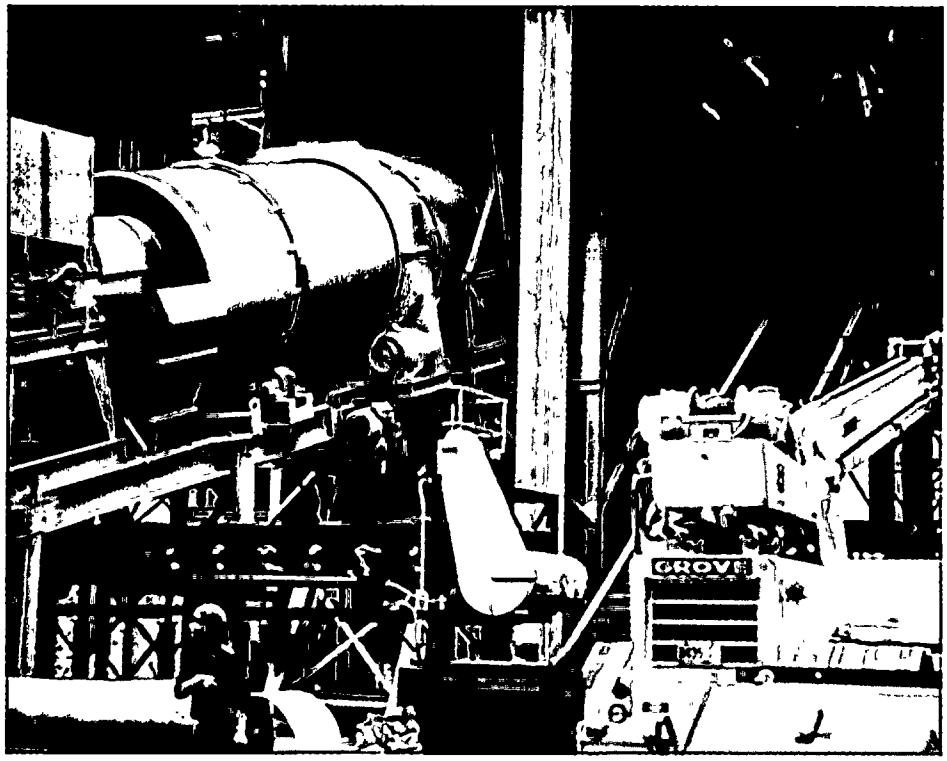
For Monroe County, the recovery facility holds the hope of reclaiming usable materials from refuse, like RDF, glass and metals while reducing landfill requirements.

The agreement called for cooperation in experimenting with the use of RDF as a supplement to coal boiler fuel at the RG&E power plant. A receiving facility had to be built at Russell Station and its boilers had to be converted to accept the RDF, which is a paper, confetti-like product that is extracted from refuse and can be burned for its heat value.

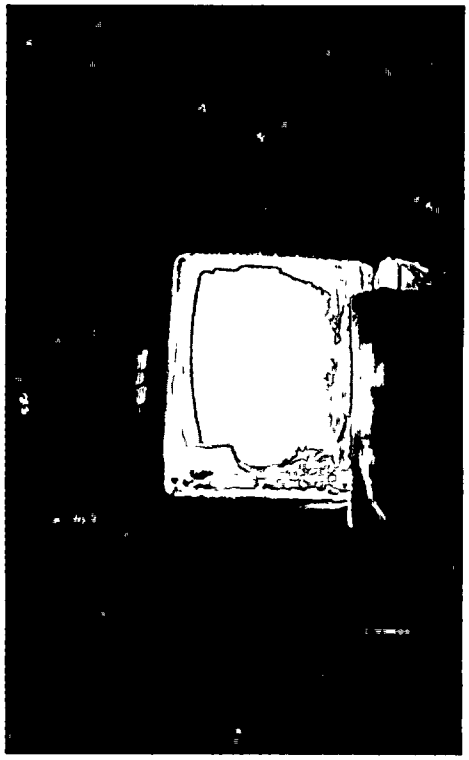
The test burns of RDF were successful and work progressed on the construction of the RDF receiving and storage facility.



Monroe County's Refuse Recovery Facility.



Inside the recovery facility, special equipment processes waste and salvages useable materials.



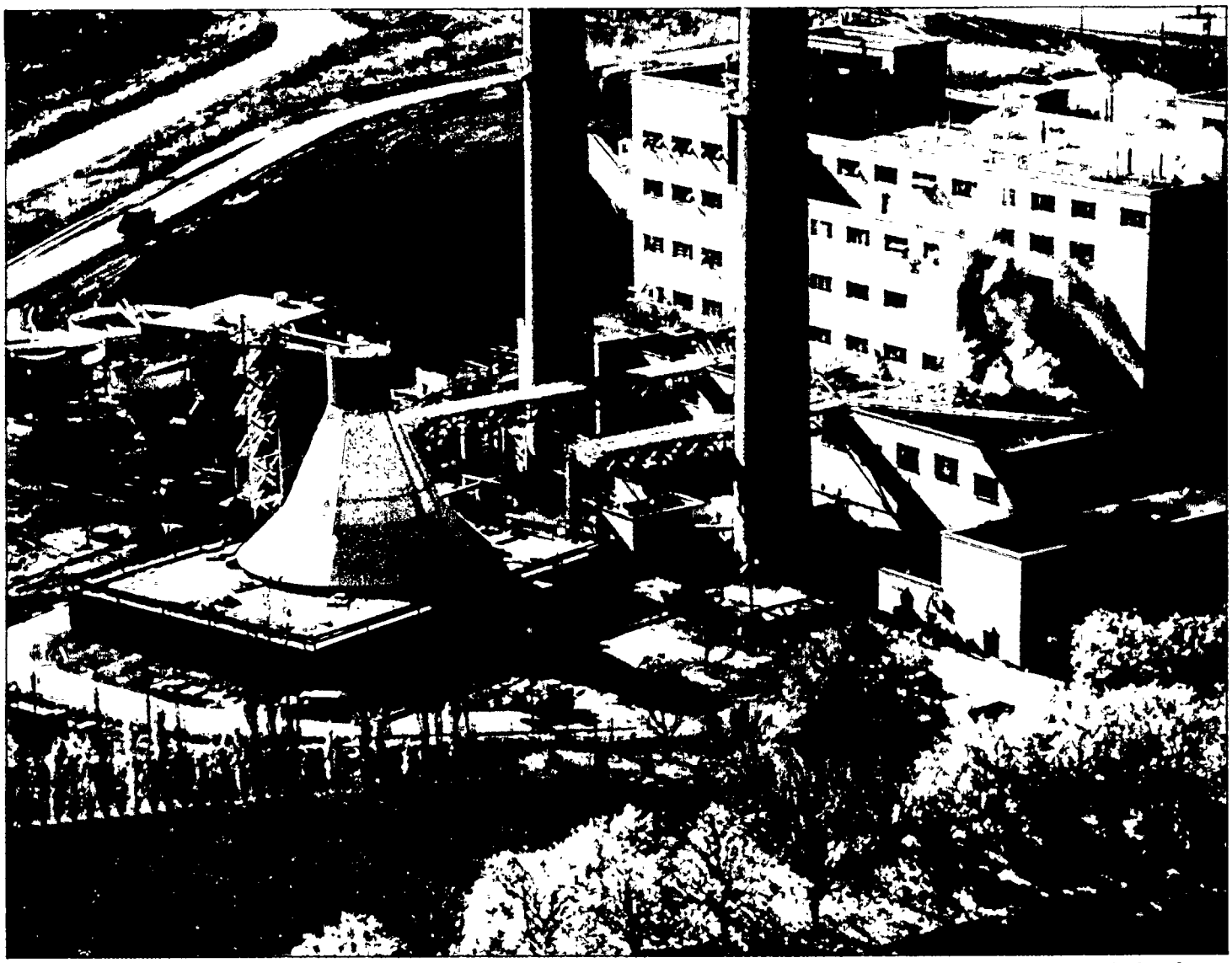
Refuse derived fuel offsets coal in Russell Station's boilers.

With the completion of the receiving station and conversion of the boilers at Russell Station, a full-scale, year-long test was begun in January 1982.

The arrangement between the County and RG&E permits the County to sell RDF to RG&E at a cost based on the market price of an equivalent amount of coal based on heat value. A pound of RDF can produce about 40 percent of the thermal yield of a pound of coal. In other words, the purchase of RDF from the County will not add to the customers' fuel costs, but will create a permanent market for the County's fuel product and an additional source of revenue for the County that can help reduce the taxpayer expense for operating the waste recycling facility.

The total cost of the installations at Russell Station is $15 million, with the County paying for the $12-million receiving facilities. Boiler conversion costs were paid by RG&E, but will be recovered over the term of the contract as the program goes into full swing late this year.

It's projected that RG&E will be able to reduce its coal requirements at Russell Station by up to 15 percent when the RDF program is fully operational. At the same time, Monroe County realizes revenue from the RDF that would otherwise have to be landfilled, and there is no effect on energy costs for RG&E customers. If successful, the RDF system will provide benefits for the community and for the interest of fuel conservation while costing RG&E customers and shareholders nothing. □



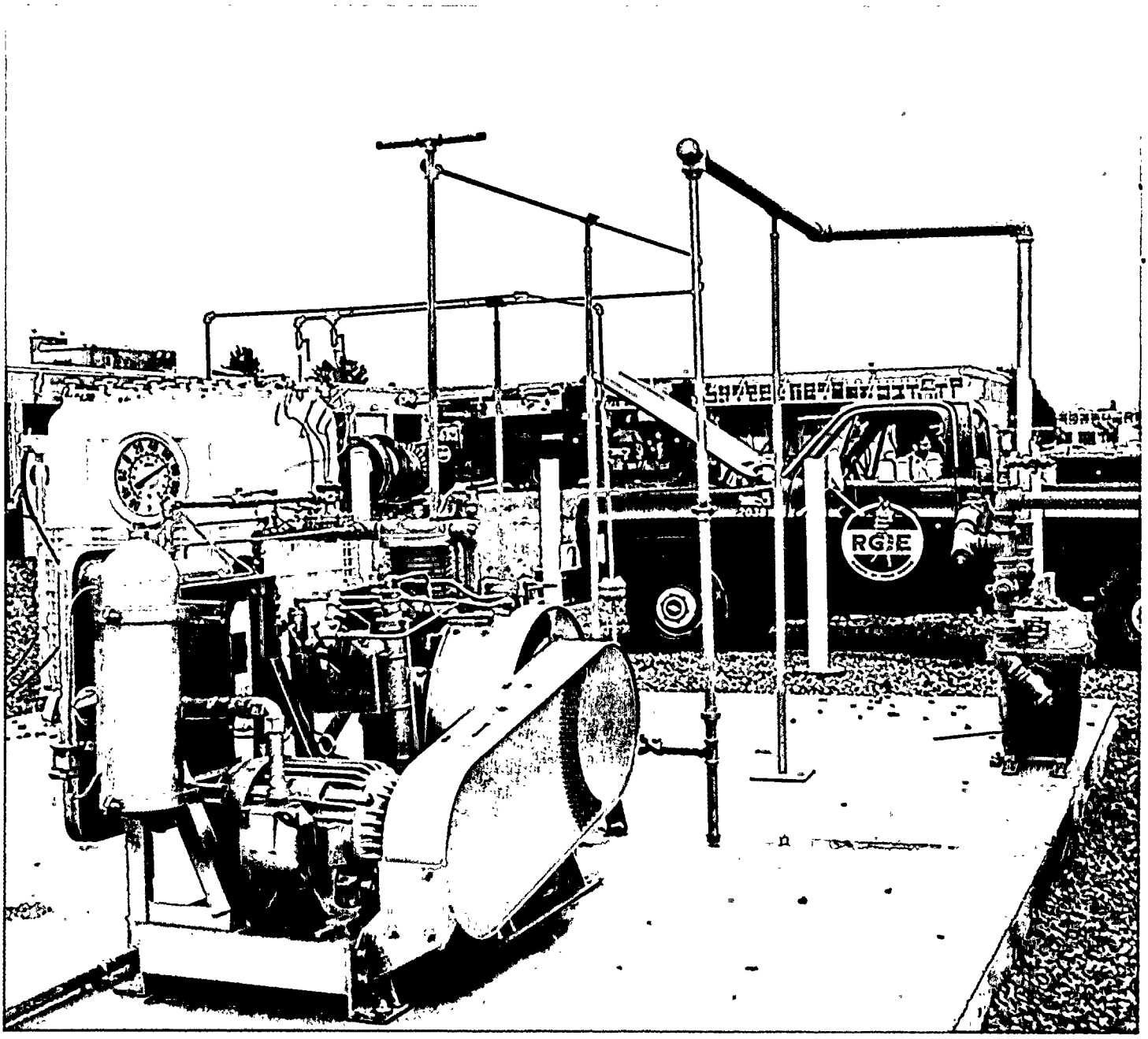
Seen from the air, the new silo in the foreground is part of the major modifications at the 34-year-old coal-fired station that allow the burning of RDF.

In 1981 RG&E launched a program to convert a number of its fleet vehicles to operate on compressed natural gas (CNG). In the test program 20 vehicles ranging from sedans to service trucks were modified to run on CNG, or methane, with the option to switch to normal gasoline fuel during operation.

In the conversion test project, standard vehicle engines were equipped with special air cleaners, fueling connections and compressed gas tanks. The conversion work was accomplished by RG&E mechanics, and a CNG fueling station was constructed at the company's Operations Center where vehicles can get a quick fill in five minutes at high pressure or an overnight fill at lower pressure.

Although the concept of CNG-fueled vehicles is not new, RG&E's experiment is expected to be successful due to the economy of CNG over higher-priced gasoline. The vehicles are getting about the same mileage from 120 cubic feet of CNG as they do from a gallon of gasoline. The RG&E cost for 120 cubic feet of CNG is currently 52 cents, compared with the average cost of a gallon of gasoline to the company of $1.30; and RG&E uses more than 800,000 gallons a year.

Besides the saving in operating



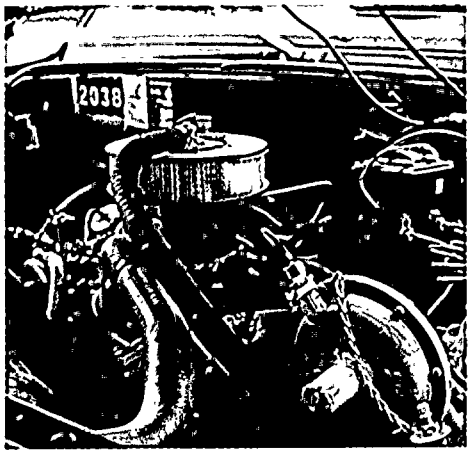
This "gas" station at RG&E's Operations Center fills experimental vehicles that can run on natural gas as well as gasoline.

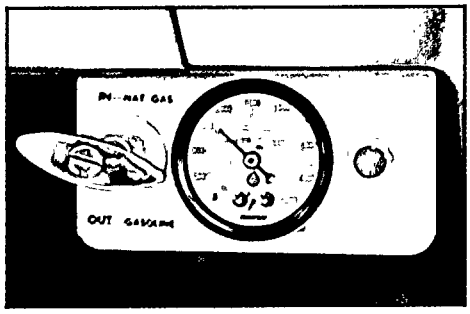
expenses, CNG has a number of side benefits. It's found, for example, that CNG significantly reduces exhaust emissions. National tests over the last 11 years on methane-fueled vehicles show that CNG produces 68 percent less hydrocarbon emissions than gasoline, 79 percent less carbon monoxide and 65 percent less nitrogen oxide. The federal Environmental Protection Agency has confirmed that CNG-fuel does not contribute to the formation of smog. There has also been evidence that engine maintenance is less costly since CNG burns cleaner than gasoline and cuts down on deposits that can foul engines.

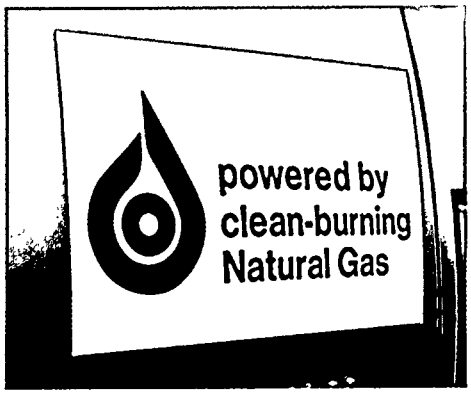
RG&E thinks there may be a future in the use of compressed natural gas as automotive fuel. Certainly, natural gas is a domestic resource that the nation can use, without relying on foreign oil. RG&E will probably convert more of its fleet vehicles if the experiment proves to be as successful as anticipated.

RG&E is sharing its CNG test program ideas and results with customers in its franchise area. There has been a good deal of interest among RG&E customers who operate automotive fleets. The day may come when CNG stations are as commonplace as gasoline stations. □

Onlookers view a vehicle engine that has been modified to run on compressed natural gas.







Top—a modified engine.
Middle—A "gas" gauge.
Bottom—A decal decorates RG&E's modified vehicles.

SALES/Electric

Kilowatt-hour sales of electricity to customers in 1981 increased 2.5 percent over 1980 sales and ran 1.7 percent ahead of forecast. This represented the best year of electric growth since 1978 and is primarily attributed to a recovery from the 1980 recession.

Electric kilowatt-hour sales to residential customers were up 1.3 percent and resulted mainly from colder-than-normal weather and the addition of new customers. Commercial kilowatt-hour sales gained 1.8 percent over the previous year and, again, were largely a result of colder-than-normal weather and new customers. Electric kilowatt-hour sales to industrial customers showed the most significant gain with a 5.6 percent increase. The sharp rise was a result of a recovery from the 1980 recessionary economic climate.

In 1982, RG&E estimates the electric kilowatt-hour use by its customers will rise by 2.3 percent, and the company has adequate capacity to meet the anticipated growth.

Revenues from sales of electricity to other utilities in 1981 were $54.3 million. These sales to other utilities were made possible mainly through the high level of availability of our Ginna nuclear power plant which economically supplied more than half the electric requirements on RG&E's system. In 1981, the Ginna plant was available 82 percent of the time, exceeding the national average for nuclear power plants.

Excess electric generation is sold to other utilities through the New York Power Pool, an association of investor-owned power companies in New York State and the New York State Power Authority. Earnings from the sales to other utilities are used to reduce bills to our electric customers. In 1981, this reduction amounted to $23.7 million.

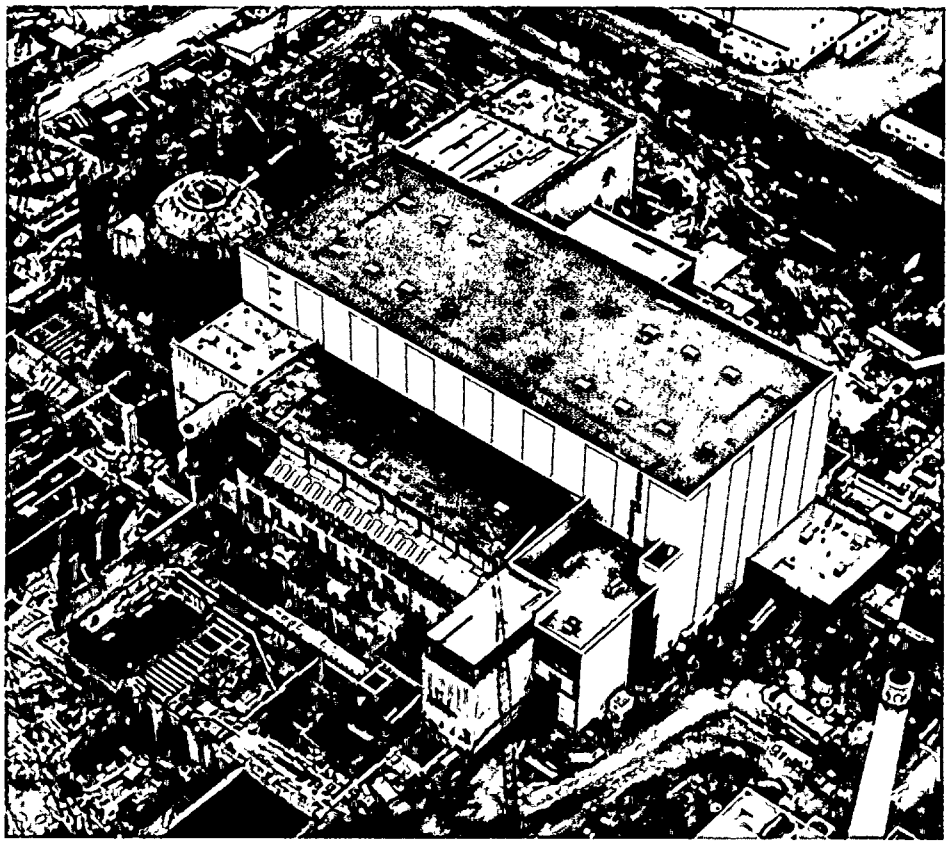
The Ginna nuclear power plant also saved electric customers more than $40 million in fuel costs as compared with an equivalent amount of electricity generated using coal as fuel. When compared with what it would have cost to generate the electricity with oil fuel, the saving to our customers is more than $120 million. Over its 12-year operating history, the Ginna plant has saved RG&E electric customers more than $275 million in fuel costs compared with coal.

SALES/Gas

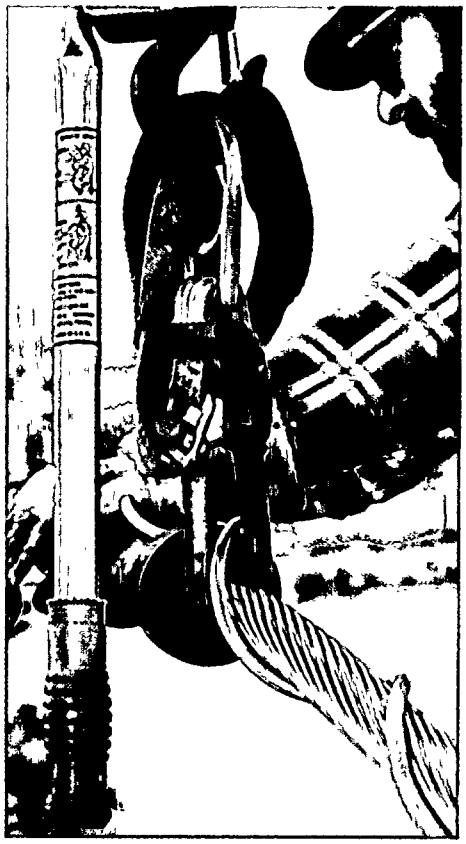
Sales of natural gas in therms increased 10.4 percent in 1981 and were slightly over forecast. The increase is attributed mainly to the addition of 10,000 gas customers through the acquisition of Pavilion Natural Gas Company, greater gas use in industrial and food processing applications, and commercial space heating conversions to natural gas.

Residential gas sales rose 1.1 percent, excluding the effect of the Pavilion acquisition. This relatively small gain in residential sales was a result of continuing conservation efforts which, in 1981, virtually offset the effect of adding 4,900 gas space heating customers to our system.

Commercial gas sales in therms were



An aerial photo taken in late 1981 shows work completed on the Nine Mile Point #2 nuclear power plant in which RG&E has a 14 percent share.



Atop a high-voltage transmission tower, an RG&E lineman secures a 115,000-volt cable.

up 5.0 percent for the year and is a result of conversions to gas for space heating. Industrial gas sales rose sharply by 9.0 percent as a result of the application of gas to industrial operations and food processing. These increases also exclude the effect of the Pavilion acquisition.

In 1982, therm sales of natural gas are expected to rise 4.5 percent. RG&E's supply of natural gas is adequate to meet the anticipated demands.

CONSTRUCTION/Electric

Engineering and construction work continues on RG&E's long-range project that will upgrade electric capacity in the Genesee Valley District to the south of Rochester. More than 248 miles of distribution lines in that area have been upgraded to 34,500 volts, representing half of the total construction work for the project which is expected to be completed in 1987.

In the Lake Shore District, more than half of the 12.2-mile stretch of the new 115,000 volt transmission line has been constructed extending east toward Sodus, New York. The project is designed to supply growing electric load in that district east of Rochester. Work is expected to be completed in September 1982.

CONSTRUCTION/Gas

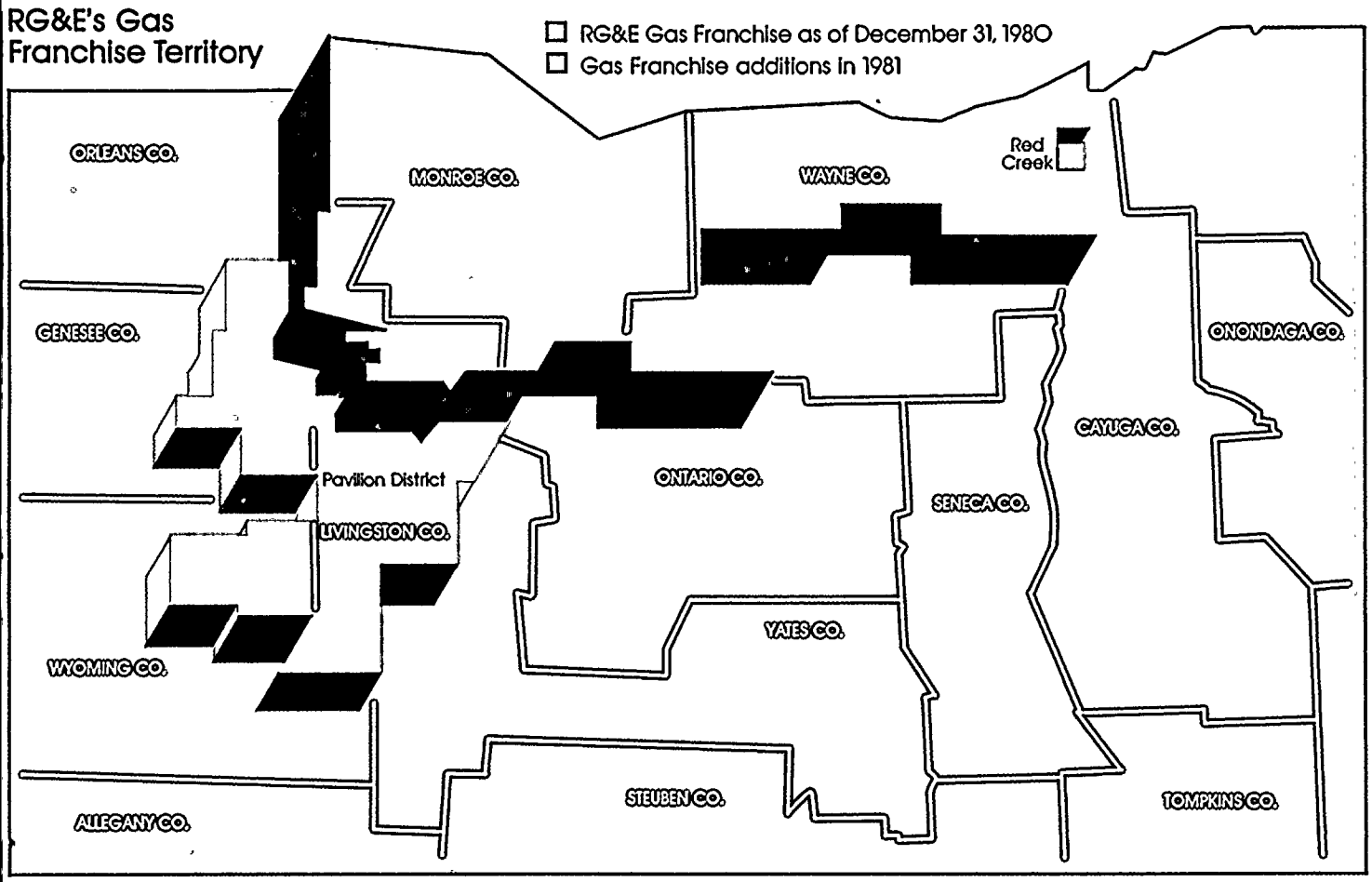
In 1981 construction work was undertaken to increase the capacity of gas delivery in the Pavilion District which was acquired by RG&E. As a result we have already gained 50 additional customers in that district.

RG&E applied for and was granted the gas franchise for the Village of Red Creek in the Lake Shore District. To accommodate new residential and commercial gas customers and a food processing plant in the Village, a six-inch gas main was constructed a distance of 6¼ miles. The construction costs in this project were $565,000, and additional annual revenue from new customers there is estimated at $550,000.

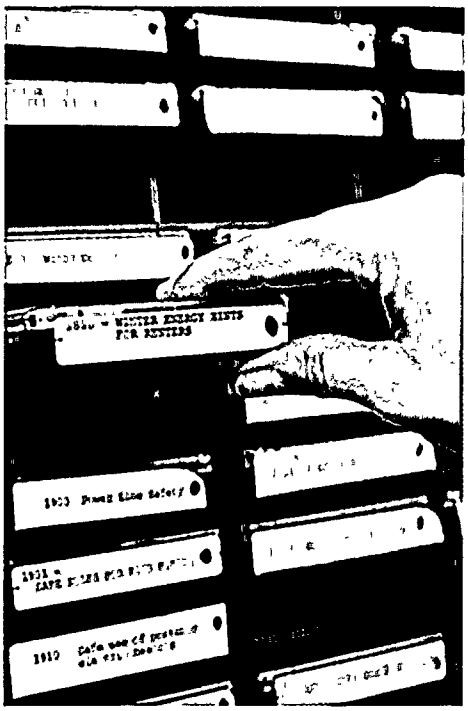
CONSTRUCTION/Steam

A reliance on expensive fuel oil in the production of steam for steam customers, and a decrease in the number of steam customers have resulted in significant increases to customer costs for steam. In an effort to help hold the line on rising costs and retain and even attract steam customers, RG&E converted boilers at Station #9 and at Beebee Station to accept natural gas as boiler fuel.

The cost of the conversions is being recovered by retaining a portion of the fuel saving. The remaining saving is passed on to steam customers as a reduction in fuel cost adjustment charges. A proposal for a long-range plan through 1985 is under consideration that would call for a further modification of steam boilers to accept economical coal as a fuel, as well as gas and oil. The flexibility could allow RG&E to maximize economies in the cost of boiler fuel and help keep steam prices in check. ◻



Above—The Ask RG&E operator draws a request tape for one of the hundreds of customers who call for information on a wide variety of subjects.
Below—More than 60 subjects are available through Ask RG&E, with more to come.



RG&E gets nearly two million phone calls a year from customers. While most of the calls deal with individual customer matters such as service transfers or questions about bills or payment arrangements, there are a number of calls that are more general in nature. Calls regarding energy conservation, nuclear power, rate increases, safety, government regulations, energy audits and home energy management are quite common.

It was thought that some of the more frequently-asked questions could be answered by a prerecorded audio tape system. This could provide the information more quickly and also relieve some of the heavy phone traffic on the system, allowing customer service representatives to better concentrate on the individual customer queries that need specific attention.

RG&E looked into the possibility of a taped message system and, in 1981, initiated its customer service known as ASK RG&E. Customers with a question relating to any of the more than 60 subjects available on prerecorded tapes at RG&E's telephone service center simply call the advertised phone number and ask for the specific tape by number or topic. The RG&E operator then inserts the tape into the multiplex playback system and the customer hears the recording.

The ASK RG&E customer program has been getting a good workout with more than 100 calls a day on the average. And, in an effort to assist customers further, the ASK RG&E system was expanded to accommodate tapes prepared by the not-for-profit Monroe County Cooperative Extension Association on a wider range of subjects dealing with home economics, general consumer information and horticulture. □

Table of Contents

STATEMENT OF INCOME

(Thousands of Dollars) Year Ended December 31	1981	1980	1979
Operating Revenues (Note 1)			
Electric	$320,325	$245,005	$219,373
Gas	212,553	181,046	140,527
Steam	26,361	23,589	19,988
	559,239	449,640	379,888
Electric sales to other utilities	54,302	52,786	37,804
Total Operating Revenues	613,541	502,426	417,692
Operating Expenses (Note 1)			
Operation			
Electric and steam fuels	94,148	86,622	62,109
Purchased electricity	26,886	23,796	31,937
Deferred fuel—electric and steam	11,408	(6,911)	(1,038)
Purchased natural gas	138,084	127,759	89,804
Other	106,514	81,960	72,264
Maintenance	36,981	32,048	30,129
Depreciation	32,877	27,800	23,703
Taxes—local, state and other	68,261	56,984	49,916
Federal income tax—current (Note 2)	6,770	393	(36)
—deferred (Note 2)	11,810	12,443	6,782
Total Operating Expenses	533,739	442,894	365,570
Operating Income	79,802	59,532	52,122
Other Income and Deductions			
Allowance for other funds used during construction (Note 1)	13,704	11,710	11,439
Other, net	6,862	4,772	3,774
Total Other Income and Deductions	20,566	16,482	15,213
Income Before Interest Charges	100,368	76,014	67,335
Interest Charges			
Long term debt	38,020	34,129	29,084
Short term debt	2,594	4,298	4,016
Other, net	1,410	755	441
Allowance for borrowed funds used during construction (Note 1)	(7,406)	(6,820)	(5,771)
Total Interest Charges	34,618	32,362	27,770
Net Income	65,750	43,652	39,565
Dividends on Preferred and Preference Stock, at required rates	10,538	8,927	6,645
Earnings Applicable to Common Stock	$ 55,212	$ 34,725	$ 32,920
Weighted average number of shares outstanding in each period, adjusted for stock dividends (000's)	18,826	16,966	16,289
Earnings per Common Share (Note 1)	$2.93	$2.04	$2.02
Cash Dividends per Common Share, adjusted for stock dividends (Note 1)	$1.53	$1.44	$1.37

STATEMENT OF RETAINED EARNINGS

(Thousands of Dollars) Year Ended December 31	1981	1980	1979
Balance at beginning of period	$ 83,970	$ 80,155	$ 77,338
Effect of merger with Pavilion Natural Gas Co. (Note 1)	1,229		
Add			
Net income	65,750	43,652	39,565
Total	150,949	123,807	116,903
Deduct			
Dividends on capital stock			
Cumulative preferred stock, at required rates (Notes 5 and 6)	8,410	6,799	4,517
Preference stock (Notes 5 and 6)	2,128	2,128	2,128
Common stock			
Cash (Note 1)	28,594	23,910	22,148
Stock (Note 5)	6,985	7,000	7,955
Total	46,117	39,837	36,748
Balance at end of period	$104,832	$ 83,970	$ 80,155

BALANCE SHEET

(Thousands of Dollars) At December 31	1981	1980
ASSETS		
Utility Plant, at original cost (Note 1)		
Electric	$ 914,479	$ 849,946
Gas	207,501	193,863
Steam	18,068	18,190
	1,140,048	1,061,999
Less: Accumulated depreciation and amortization	389,422	337,215
	750,626	724,784
Construction work in progress	280,567	225,690
Net Utility Plant	1,031,193	950,474
Investment in Subsidiary, at equity (Note 1)		1,968
Current Assets		
Cash	1,375	4,225
Accounts receivable	65,384	55,659
Materials and supplies, at average cost		
Fossil fuel	26,085	18,891
Construction and other supplies	9,931	12,230
Prepayments	3,175	1,309
Total Current Assets	105,950	92,314
Deferred Debits		
Unamortized debt expense	5,222	4,511
Deferred fuel cost (Note 1)	3,190	14,697
Other	17,435	11,416
Total Deferred Debits	25,847	30,624
Total Assets	$1,162,990	$1,075,380
CAPITALIZATION AND LIABILITIES		
Capitalization		
Long term debt (Note 4)	$ 480,508	$ 437,124
Preferred stock redeemable at option of Company (Note 5)	67,000	67,000
Preferred stock subject to mandatory redemption (Note 6)	50,000	50,000
Preference stock subject to mandatory redemption (Note 6)	28,000	28,000
Common shareholders' equity		
Common stock (Note 5)	303,793	291,346
Retained earnings	104,832	83,970
Total Common Shareholders' Equity	408,625	375,316
Total Capitalization	1,034,133	957,440
Current Liabilities		
Short term debt (Note 7)		25,300
Long term debt due within one year	6,000	
Accounts payable	41,047	32,977
Taxes accrued, including income taxes	3,340	10,199
Interest accrued	13,980	9,959
Payroll accrued	3,593	2,991
Customer advances for service	3,780	2,573
Other	1,623	1,511
Total Current Liabilities	73,363	85,510
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes (Notes 1 and 2)	34,294	28,070
Gas supplier refunds due customers	16,349	3,976
Other	4,851	384
Total Deferred Credits and Other Liabilities	55,494	32,430
Commitments and Other Matters (Note 9)		
Total Capitalization and Liabilities	$1,162,990	$1,075,380

STATEMENT OF CHANGES IN FINANCIAL POSITION

(Thousands of Dollars) Year Ended December 31	1981	1980	1979
Sources of Funds			
Operations			
Net income	$ 65,750	$ 43,652	$ 39,565
Principal non-cash charges (credits) to income			
Depreciation	32,877	27,800	23,703
Amortization of nuclear fuel	23,821	20,789	17,126
Deferred fuel—electric and steam	11,408	(6,911)	(1,038)
Deferred income taxes, net	6,112	6,927	2,596
Allowance for funds used during construction	(21,110)	(18,530)	(17,210)
Other, net	8,806	4,550	(1,754)
Total from Operations	127,664	78,277	62,988
Financing			
Sale of long term debt	50,000	55,000	10,000
Sale of common stock	6,136	25,257	6,083
Sale of preferred stock		25,000	25,000
Proceeds from short term debt, net			50,000
Total from Financing	56,136	105,257	91,083
Pavilion merger	1,609		
Total Sources of Funds	$185,409	$183,534	$154,071
Uses of Funds			
Utility plant			
Plant additions	$123,967	$ 97,600	$109,656
Nuclear fuel additions	14,907	8,672	18,981
Less: Allowance for funds used during construction	21,110	18,530	17,210
Additions to Utility Plant	117,764	87,742	111,427
Dividends on preferred stock	8,410	6,799	4,517
Dividends on preference stock	2,128	2,128	2,128
Dividends on common stock	28,594	23,910	22,148
Reduction of short term debt, net	25,300	24,700	
Retirement of long term debt	6,000		12,000
Capital stock expense	225	1,343	544
Discount and expense of issuing long term debt	1,626	858	635
Other, net	(5,121)	3,896	(683)
Increase in working capital (excluding short term debt)	483	32,158	1,355
Total Uses of Funds	$185,409	$183,534	$154,071
Changes in Components of Working Capital			
Increase (decrease) in current assets			
Cash	$ (2,850)	$ 1,300	$ (8,852)
Accounts receivable	9,725	17,974	5,985
Materials and supplies			
Fossil fuel	7,194	6,274	(56)
Construction and other supplies	(2,299)	1,470	1,117
Prepayments	1,866	59	90
Total	13,636	27,077	(1,716)
Increase (decrease) in current liabilities (excluding short term debt)			
Accounts payable	8,070	749	3,207
Taxes	(6,859)	1,745	(2,881)
Accrued interest and payroll	4,623	1,574	1,113
Long term debt due within one year	6,000	(12,000)	(4,677)
Other, net	1,319	2,851	167
Total	13,153	(5,081)	(3,071)
Increase in working capital (excluding short term debt)	$ 483	$ 32,158	$ 1,355

Note 1.

Summary of Accounting Policies

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

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

Rates and Revenue. Revenue is recorded on the basis of meters read during the calendar year.

Tariffs for electric and steam service include fuel cost adjustment clauses, which serve to adjust electric and steam rates monthly to reflect changes in the average cost of fuels used in electric and steam generation from the average cost of such fuels during the base period. Tariffs for gas service contain a comparable clause to adjust gas rates for changes in the price of purchased natural gas.

Deferred Fuel Costs. Fuel costs which are recoverable under the electric, gas and steam cost adjustment clauses included in the tariff schedules of the Company are deferred until they are billed to customers. A reconciliation of recoverable gas costs with billed gas revenues is done annually as of August 31, and the excess or deficiency is refunded to or recovered from the customers during a subsequent twelve month period.

Utility Plant and Depreciation. 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 for engineering, supervision, etc. The Company capitalizes an allowance for funds used during construction approximately equivalent to the cost of capital devoted to plant under construction. 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 accumulated depreciation and amortization.

Depreciation in the financial statements is provided on a straight line basis at rates based on the estimated useful lives of property, which have resulted in provisions of 3.2% per annum of average depreciable property in 1981 and 3.1% per annum in 1980 and 1979.

Nuclear Fuel and Decommissioning Costs. The cost of nuclear fuel and estimated permanent storage costs of spent nuclear fuel are charged to operating expense on the basis of the thermal output of the reactor. These costs are charged to customers through the fuel cost adjustment clause and base rates.

Due to a Federal government policy adopted in 1977, the Company changed its nuclear fuel cost computation to reflect the costs of permanent storage of spent nuclear fuel. Prior years' nuclear fuel cost computations had anticipated that spent nuclear fuel would be reprocessed. Cumulative prior years' fuel expenses for regions of fuel, which have been discharged from the reactor core, would have been increased by approximately $23.9 million if they had been determined on the basis of current cost estimates for permanent storage of spent nuclear fuel. Commencing in August of 1980, the PSC permitted the amortization and recovery of approximately $12 million of such additional costs through rates over a 10 year period. In a petition presently under consideration by the PSC, the Company has requested recovery of the balance of the additional costs over an 8 year period.

Decommissioning costs (costs to take the plant out of service in the future) for the Company's Ginna nuclear power plant are estimated by the Company to be approximately $150 million in the year 2006 when decommissioning is expected to commence. In August 1980, the Company began accruing these costs over the remaining life of the facility at an initial rate of $3.1 million per year. These accruals are included in base rates.

Allowance for Funds Used During Construction. The Company capitalizes an Allowance for Funds Used During Construction (AFDC) based upon the net cost of borrowed funds for construction purposes and a reasonable rate upon the Company's other funds when so used. The rates used for this purpose were 11.3%, 10.5% and 9.5% in 1981, 1980 and 1979, respectively. As of January 1982, the rate is 12.25%. In accordance with an order issued by the FERC, AFDC is segregated into two components and classified in the Statement of Income as Allowance for Borrowed Funds Used During Construction, an offset to Interest Charges, and Allowance for Other Funds Used During Construction, a part of Other Income.

Since December 1977, the Company has computed AFDC on its share of the Niagara Mohawk Power Corporation Nine Mile Point Nuclear Unit #2 and Oswego Fossil Unit #6 (until its July 1980 in-service date) at an average reduced rate which is net of the income tax effect of the interest portion of AFDC. Since May 1979, this treatment has also been applied to the Company's investment in its Sterling project. (See Note 9.) The rates for 1981, 1980 and 1979 were 8.66%, 8.0% and 7.51%, respectively.

Federal Income Tax. For income tax purposes, depreciation is computed using the most liberal methods permitted. In addition, certain costs capitalized for financial reporting purposes are deducted currently for income tax purposes. The resulting tax reductions are offset by provisions for deferred income taxes only to the extent ordered or permitted by regulatory authorities.

Investment tax credits are available at a rate of 10% of eligible property additions. As recommended by the PSC, a 4% investment tax credit rate is applied to reduce the current tax provision, while deferred tax accounting is followed in the application of the remaining 6% investment tax credit rate.

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

Pension Plan. The Company's retirement plan is noncontributory and covers all regular employees. Expenditures made by the Company to the retirement plan for the years 1981, 1980 and 1979 were $12.6 million, $11.4 million and $10.6 million, respectively, which includes amortization for: past service costs over 40 years, changes in the plan over 30 years, and experience gains or losses over 15 years. In 1981, a change in disability provisions decreased the pension expenditures by approximately $342,200; whereas changes in actuarial assumptions increased the pension expenditures by approximately $534,700. The actuarial methods and the accounting policy used to determine Company expenditures were the same each year. A comparison of accumulated plan benefits and plan net assets is presented below.

	(Thousands)	
	1981(a)	January 1 1980
Actuarial present value of accumulated plan benefits:		
Vested	$105,594	$107,486
Nonvested ..	3,415	8,885
	$109,009	$116,371
Market value of assets available for benefits ...	$120,520	$ 94,499

(a) Most recent available data

The actuarially assumed rate of return on the plan investments, used in determining the actuarial present value of accumulated plan benefits, was 8% in 1981 and 6% in 1980. The present

Note 1. (Continued)

value of accrued benefits was decreased $15.6 million and $2.0 million by the changes in the actuarial assumptions and the elimination of the immediate disability benefits, respectively.

Earnings and Dividends Per Share. Earnings applicable to each share of common stock are based on the weighted average number of shares outstanding during the respective years, adjusted for stock dividends. Cash dividends per share, as shown on page 18, are based on the shares outstanding at the time dividends are paid, adjusted for stock dividends. Cash dividends per share at the rates declared in each period were $1.54 for 1981, $1.49 for 1980 and $1.46 for 1979.

Pavilion Natural Gas Company. The Pavilion Natural Gas Company (Pavilion) merged with the Company on February 28, 1981, at which time 97,983 additional shares of common stock were issued in exchange for the common stock of Pavilion. The merger was accounted for as a pooling of interests. The 1981 financial statements include Pavilion operations for January and February 1981, which increased operating revenues by $3.4 million and net income by $.4 million ($.02 per share). The effect on reported operating revenues, net income and earnings per share for prior years was immaterial and the financial statements for these years have not been restated. Accordingly, the net assets of Pavilion as of January 1, 1981 are reported as an addition to retained earnings.

Investment in Subsidiary Company. In 1981 the Company transferred the net assets of its subsidiary, Canadea Power Corporation, to the Rushford Lake Recreation District as approved by the PSC. The effect on the financial statements of the Company was immaterial. □

Note 2.

Federal Income Taxes (Thousands of Dollars)

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. At the right is a summary of income tax expense for the three most recent years.

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

	1981	1980	1979
Charged to operating expense:			
Current	$ 6,770	$ 393	$ (36)
Deferred	11,810	12,443	6,782
Total	18,580	12,836	6,746
Credited to other income:			
Current	(3,349)	(393)	(321)
Deferred	(5,698)	(5,516)	(4,186)
Total	(9,047)	(5,909)	(4,507)
Total Federal income tax expense	$ 9,533	$ 6,927	$2,239

	1981		1980		1979	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
Net income	$65,750		$43,652		$39,565	
Add: Federal income tax expense	9,533		6,927		2,239	
Income before Federal income tax	$75,283		$50,579		$41,804	
Computed tax expense	$34,630	46.0	$23,266	46.0	$19,230	46.0
Increases (decreases) in tax resulting from:						
Excess of tax depreciation less amount deferred	(3,981)	(5.3)	(4,501)	(8.9)	(4,145)	(9.9)
Expenses capitalized for financial reporting purposes, including interest, payroll and use taxes, etc.	(12,424)	(16.5)	(11,232)	(22.2)	(10,763)	(25.7)
Investment tax credit	(5,813)	(7.7)	(458)	(.9)	(579)	(1.4)
Property taxes on basis of date of taxable status	(782)	(1.0)	(1,310)	(2.6)	(698)	(1.7)
Revenue taxes (deducted when paid)	(1,423)	(1.9)	866	1.7	381	.9
Miscellaneous items, net	(674)	(.9)	296	.6	(1,187)	(2.8)
Total Federal income tax expense	$ 9,533	12.7	$ 6,927	13.7	$ 2,239	5.4

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

	1981	1980	1979
Investment tax credit	$ 7,196	$ (458)	$ (222)
Class life depreciation	2,981	2,446	2,076
Fuel costs	(5,834)	2,195	2,108
Nuclear fuel storage costs	(3,176)	(2,808)	(2,672)
Sterling abandonment	5,817	4,656	
Other	(872)	896	1,306
Total	$ 6,112	$ 6,927	$ 2,596

At December 31, 1981, the Company had approximately $11.2 million of investment tax credits for both financial reporting and tax purposes that are available to be carried forward. Such credits must be utilized within 15 years. □

Note 3.

Departmental Financial Information (Thousands of Dollars)

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

	Electric	Gas	Steam	Total
Operating information—1981				
Operating revenues	$374,627	$212,553	$26,361	$ 613,541
Operating expenses, excluding provision for income taxes	304,624	187,110	23,425	515,159
Pretax operating income	70,003	25,443	2,936	98,382
Provision for income taxes	11,407	6,099	1,074	18,580
Net operating income	$ 58,596	$ 19,344	$ 1,862	79,802
Other income, net				20,566
Interest charges				34,618
Net income per statement of income				$ 65,750
Other information				
Depreciation	$ 26,281	$ 5,981	$ 615	$ 32,877
Nuclear fuel amortization	$ 23,821			$ 23,821
Capital expenditures	$103,536	$ 14,198	$ 30	$ 117,764
Investment information—December 31, 1981				
Identifiable assets	$945,977	$188,604	$16,416	$1,150,997
Assets utilized for overall Company operations (a)				11,993
Total assets per balance sheet				$1,162,990
Operating information—1980				
Operating revenues	$297,791	$181,046	$23,589	$ 502,426
Operating expenses, excluding provision for income taxes	237,142	170,546	22,370	430,058
Pretax operating income	60,649	10,500	1,219	72,368
Provision for income taxes	11,169	1,310	357	12,836
Net operating income	$ 49,480	$ 9,190	$ 862	59,532
Other income, net				16,482
Interest charges				32,362
Net income per statement of income				$ 43,652
Other information				
Depreciation	$ 21,859	$ 5,337	$ 604	$ 27,800
Nuclear fuel amortization	$ 20,789			$ 20,789
Capital expenditures	$ 75,080	$ 11,966	$ 696	$ 87,742
Investment information—December 31, 1980				
Identifiable assets	$870,603	$176,335	$16,439	$1,063,377
Assets utilized for overall Company operations (a)				12,003
Total assets per balance sheet				$1,075,380
Operating information—1979				
Operating revenues	$257,177	$140,527	$19,988	$ 417,692
Operating expenses, excluding provision for income taxes	209,283	129,645	19,896	358,824
Pretax operating income	47,894	10,882	92	58,868
Provision for income taxes	5,600	1,314	(168)	6,746
Net operating income	$ 42,294	$ 9,568	$ 260	52,122
Other income, net				15,213
Interest charges				27,770
Net income per statement of income				$ 39,565
Other information				
Depreciation	$ 18,224	$ 4,888	$ 591	$ 23,703
Nuclear fuel amortization	$ 17,126			$ 17,126
Capital expenditures	$ 97,577	$ 13,434	$ 416	$ 111,427
Investment information—December 31, 1979				
Identifiable assets	$789,832	$166,274	$16,415	$ 972,521
Assets utilized for overall Company operations (a)				10,329
Total assets per balance sheet				$ 982,850

(a) Consists primarily of cash, prepayments and unamortized debt expense

Note 4.
Long Term Debt

First Mortgage Bonds %	Series	Due	(Thousands) Principal Amount December 31 1981	1980
3⅜	N	June 1, 1982	$ 6,000	$ 6,000
3⅜	O	Mar. 1, 1985	10,000	10,000
4⅞	R	July 1, 1987	15,000	15,000
5	S	Oct. 15, 1989	12,000	12,000
4½	T	Nov. 15, 1991	15,000	15,000
4⅝	U	Sept. 15, 1994	16,000	16,000
5.3	V	May 1, 1996	18,000	18,000
6¼	W	Sept. 15, 1997	20,000	20,000
6.7	X	July 1, 1998	30,000	30,000
8	Y	Aug. 15, 1999	30,000	30,000
9⅛	Z	Sept. 1, 2000	30,000	30,000
10¾	AA	Aug. 1, 1983	29,667	29,667
9¼	BB	June 15, 2006	50,000	50,000
8⅜	CC	Sept. 15, 2007	50,000	50,000
9½	DD	Dec. 1, 2003	40,000	40,000
6½	EE	Aug. 1, 2009	10,000	10,000
10.95	FF	Feb. 15, 2005	55,000	55,000
16¾	GG	Aug. 15, 1991	50,000	
			486,667	436,667
Net bond premium (discount)			(159)	457
Less: Due within one year			6,000	
Total Long Term Debt			$480,508	$437,124

The 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. Such requirements may be met by certification of additional property or by depositing cash with the Trustee. The 1981 and 1980 requirements were met by certification of additional property.

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

The Series FF bonds are subject to a mandatory sinking fund of $2.8 million annually beginning February 15, 1986 and each February 15 thereafter, with the noncumulative option to double the payment in any year up to a maximum of 5 years.

The bonds maturing in the next five years total $6 million in 1982 for Series N, $29.7 million in 1983 for Series AA and $10 million in 1985 for Series O. The maximum sinking fund requirement for the next five years is $2.8 million in 1986 for Series FF. □

Note 5.
Capital Stock

Type, by Order of Seniority	Par Value	Shares Authorized	Shares Outstanding
Preferred Stock (cumulative)	$100	2,000,000	1,170,000*
Preferred Stock (cumulative)	25	4,000,000	
Preference Stock	1	5,000,000	280,000*
Common Stock	5	25,000,000	19,039,909

Preferred Stock, not subject to mandatory redemption:

%	Series	Shares Outstanding	(Thousands) December 31 1981	1980	Redemption (per share) ✓	
4	F	120,000	$12,000	$12,000	105	At any time
4.10	H	80,000	8,000	8,000	101	At any time
4¾	I	60,000	6,000	6,000	101	At any time
4.10	J	50,000	5,000	5,000	102.5	At any time
4.95	K	60,000	6,000	6,000	102	At any time
4.55	M	100,000	10,000	10,000	101	At any time
7.50	N	200,000	20,000	20,000	106	Before 6/1/82†
		670,000	$67,000	$67,000		

Common Stock:	Per Share	Shares Outstanding	(Thousands) Amount
Outstanding, January 1, 1979		14,732,747	$246,938
3% Stock Dividend	$18.00	441,983	7,955
Automatic Dividend Reinvestment Plan	14.81-17.25	309,747	4,967
TRASOP††	15.86	70,384	1,116
Capital Stock Expense			(544)
Outstanding, December 31, 1979		15,554,861	260,432
3% Stock Dividend	15.00	466,646	7,000
Sale of Stock	13.25	1,500,000	19,875
Automatic Dividend Reinvestment Plan	13.50-14.25	388,038	5,382
Capital Stock Expense			(1,343)
Outstanding, December 31, 1980		17,909,545	291,346
3% Stock Dividend	13.00	537,287	6,985
Pavilion Merger		97,983	380
Canadea Divestiture			(829)
Automatic Dividend Reinvestment Plan	12.187-12.75	495,094	6,136
Capital Stock Expense			(225)
Outstanding, December 31, 1981		19,039,909	$303,793

*See Note 6 for mandatory redemption.
✓ Redeemable at the option of the Company on 30 days minimum notice, plus accrued dividends in all cases.
† Thereafter at lesser rates.
†† Tax Reduction Act Stock Ownership Plan.

At December 31, 1981 there were 622,918 shares of common stock reserved and unissued under the Automatic Dividend Reinvestment Plan. No other shares of common, preferred or preference stock are reserved for officers or employees, or for options, warrants, conversions, or other rights. □

Note 6.

Preferred and Preference Stock Subject to Mandatory Redemption

%	Series	Shares Outstanding	(Thousands) December 31 1981	1980	Optional Redemption (per share)
Preferred Stock					
8.60	P	250,000	$25,000	$25,000	108.60 Before 9/1/84
10.84	Q	250,000	25,000	25,000	110.84 Before 9/1/85
		500,000	$50,000	$50,000	
Preference Stock					
7.6	A	280,000	$28,000	$28,000	

Mandatory redemption for the preferred stock will commence on September 1, 1984 for Series P and on September 1, 1985 for Series Q. The Company must redeem 8,125 shares of each series per year at $100 per share by means of a sinking fund provision, with the noncumulative option to redeem not more than 8,125 additional shares of each series per year on the same terms. 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.

Mandatory redemption for the preference stock will commence in January 1985, at which time the Company must offer to purchase on October 1, 1985 all of the outstanding 7.6% Series A Preference Stock at a price of $100 per share. The shares remaining outstanding after such offer are callable at $100 per share at the option of the Company at any time after December 20, 1987. □

The maximum redemption requirements through 1986 are as follows:

	Series	Redemption Value	(Thousands) 1986	1985	1984
Preferred	P	$100	$ 812.5	$ 812.5	$812.5
Preferred	Q	100	812.5	812.5	
Preference	A	100		28,000.0	
			$1,625.0	$29,625.0	$812.5

Note 7.

Short Term Debt

At December 31, 1981, the Company had no outstanding short term debt. At December 31, 1980, the Company had short term notes outstanding of $10 million and commercial paper outstanding of $15.3 million. The weighted average interest rates for 1981 were 18.16% for short term notes and 17.25% for commercial paper, and for 1980 were 14.53% for short term notes and 12.24% for commercial paper.

The Company had established bank lines of credit totaling $80 million at the end of the year. The Company has maintained its lines of credit by payment of commitment fees which amounted to $308,000 in 1981, $552,000 in 1980 and $280,000 in 1979. □

Note 8.

Jointly-Owned Facilities

The following table sets forth the jointly-owned electric generating projects in which the Company is participating. Each participant must provide its own financing for the Nine Mile Point unit in process of construction and for any additions to the Oswego unit. The Company's share of direct expenses associated with the Oswego unit are included in the appropriate operating expenses in the Statement of Income. □

	Oswego Fossil Unit #6 (1)(2)(3)	Nine Mile Point Nuclear Unit #2 (1)(4)
Net megawatt capacity	850	1,084
RG&E's share—megawatts	204	152
—percent	24	14
Year of completion	1980	1986
	(Millions of Dollars)	
Total estimated project costs		$2,516.2(5)
RG&E's share		352.3
RG&E's actual construction costs		
—1980	$ 6.0	$ 18.8
—1981	2.6	35.2
Expended by RG&E in prior years	59.8(6)	94.2
	$68.4(7)	$148.2
Accumulated depreciation (Commenced in 1980)	$ (3.8)	

(1) Constructed and operated by Niagara Mohawk Power Corporation.
(2) In accordance with an order issued by the PSC, the Company deferred all income and expenses associated with this unit until July 1980 when the plant was added to rate base for rate-making purposes.
(3) Construction costs exclude allowance for funds used during construction.
(4) Construction costs exclude allowance for funds used during construction and certain overhead costs to be capitalized.
(5) The present cost estimate excludes common facilities, but includes $116.2 million for initial nuclear fuel loading.
(6) An adjustment of $4.3 million has been made to include certain overhead costs previously excluded.
(7) Throughout the life of the plant, modifications will be made to increase operating efficiency or reliability. Costs associated with these modifications are included.

Note 9.
Commitments and Other Matters

Capital Expenditures. The Company's capital expenditures program involves an estimated expenditure of $152.7 million in 1982, not including allowance for funds used during construction, and the Company has entered into certain commitments for purchase of materials and equipment in connection with such program.

Environmental Matters. Operations of the Company's generating stations are subject to various Federal, state and local environmental standards.

Under the Clean Water Act, the Company has obtained permits to discharge pollutants into the water bodies adjoining its facilities. The United States Environmental Protection Agency (EPA) issued National Pollutant Discharge Elimination System permits for all the Company's major generating facilities, but a number of conditions relating to thermal and chemical discharge limitations were contested by the Company in adjudicatory hearing requests submitted to EPA. The Company, the New York State Department of Environmental Conservation (NYSDEC), which became a party to the adjudicatory hearings, and EPA have settled the hearing requests as described below.

The Company has reached agreement with the regulatory agencies on non-thermal effluent limitations and final permits containing these agreed limitations have been issued and are now continuing in effect, pending final action by NYSDEC on applications to renew these permits. Construction of treatment facilities required for Company compliance with permit limitations at two of the Company's generating stations was completed in 1980. Construction costs of these two facilities totaled $11.9 million.

The Company has pursued resolution of the contested thermal limitations by submitting demonstrations in an effort to justify less stringent limitations for three generating stations. The thermal conditions of the permits remain stayed pending resolution of the thermal issues either through regulatory agencies' approval of the demonstrations and less stringent thermal limitations or, in the absence of such approval, through the resumption of the adjudicatory hearing process. If the demonstrations and less stringent thermal limitations are not approved for any of the three facilities, the Company could be required to install cooling towers which would involve capital expenditures estimated at $74 million plus significant operating and maintenance expenses.

The National Pollutant Discharge Elimination System permits issued in 1978 expired on March 30, 1980. The Company applied to NYSDEC for renewal of these permits. Upon the request of NYSDEC, the Company filed new renewal applications in October 1981. NYSDEC has extended the Company's existing permits until final action is taken on the pending renewal applications. The Company has no way of determining when new permits will be issued.

The Company believes that additional expenditures and costs made necessary by environmental regulations will be fully allowable for rate-making purposes.

Sterling Project. In the mid-1970's, the Company and three other New York State utilities agreed to share in the cost of a proposed nuclear-powered electric generating plant which the Company would license, build and operate for the group at Sterling, Cayuga County, New York. Output of the plant was to have been shared in the same proportions as their participation in the project; the Company's share was 28%. Although state and federal authorizations for construction were obtained, the State siting agency ultimately revoked its authorization. The participating utilities elected not to appeal that decision, but to terminate the project. The federal construction permit was subsequently withdrawn.

The utilities participating in the Sterling project received an order dated February 19, 1980 from the PSC, in which it was ordered "(T)hat the petitioners be allowed to continue, until such time as amortization commences to be recovered in rates, to accrue and accumulate an allowance for funds used during construction with respect to project costs." The investment of $41.8 million mentioned below includes $4.6 million in AFDC accrued during 1981 and 1980 pursuant to this order. With respect to a similar continuation of AFDC under the accounting procedures prescribed by the Federal Energy Regulatory Commission (FERC), authorization by the FERC is necessary. Such action was requested on March 7, 1980. The FERC has not yet acted on the matter. If the FERC does not authorize continuation of accrual and accumulation of AFDC on the Sterling project and if alternative regulatory relief equivalent thereto is not granted by the FERC, then the participants will not be permitted to include in financial reports, based on the FERC System of Accounts, the AFDC accrued on their investment subsequent to the effective date of the discontinuance of the project. However, on the basis of the PSC order of February 19, 1980, the participants continue to accrue and accumulate such AFDC for PSC regulatory purposes and for purposes of financial reports based on PSC accounting.

At December 31, 1981, the Company's net investment, including AFDC, in the plant is summarized as follows (in thousands of dollars):

Project costs	$41,801
Less: Estimated tax effect of abandonment	12,633
	$29,168

The Company's share of the estimated additional contract termination costs would be $7 million, prior to tax savings.

The Company and the three other utilities participating in the Sterling project received permission from the PSC in January 1982 to amortize their investment in the project as a cost of service to be included in rates charged to customers. The PSC approved amortization of the Company's investment on a levelized basis over a five year period, permitted a return on the unamortized balance equal to the Company's authorized overall return and authorized the commencement of amortization upon the conclusion of the Company's pending rate proceeding. All shared costs of the participants through June 30, 1981 and unshared costs through December 31, 1980 have been determined by the PSC to be prudent and appropriate for amortization. The Company's portion of these costs is $38.6 million, prior to tax savings, and includes any termination costs expended through the aforementioned dates. Recovery of remaining costs, comprising certain termination charges and AFDC accumulated since June 30, 1981, was made subject to review by the PSC. The PSC has recognized that cancellation of a project of this magnitude would be accompanied by the reasonable incurrence of termination charges.

Nine Mile Point Nuclear Plant. The Company and four other New York State utilities are participating in the construction of a nuclear-powered electric generating plant at Nine Mile Point. The project will be licensed, built and operated by Niagara Mohawk Power Corporation; the Company's share of the project is 14%. In July 1981, various parties petitioned the PSC to establish a single consolidated public evidentiary proceeding involving all of the participants to consider the future of the unit. In addition, certain participants' rate proceedings included various motions and petitions filed by intervening parties requesting a separate examination of the project. The Staff of the PSC issued a report in September 1981 on a comparative analysis of the economic and financial feasibility of the unit and coal-powered alternatives,

which concluded that completion of the project is warranted. The PSC then ordered an expedited public proceeding to inquire into the financial and economic cost implications of completing the project. In December 1981, public evidentiary hearings were held and briefs submitted to the PSC. See Note 10.

Other Matters. The Company presently has a contract with the Department of Energy for future nuclear fuel enrichment services, which provides for specified units to be enriched annually for a period in excess of one year. Payment is required under this contract whether or not the services are utilized. However, the Company may satisfy its commitment through the sale of unutilized services to other utilities at then prevailing market rates. The services utilized by the Company in 1981, 1980 and 1979 amounted to $6.6 million, $.2 million and $6.4 million, respectively. Future minimum payments are as follows:

	(Thousands)(a)
1982	$ 7,584
1983	7,883
1984	1,700
1985	—
1986	7,453
Subsequent years	8,237
Total	$32,857

(a) Priced at most current rate.

Legal actions have been instituted against the Company seeking $34.5 million in compensatory and $64 million in punitive damages for alleged personal injuries as a result of exposure to radiation at the Company's Ginna nuclear power plant in 1974. The Company has not completed its investigation of the plaintiffs' allegations and it cannot predict the outcome of these actions, nor can it predict whether any additional similar actions might be commenced. Based, however, on its investigation to date, the Company does not believe the plaintiffs will prevail on the merits, and it intends to contest these claims vigorously.

The Company is fully insured for the total compensatory damages that are sought in these actions, and its insurer has advised the Company that it will fully defend all claims. However, the insurer has disclaimed any obligation for the payment of any punitive damages which may be assessed against the Company. There is precedent in New York State that it is contrary to public policy for an insurance carrier to pay punitive damages assessed against its insured, but it is unclear whether that precedent would apply to the nuclear liability insurance involved in these actions. The Company intends to contest the disclaimer of coverage for punitive damages.

An additional legal action has been brought by the plaintiffs in those actions. This action seeks to recover $10 million in compensatory damages and $13 million in punitive damages for various alleged wrongs arising out of a Company interoffice memorandum advising its facility supervisors that none of the plaintiffs should be permitted on the Company's property. The Company has insurance for compensatory damages sought in this claim, but does not for punitive damages. The Company intends to contest these claims vigorously. □

Note 10.
Subsequent Events

Ginna Nuclear Plant. On January 25, 1982, the Company shut down its Ginna Nuclear Plant when the primary system experienced a sudden loss of pressure. The problem was promptly diagnosed as a ruptured tube in one of the two steam generators. All safety equipment functioned properly and the Company brought the plant to a safe, cold shutdown.

The Company plans to return the Plant to service by early May, subject to U.S. Nuclear Regulatory Commission approval. The annual refueling, inspection and maintenance programs have been rescheduled so that they can be accomplished concurrently with repair of the steam generator.

The Plant is insured against accidental property losses with a $1 million deductible. During the Ginna shutdown, customers' electric requirements will be provided by Company fossil fuel and hydroelectric plants supplemented by purchased power. Replacement power cost of approximately $1.8 million per week will be recovered from customers through the fuel cost adjustment portion of customers' rates. The Company believes that this recent incident will not have a material adverse effect on earnings.

Nine Mile Point Nuclear Plant. In a February 23, 1982 notice, the PSC stated that a majority of the Commissioners favored completion of the Nine Mile Point Nuclear Plant project. The Commission, however, is considering various mechanisms for risk-sharing in order to improve project performance by use of incentives and penalties intended to affect earnings. The Company is unable to predict what recommendations or actions may be formulated by the PSC or what further actions, if any, may be brought by the intervening parties. □

REPORT OF INDEPENDENT ACCOUNTANTS

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

In our opinion, the accompanying balance sheets and the related statements of income, retained earnings, and of changes in financial position appearing on pages 18 through 20 present fairly the financial position of Rochester Gas and Electric Corporation at December 31, 1981 and 1980, and the results of its operations and the changes in its financial position for each of the three years in the period ended December 31, 1981, in conformity with generally accepted accounting principles consistently applied. Our examinations of these statements were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Price Waterhouse

1900 Lincoln First Tower
Rochester, New York 14604
January 29, 1982
(Except as to Note 10, for which the date is March 2, 1982)

Concerning the Effects of Inflation

The estimates of the effect of inflation on the operations of the Company, as set forth below, were prepared on bases prescribed by the Financial Accounting Standards Board (FASB) Statement No. 33, "Financial Reporting and Changing Prices." This statement requires adjustments to historical costs to estimate the effects that general inflation (Constant Dollar) and changes in specific prices (Current Cost) have had on the Company's results of operations. These data are not intended as substitutes for earnings reported on a historical cost basis. They offer some perspective of the approximate effects of inflation rather than a precise measurement of these effects.

Utility Plant. Estimated utility plant, primarily consisting of plant in service and construction work in progress, was determined for constant dollars by applying the Consumer Price Index for All Urban Consumers (CPI-U) to the historical cost of utility plant. The current cost estimates were measured by applying the Handy-Whitman Index of Public Utility Construction Costs to the historical cost of utility plant. Current cost is an estimate of the cost of currently replacing existing plant. The resulting adjusted data for plant under either of the above methods is not necessarily indicative of the Company's future capital requirements because the actual replacement of existing plant will take place over many years and is not likely to be a reproduction of presently existing plant.

The difference between current cost and the constant dollar data results from specific prices of plant increasing at a rate different from the rate of general inflation.

Accumulated Depreciation. The accumulated provision for depreciation for constant dollars and current cost was developed by applying, for each class of plant, the same percentage relationship that existed between gross plant and accumulated provision for depreciation on a historical basis to the respective adjusted plant data.

Depreciation Expense. Depreciation expense for both methods was determined by applying the Company's depreciation rates to the respective indexed plant amounts.

Reduction of Utility Plant to Net Recoverable Cost. The regulatory process limits the Company to the recovery of the historical cost of service in its rates. Therefore, any excess of the value of utility plant under constant dollars or current cost must be reduced to the net recoverable cost, which is historical cost. The amount of this excess that accrued as a result of inflation in the current year must be reduced to net recoverable cost.

Gain From the Decline of Purchasing Power of Net Amounts Owed. The Company, by holding assets such as receivables, prepayments, and inventory, suffers a loss of purchasing power during periods of inflation because the amount of cash received in the future for these items will purchase less. Conversely, by holding monetary liabilities, primarily long term debt, the Company benefits because the payment in the future will be made with nominal dollars having less purchasing power. The Company has significant amounts of long term debt outstanding which will be paid back in dollars having less purchasing power and, therefore, for purposes of these calculations, has a net gain from holding monetary liabilities in excess of monetary assets.

Other Items. As allowed by FASB Statement No. 33, items in the income statement, other than depreciation expense, were not adjusted. The cost of fuel used in electric production and the cost of gas sold were not adjusted because the effect on earnings was not material due to the relatively short turnover period between the incurrence of these costs and their recovery through the fuel adjustment clause.

The regulatory process limits the amount of depreciation expense included in the Company's revenue allowance and limits utility plant in rate base to original cost. Such amounts produce cash flows which are inadequate to replace such property in the future or preserve the purchasing power of common equity capital previously invested. While this effect is partially mitigated by the benefit derived from having long term debt, the Company has a net purchasing power loss which is experienced by the common stock shareholder and can only be overcome as a result of adequate rate relief. However, the Company expects that it will be able to establish rates which will cover the increased costs of new plant when such costs are incurred.

Federal income tax policy ignores the effects of inflation in measuring taxable income. Higher depreciation expense under constant dollar and current cost accounting is not tax deductible. Therefore, the Company's effective Federal income tax rate, when adjusted for inflation, is 39.4 percent under constant dollar and 52.8 percent under current cost for 1981, each of which exceeds its reported effective tax rate of 22.0 percent. □

The erosion of stockholders' equity due to changing prices is summarized in terms of general inflation and in terms of changes in specific prices, as follows:

In Thousands of Average 1981 Dollars	In Terms of General Inflation	In Terms of Changes in Specific Prices
Increase in provision for depreciation	$37,229	$49,117
Increase in general price level less increase in specific prices		(34,938)
Reduction of utility plant to net recoverable cost	43,811	66,861
Gain from the decline in purchasing power of net amounts owed	(51,394)	(51,394)
Total erosion of stockholders' equity due to inflation	$29,646	$29,646

Statement of Income from Continuing Operations Adjusted for Changing Prices

(Thousands of Dollars) For the Year Ended December 31, 1981	Historical Cost	Constant Dollar Average 1981 Dollars	Current Cost Average 1981 Dollars
Operating revenues	$613,541	$613,541	$613,541
Operating expense	377,040	377,040	377,040
Maintenance expense	36,981	36,981	36,981
Depreciation expense	32,877	70,109	81,997
Tax expense—local, state and other	68,261	68,261	68,261
Income tax expense	18,580	18,580	18,580
Interest expense	42,024	42,024	42,024
Other income and deductions—net	(27,972)	(27,972)	(27,972)
	547,791	585,023	596,911
Net income	65,750	28,518	16,630
Dividends on preferred and preference stock	10,538	10,538	10,538
Earnings applicable to common stock	$ 55,212	$ 17,980*	$ 6,092
Change in net assets during 1981 due to increase in specific prices			$219,355**
Less: Increase in general price level			184,417
Net change during 1981			$ 34,938
Reduction of utility plant to net recoverable cost		$ (43,811)	$ (66,861)
Gain from decline in purchasing power of net amounts owed		$ 51,394	$ 51,394

*Earnings applicable to common stock on a constant dollar basis would have been a loss of $25,831 if it had included the reduction of utility plant to net recoverable cost.

**At December 31, 1981, current cost of utility property net of accumulated depreciation was $2,285,953, while related historical cost or net recoverable cost was $984,309, excluding the Sterling Nuclear Plant.

Five-Year Comparison of Selected Financial Data Adjusted for Changing Prices

(In Thousands of Average 1981 Dollars) Year Ended December 31	1981	1980	1979	1978	1977
Operating revenues					
As reported	$613,541	$502,426	$417,692	$368,948	$331,144
In average 1981 dollars	613,541	554,317	523,364	514,337	496,990
Historical cost information adjusted for general inflation					
Earnings applicable to common stock*	17,980	5,001	11,341		
Earnings per common share, adjusted for stock dividends*	$ .96	$ .29	$ .70		
Net assets at year-end at net recoverable cost**	350,047	351,355	356,847		
Current cost information					
Earnings (loss) applicable to common stock*	6,092	(7,624)	(3,398)		
Earnings (loss) per common share, adjusted for stock dividends*	$ .32	$ (.45)	$ (.21)		
Excess of increase in general price level over increase in specific prices after reduction to net recoverable cost	31,923	68,352	82,806		
Net assets at year-end at net recoverable cost**	350,047	351,355	356,847		
General information					
Gain from decline in purchasing power of net amounts owed	51,394	73,616	81,483		
Cash dividends per common share, adjusted for stock dividends					
As reported	$ 1.53	$ 1.44	$ 1.37	$ 1.29	$ 1.18
In average 1981 dollars	1.53	1.59	1.72	1.80	1.77
Market price per common share at year-end					
As reported	$14.75	$12.25	$14.88	$18.00	$21.13
In December 1981 dollars	14.75	13.35	18.21	24.97	31.95
Average consumer price index	272.4	246.9	217.4	195.4	181.5
December consumer price index	281.5	258.4	229.9	202.9	186.1

*Excludes the reduction of utility plant to net recoverable cost. **Excludes the Sterling Nuclear Plant.

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 the Company's Ginna nuclear plant. Earnings per common share have been adjusted for stock dividends. ◻

	(Thousands)				
Quarter Ended	Operating Revenues	Operating Income	Net Income	Earnings On Common Stock	Earnings Per Common Share (in dollars)
December 31, 1981	**$161,622**	**$20,236**	**$15,420**	**$12,786**	**$ .67**
September 30, 1981	**132,846**	**16,057**	**12,412**	**9,777**	**.51**
June 30, 1981	**114,259**	**13,812**	**11,498**	**8,863**	**.47**
March 31, 1981	**204,814**	**29,697**	**26,420**	**23,786**	**1.27**
December 31, 1980	141,344	12,774	8,159	5,525	.31
September 30, 1980	102,130	14,268	9,335	6,956	.41
June 30, 1980	105,395	12,233	9,141	7,184	.43
March 31, 1980	153,557	20,257	17,017	15,060	.90
December 31, 1979	108,243	11,279	7,194	5,237	.31
September 30, 1979	83,010	8,244	5,211	3,362	.20
June 30, 1979	105,766	14,265	10,939	9,520	.58
March 31, 1979	120,673	18,334	16,220	14,801	.91

A 3% stock dividend was paid by the Company on February 25, 1982. Concurrent with the declaration of the 1982 stock dividend, the Board of Directors announced the termination of the annual stock dividend policy. The following Common Stock prices have not been adjusted for subsequent 3% stock dividends paid in February 1979, 1980, 1981 and 1982.

The Company has paid cash dividends quarterly on its Common Stock without interruption since it became publicly held in 1949. The Company intends to continue the practice of paying cash dividends quarterly, although there can be no assurance as to the declaration of future cash dividends since they necessarily will be dependent upon the Company's future earnings, its financial requirements and other factors.

In the event the Company should be in arrears in the redemption of its Series P or Series Q Preferred Stock pursuant to the sinking fund provision of such series, the Company may not purchase or otherwise acquire for value, or pay dividends on, any shares of its Common Stock.

For the year 1979 cash dividends paid were 100% taxable for Federal income tax purposes. Cash dividends paid were 100% nontaxable for the year 1980. Cash dividends paid during 1981 are 100% taxable. □

		1981		1980		1979
Earnings per weighted average share		$2.93		$2.04		$2.02
Number of shares (000's)						
Weighted average		18,826		16,966		16,289
Pro forma weighted average after stock dividend paid in following year (See above)		19,390		17,475		16,778
Actual number at December 31		19,040		17,910		15,555
Number of shareholders at December 31		50,538		50,416		48,543
Price range (Sales on New York Stock Exchange)	High	Low	High	Low	High	Low
1st quarter	14⅛	11¾	15¾	11¼	18⅜	16¾
2nd quarter	14	12	15¼	11⅜	17⅝	15⅝
3rd quarter	13½	12¼	14¾	13¾	17	16
4th quarter	15	12⅛	13⅞	11½	16	14½
Cash dividends paid						
1st quarter		$.38		$.37		$.36
2nd quarter		.38		.37		.36
3rd quarter		.38		.37		.37
4th quarter		.40		.38		.37
Stock dividend paid (See above)		3%		3%		3%

Although the Company's financial results for 1981 show a marked improvement over 1980 and 1979, inflation continues to be a major problem for our capital intensive industry. Inflation, along with skepticism in the financial markets regarding any immediate solutions to it, has resulted in a gradual erosion of the long term fundamental financial strength of the Company. While it may be too soon to view it as a trend, the year 1981 has turned in the right direction.

The Company faces large capital expenditures over the next five years due to the necessity to commit to major construction projects to meet the anticipated energy needs of customers. Planned increases in electric generating capacity require long term capital commitments. A major project is Nine Mile Point Unit 2, a nuclear unit being built by Niagara Mohawk Power Corporation in which the Company has a 14% interest. This unit is scheduled for commercial operation in late 1986. Also, a significant portion of the Company's capital expenditure program is comprised of government-mandated modifications and additions to existing plant and equipment.

At present, the Company anticipates that 30% to 40% of the additional funds it requires will be generated internally. The balance will have to be obtained through the sale of securities and short term borrowing.

Regulatory policies regarding both cash flow items and rates of earnings have restricted the Company's ability to internally generate greater amounts of cash to finance its on-going construction program. The July 1981 PSC rate decision contained some elements of improvement, most particularly the authorized rate of return on common equity of 16%. In order to keep pace with the effects of inflation as much as possible, on August 21, 1981, the Company filed for increased rates, including a requested 18% return on common equity, to become effective in July 1982.

On January 25, 1982 the Company's Ginna Nuclear Plant experienced a leak in one of the 6,520 tubes that pass through its two steam generators. All equipment and personnel responded to this incident according to prescribed plans. Pursuant to the Price-Anderson Act and related Federal regulations, the Company is insured for payments of liabilities resulting from a nuclear incident. Nuclear Electric Insurance Limited provides additional insurance that would help pay the extra cost of replacement power in the event of a prolonged outage of the Ginna Nuclear Plant. At this time the Company believes that this recent incident at the Ginna Nuclear Plant will not have a material adverse effect on either its liquidity, future capital resources or earnings. (See Note 10 to the Notes to Financial Statements.)

The following financial review identifies the causes of significant changes in the amounts of revenues and expenses, comparing 1981 to 1980 and 1980 to 1979. The Notes to Financial Statements on pages 21 to 27 of this report contain additional related information.

Changes in Operating Revenues

Increase or (Decrease) from Prior Year (Thousands of Dollars)	Electric Department 1981	Electric Department 1980	Gas Department 1981	Gas Department 1980	Steam Department 1981	Steam Department 1980
Customer Revenues (Estimated) from:						
Rate Increases	$41,261	$21,878	$ 9,163	$ 8,232	$ 2,296	$ 2,316
Fuel Cost Adjustment	30,119	2,317	6,845	30,436	2,251	3,441
Weather Effects	71	(27)	902	(1,452)	78	(279)
Customer Consumption	5,044	607	5,604	2,671	(1,784)	(2,042)
Acquisition of Pavilion Natural Gas Company	—	—	10,232	—	—	—
Other	(1,175)	857	(1,239)	632	(69)	165
Total Change in Customer Revenues	75,320	25,632	31,507	40,519	2,772	3,601
Electric Sales to Other Utilities	1,516	14,982	—	—	—	—
Total Change in Operating Revenues	$76,836	$40,614	$31,507	$40,519	$ 2,772	$ 3,601

Revenues from electric sales to other utilities increased in both 1981 and 1980. Fluctuations in those sales, and in purchased electricity discussed below, generally are related to the availability of electric generation from the Ginna Nuclear Plant.

Changes in Operation and Maintenance Expenses

Increase or (Decrease) from Prior Year (Thousands of Dollars)	1981	1980
Electric and Steam Fuels	$25,845	$18,640
Purchased Electricity	3,090	(8,141)
Purchased Natural Gas	10,325	37,955
Other Operation	24,554	9,696
Maintenance	4,933	1,919
Total Change in Operation and Maintenance Expense	$68,747	$60,069

The increases in electric and steam fuels expense in 1981 and 1980 were mainly due to an increase in electricity generated and increased fuel costs per kilowatt-hour generated.

Purchased electricity expense increased in 1981 due to higher costs for kilowatt-hours purchased. Purchased electricity expense decreased in 1980 compared to 1979 due mainly to the higher availability of the Ginna Nuclear Plant and an increase in system net generating capacity occasioned by the start-up of Oswego Unit 6.

Purchased natural gas expense increased in 1981 due primarily to the addition of customers through the acquisition of Pavilion Natural Gas Company. The 1980 increase was attributed primarily to higher pipeline rates. Both 1981 and 1980 reflect a modest increase in consumption in the nonresidential sector.

Other operation and maintenance expenses increased in 1981 and in 1980 largely as a result of higher wages and employee benefit costs and the higher cost of materials and supplies used for the maintenance of existing facilities.

With respect to other operating expense items, taxes—local, state and other increased in 1981 and in 1980 principally due to the increased gross income tax rate and increased revenues. The 1980 increase also reflects taxes on Oswego Unit 6 which were capitalized during its construction and are now being expensed. Changes in Federal income taxes are explained in Note 2 to the Notes to Financial Statements.

The 1981 increase of $2.6 million in allowance for funds used during construction was due to increased rates applied during the period and to increased utility plant expenditures. The 1980 increase in allowance for funds used during construction of $1.3 million was due to the increased rates applied during the period, the effect of which was reduced by lower utility plant expenditures and by the transfer of the Company's share of the Oswego Unit 6 oil-fired generating plant from construction work in progress to utility plant.

Interest on long term debt increased in 1981 and in 1980 as a result of additional bonds issued in August 1981, February and May 1980, and August 1979. The $1.7 million decrease in short term interest expense for 1981 reflects significantly lower borrowing levels than those experienced in 1980.

Dividends on preferred and preference stock increased $1.6 million in 1981 and $2.3 million in 1980 because of additional preferred stock issued in August 1980 and July 1979. □

Summary of Operations (Thousands of Dollars) Year Ended December 31	1981*	1980	1979	1978	1977	1976
Operating Revenues						
Electric	$320,325	$245,005	$219,373	$202,631	$179,940	$170,558
Gas	212,553	181,046	140,527	118,531	105,797	101,027
Steam	26,361	23,589	19,988	19,110	19,004	18,383
	559,239	449,640	379,888	340,272	304,741	289,968
Electric sales to other utilities	54,302	52,786	37,804	28,676	26,403	18,259
Total Operating Revenues	613,541	502,426	417,692	368,948	331,144	308,227
Operating Expenses						
Operation						
Electric and steam fuels	105,556	79,711	61,071	58,140	56,993	46,361
Purchased electricity	26,886	23,796	31,937	19,337	13,635	18,195
Purchased natural gas	138,084	127,759	89,804	71,109	62,086	56,192
Other	106,514	81,960	72,264	65,685	62,494	57,677
Maintenance	36,981	32,048	30,129	26,246	22,372	20,206
Depreciation	32,877	27,800	23,703	22,206	21,053	18,621
Taxes—local, state and other	68,261	56,984	49,916	45,935	43,876	40,502
Federal income tax—current	6,770	393	(36)	5,166	961	(291)
—deferred	11,810	12,443	6,782	5,875	2,897	5,656
Total Operating Expenses	533,739	442,894	365,570	319,699	286,367	263,119
Operating Income	79,802	59,532	52,122	49,249	44,777	45,108
Other Income and Deductions						
Allowance for other funds used during construction	13,704	11,710	11,439	8,705	6,473	4,678
Other, net	6,862	4,772	3,774	4,418	1,310	1,128
Total Other Income and Deductions	20,566	16,482	15,213	13,123	7,783	5,806
Income before Interest Charges	100,368	76,014	67,335	62,372	52,560	50,914
Interest Charges						
Long term debt	38,020	34,129	29,084	25,594	22,542	19,378
Short term debt	2,594	4,298	4,016	1,588	1,319	1,054
Other, net	1,410	755	441	416	494	246
Allowance for borrowed funds used during construction	(7,406)	(6,820)	(5,771)	(4,812)	(4,844)	(2,853)
Total Interest Charges	34,618	32,362	27,770	22,786	19,511	17,825
Net Income	65,750	43,652	39,565	39,586	33,049	33,089
Dividends on Preferred and Preference Stock, at required rates	10,538	8,927	6,645	5,678	6,512	6,245
Earnings Applicable to Common Stock	$ 55,212	$ 34,725	$ 32,920	$ 33,908	$ 26,537	$ 26,844
Weighted average number of shares outstanding in each period, adjusted for stock dividends (000's)	18,826	16,966	16,289	15,051	13,631	13,095
Earnings per Common Share	$2.93	$2.04	$2.02	$2.25	$1.94	$2.05
Cash Dividends per Common Share, adjusted for stock dividends	$1.53	$1.44	$1.37	$1.29	$1.18	$1.10

*Figures reflect the merger of the Pavilion Natural Gas Company for the entire year of 1981. See Note 1 to the Notes to Financial Statements.

Condensed Balance Sheet
(Thousands of Dollars)

At December 31	1981	1980	1979	1978	1977	1976
ASSETS						
Utility Plant, at original cost	$1,140,048	$1,061,999	$928,796	$857,959	$789,775	$727,687
Less—Accumulated depreciation and amortization	389,422	337,215	295,328	261,477	229,122	198,778
	750,626	724,784	633,468	596,482	560,653	528,909
Construction work in progress	280,567	225,690	260,063	213,534	162,127	120,702
Net utility plant	1,031,193	950,474	893,531	810,016	722,780	649,611
Investment in Subsidiary, at equity		1,968	2,062	1,996	1,947	1,911
Current Assets	105,950	92,314	65,237	66,953	58,387	61,090
Deferred Debits	25,847	30,624	22,020	14,421	15,260	8,151
Total Assets	$1,162,990	$1,075,380	$982,850	$893,386	$798,374	$720,763
CAPITALIZATION AND LIABILITIES						
Capitalization						
Long term debt	$ 480,508	$ 437,124	$382,162	$384,303	$361,022	$311,395
Preferred stock subject to mandatory redemption	50,000	50,000	25,000			
Preferred stock redeemable at option of Company	67,000	67,000	67,000	67,000	67,000	92,000
Preference stock subject to mandatory redemption	28,000	28,000	28,000	28,000	28,000	
Common shareholders' equity						
Common stock	303,793	291,346	260,432	246,938	212,533	181,301
Retained earnings	104,832	83,970	80,155	77,338	70,819	67,812
Total common shareholders' equity	408,625	375,316	340,587	324,276	283,352	249,113
Total Capitalization	1,034,133	957,440	842,749	803,579	739,374	652,508
Current Liabilities	73,363	85,510	115,291	68,362	42,813	54,652
Deferred Credits and Other Liabilities	55,494	32,430	24,810	21,445	16,187	13,603
Total Capitalization and Liabilities	$1,162,990	$1,075,380	$982,850	$893,386	$798,374	$720,763

Financial Data

At December 31	1981	1980	1979	1978	1977	1976
Capitalization Ratios (percent)						
Long term debt	46.5	45.7	45.4	47.8	48.8	47.7
Preferred and preference stock	14.0	15.1	14.2	11.8	12.9	14.1
Common shareholders' equity	39.5	39.2	40.4	40.4	38.3	38.2
Total	100.0	100.0	100.0	100.0	100.0	100.0
Book Value per Common Share Adjusted for Stock Dividends—Year End	$21.46	$20.35	$20.64	$20.14	$19.53	$18.91
Rate of Return On Average Common Equity (percent)	13.91	9.86	9.85	11.22	10.02	11.16
Effective Federal Income Tax Rate (percent)	12.7	13.7	5.4	12.8	6.2	10.6
Depreciation Rate—Electric	3.09	3.09	3.10	3.09	3.00	2.90
—Gas	2.98	2.86	2.79	2.79	2.67	2.63
Interest Coverages						
Before federal income taxes (incld. AFDC)	2.79	2.33	2.25	2.65	2.45	2.79
(excld. AFDC)	2.29	1.86	1.73	2.16	1.98	2.43
After federal income taxes (incld. AFDC)	2.56	2.11	2.18	2.43	2.36	2.60
(excld. AFDC)	2.06	1.64	1.67	1.94	1.89	2.24

Year Ended December 31	1981	1980	1979	1978	1977	1976
Electric Revenue (000's)						
Residential	$111,549	$ 88,083	$ 78,140	$ 72,854	$ 64,986	$ 61,498
Commercial	92,412	70,407	63,104	58,985	53,520	50,791
Industrial	83,092	60,373	54,404	48,792	41,783	39,402
Other	33,272	26,142	23,725	22,000	19,651	18,867
Electric revenue from our customers	320,325	245,005	219,373	202,631	179,940	170,558
Other electric utilities	54,302	52,786	37,804	28,676	26,403	18,259
Total electric revenue	374,627	297,791	257,177	231,307	206,343	188,817
Electric Expense (000's)						
Fuel used in electric generation	88,134	63,430	46,999	45,093	44,010	34,247
Purchased electricity	26,886	23,796	31,937	19,337	13,635	18,195
Other operation	87,371	64,139	54,277	47,602	45,011	40,930
Maintenance	28,515	24,404	22,675	19,305	16,339	14,796
Depreciation	26,281	21,859	18,223	16,983	15,333	13,865
Taxes—local, state and other	47,437	39,514	35,172	33,108	31,530	28,543
Electric revenue deductions	304,624	237,142	209,283	181,428	165,858	150,576
Operating Income before Federal Income Tax	70,003	60,649	47,894	49,879	40,485	38,241
Federal income tax including regulatory allowance	11,407	11,169	5,600	9,244	4,041	3,102
Operating Income from Electric Operations (000's)	$ 58,596	$ 49,480	$ 42,294	$ 40,635	$ 36,444	$ 35,139
Electric Operating Ratio %	61.6	59.0	60.6	56.8	57.7	57.3
Electric Sales—KWH (000's)						
Residential	1,752,335	1,730,213	1,710,090	1,701,938	1,660,425	1,618,314
Commercial	1,449,361	1,424,283	1,404,931	1,417,624	1,392,023	1,366,094
Industrial	1,652,122	1,564,952	1,579,364	1,517,988	1,431,855	1,384,235
Other	460,812	466,975	469,135	465,373	454,059	437,097
Electric sales to our customers	5,314,630	5,186,423	5,163,520	5,102,923	4,938,362	4,805,740
Other electric utilities	1,371,077	1,620,929	1,526,925	1,445,391	1,453,590	1,187,942
Total electric sales	6,685,707	6,807,352	6,690,445	6,548,314	6,391,952	5,993,682
Electric Customers at December 31						
Residential	261,843	257,227	254,097	251,645	250,121	249,177
Commercial	24,596	24,524	24,234	24,137	24,023	23,983
Industrial	1,425	1,388	1,394	1,348	1,353	1,371
Other	2,222	2,331	2,374	2,423	2,328	2,271
Total electric customers	290,086	285,470	282,099	279,553	277,825	276,802
Electricity Generated and Purchased—KWH (000's)						
Fossil	2,164,110	2,301,288*	1,956,599	2,025,645	2,272,182	2,060,186
Nuclear	3,314,599	3,081,572	2,945,721	3,206,313	3,018,305	2,040,746
Hydro	223,399	179,335	210,353	192,278	222,391	277,010
Pumped storage	169,553	122,809	151,911	133,287	193,340	118,716
Less energy for pumping	(260,541)	(191,044)	(217,758)	(189,453)	(283,573)	(180,317)
Other	20,867	9,389	17,257	1,086	850	2,797
Total generated—Net	5,631,987	5,503,349	5,064,083	5,369,156	5,423,495	4,319,138
Purchased	1,463,207	1,758,608	2,051,568	1,579,863	1,400,505	2,106,904
Total electric energy	7,095,194	7,261,957	7,115,651	6,949,019	6,824,000	6,426,042
Electric Generation Costs (000's)						
Fossil	$ 71,429	$ 62,554	$ 42,116	$ 38,995	$ 40,557	$ 36,901
Nuclear	46,302	39,713	29,943	25,561	22,330	13,485
Hydro	1,116	1,355	1,233	1,229	1,132	973
Other	1,117	518	813	57	44	118
Electric Department Fuel						
Fossil —Total BTU (million)	23,300,002	24,610,400	20,874,198	21,139,146	23,862,599	21,822,976
—Cents per million BTU	236.69	205.31	152.18	144.27	136.92	137.42
Nuclear—Total BTU (million)	36,530,302	33,878,804	31,897,513	35,812,171	37,822,209	23,837,620
—Cents per million BTU	65.21	61.36	53.81	43.97	38.04	25.69
System Net Capability—KW at December 31						
Fossil	605,000	637,000	443,000	443,000	443,000	452,000
Nuclear	470,000	470,000	470,000	470,000	470,000	470,000
Hydro	47,000	47,000	47,000	47,000	47,000	47,000
Other	29,000	29,000	29,000	29,000	29,000	29,000
Purchased	356,000	357,000	359,000	339,000	338,000	342,000
Total system net capability	1,507,000	1,540,000	1,348,000	1,328,000	1,327,000	1,340,000
Net Peak Load—KW	1,048,000	1,003,000	950,000	983,000	987,000	934,000
Annual Load Factor—Net %	62.6	64.0	67.1	63.9	62.0	63.8

*Excludes 79,274,000 KWH of test period generation at Oswego Unit 6.

Year Ended December 31	1981*	1980	1979	1978	1977	1976
Gas Revenue (000's)						
Residential	$ 7,223	$ 6,444	$ 5,553	$ 5,096	$ 4,828	$ 4,426
Residential spaceheating	119,951	105,371	85,269	74,425	66,900	63,974
Commercial	39,692	33,879	25,653	20,535	18,057	16,848
Industrial	34,447	27,379	18,657	13,891	12,014	11,900
Municipal and other	11,240	7,973	5,395	4,584	3,998	3,879
Total gas revenue	212,553	181,046	140,527	118,531	105,797	101,027
Gas Expense (000's)						
Purchased natural gas	138,084	127,759	89,804	71,109	62,086	56,192
Other operation	18,391	16,546	16,519	15,810	15,072	14,921
Maintenance	7,120	6,309	6,246	5,768	5,078	4,510
Depreciation	5,981	5,338	4,889	4,641	5,140	4,194
Taxes—local, state and other	17,534	14,594	12,187	10,545	10,089	9,729
Gas revenue deductions	187,110	170,546	129,645	107,873	97,465	89,546
Operating Income before Federal Income Tax	25,443	10,500	10,882	10,658	8,332	11,481
Federal income tax	6,099	1,310	1,314	1,966	147	2,212
Operating Income from Gas Operations (000's)	$ 19,344	$ 9,190	$ 9,568	$ 8,692	$ 8,185	$ 9,269
Gas Operating Ratio %	77.0	83.2	80.1	78.2	77.7	74.9
Gas Sales—Therms (000's)						
Residential	14,245	13,257	13,149	13,465	13,833	14,404
Residential spaceheating	256,016	240,273	247,389	255,951	252,923	275,582
Commercial	93,543	85,291	83,248	82,451	77,751	86,400
Industrial	89,956	75,829	65,995	63,709	59,956	72,847
Municipal	25,743	19,842	16,962	17,748	15,975	18,598
Total gas sales	479,503	434,492	426,743	433,324	420,438	467,831
Gas Customers at December 31						
Residential	32,501	32,479	35,258	38,013	39,977	40,892
Residential spaceheating	178,932	165,556	159,916	154,366	152,856	153,583
Commercial	14,539	13,281	12,600	12,092	11,268	11,475
Industrial	932	846	821	759	746	757
Municipal	1,049	995	1,047	1,084	989	936
Total gas customers	227,953	213,157	209,642	206,314	205,836	207,643
Gas—Therms (000's)						
Purchased for reforming and mixing						9,830
Purchased for resale	482,745	458,697	436,956	449,904	428,811	478,935
Other	22,961	18,392	16,388	13,178	10,123	7,911
Total gas available	505,706	477,089	453,344	463,082	438,934	496,676
Cost of gas per therm	27.20¢	26.34¢	20.63¢	15.26¢	14.43¢	11.37¢
Total Daily Capacity—Therms at December 31	3,880,000**	3,660,000**	4,164,000	4,164,000	4,164,000	4,164,000
Maximum daily sendout—Therms	3,430,940	3,274,740	3,380,670	3,183,678	3,578,468	3,497,861
Degree Days (Customer Billing)						
For the period	6,907	6,833	6,981	7,021	6,726	6,905
Percent (warmer) colder than normal	2.7	1.4	4.3	4.5	(0.1)	1.6

*Figures reflect the merger of the Pavilion Natural Gas Company for the entire year of 1981. See Note 1 to the Notes to Financial Statements.
**Method for determining daily capacity, based on current network analysis, reflects the maximum demand which the transmission system can accept without a deficiency.

Year Ended December 31	1981	1980	1979	1978	1977	1976
Steam Revenue (000's)						
Commercial	$ 7,174	$ 6,915	$ 5,873	$ 6,087	$ 6,352	$ 6,401
Industrial	16,320	14,222	11,833	10,732	10,455	9,799
Municipal and other	2,867	2,452	2,282	2,291	2,197	2,183
Total steam revenue	26,361	23,589	19,988	19,110	19,004	18,383
Steam Expense (000's)						
Fuel used in steam generation	17,422	16,281	14,072	13,047	12,983	12,114
Other operation	752	1,275	1,468	2,273	2,411	1,826
Maintenance	1,346	1,335	1,208	1,173	955	900
Depreciation	615	603	591	581	580	562
Taxes—local, state and other	3,290	2,876	2,557	2,282	2,257	2,230
Steam revenue deductions	23,425	22,370	19,896	19,356	19,186	17,632
Operating Income before Federal Income Tax	2,936	1,219	92	(246)	(182)	751
Federal income tax	1,074	357	(168)	(168)	(330)	51
Operating Income from Steam Operations (000's)	$ 1,862	$ 862	$ 260	$ (78)	$ 148	$ 700
Steam Operating Ratio %	74.1	80.1	83.8	86.3	86.0	80.7
Steam Sales—Lbs. (000's)						
Commercial	568,944	678,225	789,364	898,904	933,609	1,041,415
Industrial	1,345,062	1,487,176	1,682,780	1,718,565	1,682,033	1,738,391
Municipal	232,550	248,478	320,026	346,031	334,645	367,553
Total steam sales	2,146,556	2,413,879	2,792,170	2,963,500	2,950,287	3,147,359
Steam Customers at December 31						
Commercial	154	186	221	238	254	271
Industrial	59	61	70	70	74	77
Municipal	21	24	27	31	32	32
Total steam customers	234	271	318	339	360	380
Steam Produced—Lbs. (000's)						
Produced by steam department	1,301,185	1,376,153	1,391,245	1,353,053	1,194,132	1,408,029
By-product steam from electric department	1,123,703	1,395,995	1,736,744	1,987,638	2,133,853	2,193,283
Total steam produced	2,424,888	2,772,148	3,127,989	3,340,691	3,327,985	3,601,312
Steam Department Fuel						
Total BTU (million)	3,987,045	4,658,641	5,378,454	5,705,943	5,548,290	6,022,360
Cents per million BTU	435.66	357.43	271.28	226.21	232.60	203.35

DIRECTORS

Theodore J. Altier
Chairman of the Board and Treasurer,
Altier & Sons Shoes, Inc.

Keith W. Amish*
President and Chief Operating Officer,
Rochester Gas and Electric Corporation

Paul W. Briggs*
Chairman of the Board and
Chief Executive Officer,
Rochester Gas and Electric Corporation

Wilmot R. Craig†
Former Chairman of the Board,
Lincoln First Banks Inc.

E. Kent Damon*†‡
Vice-President and Secretary,
Xerox Corporation

Francis E. Drake, Jr.*†‡
Chairman of the Executive
and Finance Committee,
Rochester Gas and Electric Corporation

J. Wallace Ely*†
Chairman of the Board,
Security New York State Corporation

Walter A. Fallon
Chairman of the Board and
Chief Executive Officer,
Eastman Kodak Company

Daniel G. Kennedy*
Retired Partner,
Nixon, Hargrave, Devans & Doyle

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

Paul A. Miller
Professor,
Rochester Institute of Technology

Constance M. Mitchell
Community Relations Coordinator,
Industrial Management Council
of Rochester, New York, Inc.

Cornelius J. Murphy
Group Vice-President and General Manager,
Eastman Kodak Company

William G. vonBerg*†‡
Chairman of the Board and
Chief Executive Officer,
Sybron Corporation

Leon D. White, Jr.
Executive Vice-President,
Rochester Gas and Electric Corporation

* Member of the Executive and Finance Committee of the Board of Directors
† Member of the Audit Committee of the Board of Directors
‡ Member of the Salary Review Committee of the Board of Directors
Member of the Nominating Committee of the Board of Directors

OFFICERS

Paul W. Briggs
Chairman of the Board and
Chief Executive Officer
Age 59, Years of Service, 36

Keith W. Amish
President and Chief Operating Officer
Age 58, Years of Service, 34

Leon D. White, Jr.
Executive Vice-President
Age 62, Years of Service, 44

Harry G. Saddock
Senior Vice-President, Finance and Rates
Age 52, Years of Service, 31

Mario Silvestrone
Senior Vice-President, General Services
Age 58, Years of Service, 31

John E. Arthur
Vice-President and Chief Engineer
Age 52, Years of Service, 26

Joseph J. Hartman
Vice-President, Gas and Transportation
Age 57, Years of Service, 35

Robert C. Henderson
Vice-President, Rates
Age 41, Years of Service, 18

David K. Laniak
Vice-President, Electric System Planning
and Operation
Age 46, Years of Service, 27

John E. Maier
Vice-President, Electric and Steam Production
Age 54, Years of Service, 34

Richard J. Rudman
Vice-President, Electric Transmission
and Distribution
Age 54, Years of Service, 36

Dean W. Caple
Secretary
Age 58, Years of Service, 33

David C. Heiligman
Treasurer and Assistant Secretary
Age 41, Years of Service, 18

Francis A. Sullivan, Jr.
Controller
Age 58, Years of Service, 31

Stephen Kowba
Assistant Controller
Age 62, Years of Service, 31

John M. Kuebel
Auditor
Age 46, Years of Service, 17

INVESTOR INQUIRIES

Communications regarding stock transfer requirements, lost certificates or dividend payments may be directed to Lincoln First Bank, N.A.

Other inquiries should be directed to D.W. Caple, Secretary at the Company.

The Company will provide, without charge, a copy of the Annual Report on Form 10-K filed with the Securities and Exchange Commission with respect to fiscal year 1981, upon written request of any shareholder addressed to the Secretary.

Principal Office
89 East Avenue
Rochester, New York 14649
(716) 546-2700

Financial Contact
Harry G. Saddock
Senior Vice-President, Finance and Rates

Annual Meeting
May 19, 1982
At Rochester, New York

New York Stock Exchange Symbol
Rochester Gas and Electric Corporation
Common Stock—RGS

Transfer and Dividend Disbursing Agent
Lincoln First Bank, N.A.
Stock Transfer Department
Post Office Box 1250
Rochester, New York 14603

Registrar
Security Trust Company of Rochester
One East Avenue
Rochester, New York 14638

Co-transfer Agent
Morgan Guaranty Trust Company of New York
30 West Broadway
New York, New York 10015

Co-registrar
The Chase Manhattan Bank, N.A.
One Chase Manhattan Plaza
New York, New York 10015

Agent for Automatic Dividend Reinvestment Plan
Lincoln First Bank, N.A.
Automatic Dividend Reinvestment Service
Post Office Box 1507
Rochester, New York 14603

Bond Trustee and Paying Agent
Bankers Trust Company
Post Office Box 318
Church Street Station
New York, New York 10015

RGE
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89 East Avenue
Rochester, New York 14649