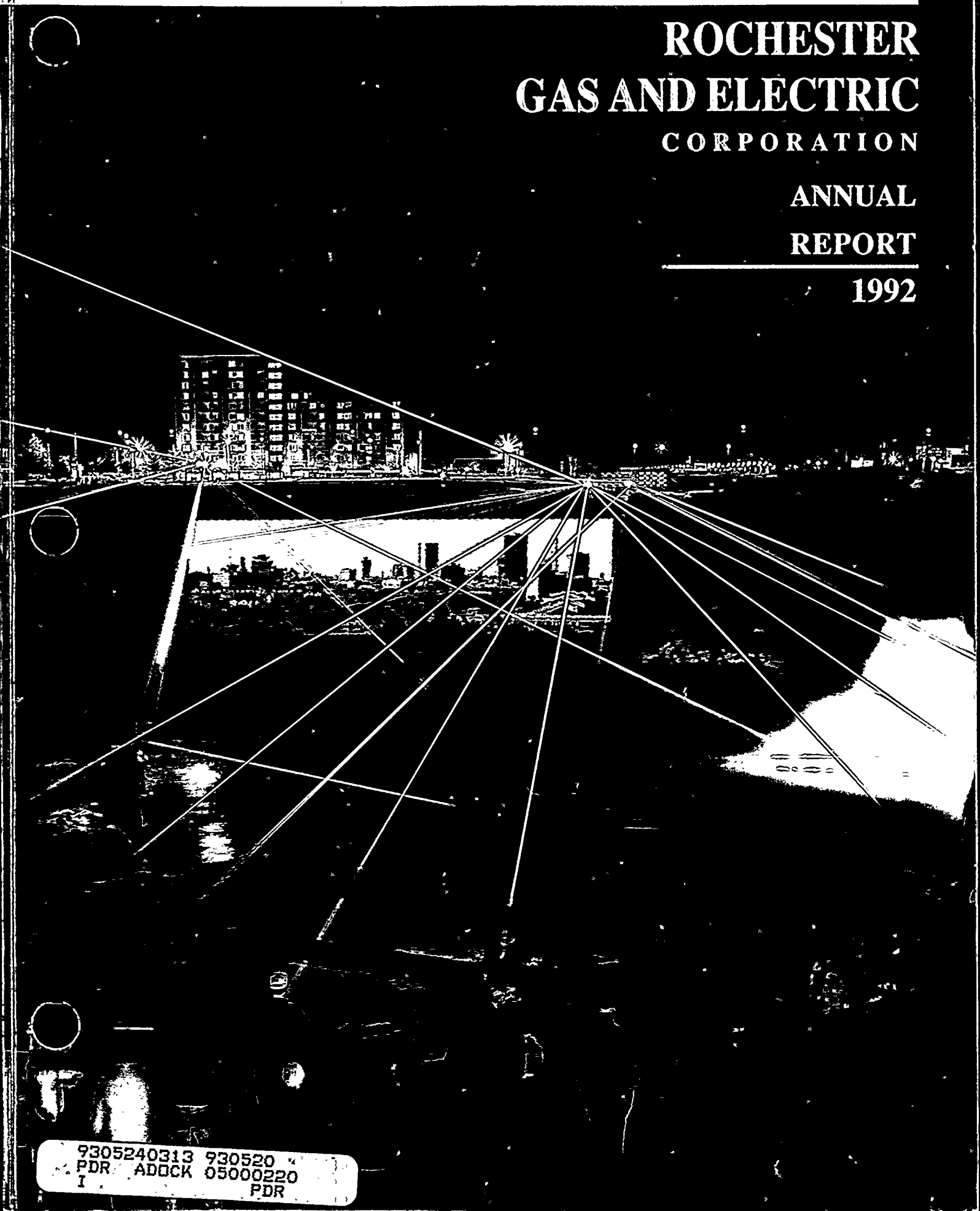
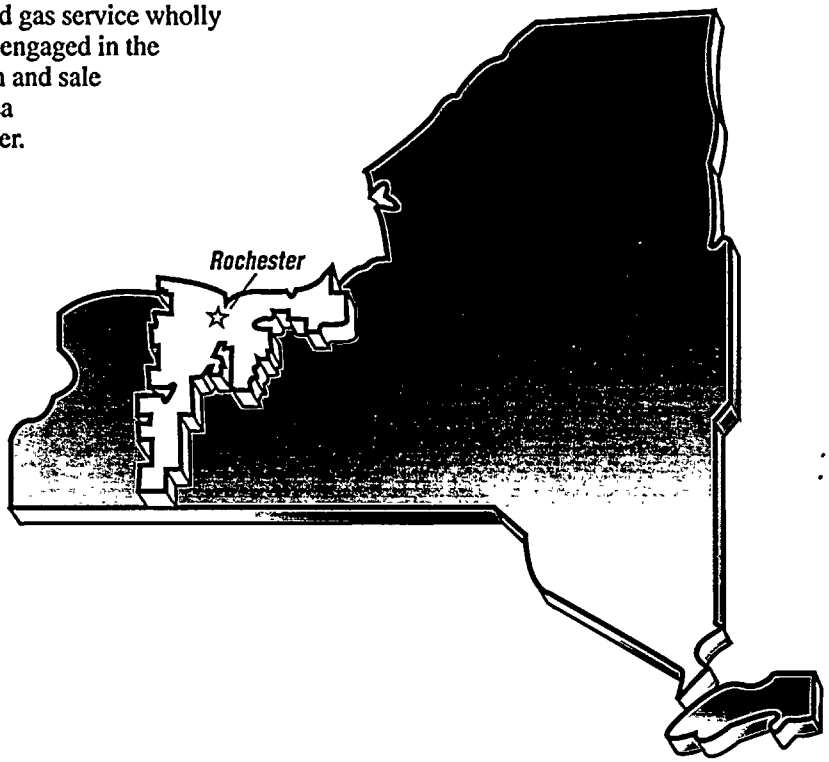
ROCHESTER GAS AND ELECTRIC CORPORATION

ANNUAL REPORT 1992

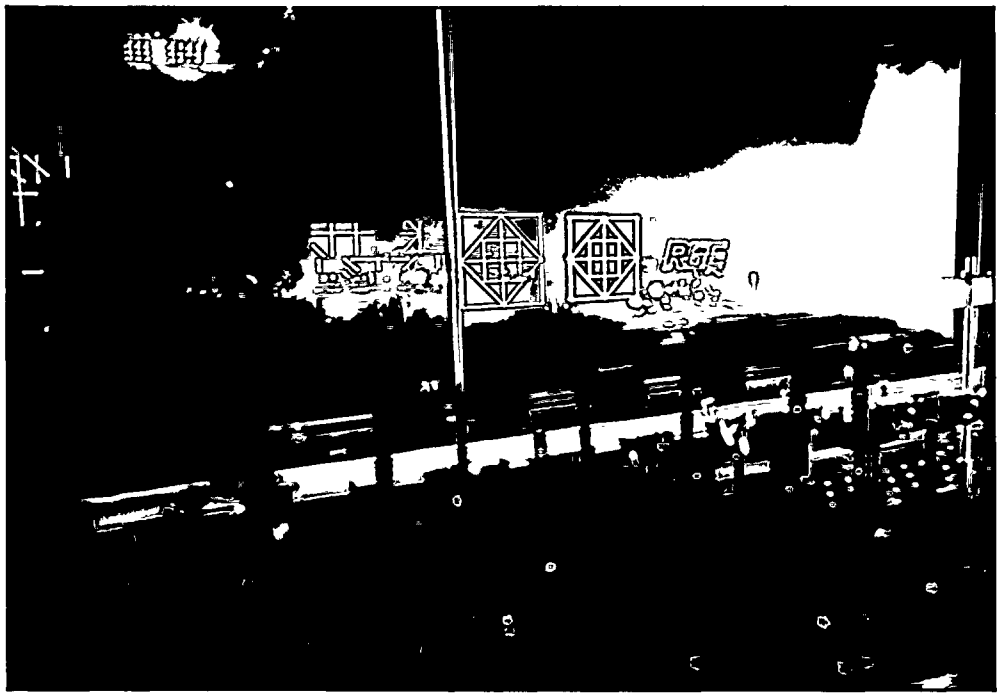


The Company supplies electric and gas service wholly within the State of New York, and is engaged in the production, transmission, distribution and sale of these services in a nine-county area centering around the City of Rochester.

The Company's territory, which has a population of approximately 920,000, is well diversified among residential, commercial and industrial customers. In addition to the City of Rochester, which is the third largest city and a major industrial center in the State, it includes a large and prosperous farming area.



(COVER) The cover pictures bursts of light from RG&E's laser show at the recently restored High Falls area of downtown Rochester. As part of a hydroelectric relicensing community improvement program, RG&E created the spectacular light show in this historic locale. Rochester's birth and the river's history are displayed on the gorge wall with photo projections, laser lights and special High Falls lighting. In its series of performances last October, more than 125,000 people viewed the River of Light Program.



(SHOWN LEFT) A look into the control room of the laser show at High Falls. All functions of the elaborate visual display are controlled from here.

(SHOWN RIGHT) A look out of the control room.

FINANCIAL REPORTS

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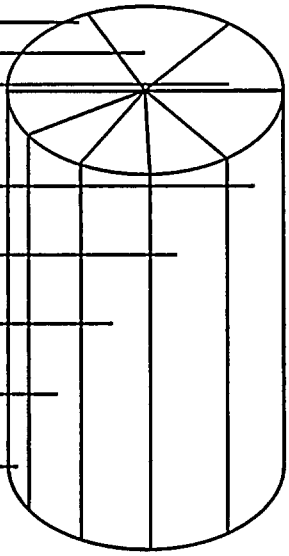
1992 REVENUE DOLLAR

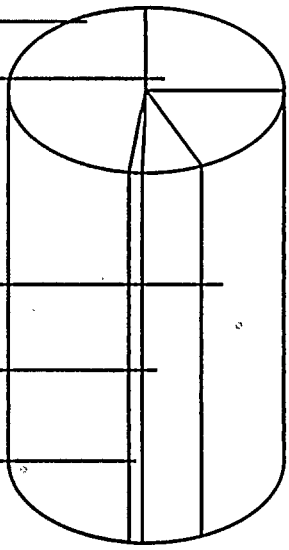
Use of 1992 Revenue Dollar

Taxes	18¢
Other Operations	17¢
Purchased Gas	16¢
Wages & Benefits	15¢
Depreciation & Amortization	10¢
Electric Fuel & Purchased Electricity	9¢
Dividends & Reinvested Earnings	8¢
Interest	7¢



Source of 1992 Revenue Dollar

Residential (25¢ Electric, 21¢ Gas)	46¢
Commercial (20¢ Electric, 5¢ Gas)	25¢
Industrial (16¢ Electric, 1¢ Gas)	17¢
Other (7¢ Electric, 2¢ Gas)	9¢
Electric Sales to Other Utilities	3¢



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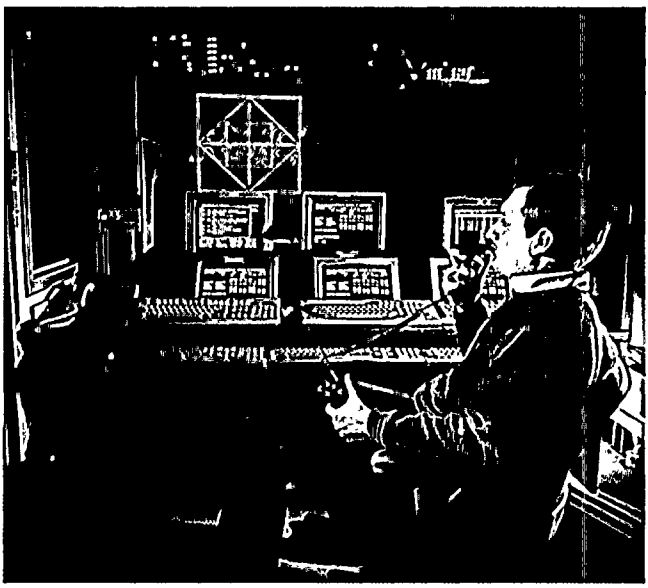


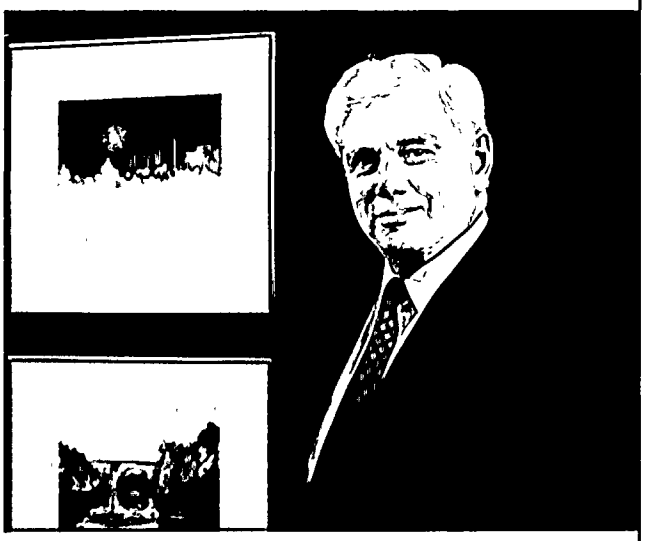
	1992	1991	% Change
Financial Data (Dollars in Thousands)			
Operating revenues: Electric	$633,808	$617,542	3
Gas	$261,724	$235,728	11
Operating expenses	$761,588	$728,511	5
Operating income	$133,944	$124,759	7
Net income	$ 70,439	$ 57,997	21
Earnings applicable to common stock	$ 62,149	$ 51,034	22
Rate of return on average common equity	9.98%	8.60%	16
Common Stock Data			
Weighted average number of shares outstanding (thousands)	33,258	31,794	5
Per common share:			
Earnings	$1.86	$1.60	16
Dividends	$1.68	$1.62	4
Book Value (year end)	$18.92	$18.41	3
Year-end market price	$24.50	$23.25	5
Operating Data			
Sales (thousands)			
Kilowatt-hours to customers	6,455,986	6,447,377	—
Kilowatt-hours to other utilities	1,062,738	1,034,370	3
Therms of gas sold and transported	526,443	470,938	12
Customers (year end)			
Electric	333,674	331,242	1
Gas	267,954	264,844	1
Construction expenditures, less allowance for funds used during construction (thousands)	$125,205	$124,057	1
Employees (year end)	2,702	2,755	(2)

Last year I wrote about our corporate vision to change from the traditional "utility-business-as-usual approach" in managing this company. I talked about "simplification, instilling a new feeling of competitiveness, streamlining of operations, and eliminating layers of bureaucracy." To improve the way we do business, I said our most important short-term goal is to fortify our pledge to customer satisfaction. We want to become partners with our customers. As the partnerships take place, the balance of our ambitious business plan will come into reach. We want RG&E to be a leader in the new competitive environment.

Well, we're on our way. We met most of our 1992 objectives in the new Corporate Business Plan. But, to me, that achievement is not nearly as important or revealing as the reform in management philosophy that is taking place here. We had *talked* about breaking out of the obsolescent "utility mentality" mold. It's no longer talk; we're doing it!

PROFITABILITY

Let's start with financial performance; probably your main concern as a shareholder. If you've read our 1992 fourth-quarter and year-end fiscal report you already know our reported earnings are up from 1991. That's a good result when we consider the write-off for some disallowed costs stemming from the 1991 ice storm and a cool summer that drew down heavily on air conditioning electric revenues.



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

Revenues were off at mid year. I called for expense reductions and asked our people to try to offset what the ice storm write-off and unfavorable weather were taking away. They came through for us. Their efforts made the difference. While I and the Executive Management Team take credit for aggressively promoting thoughtful change in the way we do business, it was the determination of RG&E people that really turned things around in 1992.

When you think about it, that call to action was a corporate milestone. You see, we assumed responsibility within the company for unpredictable, adverse events and still managed to increase shareholder earnings. That management strategy has not too often been applied in the natural monopoly environment of the utility business.

The strategy is consistent with our intent to break away from the old, more vulnerable utility business mentality. This is a driving force in the new thinking that is moving

RG&E to the leading edge of utility reform, ensuring our place in the rapidly shifting utility business climate.

We *are* more competitive. We *are* looking for more ways to work with customers who will have a choice of energy supplier. We *are* building partnerships with our customers and our regulators to help us run a solvent business.

RESOURCE PLANNING

In this report last year I described our Corporate Business Plan and its major objectives. In 1992 we constructed a companion landmark plan that is the basis for charting the successful future of our operations. Our Integrated Resource Plan (IRP) is one of the most comprehensive and innovative approaches to long-range electric supply strategies.

In our IRP we applied exhaustive study to the components of our operations. Each of our owned-and-operated electric generating facilities was subjected to intense cost-benefit analyses based on projected lifetimes, fuel, operating expenses, capital costs and environmental considerations. Other potential sources of power were factored in, such as electric load control through our energy management efforts that can control energy requirements and forestall power plant construction. Electric power potential from cogenerators in the private sector was calculated as well.

After closely examining all the individual pieces, we assembled more than a dozen comprehensive scenarios. The idea was to minimize costs to the customer while providing an attractive rate of return for investors and producing environmental benefits for the communities. We're saying "that's being competitive!"

We're not the only power company with an IRP, but there is at least one wrinkle that I think sets us apart. If it's unusual for a power company to consider embracing potential competitors in energy supply, then our IRP is unusual. We are seeking active partnerships with industrial and commercial customers in workable energy-producing projects.

...it was the determination of RG&E people that really turned things around in 1992.

Partnerships with customers may result in RG&E operating customers' electric generating or cogenerating equipment. We may become part owners with customers in energy-producing projects or even own the whole facility under a contractual relationship with an industrial, commercial or institutional customer. Another example is our partnership in the Empire State Pipeline that will offer an alternative natural gas supply in upstate New York.

This all has to do with new ways of thinking. To prepare for the new utility environment and remain competitive we're finding ways to do things better. Where other gas and electric companies may see obstacles, we see opportunities. It's all part of our commitment to the goals of the Corporate Business Plan that center largely on price of product, customer satisfaction and financial reward for shareholders.

WHERE DO WE DRAW THE LINE?

In line with our departure from traditional utility thinking, we are taking a critical look at the components of our business. If a component is shown not to be competitive we will do one of two things. Either we will make that operation competitive, or we'll get

rid of it. The principle is simple; if a unit can't continue to contribute to a company's success, it's no longer an asset; it's a liability. You keep assets and get rid of liabilities.

CASE IN POINT

Our Ginna nuclear power plant is more than 20 years old. It has served our customers well since it first went into commercial operation in 1970, economically and competitively producing half of our customers' electric power needs. I said our IRP closely studied the useful futures of our power plants. The IRP examined the remaining operating life of the Ginna plant to the expiration of its license in the year 2009.

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

Three options were open for the Ginna plant. One was to shut the plant down. Another was to continue to operate the plant with the existing and aging steam generators until 2009 at reduced efficiencies. Replacing the steam generators was the third.

No scenario showed any benefit for the customers in shutting the plant down, so that option was set aside. Continuing to operate the plant with the original steam generators showed, under close examination, that there would be no cost saving, and that declining generating capacity would likely require replacement power from fossil-fired stations with attending air-quality impact. In contrast, replacement of the steam generators could restore declining electric capacity at the plant, better ensure reliability, reduce planned shutdowns for refueling and maintenance and save our customers $30 million by the year 2009.

Applying the criterion of insisting that an asset remain an asset, we decided to replace the steam generators. Preliminary work began this year with actual replacement scheduled for 1996. The project will cost $115 million over four years.

Here's some further evidence of our redirected thinking. Our contracts for the steam generator replacement call for the contractors to absorb any cost overruns, and set incentives to complete the job on schedule. That's become the corporate policy in dealing with vendors. We're running our place like a business and we expect the same from our suppliers.

ONE-STOP SHOPPING

Customer satisfaction is at the root of our business reform at RG&E. In 1992, we further obligated our corporate culture to improve customer service. Customer contact training programs have been intensified. A customer satisfaction communications program was started so that employees can track measurable results. We look for better ways to accommodate our customers—residential, commercial, industrial, institutional and municipal alike.

We ask ourselves tough questions. Why, for example, should it be that a gas and electric company performs customer services on its own schedule? How about thinking about the customer's schedule and the customer's convenience? And, why should it be that a customer sometimes has to make several calls or be shuffled from one service department to another to get what they want? And, where is it written that our connection with our customers ends at the meter? We have to minimize what has to be

done to serve customers and offer better ways for customers to do business with us.

Here's one thing we came up with. We're designing a customer service concept that we call "One-Stop Shopping." A new organizational structure, drawn from existing departments and personnel, is being set into place so that an RG&E customer can always make just one call or visit us and get their business taken care right there and then.

Our One-Stop Shopping plan starts this year. We have leased a commercial complex in Rochester that will house the One-Stop resources under one roof. We think meshing the components of customer service into a new structure at a common location will produce impressive results. The new facility is expected to be fully staffed and functional this year.

WHERE IT'S ALL GOING

This business is changing fast, and we're trying to place RG&E in the best position to take advantage of the opportunities out there. Innovation, action and employee commitment are key to our progress. We're separating ourselves from the old utility business that too often relied on regulators to help cover costs and not often enough on effective, strategic thinking. We are moving beyond regulation so that we will become what we *plan* to do, not what we're *told* to do.

Our new thinking is demonstrated by the proposed three-year rate settlement agreement before the Public Service Commission. The proposed agreement achieves the objective of joining the interests of the company and our customers by improving service and controlling costs.

To help shape RG&E for the future, I established a nine-member Executive Management Team reporting directly to me. This group of executives represents a departure from the more traditionally narrow scope of utility management in the old marketplace that was free from competition. It is a team concept in which the members have accepted a willingness to change business operations; to constantly reinvent the way we do business. We believe good performance breeds good business, and we believe we're on the way to becoming a gas and electric company that will flourish in the new world of utility operations. To sum up our real success in 1992, I say this. "In 1992 RG&E got hold of its future."

Where other gas and electric companies may see obstacles, we see opportunities.

And, as for the immediate future as we see it, we are responding to three critical areas in our business. We will increase customer satisfaction, become more cost competitive, and we will grow this business.

In the theme section of this report that follows this letter we describe and illustrate some progress in energy management and employee achievement that is putting us in the lead of the changing gas and electric business. Following the theme section is our Management's Discussion and Analysis report where you'll find our 1992 operations and results covered in detail.

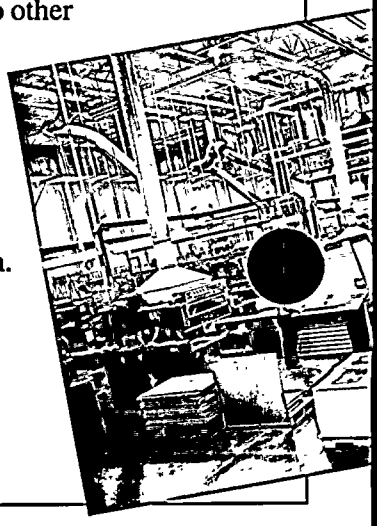
Roger W. Kober
Chairman of the Board,
President and
Chief Executive Officer
February 3, 1993

Customer satisfaction is at the core of our vision. Satisfied customers are the best guarantee for a healthy corporate future that advances public acceptance, competitive prices, employee effectiveness and attractive financial performance. Our 1993 Corporate Business Plan plainly states the corporate direction. "Our first priority is providing—as the supplier of choice—safe, reliable, environmentally responsible, cost-efficient energy and service to our customers." ■ Customer satisfaction comes from good service. Getting your money's worth is good service in anybody's book. We're forming partnerships with our customers that will help them get the most for their energy dollar.

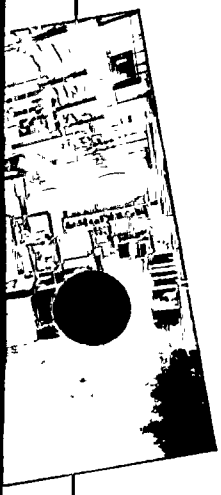
Rochester-based printers, Case-Hoyt Corporation, found substantial energy savings and incentives in partnership with RG&E. Project engineers from Case-Hoyt and RG&E are seen going over specifications.

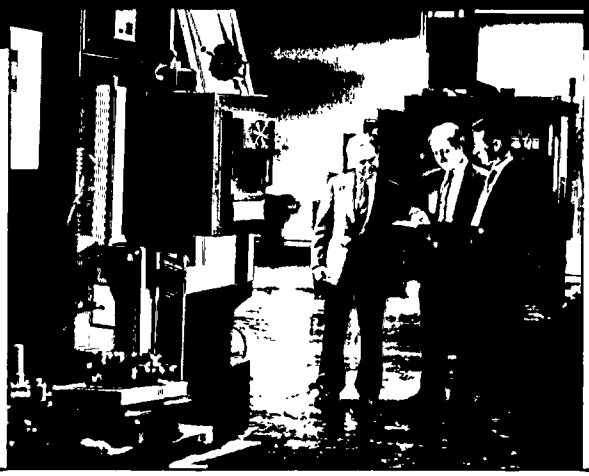
COMMERCIAL & INDUSTRIAL

Case-Hoyt operates a large printing complex in the Rochester area. The company was planning an expansion of the facility but there was some thought on the part of the parent company to relocate it instead. ■ Printing is energy intensive with large presses, chiller systems for processes, and temperature and humidity control equipment. After an energy audit, we made recommendations and provided technical support and cash incentives for energy-efficient equipment and lighting that are substantially cutting Case-Hoyt's energy bills. The reduced costs of operating, due to RG&E's energy management programs, allow Case-Hoyt to put the savings into other programs that protect and even create industrial jobs in this area.



Gleason Works, a longtime Rochester-based manufacturer of gears and tool and die equipment, received engineering and incentives from RG&E for chillers, motor drives and lighting. Energy savings are substantial here, too.

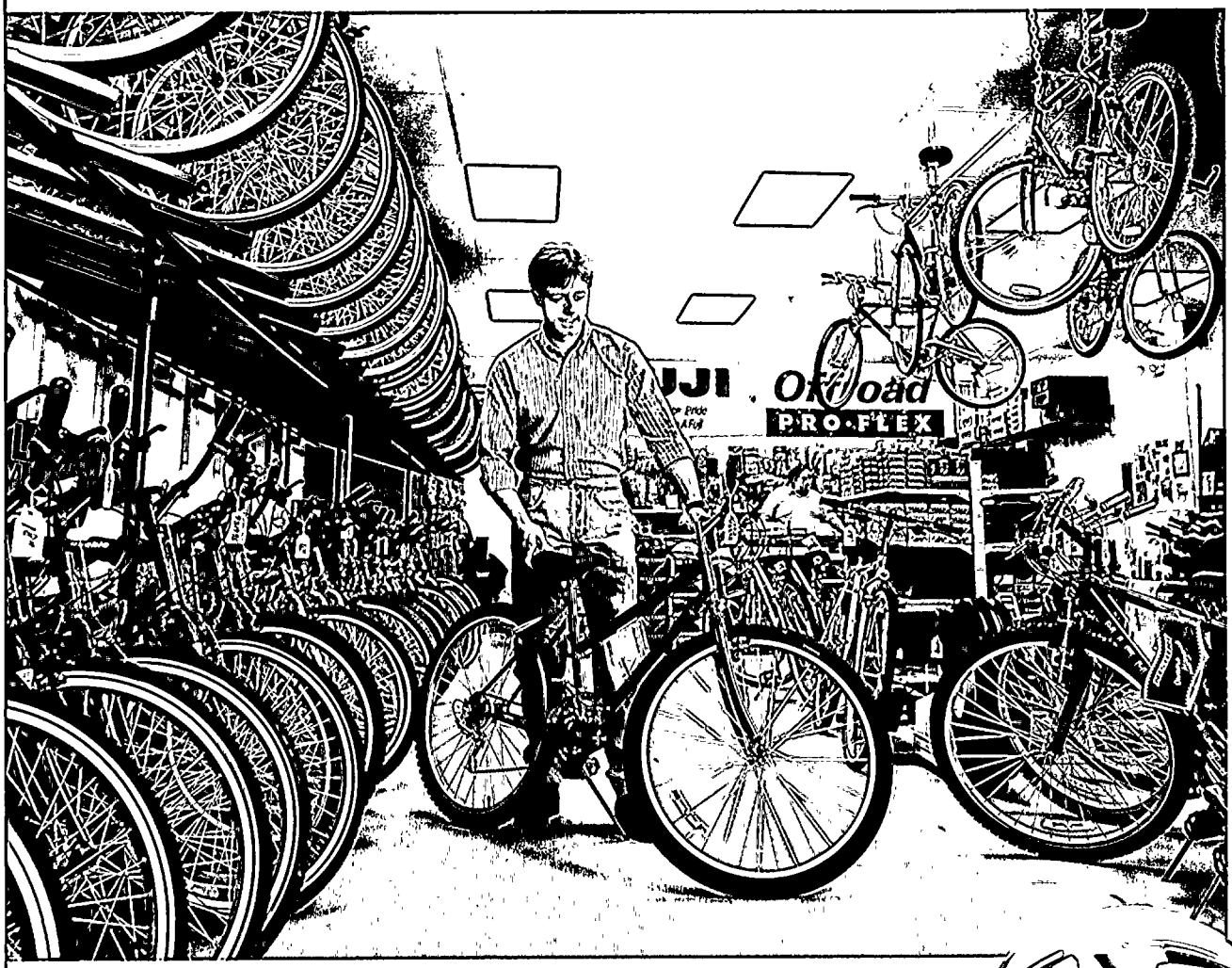




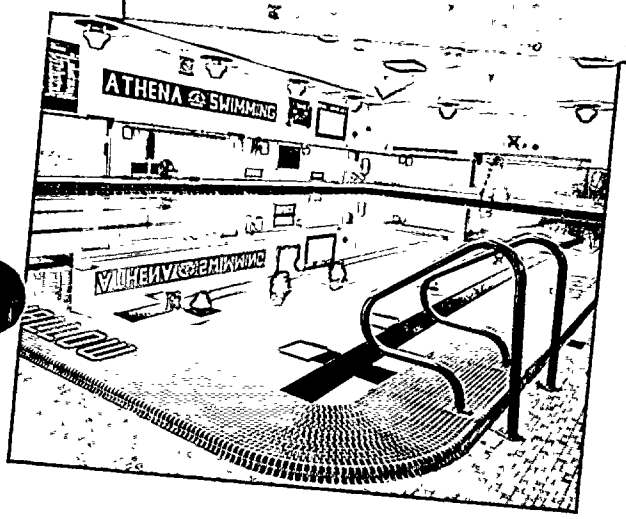
A comprehensive RG&E industrial energy audit of Gleason Works led to greater electric value and savings for this Rochester industry.

Our partnerships with institutional customers brought more efficient lighting, motors and special energy-efficient equipment to many schools such as Greece Athena High School pictured in this report. At Greece Athena RG&E provided engineering and incentives for state-of-the-art, natural-gas-fueled equipment that offers cost-saving building air conditioning while heating the school's swimming pool.

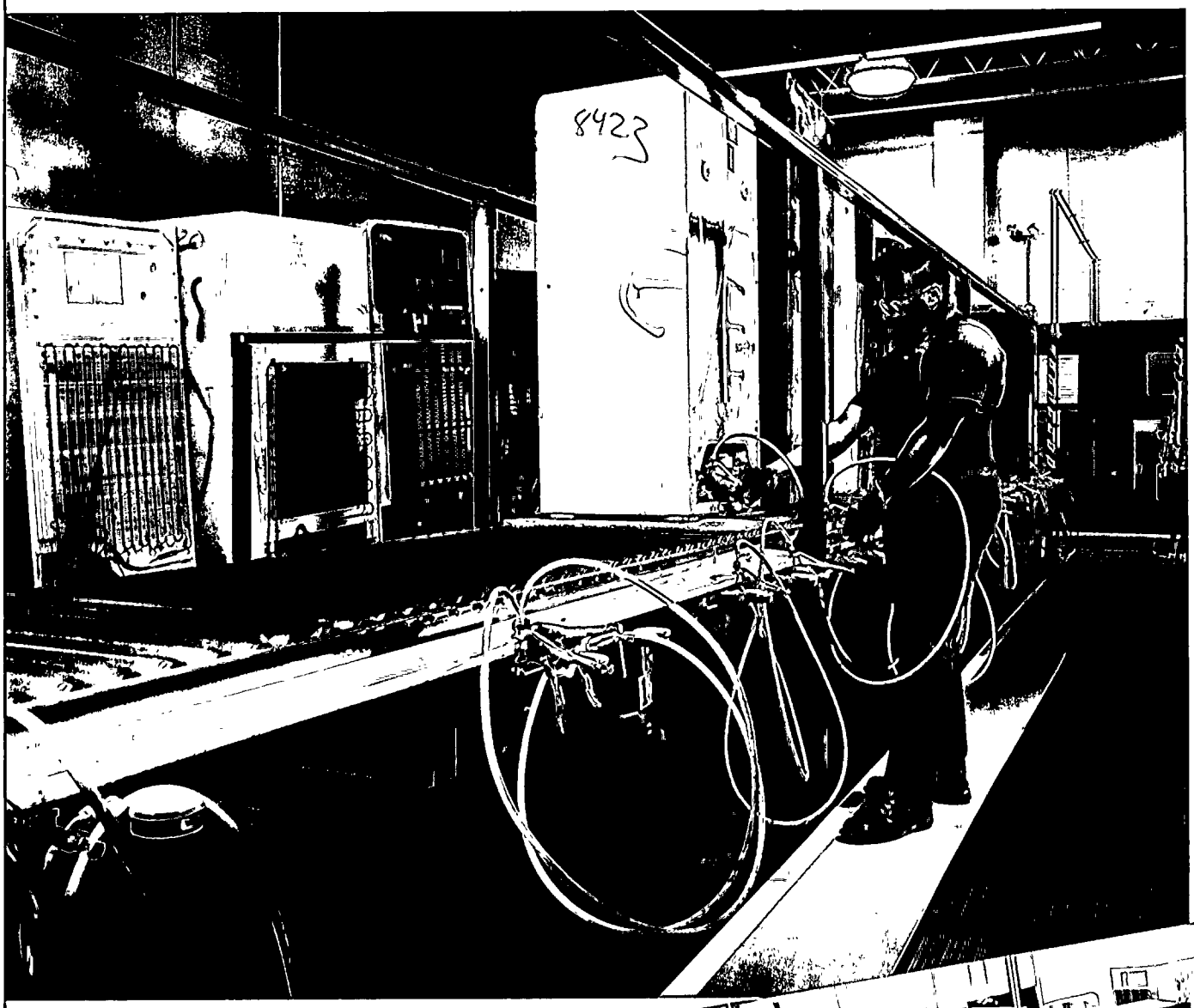
On a smaller scale, a family-owned bike repair shop received added energy product value from us in the form of improved, energy-efficient lighting. More than 2,000 commercial and industrial customers benefited from RG&E's energy utilization programs in 1992.



Family-owned bike shop, Bicycle Country, found better lighting and energy efficiency in partnership with RG&E.



Greece Athena High School found energy savings with a natural-gas-fueled chiller that helps air condition the school in one mode while heating the pool in another. RG&E formed energy partnerships with many schools and institutions in 1992.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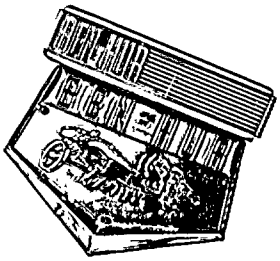
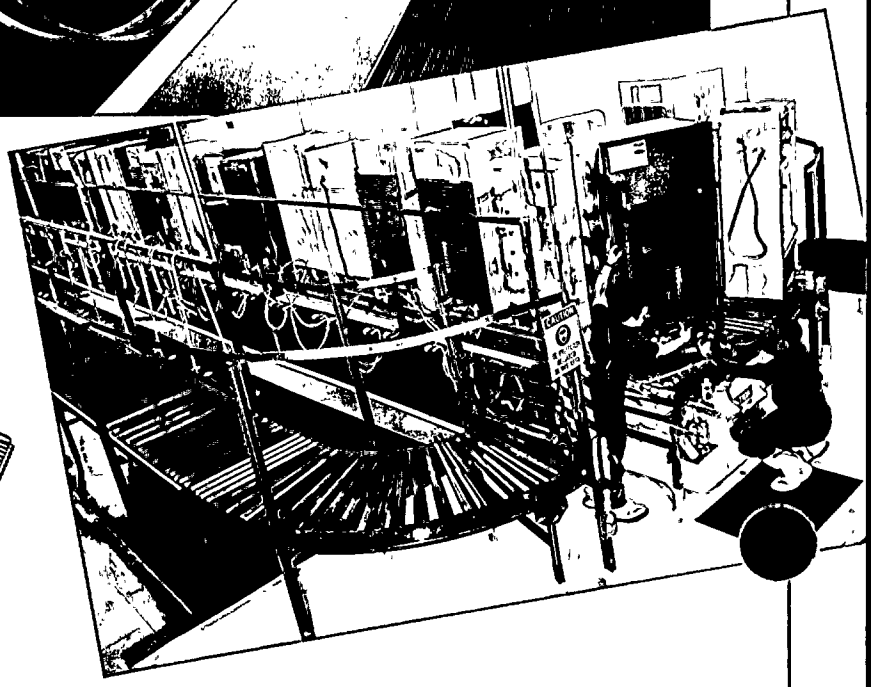
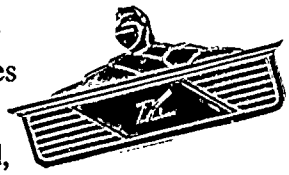
LEONARD





RESIDENTIAL

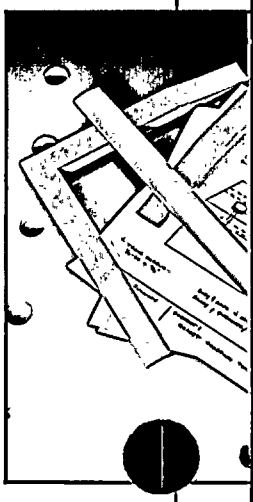
Many households harbor an old second refrigerator operating in the basement or garage. The older models are neither energy efficient nor often used for much. People hang on to them because it's not easy to get rid of them. You have to pay a company to pick them up and dispose of them in an environmentally acceptable manner. ■ In an advertising campaign we call these second refrigerators "energy hogs," and we offer our residential electric customers an easy way to get rid of them. We'll have them removed at no cost and even leave a $50 U.S. Savings Bond behind as an added incentive. ■ Our contractor collects the refrigerators and disposes of them in an environmentally approved manner. As of year-end, more than 7,000 second refrigerators were collected. ■ We're offering rebate incentives for customers to shift from electric to gas appliances. Qualifying electric customers can get anywhere from $140 to $220 back on the purchase of certain gas appliances such as water heaters, dryers and ranges. Last year, 2,573 customers took advantage of the offers. ■ We are giving rebates for qualifying high-efficiency central air conditioning systems, heat pumps and electric water heaters. More than 1,000 residential customers took advantage of these offers last year. ■ In all, energy partnerships with customers are producing annual energy savings of 69,745,000 kilowatt-hours. That's enough electricity to power 10,000 homes for a year. And, that's better value for our customers' energy dollar, a key part of customer service, and another step forward in controlling the higher costs of energy.



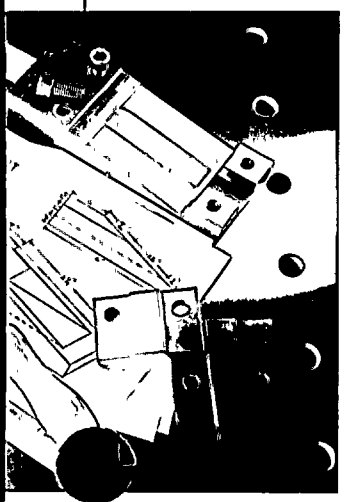
Residential electric customers take advantage of incentives to switch from electric appliances to gas appliances. Pictured is a customer who is switching from electric coils to gas burners.

IDEAS THAT ARE PAYING OFF

Looking for better ways to do things is another key to success. Our Employee Suggestion Program offers a formal channel where employees can contribute ideas that may reduce costs and improve productivity. While working on a scheduled refueling, maintenance and inspection outage at the Ginna nuclear power plant, some RG&E people thought of a way to improve the steam generator tube sleeving process. Sleeving restores tube strength and helps maintain steam generator efficiency. In that process, technicians enter the steam generators to operate sleeving equipment. They are exposed to very low levels of radiation. The exposure is closely monitored, and as workers approach the conservative, safe limit of accumulated dose, they have to be replaced. ■ Three inventive RG&E employees working at the plant came up with a special fitting for a sleeving mechanism that cuts the time technicians spend inside the steam generators, increasing their productive time on the job. They fabricated the tool in an RG&E machine shop.



■ Another idea is saving nearly $70,000. A few electric substation people thought they could make barrier board gaskets right at RG&E rather than ordering them from a supplier. These gaskets, costing more than $3,500 apiece, are used in large substation transformers. Their thinking proved right when they showed that the gaskets could be produced by skilled workers at RG&E for less than $100 each. ■ Cash awards in 1992 ranged from the $50 minimum to the $10,000 maximum for a total payout of $85,173. The ideas adopted are saving the company more than $500,000 a year. And 1993 is off to a great start with an employee idea that can potentially save the company $230,000 a year by compressing a five-day training and qualification program into three days. ■ Better energy values for our customers, and better ways of doing things are moving us along well in our goal of improved customer satisfaction as their energy supplier of choice.



These RG&E employees thought there may be a better way to produce special substation gaskets. Kevin Sullivan [left] and Jim Suter found a way that already saved the company $70,000. (above)

RG&E's Sharon Eckert restructured a five-day training and qualification program for nuclear plant contractors to take place in just three days, producing a potential annual savings of more than $200,000. (left)

Imaginative RG&E employees brought an idea for a special steam generator maintenance tool to life in a company machine shop. Pictured are Lauren Blood [left] and Dick Cantwell. Tom May [not pictured] was the third in this team of inventors. (page 12)

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

Liquidity and Capital Resources

During 1992 cash flow from operations, together with proceeds from external financing activity (see Statement of Cash Flows, page 33) provided the funds for construction expenditures and the retirement and refinancing of long-term debt. Additional external financing during 1993 is anticipated by the Company to satisfy capital requirements, including security maturities and sinking fund obligations.

Projected Capital and Other Requirements.

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

The Company has no current plans to install additional baseload generation. The Company has accepted bids and is continuing negotiations for the addition of approximately 24 megawatts of capacity savings to be phased-in over the 1993–1995 period and, beginning in 1994, expects approximately 55 megawatts of capacity to be supplied by a cogenerator under contract with the Company.

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

One result of the IRP was the decision made by the Company in December 1992 to replace the two steam generators at the Ginna nuclear plant in 1996. Like similar plants, the Ginna nuclear plant has experienced degradation in some of the tubes that make up each steam generator. About 30 percent of these tubes have required repair. In addition, a chemical buildup in some of the tubes has reduced their heat transfer capability. Both conditions would continue to erode the plant's performance if the existing steam generators were left in place. Installation of new steam generators was the most cost-effective, reliable and environmentally compatible option for the plant evaluated as part of the IRP. The new steam generators should result in reduced maintenance costs and help sustain a high level of plant availability. Cost of replacement is estimated at $115 million, with preparation to begin during the plant's routine 1993 fuel outage.

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

- The plan calls for evaluating the possibility of using either alternative generation or current generating equipment in partnership with certain large industrial customers.
- The Company will continue to use demand side management programs to reduce the need for generating capacity.

- The Company will consider phasing out our coal-fired Beebee Station by the year 2000, unless it is converted to natural gas and operated under a partnership arrangement with a large customer.
- Two of the four units at the Company's coal-fired Russell Station are expected to be converted to burn low-sulfur coal by the year 2000. The remaining two units will either be converted to burn low-sulfur coal or natural gas, or will be phased out by that same year.

The Company has four hydroelectric generating facilities (aggregate capability of 49 megawatts) operating under licenses issued by the Federal Energy Regulatory Commission (FERC), all for terms expiring December 31, 1993. In December 1991 the Company submitted final license renewal applications to FERC for these facilities. At the expiration of the licenses, FERC may issue new licenses to the Company or, in the alternative, may issue licenses to new licensees or recommend to the United States Congress takeover of the stations by the Federal government. In the event of a takeover of a station by the Federal government or the issuance of a license to a new licensee, the Federal Power Act (FPA) provides that the Company may be compensated for the loss of the station in an amount to be determined by FERC. There are no competing applications. After the Company provided supplemental information, FERC accepted all four renewal applications for filing and commenced its environmental review. As a part of the FERC licensing process under the FPA, the New York State Department of Environmental Conservation (NYSDEC) recently issued certifications for each of these four hydro stations. The certifications contain a wide array of conditions, some of which could be difficult and/or expensive for the Company to meet. Several of the conditions appear to be beyond NYSDEC's ability to impose, under present law, in such certifications. NYSDEC has requested FERC to require the same or similar measures as conditions of the FERC renewal licenses, which request the Company intends to oppose. Upon the expiration of its current extensions of time in which to respond to these conditions, the Company plans to request a NYSDEC hearing on them and to negotiate with the NYSDEC for their amicable resolution. Unless so resolved or vacated through litigation, certain of the conditions would negate economic operation of one or more of the stations and may require the Company to abandon efforts to relicense the stations so affected.

Construction is expected to begin in 1993 on the Empire State Pipeline Project (Empire), an intrastate natural gas pipeline subject to PSC regulation which is proposed to be constructed between Grand Island and Syracuse, New York. The Company is participating as an equity owner of Empire, along with subsidiaries of Coastal Corporation and Union Enterprises, LTD. In June 1991 the PSC authorized the Company to invest up to $20 million in Empire subject to certain conditions, notably that the investment not be included in rate base. This project will provide capacity for up to 50 percent of the Company's gas requirements by its second year of operation. The construction of Empire was approved by the PSC in March 1991 and proceedings in October 1991 for State judicial review of the PSC decision were dismissed in July 1992. The Canadian National Energy Board in June 1992 granted authorization for TransCanada, a gas transmission company, to construct the Blackhorse extension to its existing main line in order to connect with Empire at Grand Island. The only remaining major regulatory requirements for Empire involve Corps of Engineers permits to cross navigable waters and federally-regulated wetlands and that process is underway. An inservice date for Empire of November 1993 is currently anticipated. In 1992 the Company formed a wholly-owned subsidiary, Energyline Corporation, to

acquire its ownership interest in Empire. During 1992 approximately $10 million was invested by the Company in the Energyline Corporation, and up to an additional $10 million is expected to be invested during 1993. The Company's share of ownership in Empire will be dependent upon final project costs and the timing and method of financing selected by the Company.

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

Capital Requirements and Electric Operations. Electric production plant expenditures in 1992 included $35 million of expenditures made at the Company's Ginna nuclear plant and $3 million for its 14 percent share of expenditures at the Nine Mile Two nuclear facility, exclusive of fuel costs. Nuclear fuel expenditures of $9 million were incurred at Ginna in 1992 and expenditures of $2 million were made for nuclear fuel at Nine Mile Two. On March 4, 1992 Nine Mile Two was taken out of service for a scheduled refueling outage. Refueling was completed and Nine Mile Two resumed operation on July 4, 1992. The prior refueling outage occurred from early September 1990 to month-end January 1991. The next refueling outage for Nine Mile Two is anticipated to begin in September 1993. A refueling outage at Ginna normally occurs annually for a period of approximately 40 to 50 days.

Electric transmission and distribution expenditures, as presented in the table below, totaled $35 million in 1992, of which $30 million was for the upgrading of electric distribution facilities to meet the energy requirements of new and existing customers. In 1992 the Company also recognized $3.9 million of transmission and distribution improvements, a portion of the Company's

Capital Requirements

	Actual			Projected		
Type of Facilities	1990	1991	1992	1993	1994	1995
	(Millions of Dollars)					
Electric Property:						
Production	$ 47	$ 44	$ 47	$ 55	$ 59	$ 60
Transmission and Distribution	31	29	35	32	35	36
Street Lighting and Other	2	2	2	2	2	2
Subtotal	80	75	84	89	96	98
Nuclear Fuel	7	12	11	15	19	14
Total Electric	87	87	95	104	115	112
Gas Property	20	22	19	17	19	24
Common Property	15	13	15	18	12	19
Total	122	122	129	139	146	155
Carrying Costs:						
Allowance for Funds Used During Construction (AFUDC)	5	4	2	3	3	4
Deferred Financing Charges Included in Other Income	3	5	3	1	–	–
Total Construction Requirements	130	131	134	143	149	159
Securities Redemptions, Maturities and Sinking Fund Obligations*	28	92	160	116	27	9
Total Capital Requirements	$158	$223	$294	$259	$176	$168

*Excludes prospective refinancings.

cost associated with a severe March 1991 ice storm (see following paragraph).

In early March 1991, the City of Rochester, New York and surrounding counties were hit by a severe ice storm, the worst storm in the history of the Company's service territory. Pending a review at the time by the PSC of storm-related costs, as well as the Company's performance during the storm, $36.4 million of storm-damage repair costs were reflected under deferred debits on the Company's December 31, 1991 Balance Sheet. The Company had estimated that approximately 20 percent of these deferred costs were related to capital improvements (with operating and maintenance expenses comprising the balance). In the Company's June 1992 rate decision, the PSC accepted the Company's estimated capital improvements and, accordingly, in 1992 the Company commenced recognizing those storm-related capital costs. The final determination of the amount to be capitalized has not yet been made by the Company. Additional details of the Company's June 1992 rate decision, including recovery of the 1991 storm-damage repair costs, are discussed on page 21 under the heading New York State Public Service Commission (PSC).

Capital Requirements and Gas Operations. In the Gas Department, the replacement of older cast iron mains with longer-lasting and less expensive plastic and coated steel pipe, the relocation of gas mains for highway improvement, and the installation of gas services for new load resulted in construction expenditures of $19 million in 1992. Following its construction during 1991 at a cost of approximately $3.3 million, a new 5.0 mile, 24-inch gas pipeline was placed in service in January 1992. This new gas connection has helped the Company improve supply reliability in the northwestern quadrant of the Company's gas franchise area.

Environmental Issues.

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

As a part of our commitment to environmental excellence, the Company is conducting voluntary Site Investigation and Remediation (SIR) efforts at Company-owned sites where past contaminant handling and disposal may have occurred. The purpose of these investigations is to determine if remedial measures are appropriate. The Company estimates spending $10 million over the next 5 years on SIR initiatives.

On November 15, 1990 the Federal Clean Air Act Amendments of 1990 (Amendments) became law. The Amendments will affect air emissions and quality control measures primarily at the Company's fossil-fueled electric generating facilities (see Note 10 of the Notes to Financial Statements). A Clean Air Act Task Force has been formed within the Company to review compliance with these requirements and is in the process of identifying the optimum mix of control measures and associated potential technology changes that will allow the fossil-fuel based

portion of the generation system to fully comply with state and federal environmental requirements. Although work is continuing, the compliance control options have not as yet been determined for the entire fossil-fueled system. More detailed compliance decisions are expected to be made by mid-1993. Capital costs, however, between $30 million and $50 million (1992 dollars) have currently been estimated for the implementation of several potential compliance scenarios. Such capital costs would be incurred between 1993 and 2000 if the Company elected to go forward with any such scenario. The Company currently estimates that it could also incur up to $1.5 million (1992 dollars) of additional annual operating expenses, excluding fuel, to comply with the Amendments. The use of scrubbing equipment is not presently being considered. Likewise, the purchase or sale of "emission allowances", as allowed by the Amendments, is not currently being considered. The Company anticipates that the costs incurred to comply with the Amendments will be recoverable through rates based on previous rate recovery of environmental costs required by governmental authorities.

Redemption of Securities.

A $75 million first mortgage bond maturity and $5 million of sinking fund obligations were a part of the Company's capital requirements in 1992. In addition, discretionary first mortgage bond redemptions totaled $79.5 million during 1992.

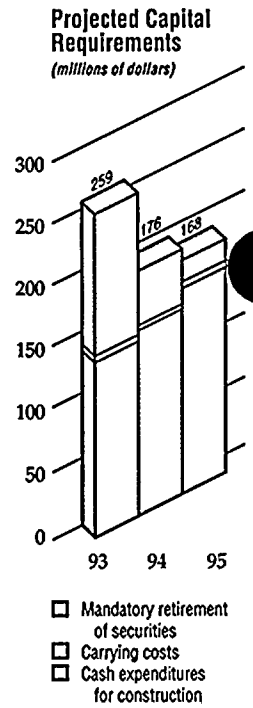
Capital requirements in 1991 included $28 million of sinking fund redemptions, a $15 million first mortgage bond maturity, and a discretionary first mortgage bond redemption of $49.3 million.

Capital Requirements—Summary.

The Company's capital program is designed to maintain reliable and safe electric and natural gas service and to meet future customer service requirements. Capital requirements for the three-year period 1990 to 1992 and the current estimate of capital requirements through 1995 are summarized in the table on page 16.

For the period 1993 to 1995, the Company anticipates construction requirements to total approximately $450 million. Expenditures made at the Company's nuclear facilities to improve operating efficiency and reliability and to comply with regulatory requirements are a significant component of electric production plant costs over the period. Such projected plant costs include an allowance by the Company of $14 million in 1993, $20 million in 1994 and $15 million in 1995 for the replacement of the steam generators at the Ginna nuclear plant.

In addition to its construction expenditures, the Company has security maturities and sinking fund obligations totaling $152 million over the three-year period 1993 to 1995 as shown by the graph to the right. Excluded from the capital requirements table on page 16 are expenditures associated with the Empire project and the Company's obligations to the United States Department of Energy for nuclear waste disposal and uranium enrichment decommissioning (see Notes 1 and 10 of the Notes to Financial Statements).

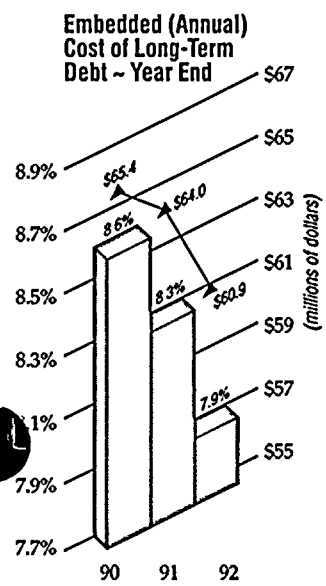


The AFUDC amounts included in the table on page 16 are the financing costs associated with major projects under construction. This carrying cost becomes part of the capitalized cost of the related project. The Company begins to earn a cash return on its investment, including this carrying cost, when the cost of the project is included in rate base, which generally is at the time the project

enters service. In addition to AFUDC, carrying charges include the recognition of certain customer prepaid financing costs, as further discussed on page 23.

Liquidity, Financing and Capital Structure.

Capital requirements in 1992 were satisfied by a combination of long-term debt and equity issues, internally generated funds, and short-term borrowings. The Company during 1992 continued to take advantage of favorable market rates and security provisions which allow early redemption to refinance $50 million of its higher cost long-term debt. Such refinancing activity over the past two years has helped to reduce the annual cost of long-term debt by approximately $4.5 million and contributed to a drop in the Company's embedded cost of long-term debt from 8.6% at year-end 1990 to 7.9% at the end of 1992, as illustrated by the graph to the left. Common shareholders equity increased during 1992 as the result of a public issue of two million shares of Common Stock in August.



The Company believes that an average of approximately 80 percent to 85 percent of the funds required per year for its 1993 through 1995 construction program will be generated internally and the balance will be obtained through the sale of securities and short-term borrowings. The Company also anticipates that the sale of securities and short-term borrowings will be required to satisfy security maturities and sinking fund obligations over the three years 1993 through 1995. Although the Company expects to issue securities during 1993, it is the Company's intention to utilize its credit agreements to meet any interim external financing needs prior to the issue of such securities. As financial market conditions warrant, the Company may, from time to time, issue securities to permit the early redemption of higher-cost senior securities. The Company's financing program is under continuous review and may be revised depending upon the level of construction, financial market conditions, rate relief, cost of capital and other factors.

Financing. Interim financing is available from certain domestic banks in the form of short-term borrowings under a $90 million revolving credit agreement which continues until December 31, 1995 and may be extended annually. Borrowings under this agreement are secured by a subordinate mortgage on substantially all property except cash and accounts receivable. Additional borrowing capability for up to $20 million of short-term debt is also available under a separate credit agreement with a domestic bank. Borrowings under this agreement, which can be renewed annually, are secured by the Company's accounts receivable. Also, beginning in August 1992, additional unsecured short-term borrowing capacity of up to $25 million is available from a domestic bank, at its discretion. At December 31, 1992 the Company had short-term borrowings outstanding of $50.8 million, consisting of $20.8 million of unsecured short-term debt and $30.0 million of secured short-term debt.

Under provisions of the Company's Certificate of Incorporation (Charter), the Company may not issue unsecured debt if immediately after such issuance the total amount of unsecured debt outstanding would exceed 15 percent of the Company's total secured indebtedness, capital, and surplus without the approval of at least a majority of the holders of outstanding Preferred Stock. Under this restriction, the Company as of December 31, 1992 was able to issue $45.2 million of additional unsecured debt. Additional interim financing capability remains available with secured borrowings under the Company's credit agreements, as discussed above.

In March 1992 the Company completed the public sale of $100 million principal amount of First Mortgage 8¼% Bonds, due 2002, Series QQ. Proceeds from this financing were used to repay certain of the Company's outstanding short-term debt and to finance a portion of the Company's capital requirements.

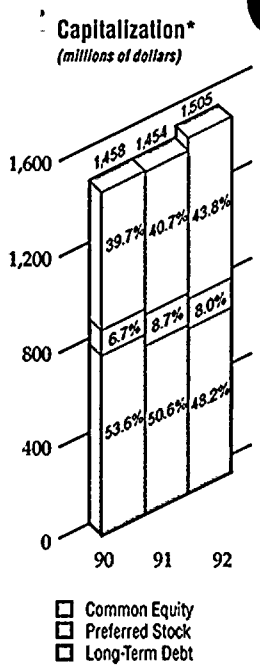
In June 1992 the Company refinanced $60.5 million of long-term debt when it completed a public offering of $10.5 million First Mortgage 6.35% Bonds, Series RR, and $50 million First Mortgage 6½% Bonds, Series SS, both due 2032, in connection with the issuance of a like amount of New York State Energy Research and Development Authority Pollution Control Refunding Revenue Bonds. The proceeds were used for the early redemption of $10.5 million of First Mortgage 12¼% Bonds, Series HH, and a $50 million Annual Adjustable Rate Promissory Note. Redemption of this unsecured Promissory Note has given the Company additional financing flexibility under the terms of its Charter to issue unsecured debt.

In August 1992 the Company issued 2,000,000 shares of new Common Stock. The shares were offered to the public at a price of $24 per share. The offering raised $46,460,000 in net proceeds, which were used to retire short-term debt incurred in the Company's construction program.

In September 1992 the Company filed a shelf registration with the Securities and Exchange Commission to issue up to $200 million of First Mortgage Bonds, Designated Secured Medium-Term Notes, on terms to be determined at the time of sale. This registration statement became effective October 8, 1992 and allows the Company financing flexibility regarding the timing of new issues. The Company plans to use the net proceeds from the sale of these notes to finance a portion of its capital requirements or to discharge or refund outstanding indebtedness. In January 1993, the Company issued $30 million of such Medium-Term Notes at an annual interest rate of 7.00% to refinance its outstanding First Mortgage 9⅛% Bonds, Series Z.

During 1992 the Company received $13.3 million to help finance its capital expenditures program from the sale of approximately 585,000 new shares of Common Stock through its Automatic Dividend Reinvestment and Stock Purchase Plan (ADR Plan). New shares issued in 1991 and 1992 through the ADR Plan were purchased from the Company at a market price above the book value per share at the time of purchase.

Capital Structure. The Company improved its ratio of common equity to total capitalization during 1992 primarily through the public sale of Common Stock as discussed earlier. The Company's retained earnings at December 31, 1992 were $67.0 million, an increase of approximately $5.5 million compared with December 31, 1991. As discussed on page 21 under the heading New York State Public Service Commission, earnings were reduced in June 1992 when the Company recorded an $8.2 million ($5.4 million after tax) write-off of ice storm-related costs. Likewise, the Company recorded the effect of a fuel audit settlement with the PSC of $10.0 million ($6.6 million after tax) in December 1991. As shown by the graph to the right, common equity (including retained earnings) comprised 43.8 percent of the Company's capitalization at December 31, 1992, with the balance being comprised of 8.0 percent preferred equity and 48.2 percent long-term debt. At December 31, 1992 the Company had



*Excludes amounts due or redeemable within one year.

$110.3 million of long-term debt due within one year and $6.0 million of preferred stock redeemable within one year which, if included in capitalization, would increase the long-term debt component of capitalization at 1992 year-end to 51.5 percent, reduce the preferred equity to 7.9 percent and reduce common equity to 40.6 percent of capitalization. As presented, these percentages are based on the Company's capitalization inclusive of its long-term liability to the United States Department of Energy (DOE) for nuclear waste disposal as explained in Note 1 of the Notes to Financial Statements. Excluded from the capitalization percentages is the DOE long-term liability for uranium enrichment decommissioning. It is the Company's long-term objective to move to a less leveraged capital structure and to increase the common equity percentage of capitalization toward the 45 percent range. To improve its capital structure, the Company will consider the redemption of higher-cost senior securities and the issuance of new shares of common stock.

Rate Base and Regulatory Policies.

The Company is subject to regulation of rates, service, and sale of securities, among other matters, by the PSC. The Company was granted authority in June 1992 to increase its rates for electric and gas service effective July 1992. These new rates were based on a forecasted test year for the twelve months ending June 30, 1993. The Company has filed a request with the PSC to increase base rates for electric and gas service effective July 1993. On January 29, 1993 the Company, the PSC Staff and other interested parties filed a proposed Settlement Agreement with the PSC. Such Settlement Agreement, if approved by the PSC, would determine the Company's rates through June 30, 1996 and includes certain incentive arrangements providing for both rewards and penalties. If operation and maintenance costs are below projected levels, the Company will share up to 50% of the savings with its customers. If such costs exceed projections, the Company must absorb 50% to 100% of the additional costs. The Settlement Agreement provides for a return on equity of 11.50% for each rate year, with the Company allowed to retain any earnings up to 14.5%. Earnings above 14.5% will be refunded to customers. Should earnings fall below 8.5%, or cash interest coverage fall below 2.2 times, the Settlement Agreement provides that the Company can seek relief by petitioning the PSC for a review of the settlement terms. The Company is unable to predict whether the Settlement Agreement will be approved by the PSC. A decision is not likely until mid-1993.

New York State Public Service Commission (PSC). Recent PSC rate decisions and the Company's pending rate requests are summarized in the table on page 22. The PSC concluded that the July 1992 rate increases should, for the twelve months ending June 1993, allow the Company to achieve approximately a 2.88 times pretax interest coverage, exclusive of AFUDC and the amortization of deferred Nine Mile Two customer prepaid financing costs, discussed on page 23. In addition to the amounts indicated in the table on page 22, the June 1992 PSC rate order authorized the amortization of certain non-cash rate moderators (primarily deferred Nine Mile Two customer prepaid financing costs) totaling $5.1 million in the Electric Department.

In its June 1992 rate decision, the PSC allowed the Company to defer and recover through rates over a period of ten years approximately $21.3 million of non-capital incremental storm-damage repair costs which the Company had incurred as a result of a March 1991 ice storm (see Capital Requirements and Electric Operations). The PSC has permitted the unamortized balance of these allowed costs to be included in rate base. An additional $8.2 million of non-capital storm-damage costs incurred by the Company were disallowed rate recovery by the PSC and the Company accordingly recorded in the second quarter of the year a charge to earnings in the

Rate Increases

Granted

Class of Service	Effective Date of Increase	Amount of Increase (Annual Basis) (000's)	Percent Increase	Authorized Rate of Return on Rate Base	Authorized Rate of Return on Equity
Electric	July 12, 1990	$36,059	6.6%	9.91%	12.10%
	July 1, 1991	33,133	5.5	9.66	11.70
	July 1, 1992	32,220	5.2	9.31	11.00
Gas	July 12, 1990	4,250	1.7	9.91	12.10
	July 1, 1991	1,148	0.4	9.66	11.70
	July 1, 1992	12,316	4.1	9.31	11.00

Pending

Class of Service	Date of Filing	Amount of Increase* (Annual Basis) (000's)	Percent Increase*	Requested Rate of Return on Rate Base	Requested Rate of Return on Equity
Electric	July 31, 1992	$18,462	2.8%	9.46%	11.50%
Gas	July 31, 1992	2,615	1.1	9.46	11.50

*As amended, for the rate year ending June 1994, as provided in the proposed Settlement Agreement. For the subsequent two rate years, the Settlement Agreement also provides for a return on equity of 11.50%.

amount of $8.2 million, equivalent to approximately $.17 per share, net of tax. After issuance of the two million shares of stock in August 1992, the net-of-tax effect for the year was $.15 per share. As previously discussed, Company-estimated capital costs resulting from the ice storm were allowed rate recognition by the PSC.

Following the March 1991 ice storm, electric rates which the PSC authorized for the Company in June 1991 were made subject to a refund of $4 million contingent upon the filing with the PSC of a revised storm emergency plan. In an order issued June 10, 1992, the PSC determined that this plan-filing contingency had been met and that the $4 million was no longer subject to refund.

In late July 1992 the Company filed rate requests with the PSC as summarized under the heading "Pending" in the table above. The higher rates were requested to cover those increases in capital and operating costs projected for the rate year ending June 30, 1994 that are neither adequately provided for in present rates nor expected to be offset by increased revenues from sales. As discussed earlier, the Company has negotiated a multi-year settlement agreement with the PSC Staff and other interested parties regarding this filing, but a final PSC decision on this filing may not be made before June 1993.

In March 1991 the PSC issued an order regarding a settlement agreement among the Nine Mile Two owners, the PSC Staff and other intervenors resolving all open ratemaking issues with respect to the construction of the unit and its operation through January 19, 1990. Under the provisions of this settlement, a Nine Mile Two commercial operation date of April 5, 1988 was recognized by the PSC with respect to the rates and accounts of the Company. Accordingly, final accounting entries reflecting recognition of this agreement in conformity with the Uniform Systems of Accounts of the PSC were made in the first quarter of 1991 increasing electric utility plant together with a corresponding increase in accumulated depreciation. Supplemental agreements approved by the PSC in early 1992 and 1993, respectively, have established for each Nine Mile Two owner an allowed level of shared costs for ratemaking purposes through December 31, 1993.

In a series of rate orders preceding the commercial operation of Nine Mile Two, the

Company was allowed to include certain Nine Mile Two plant costs in rate base prior to commercial operation. AFUDC was not accrued on these amounts. Instead, the Company accumulated a similarly calculated amount until commercial operation and recorded it on the Balance Sheet as a deferred credit (liability), with an equivalent amount recorded as a deferred debit (asset). The deferred credit represents customer prepaid financing costs, while the deferred debit represents financing cost (or AFUDC). The latter is expected to be recovered over the life of the facility through amortization if the PSC chooses to utilize these prepaid financing costs to moderate customer rates. For the rate year beginning July 1992, the Company started amortizing $2.5 million of these deferred credits to Other Income as permitted by the PSC's June 1992 rate order. Amortization of these deferred credits to Other Income has aggregated $21.4 million through December 31, 1992. The June 1992 rate order also authorized the Company to write off $2.5 million of deferred and other expenses as an offset to these deferred credit balances. In the pending multi-year Settlement Agreement discussed above, no additional amounts of such deferred credits are proposed to be used through the period ending June 30, 1996.

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

National Energy Policy Act of 1992. In October 1992 the National Energy Policy Act of 1992 (Energy Act) was signed into law. This legislation changes the Federal regulation of utilities in a number of ways. One provision of the Energy Act provides that United States utilities with nuclear generating facilities be assessed an annual decontamination and decommissioning fee payable to the DOE. This annual fee will be in place for 15 years and could be assessed as early as 1993. The Company's annual fee is approximately $1.8 million for the Ginna nuclear plant and the estimated amount for its share of Nine Mile Two is approximately $.1 million. This obligation has been reflected on the Company's December 31, 1992 Balance Sheet, together with a corresponding deferred debit based on the language of the Energy Act. The Company believes it will receive the ultimate recovery of this deferral through its fuel adjustment clause. The Company is currently reviewing other provisions of the Energy Act as they relate to the Company.

Results of Operations

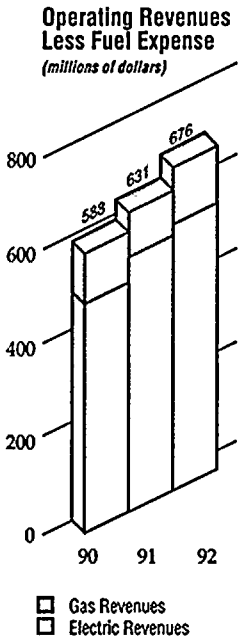
The following financial review identifies the causes of significant changes in the amounts of revenues and expenses, comparing 1992 to 1991 and 1991 to 1990. The Notes to Financial Statements on pages 34 to 49 of this report contain additional information.

Operating Revenues and Sales.

Compared with a year earlier, operating revenues rose five percent in 1992 after increasing three percent in 1991. Gains in retail customer electric and gas revenues offset a decline in electric revenues from the sale of electric energy to other utilities. Customer revenue increases due to rate relief were partially offset by lower gas unbilled revenues and the impact of colder weather on air conditioning usage. Operating revenues adjusted to exclude fuel expense were also up in 1992 as shown by the graph on page 24. Details of the revenue changes are presented in the table on page 24.

Unbilled revenues are the estimated revenues attributable to energy which has

been delivered to customers but for which the metered amount has not been read and recorded on the Company's books. Such revenues do not enhance the Company's cash position. The Company records monthly accruals for unbilled revenues. The Company's Statement of Income reflects net unbilled revenues of $5.0 million in 1990, $2.6 million in 1991, and $(0.8) million in 1992. Primarily as a result of the seasonal nature of gas revenues, unbilled revenues will normally be near their maximum around January and at their minimum near the end of June.



The Company's fuel clause provisions currently provide that customers and shareholders will share, generally on an 80%/20% basis, respectively, the benefits and detriments realized from actual electric fuel costs, generation mix, sales of gas to dual-fuel customers and sales of electricity to other utilities compared with PSC-approved forecast amounts. As a result of these sharing arrangements, discussed further in Note 1 of the Notes to Financial Statements, pretax earnings were increased $2.4 million in 1991 and increased $4.4 million in 1992, primarily reflecting actual experience in both electric fuel costs and generation mix compared with rate assumptions. In addition, beginning in September 1990, fuel clause revenues include the recovery of margins (revenues less incremental cost of fuel) not currently provided for in base rates and which are not collected due to the implementation of the Company's energy efficiency programs (discussed below in this section). For the 1992 comparison period, fuel clause revenues also reflect a revenue matching adjustment resulting from a refund to electric customers as described in the last paragraph under the heading New York State Public Service Commission.

The effect of weather variations on operating revenues is most measurable in the Gas Department, where revenues from space heating customers comprise about 85 to 90 percent of total gas operating revenues. Variation in weather conditions can also have a meaningful impact on the volume of gas delivered and the revenues derived from the transportation of customer-owned gas since a substantial portion of these gas deliveries is ultimately used for spaceheating. As displayed by the graph to the left on page 25,

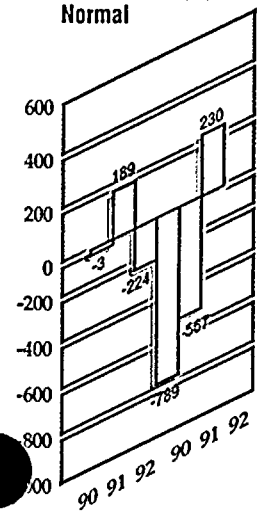
Operating Revenues

Increase or (Decrease) from Prior Year

	Electric Department		Gas Department	
(Thousands of Dollars)	1992	1991	1992	1991
Customer Revenues (Estimated) from:				
Rate Increases	$30,108	$33,666	$ 4,437	$3,106
Unbilled Revenues, Net	2,559	(9,894)	(5,943)	7,557
Fuel Clause Adjustments	(14,258)	2,236	906	(4,052)
Weather Effects (Heating)	1,636	(204)	20,372	(3,333)
Customer Consumption	(7,572)	7,197	8,412	(3,181)
Transportation Gas, Net Effect	—	—	(6,828)	(4,036)
Other	6,864	3,999	4,640	3,171
Total Change in Customer Revenues	19,337	37,000	25,996	(768)
Electric Sales to Other Utilities	(3,071)	(13,853)	—	—
Total Change in Operating Revenues	$16,266	$23,147	$25,996	$ (768)

after experiencing unseasonably mild weather during the 1990 and 1991 heating seasons, weather in the Company's service area during 1992 was 3.4 percent colder than normal and 13.6 percent colder compared with 1991. While this cooler weather during 1992 enhanced gas sales, unseasonably cold summer weather during the year limited electric energy sales to meet the demand for air conditioning usage, compared with the hot, dry 1991 summer weather conditions. Overall, 1991 was 8.4 percent warmer than normal, but 3.7 percent cooler than 1990.

Degree Day Variations From Normal



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

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

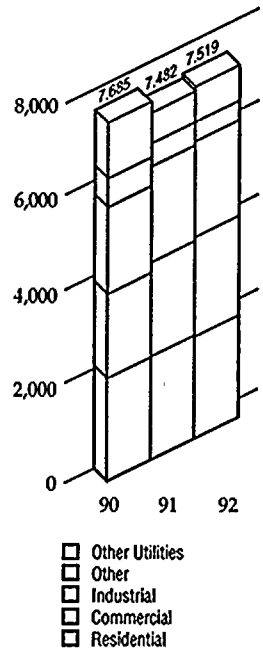
Normal	
Heating Degree Days	6,713
Cooling Degree Days	531

As part of the June 1992 rate decision, customers who use gas for spaceheating and are provided service under Service Classification No. 1 (primarily residential customers) are subject to a weather normalization adjustment to reflect the impact of variations from normal weather on a billing-cycle month basis for the months of October 1992 through May 1993, inclusive. The weather normalization adjustment for a billing-cycle will apply only if the actual heating degree days are lower than 97.5 percent or higher than 102.5 percent of the normal heating degree days. Weather normalization adjustments lowered gas revenues in 1992 by approximately $1.8 million.

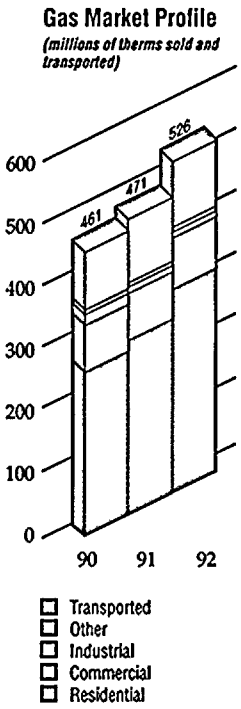
After climbing one percent in 1991, growth in kilowatt-hour sales of energy to retail customers was nearly flat in 1992 as illustrated by the graph to the right. Growth in electric energy sales in 1992 was inhibited by the impact of cooler weather during the summer months on air conditioning usage. Electric sales to industrial customers led the increase in sales to all major customer groups in 1992; but, like 1991, the combined growth in electric sales to commercial and industrial customers was limited to approximately one percent as these customers continued to feel the constraints of the national economy. Strengthening kilowatt-hour sales of energy in 1992 was the impact of nearly 2,400 new electric customers, which follows the addition of approximately 2,350 customers a year earlier.

Like many other electric utilities, the Company is encouraging energy efficiency through demand side management (DSM) programs. Objectives of the DSM programs include increasing the efficiency with which electricity is used and shifting electric load from peak to non-peak times, thus helping to save energy and delay the need to add new generating capacity. DSM programs include rebates for energy-efficient equipment, audits which focus on potential techniques for saving energy, consumer information and outreach, and design assistance to encourage energy-efficient new construction. In general, the Company is being allowed to amortize major DSM program expenditures over a five-year period. An incentive allowance (award) of approximately $1.1 million was provided for in the Company's June 1992 rate decision based on the Company's DSM performance through December 31, 1991. The reduction in margins (revenues less incremental cost of fuel) resulting from the implementation of DSM projects is estimated and is recovered in rates.

Electric Market Profile
(thousands of mwh sold)



Fluctuations in revenues from electric sales to other utilities are generally related to



the Company's customer energy requirements, New York Power Pool energy market and transmission conditions and the availability of electric generation from Company facilities. Such revenues in 1992 also reflect the sale of energy at a lower rate per megawatt hour and the impact of lower contract sales of energy. A decline in these contract sales, together with generally lower New York Power Pool requirements, led to lower kilowatt-hour sales to other utilities in 1991.

The transportation of gas for large-volume customers who are able to purchase natural gas from sources other than the Company remains an important component of the Company's marketing mix. Company facilities are used to transport this gas, which amounted to 12.6 million dekatherms in 1992 and 10.9 million dekatherms in 1991. These purchases have caused decreases in customer revenues, as shown in the table on page 24, with offsetting decreases in fuel expenses, but do not adversely affect earnings because transportation customers are billed at rates which, except for the cost of gas, approximate the rates charged the Company's other gas service customers. Gas supplies transported in this manner are not included in Company therm sales, depressing reported gas sales to non-residential customers.

Therms of gas sold and transported, including unbilled sales, were up 11.8 percent in 1992, following a 2.2 percent increase in 1991 as illustrated by the graph to the upper left. These increases reflect, primarily, the effect of weather variations on therm sales to customers with spaceheating. If adjusted for normal weather conditions, residential gas sales would have increased about 2.3 percent in 1992 over 1991, while nonresidential sales, including gas transported, in 1992 would have increased approximately 4.0 percent. The average use per residential gas customer, when adjusted for normal weather conditions was up in 1992, following a decrease in 1991. Total therms of gas transported increased in 1992 and 1991, primarily as a result of higher sales to certain large industrial and municipal transportation customers.

Fluctuations in "Other" customer revenues shown in the table on page 24 for both comparison periods is largely the result of revenues associated with a New York State tax enacted in 1991 (see Taxes Charged to Operating Expense), and, variations in miscellaneous revenues and consumption (billing) days.

Operating Expenses.

Compared with the prior year, operating expenses were up 4.5 percent in 1992 following a two percent increase in 1991, as summarized in the table on page 27 and as illustrated by the graph on page 28. Excluding the effect of higher taxes and the 1992 recognition of certain postretirement benefits discussed on page 28, operating expenses were up only 1.4 percent in 1992 and a modest one-half percent in 1991. Operating expenses were increased approximately $1.0 million in 1992 as the Company began in July to recognize over a ten-year period the deferred March 1991 ice storm costs as allowed by the PSC (see New York State Public Service Commission).

Energy Costs—Electric. For the 1992 comparison period, fuel expense for electric generation was lower by $16.7 million due, in part, to a revenue matching adjustment resulting from a refund to electric customers as described in the last paragraph under New York State Public Service Commission. Although the Company generated less electric power in 1992, the decrease in electric fuel expense was more than the decrease in electric generation as the average cost of coal and nuclear fuel declined. For

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

The Company purchased fewer kilowatt-hours of energy in 1992 and 1991 compared with the prior year. The variation in purchased electricity expense for both comparison periods was primarily caused by a fluctuation in the average rates for purchased electricity.

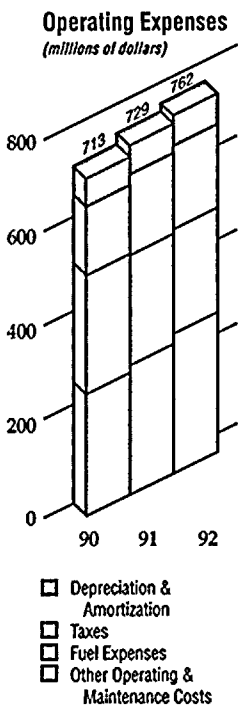
Energy Costs and Supply—Gas. The Company receives gas supply and related transportation services under a series of contracts with CNG Transmission Corporation (CNG). These contracts provide for a combination of unbundled services (storage and transmission of Company-purchased gas) for approximately 30% of the Company's annual gas purchases, and bundled sales services (including gas supply, storage and transmission) for the remainder of the Company's annual supplies that will not otherwise be purchased for transport to the Company via the proposed Empire project (see Projected Capital and Other Requirements). The Company expects that it will annually purchase a quantity of gas equal to 25% of the CNG bundled sales service gas supply from other sources under short-term contracts when: 1) those supplies are available at prices lower than CNG's commodity price and 2) the acquisition of those short-term supplies would not jeopardize the reliability of the Company's long-term supply or unduly increase its cost. Under the contracts with CNG, the Company has obtained rights to 4.2 million dekatherms of CNG storage capacity. With underground natural gas storage capability, the Company is in a better position to take advantage of off-peak season purchases of gas and enhance its supply reliability to serve projected peak day requirements. Also, in connection with the Empire project, additional transportation agreements have been entered into with pipelines upstream of Empire that permit the Company to directly access U.S. and Canadian natural gas supplies and storage facilities once Empire becomes operational.

In April 1992 FERC issued Order No. 636 with the intention of fostering competition and improving access of customers to gas supply sources. In essence, FERC Order No. 636 "divests" the natural gas pipelines of sole ownership of transportation capacity rights, transfers those capacity rights, in part, to the pipelines' customers, and requires the pipelines to offer their services so that the reliability of service associated with gas from any source is equal and terminates the

Operating Expenses

Increase or (Decrease) from Prior Year

(Thousands of Dollars)	1992	1991
Fuel for Electric Generation	$(16,729)	$(11,315)
Purchased Electricity	2,023	(6,581)
Gas Purchased for Resale	11,512	(2,733)
Other Operation	18,184	13,846
Maintenance	(2,695)	3,024
Depreciation	478	8,346
Amortization of Other Plant	369	(1,932)
Taxes Charged to Operating Expenses		
Local, State and Other Taxes	10,603	12,614
Federal Income Tax	9,332	(231)
Total Change in Operating Expenses	$ 33,077	$ 15,038



pipelines' monopoly in providing gas merchant services. The Company's gas procurement strategy, as discussed above, has pursued such rights; therefore, FERC Order No. 636 enhances the Company's ability to implement this strategy by establishing a regulatory basis for its rights, rather than requiring it to negotiate for such rights in individual pipeline rate cases.

The cost of gas purchased for resale increased in the 1992 comparison period primarily due to higher residential and commercial spaceheating sales, reflecting colder weather. In contrast to 1991, however, when lower average rates led to a drop in the cost of gas purchased for resale, a decline in 1992 average rates could not offset the effect of the higher volume of gas required for sales during the year.

Operating Expenses, Excluding Fuel. Other operation expenses rose over both comparison periods as shown by the table on page 27. The recording of certain postretirement benefits other than pensions, as required by Statement of Financial Accounting Standards No. 106 (SFAS-106) and discussed in the following paragraph, increased other operation expenses in 1992 by $4.9 million. Compared with a year earlier, other operation expenses in 1992 also reflect an increase of $3.0 million for transmission wheeling charges and additional expenses of about $1.6 million associated with the Company's share of Nine Mile Two operation expenses. The increase in other operation expenses for the 1991 comparison period primarily resulted from higher payroll costs, increased regulatory assessments, and higher transmission wheeling charges.

During the first quarter of 1992, the Company adopted the Financial Accounting Standards Board's (FASB) SFAS-106 for financial reporting purposes. Among other things, SFAS-106 requires accrual accounting for postretirement benefits other than pensions. The Company estimates that the net periodic cost for postretirement benefits, excluding pensions, will be approximately $7.8 million based on accrual accounting required by SFAS-106. The net periodic cost includes approximately $2.8 million amortization of the unrecognized transition obligation (the accumulated postretirement benefit obligation at adoption), currently estimated at $56.4 million to be amortized over twenty years. The PSC allowed the Company revenues in rates equal to $7.0 million in 1992 in recognition of this obligation. The Company has filed a petition with the PSC for deferral accounting treatment for the balance of the expense to be accrued.

Fluctuation of maintenance expense in both comparison periods was largely due to increased activity in 1991 associated with electric distribution facilities; and, for the 1992 comparison period, lower maintenance expense at nuclear production facilities.

Depreciation expense in the 1992 comparison period was basically unchanged as the effect of an increase in depreciable plant was nearly offset by a decrease in the depreciation related to the Ginna nuclear plant due to a three-year extension of its operating license. The amortization of the Sterling property abandonment was completed in July 1992. An increase in accrued decommissioning expenses and additional depreciable plant caused depreciation expense to increase in the 1991 comparison period.

Taxes Charged to Operating Expenses. The increase in local, state and other taxes for both comparison periods resulted from increases in revenue taxes. These were impacted by a one-half percent increase in the New York State gross revenue tax, the accounting for which began in October 1991

retroactive to January 1, 1991. Also, higher assessments and tax rates on property increased these taxes.

In February 1992, FASB issued SFAS-109 entitled "Accounting for Income Taxes", superseding SFAS-96. SFAS-109 requires the Company to adjust certain of its deferred tax assets and liabilities to reflect periodic changes in tax rates. In addition, the Company will also be required to provide deferred taxes for the effect of tax benefits previously flowed through to the Income Statement. The Company will adopt SFAS-109 in the first quarter of 1993. The Company has proposed in its current rate filing with the PSC that, upon adoption of SFAS-109, any charge or credit to earnings that might result from the change in accounting method be deferred and subsequently amortized with carrying charges. Since the Company's deferred taxes have been adjusted for regulatory purposes to the current statutory rate where permissible, the impact of SFAS-109 is believed to be immaterial. See Note 2 of the Notes to Financial Statements for an analysis of Federal income taxes.

Other Statement of Income Items

AFUDC variances are generally related to the amount of utility plant under construction and not included in rate base. AFUDC levels also reflect decreases in the gross rate to 4.50 percent effective September 1992 from earlier rates of 5.50 percent, 7.10 percent, and 8.60 percent.

Variations in non-operating Federal income tax reflect mainly June 1992 accounting adjustments related to the March 1991 ice storm and a 1991 accounting adjustment in connection with the Nine Mile Two settlement agreement.

Recorded under the caption "Other Income and Deductions" is the recognition of the 1991 PSC order associated with the Company's fuel procurement practices (see page 23) and the 1992 PSC order related to the March 1991 ice storm (see page 21).

For the 1991 comparison period, the fluctuation in Other Income is primarily associated with the amortization of customer prepaid Nine Mile Two financing costs which had been deferred, as discussed under the heading New York State Public Service Commission. Such non-cash earnings were $3.3 million in 1990, $4.8 million in 1991, and $2.5 million in 1992. Other income in 1992 also includes $3.5 million of proceeds received in settlement of lawsuits filed against certain contractors involved in the construction of the Nine Mile Two nuclear plant.

Both mandatory and optional redemptions of certain higher-cost first mortgage bonds have helped to reduce long-term debt expense interest over the three-year period 1990–1992, despite the issuance of additional long-term debt in 1991 and 1992. In 1992, the effect of lower interest rates on debt expense was partially offset by increased short-term borrowings.

Earnings/Summary

Presented on page 30 is a table which summarizes the Company's Common Stock earnings in total and on a per-share basis. As previously explained, Common Stock earnings per share in the second quarter of 1992 were reduced by approximately $.17 per share, net of tax, following recognition of the disallowance of $8.2 million of deferred ice storm-related costs. After issuance of the two million additional shares of stock in August 1992, the net-of-tax effect for the year was $.15 per share. In the fourth quarter of 1991, earnings were reduced by $.21 per share when the Company recorded the effects of the fuel procurement settlement approved by the PSC as discussed earlier. Also, the Company estimates that a loss of revenues as a result of the 1991 ice storm reduced

earnings by $.07 per share, net of tax, for calendar year 1991.

In December 1991 the Company announced a quarterly dividend increase from $.405 to $.42 per share of Common Stock payable in January 1992. Subsequently, in December 1992 the Company announced a new quarterly dividend rate of $.43 per share payable in January 1993. The Company's Charter provides for the payment of dividends on Common Stock out of the surplus net profits (retained earnings) of the Company. Accordingly, dividend payments are dependent on future earnings, in addition to financial requirements and other factors.

Earnings Summary

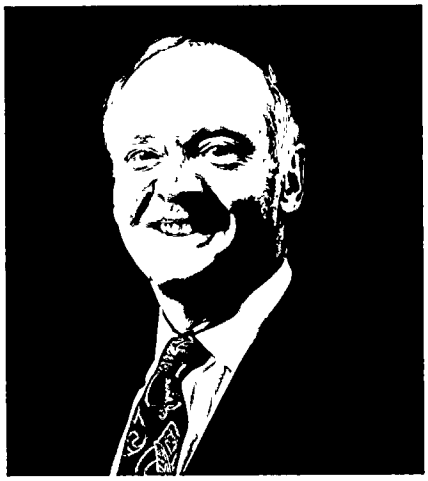
	Earnings (Thousands of Dollars)	Shares* (Thousands)	Earnings per Share
1992	**$62,149**	**33,258**	**$1.86**
1991	$51,034	31,794	$1.60
1990	$53,856	31,293	$1.72

*Weighted average shares outstanding

BOARD APPOINTMENTS

At the 1992 annual meeting of shareholders in May, Angelo J. Chiarella and Jay T. Holmes were elected to the Company's board of directors.

Angelo J. Chiarella is president and chief executive officer, Midtown Holdings Corp. He replaces Theodore J. Altier, former chairman and chief executive officer, Altier & Sons Shoes, Inc. who served on the board for more than 12 years.



Jay T. Holmes is senior vice president—corporate affairs and secretary of Bausch & Lomb Incorporated. He replaces William G. vonBerg, executive director, Executive Service Corps of Rochester, Inc. who served on the board for more than 20 years.

STATEMENT OF INCOME

(Thousands of Dollars) Year Ended December 31	1992	1991	1990
Operating Revenues			
Electric	$ 608,267	$ 588,930	$ 551,930
Gas	261,724	235,728	236,496
	869,991	824,658	788,426
Electric sales to other utilities	25,541	28,612	42,465
Total Operating Revenues	895,532	853,270	830,891
Operating Expenses			
Fuel Expenses			
Fuel for electric generation	48,376	65,105	76,420
Purchased electricity	29,706	27,683	34,264
Gas purchased for resale	141,291	129,779	132,512
Total Fuel Expenses	219,373	222,567	243,196
Operating Revenues Less Fuel Expenses	676,159	630,703	587,695
Other Operating Expenses			
Operations excluding fuel expenses	226,624	208,440	194, 594
Maintenance	62,720	65,415	62,391
Depreciation and amortization	85,028	84,181	77,767
Taxes—local, state and other	124,252	113,649	101,035
Federal income tax	43,591	34,259	34,490
Total Other Operating Expenses	542,215	505,944	470,277
Operating Income	133,944	124,759	117,418
Other Income and Deductions			
Allowance for other funds used during construction	164	675	2,689
Federal income tax	4,195	4,580	2,459
Regulatory disallowances (Note 10)	(8,215)	(10,000)	—
Other, net	6,155	6,078	4,062
Total Other Income and Deductions	2,299	1,333	9,210
Income Before Interest Charges	136,243	126,092	126,628
Interest Charges			
Long term debt	60,810	63,918	64,873
Other, net	7,178	7,082	4,593
Allowance for borrowed funds used during construction	(2,184)	(2,905)	(2,719)
Total Interest Charges	65,804	68,095	66,747
Net Income	70,439	57,997	59,881
Dividends on Preferred Stock	8,290	6,963	6,025
Earnings Applicable to Common Stock	$ 62,149	$ 51,034	$ 53,856
Weighted Average Number of Shares for Period (000's)	33,258	31,794	31,293
Earnings per Common Share	$ 1.86	$ 1.60	$ 1.72

STATEMENT OF RETAINED EARNINGS

(Thousands of Dollars) Year Ended December 31	1992	1991	1990
Balance at Beginning of Period	$ 61,515	$ 62,542	$ 57,983
Add			
Net Income	70,439	57,997	59,881
Total	131,954	120,539	117,864
Deduct			
Dividends declared on capital stock			
Cumulative preferred stock	8,290	6,963	6,025
Common stock	56,696	52,061	49,297
Total	64,986	59,024	55,322
Balance at End of Period	$ 66,968	$ 61,515	$ 62,542

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

(Thousands of Dollars) At December 31	1992	1991
Assets		
Utility Plant		
Electric	$ 2,175,255	$ 2,122,248
Gas	341,466	320,385
Common	123,034	116,858
Nuclear fuel	158,826	147,063
	2,798,581	2,706,554
Less: Accumulated depreciation	1,125,502	1,067,471
Nuclear fuel amortization	127,615	111,178
	1,545,464	1,527,905
Construction work in progress	83,832	76,848
Net Utility Plant	1,629,296	1,604,753
Current Assets		
Cash and cash equivalents	1,759	1,488
Accounts receivable, net of allowance for doubtful accounts: 1992—$500; 1991—$411	92,292	84,053
Unbilled revenue receivable	60,184	55,921
Materials and supplies, at average cost		
Fossil fuel	12,273	10,766
Construction and other supplies	13,130	12,539
Gas stored underground	9,998	7,057
Prepayments	19,985	17,185
Total Current Assets	209,621	189,009
Deferred Debits		
Unamortized debt expense	13,553	9,611
Deferred finance charges—Nine Mile Two	20,492	25,586
Deferred ice storm charges	24,197	36,431
Uranium enrichment decommissioning deferral	28,613	—
Nuclear generating plant decommissioning funds	29,549	19,221
Nine Mile Two deferred costs	34,300	30,121
Other	59,821	39,064
Total Deferred Debits	210,525	160,034
Total Assets	$ 2,049,442	$ 1,953,796
Capitalization and Liabilities		
Capitalization		
Long term debt—mortgage bonds	$ 566,980	$ 530,422
—promissory notes	91,900	141,900
Preferred stock redeemable at option of Company	67,000	67,000
Preferred stock subject to mandatory redemption	54,000	60,000
Common shareholders' equity		
Common stock	591,532	529,339
Retained earnings	66,968	61,515
Total Common Shareholders' Equity	658,500	590,854
Total Capitalization	1,438,380	1,390,176
Long Term Liability (Department of Energy):		
Nuclear waste disposal	65,989	63,626
Uranium enrichment decommissioning	28,613	—
Total Long Term Liabilities	94,602	63,626
Current Liabilities		
Long term debt due within one year	110,250	96,750
Preferred stock redeemable within one year	6,000	—
Short term debt	50,800	59,500
Accounts payable	40,579	53,983
Dividends payable	17,035	15,555
Taxes accrued	13,743	12,050
Interest accrued	15,461	16,313
Other	13,409	13,450
Total Current Liabilities	267,277	267,601
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes	171,673	162,955
Deferred finance charges—Nine Mile Two	20,492	25,586
Pension costs accrued	20,278	13,515
Other	36,740	30,337
Total Deferred Credits and Other Liabilities	249,183	232,393
Commitments and Other Matters (Note 10)	—	—
Total Capitalization and Liabilities	$ 2,049,442	$ 1,953,796

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

STATEMENT OF CASH FLOWS

(Thousands of Dollars) Year Ended December 31	1992	1991	1990
Cash Flow from Operations			
Net income	$ 70,439	$ 57,997	$ 59,881
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation and amortization	85,028	84,181	77,767
Amortization of nuclear fuel	18,803	23,606	25,573
Deferred fuel—electric	2,543	4,122	(477)
Deferred income taxes	10,466	9,124	16,682
Allowance for funds used during construction	(2,348)	(3,580)	(5,408)
Unbilled revenue, net	(6,631)	(8,931)	(2,818)
Ice storm costs	12,234	(36,431)	—
Nuclear generating plant decommissioning	(10,328)	(15,581)	(3,640)
Changes in certain current assets and liabilities:			
Accounts receivable	(8,239)	(4,773)	1,519
Materials and supplies—fossil fuel	(1,507)	7,506	(5,183)
—construction and other supplies	(591)	(315)	(1,246)
Taxes accrued	1,693	1,444	(2,805)
Accounts payable	(13,404)	6,914	(6,077)
Interest accrued	(852)	1,722	(690)
Other current assets and liabilities, net	(2,528)	(592)	(6,602)
Other, net	(13,726)	(6,966)	5,616
Total Operating	$ 141,052	$ 119,447	$ 152,092
Cash Flow from Investing Activities			
Utility Plant			
Plant additions	$ (115,790)	$ (114,579)	$ (123,887)
Nuclear fuel additions	(11,763)	(13,058)	(8,297)
Less: Allowance for funds used during construction	2,348	3,580	5,408
Additions to Utility Plant	(125,205)	(124,057)	(126,776)
Other, net	490	(685)	(98)
Total Investing	$ (124,715)	$ (124,742)	$ (126,874)
Cash Flow from Financing Activities			
Proceeds from:			
Sale/Issue of common stock	$ 63,928	$ 13,446	$ 3,058
Sale of preferred stock	—	30,000	—
Sale of long term debt, mortgage bonds	160,500	100,000	—
Short term borrowings	(8,700)	17,100	42,400
Retirement of long term debt	(160,000)	(92,334)	(28,000)
Capital stock expense	(1,735)	(495)	(230)
Discount and expense of issuing long term debt	(6,368)	(3,310)	—
Dividends paid on preferred and common stock	(63,506)	(57,704)	(54,787)
Other, net	(185)	(464)	908
Total Financing	$ (16,066)	$ 6,239	$ (36,651)
Increase (decrease) in cash and cash equivalents	$ 271	$ 944	$ (11,433)
Cash and cash equivalents at beginning of year	$ 1,488	$ 544	$ 11,977
Cash and cash equivalents at end of year	$ 1,759	$ 1,488	$ 544

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

(Thousands of Dollars) Year Ended December 31	1992	1991	1990
Cash Paid During the Year			
Interest paid (net of capitalized amount)	$ 64,431	$ 63,848	$ 64,851
Income taxes paid	$ 22,911	$ 20,399	$ 17,516

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

Note 1. Summary of Accounting Principles

General.

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

In June 1988, the Board of Directors authorized the creation of Utilicom, Inc. as a wholly owned subsidiary. Utilicom develops and markets computer software to assist customers in complying with state and federal environmental and safety regulations. The subsidiary activity has to date remained insignificant to the Company's financial position and results of operation.

In April 1990, the Board of Directors authorized the creation of Energyline Corporation, a wholly owned subsidiary, which was incorporated in July 1992. Energyline was formed as a gas pipeline corporation to fund the Company's investment in the Empire State Pipeline project. The Company has invested approximately $10 million in Empire as of December 31, 1992.

The financial statements reflect the reclassification of Pension Costs Accrued from Current Liabilities to Other Liabilities, and the reclassification of certain deferred costs. Prior periods have been restated for comparative purposes.

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

Rates and Revenue.

Revenue is recorded on the basis of meters read. In addition, beginning in July 1988, as part of a PSC rate decision, the Company commenced recording an estimate of unbilled revenue for service rendered subsequent to the meter-read date through the end of the accounting period. Pursuant to rate orders, $2.4 million, $2.2 million and $13.8 million was amortized to earnings in lieu of cash rate relief in 1992, 1991 and 1990, respectively.

Tariffs for electric and gas service include fuel cost adjustment clauses which adjust the rates monthly to reflect changes in the actual average cost of fuels. The electric fuel adjustment provides that ratepayers and the Company will share the effects of any variation from forecast monthly unit fuel costs on an 80%/20% basis up to a $2.6 million cumulative, after-tax, annual gain or loss to the Company. Thereafter, 100 percent of additional fuel clause adjustment amounts are assigned to customers. The electric fuel cost adjustment also provides that any variation from forecast net revenues on sales to electric utilities be shared on the same 80%/20% basis.

In addition, there is a similar 80%/20% sharing process of variances from forecasted margins derived from sales and the transportation of privately owned gas to large customers that can use alternate fuels.

As part of the June 1992 rate decision, rates for customers who use gas for spaceheating and are provided service under Service Classification No. 1 (primarily residential customers) are subject to a weather normalization adjustment to reflect the impact of variations from normal weather on a billing cycle month basis for the months of October 1992 through May 1993, inclusive. The weather normalization adjustment for a billing cycle will apply only if the actual heating degree days are lower than 97.5 percent or higher than 102.5 percent of the normal heating degree days. Weather normalization adjustments lowered gas revenues in 1992 by approximately $1.8 million.

Deferred Fuel Costs.

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

Utility Plant, Depreciation and Amortization.

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

Depreciation in the financial statements is provided on a straight-line basis at rates based on the estimated useful lives of property, which have resulted in provisions of 2.9%, 3.3% and 3.5% per annum of average depreciable property in 1992, 1991 and 1990, respectively. The decrease in depreciation provision percentages over the last 2 years is the result of a combination of the 3½ year extension of Ginna's license term and generally lengthening estimated useful lives. Amortization includes $.7 million in 1992, $.3 million in 1991 and $2.2 million in 1990 related to the Sterling project property loss.

Nuclear Fuel Disposal Costs.

The Nuclear Waste Policy Act (Act) of 1982, as amended, requires the United States Department of Energy (DOE) to establish a nuclear waste disposal site and to take title to nuclear waste. A permanent DOE high-level nuclear waste repository is not expected to be operational before the year 2010. The DOE is pursuing efforts to establish a monitored retrievable interim storage facility which may allow it to take title to and possession of nuclear waste prior to the establishment of a permanent repository. The Act provides for a determination of the fees collectible by the DOE for the disposal of nuclear fuel irradiated prior to April 7, 1983 and for three payment options. The option of a single payment to be made at any time prior to the first delivery of fuel to the DOE was selected in June 1985. The Company estimates the fees, including accrued interest, owed to the DOE to be $66.0 million at December 31, 1992. The Company is allowed by the PSC to recover these costs in rates. The estimated fees are classified as a long-term liability and interest is accrued at the current three-month Treasury bill rate, adjusted quarterly. The Act also requires the DOE to provide for the disposal of nuclear fuel irradiated after April 6, 1983, for a charge of one mill ($.001) per KWH of nuclear energy generated and sold. This charge is currently being collected from customers and paid to the DOE pursuant to PSC authorization. The Company expects to utilize on-site storage for all spent or retired nuclear fuel assemblies until an interim or permanent nuclear disposal facility is operational.

Nuclear Decommissioning Costs.

Decommissioning costs (costs to take the plant out of service in the future) for the Company's Ginna Nuclear Plant are estimated to be approximately $145.8 million, and those for the Company's 14% share of Nine Mile Two's decommissioning costs are estimated to be approximately $33.5 million (1991 dollars). Through December 31, 1992, the Company has accrued and recovered in rates $52.4 million for this purpose and is currently accruing for decommissioning costs at a rate of approximately $8.9 million per year based on the use of a combination of internal and external sinking funds. (See Note 10.)

The decommissioning costs, which form the basis for current accruals, were derived from the record of the Company's prior rate proceeding (PSC Opinion 92-15, issued June 1992).

Uranium Enrichment Decontamination and Decommissioning Fund.

As part of the National Energy Act (Act) issued in October 1992, utilities with nuclear generating facilities will be assessed an annual fee payable over 15 years to pay for the decommissioning of Federally owned uranium enrichment facilities. The assessments for Ginna and Nine Mile Two are estimated to total $28.6 million, excluding inflation and interest. A liability has been recognized on the financial statements along with an offsetting regulatory asset. The Company believes that this amount will be recoverable in rates as described in the Act.

(Note 1 continued on page 36)

(continued from page 35)

Allowance for Funds Used During Construction.

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

The gross rates approved by the PSC for purposes of computing AFUDC were: 4.5% effective September 1, 1992 through December 31, 1992; 5.5% effective April 1, 1992 through August 31, 1992; 7.1% effective July 1, 1991 through March 31, 1992; 8.6% effective February 1, 1991 through June 30, 1991; 9.6% effective July 1, 1990 through January 31, 1991; and 10.25% effective January 1, 1988 through June 30, 1990.

Effective July 16, 1984, pursuant to PSC authorization, the Company discontinued accruing AFUDC on $50 million of construction work in progress related to its investment in Nine Mile Two for which a cash return was being allowed through its inclusion in rate base. The PSC also ordered that amounts be accumulated in deferred debit and credit accounts equal to the amount of AFUDC which was no longer accrued. The balance in the deferred credit account would be available to reduce future revenue requirements over a period substantially shorter than the life of Nine Mile Two, and the balance in the deferred debit account would then be collected from customers over a longer period of time. The balances of $20.5 million at December 31, 1992, if not used by mid-1994, may be offset against each other pursuant to PSC directives. In connection with the Company's 1992 rate case decision, $2.5 million will be amortized through the Statement of Income during the year commencing July 1, 1992.

Federal Income Tax.

For income tax purposes, depreciation is computed using the most liberal methods permitted. The resulting tax reductions are offset by provisions for deferred income taxes only to the extent ordered or permitted by regulatory authorities. The cumulative balance of tax deductions not offset by provisions for deferred income taxes through 1992 is approximately $415 million.

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

SFAS-109, Accounting for Income Taxes, has not yet been adopted by the Company. SFAS-109 requires adoption in calendar year 1993 and also requires that a deferred tax liability or asset be adjusted in the period of enactment for the effect of changes in tax laws or rates. The Company presently believes the impact from adopting SFAS-109 to be immaterial.

Retirement Health Care and Life Insurance Benefits.

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

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

Earnings Per Share.

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

Note 2. Federal Income Taxes

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

(Thousands of Dollars)	1992	1991	1990
Charged to operating expense:			
Current	$36,101	$28,766	$20,660
Deferred	7,490	5,493	13,830
Total	43,591	34,259	34,490
Charged (Credited) to other income:			
Current	(7,171)	(8,211)	(5,311)
Deferred	2,976	3,631	2,852
Total	(4,195)	(4,580)	(2,459)
Total Federal income tax expense	$39,396	$29,679	$32,031

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

(Thousands of Dollars)	1992		1991		1990	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
Net Income	$ 70,439		$57,997		$59,881	
Add: Federal income tax expense	39,396		29,679		32,031	
Income before Federal income tax	$109,835		$87,676		$91,912	
Computed tax expense	$ 37,344	34.0	$29,810	34.0	$31,250	34.0
Increases (decreases) in tax resulting from:						
Difference between tax depreciation and amount deferred	6,775	6.2	5,606	6.4	4,127	4.5
Investment tax credit	(2,426)	(2.2)	(2,432)	(2.8)	(2,752)	(3.0)
Miscellaneous items, net	(2,297)	(2.1)	(3,305)	(3.7)	(594)	(0.7)
Total Federal income tax expense	$ 39,396	35.9	$29,679	33.9	$32,031	34.8

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

(Thousands of Dollars)	1992	1991	1990
Investment tax credit	$ (3,284)	$ (4,235)	$ (2,414)
Depreciation	25,553	24,158	22,906
Fuel costs	(2,442)	205	1,180
Sterling abandonment	—	512	(796)
Deferred ice storm charges	(3,147)	9,666	—
Accrued revenue	342	(353)	1,596
Demand Side Management	2,977	1,348	708
Alternative Minimum Tax	(4,839)	(13,768)	(2,475)
Revenues Deferred—Nine Mile Two	(2,013)	(2,413)	1,028
Pension	(2,264)	(2,721)	(2,729)
Other items	(417)	(3,275)	(2,322)
Total	$10,466	$ 9,124	$16,682

Note 3. Pension Plan and Other Retirement Benefits

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

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

(Millions)	1992	1991
Accumulated benefit obligation, including vested benefits of $249.6 in 1992 and $237.4 in 1991	$268.1*	$251.9*
Projected benefit obligation for service rendered to date	$378.0*	$359.7*
Less—Plan assets at fair value, primarily listed stocks and bonds	449.9	433.3
	(71.9)	(73.6)
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions	102.4	98.0
Less—Prior service cost not yet recognized in net periodic pension cost	5.4	5.5
Less—Unrecognized net obligation at December 31	4.8	5.4
Pension liability recognized on the balance sheet	$ 20.3	$ 13.5

*Actuarial present value

Net pension cost included the following components:

(Millions)	1992	1991	1990
Service cost—benefits earned during the period	$ 8.8	$ 7.1	$ 7.3
Interest cost on projected benefit obligation	27.9	26.4	25.3
Actual return on plan assets	(35.1)	(58.6)	(9.0)
Net amortization and deferral	5.5	33.1	(15.1)
Net periodic pension cost	$ 7.1	$ 8.0	$ 8.5

The projected benefit obligation at December 31, 1992 and 1991 assumed a discount rate of 7¾ percent and a long-term rate of increase in future compensation levels of 6½ percent. The assumed long-term rate of return on plan assets at December 31, 1992 and 1991 was 8½ percent. The unrecognized net obligation is being amortized over 15 years beginning January, 1986.

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits to retired employees and health care coverage for surviving spouses of retirees. Substantially all of the Company's employees are eligible provided that they retire as employees of the Company. In 1992, the health care benefit consisted of a contribution of up to $160 per month towards the cost of a group health policy provided by the Company. The life insurance benefit consists of a Basic Group Life benefit, covering substantially all employees, providing a death benefit equal to one-half of the retiree's final pay. In addition, certain employees and retirees, employed by the Company at December 31, 1982, are entitled to a Special Group Life benefit providing a death benefit equal to one times the employee's December 31, 1982 pay (frozen). The out-of-pocket cost of providing these benefits was approximately $3.0 million in 1991 and $2.5 million in 1990, and with the adoption of SFAS-106 in 1992, the total cost of these benefits increased by approximately $4.5 million.

The Company adopted SFAS-106, "Accounting for Postretirement Benefits Other than Pensions" as of January 1, 1992 for financial accounting purposes. The Company has elected to amortize the unrecognized, unfunded Accumulated Postretirement Benefit Obligation (APBO) at January 1, 1992 over twenty years as provided by SFAS-106. The Company intends to continue funding these benefits on a pay-as-you-go basis. The pro-forma impact of the adoption of SFAS-106 on years prior to 1992 was not determinable.

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

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

Net periodic postretirement benefit cost included the following components:

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

The APBO at December 31, 1992 assumed a discount rate of 7¾ percent and a long-term rate of increase in future compensation levels of 6½ percent.

The PSC has allowed the Company revenues in rates equal to $7.0 million in 1992 in recognition of these benefits. The Company has filed a petition with the PSC for deferral accounting treatment for the balance of the expense to be accrued.

The staff of the New York Public Service Commission has proposed a "Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other Than Pensions". The Statement recommends certain accounting procedures for ratemaking purposes. The Statement has not been presented to nor approved by the Public Service Commission; however the Company believes that the Statement, when ultimately issued, will not adversely impact the financial statements.

Note 4. Departmental Financial Information

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

(Thousands of Dollars)	1992	1991	1990
Electric			
Operating Information			
Operating revenues	$ 633,808	$ 617,542	$ 594,395
Operating expenses, excluding provision for income taxes	482,968	478,101	464,478
Pretax operating income	150,840	139,441	129,917
Provision for income taxes	38,046	31,390	30,670
Net operating income	$ 112,794	$ 108,051	$ 99,247
Other Information			
Depreciation and amortization	$ 73,213	$ 72,746	$ 67,302
Nuclear fuel amortization	$ 18,803	$ 23,606	$ 25,573
Capital expenditures	$ 100,974	$ 97,294	$ 101,024
Investment Information			
Identifiable assets (a)	$1,671,492	$1,607,210	$1,557,176
Gas			
Operating Information			
Operating revenues	$261,724	$ 235,728	$ 236,496
Operating expenses, excluding provision for income taxes	235,029	216,151	214,505
Pretax operating income	26,695	19,577	21,991
Provision for income taxes	5,545	2,869	3,820
Net operating income	$ 21,150	$ 16,708	$ 18,171
Other Information			
Depreciation and amortization	$ 11,815	$ 11,435	$ 10,465
Capital expenditures	$ 24,231	$ 26,763	$ 25,752
Investment Information			
Identifiable assets (a)	$354,528	$ 325,451	$ 291,088

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

Note 5. Jointly-Owned Facilities

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

	Oswego Unit No. 6	Nine Mile Point Nuclear Unit No. 2
Net megawatt capacity	850	1,080
RG&E's share—megawatts	204	151
—percent	24	14
Year of completion	1980	1988
	Millions of Dollars at December 31, 1992	
Plant In Service Balance	$98.6	$867.6
Accumulated Provision For Depreciation	$30.9	$428.9
Plant Under Construction	$ 0.4	$ 9.4

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

Note 6. Long Term Debt

First Mortgage Bonds

%	Series	Due	(Thousands) Principal Amount December 31 1992	1991
4⅝	U	Sept. 15, 1994	$ 16,000	$ 16,000
5.3	V	May 1, 1996	18,000	18,000
6¼	W	Sept. 15, 1997	20,000	20,000
6.7	X	July 1, 1998	30,000	30,000
8	Y	Aug. 15, 1999	30,000	30,000
9⅛	Z	Sept. 1, 2000	30,000	30,000
9¼	BB	June 15, 2006	50,000	50,000
8⅜	CC	Sept. 15, 2007	50,000	50,000
9.5	DD	Dec. 1, 2003	40,000	40,000
6½	EE (a)	Aug. 1, 2009	10,000	10,000
10.95	FF	Feb. 15, 2005	5,500	27,500
12¼	HH	May 15, 2012	—	10,500
13⅞	JJ	June 15, 1999	17,500	20,000
8.6	LL (b)	Aug. 1, 1993	75,000	75,000
8⅞	MM	May 1, 1992	—	75,000
8⅜	OO (a)	Dec. 1, 2028	25,500	25,500
9⅜	PP	Apr. 1, 2021	100,000	100,000
8¼	QQ (b)	Mar. 15, 2002	100,000	—
6.35	RR (a)	May 15, 2032	10,500	—
6.50	SS (a)	May 15, 2032	50,000	—
			678,000	627,500
Net bond discount			(770)	(328)
Less: Due within one year			110,250	96,750
Total			$566,980	$530,422

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

(b) The Series LL and QQ First Mortgage Bonds are generally not redeemable prior to maturity.

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

Sinking and improvement fund requirements aggregate $333,540 per annum under the First Mortgage, excluding mandatory sinking funds of individual series. Such requirements may be met by certification of additional property or by depositing cash with the Trustee. The 1991 and 1992 requirements were met by certification of additional property.

In October 1992 the Company established a $200 million medium-term note program entitled "First Mortgage Bonds, Designated Secured Medium-Term Notes, Series A" with maturities that may range from one year to thirty years. At December 31, 1992 there were no medium-term notes outstanding. On January 14, 1993 the Company issued $30 million of the medium-term notes at an interest rate of 7.00% with a maturity date of January 14, 2000. The issue is generally not redeemable before maturity.

(Note 6 continued on page 42)

(continued from page 41)

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

(Thousands)	1993	1994	1995	1996	1997
Series Z (c)	$ 30,000				
Series FF (d)	2,750	$ 2,750			
Series JJ (e)	2,500	2,500	$2,500	$ 2,500	$ 2,500
Series LL	75,000				
Series U		16,000			
Series V				18,000	
Series W					20,000
	$110,250	$21,250	$2,500	$20,500	$22,500

(c) On January 15, 1993 the Company exercised its option to redeem $30 million principal amount of Series Z Bonds at a price of 102.21%.

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

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

Promissory Notes

		(Thousands) December 31	
Issued	Due	1992	1991
November 15, 1984 (f)	October 1, 2014	$51,700	$ 51,700
December 5, 1985 (g)	November 15, 2015	40,200	40,200
July 22, 1987 (h)	Cancelled—See Note Below		50,000
Total		$91,900	$141,900

(f) The $51.7 million Promissory Note was issued in connection with NYSERDA's Floating Rate Monthly Demand Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), Series 1984. This obligation is supported by an irrevocable Letter of Credit expiring October 15, 1994. The interest rate on this note for each monthly interest payment period will be based on the evaluation of the yields of short term tax-exempt securities at par having the same credit rating as said Series 1984 Bonds. The average interest rate was 2.74% for 1992, 4.32% for 1991 and 5.55% for 1990. The interest rate will be adjusted monthly unless converted to a fixed rate.

(g) The $40.2 million Promissory Note was issued in connection with NYSERDA's Adjustable Rate Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), Series 1985. This obligation is supported by an irrevocable Letter of Credit expiring November 30, 1994. The annual interest rate was adjusted to 5.70% effective November 15, 1990, to 4.50% effective November 15, 1991 and to 3.10% effective November 15, 1992. The interest rate will be adjusted annually unless converted to a fixed rate.

(h) The $50.0 million Promissory Note was issued in connection with NYSERDA's Adjustable Rate Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), Series 1987. The annual interest rate was adjusted to 6.30% effective July 15, 1990 and to 5.50% effective July 15, 1991. On June 15, 1992 the Series 1987 Bonds were redeemed at a price of 100% and the Promissory Note was cancelled.

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

Based on an estimated borrowing rate at year-end 1992 of 7.64% for long term debt with similar terms and average maturities (13 years), the fair value of the Company's long term debt outstanding (including Promissory Notes as described above) is approximately $787 million at December 31, 1992.

Note 7. Preferred and Preference Stock

Type, by Order of Seniority	Par Value	Shares Authorized	Shares Outstanding
Preferred Stock (cumulative)	$100	2,000,000	1,270,000*
Preferred Stock (cumulative)	25	4,000,000	—
Preference Stock	1	5,000,000	—

*See below for mandatory redemption requirements

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

A. Preferred Stock, not subject to mandatory redemption:

%	Series	Shares Outstanding December 31, 1992	(Thousands) December 31 1992	1991	Optional Redemption* (per share)#
4	F	120,000	$12,000	$12,000	$105
4.10	H	80,000	8,000	8,000	101
4¾	I	60,000	6,000	6,000	101
4.10	J	50,000	5,000	5,000	102.5
4.95	K	60,000	6,000	6,000	102
4.55	M	100,000	10,000	10,000	101
7.50	N	200,000	20,000	20,000	102
Total		670,000	$67,000	$67,000	

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

B. Preferred Stock, subject to mandatory redemption:

%	Series	Shares Outstanding December 31, 1992	(Thousands) December 31 1992	1991	Optional Redemption (per share)
8.25	R	300,000	$30,000	$30,000	$104.00 Before 3/1/93+
7.45	S	100,000	10,000	10,000	Not applicable
7.55	T	100,000	10,000	10,000	Not applicable
7.65	U	100,000	10,000	10,000	Not applicable
		600,000	$60,000	$60,000	
Less: Due within one year		60,000	6,000	—	
Total		540,000	$54,000	$60,000	

+Thereafter at lesser rates

Mandatory Redemption Provisions.

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

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

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

Based on an estimated dividend rate at year-end 1992 of 6.00% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (3.5 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $65 million at December 31, 1992.

Note 8. Common Stock

At December 31, 1992, there were 50,000,000 shares of $5 par value Common Stock authorized, of which 34,796,659 were outstanding. No shares of Common Stock are reserved for options, warrants, conversions, or other rights. There were 208,649 shares of Common Stock reserved and unissued for shareholders under the Automatic Dividend Reinvestment and Stock Purchase Plan and 52,660 shares reserved and unissued for employees under the RG&E Savings Plus Plan.

Common Stock:

	Per Share	Shares Outstanding	Amount (Thousands)
Balance, January 1, 1990		31,257,968	$513,560
Automatic Dividend Reinvestment and Stock Purchase Plan	$18.600–$19.288	134,828	2,513
Savings Plus Plan	$18.625–$19.750	28,472	545
Capital Stock Expense			(230)
Balance, December 31, 1990		31,421,268	$516,388
Automatic Dividend Reinvestment and Stock Purchase Plan	$18.750–$23.163	571,669	11,252
Savings Plus Plan	$19.375–$23.563	108,202	2,194
Capital Stock Expense			(495)
Balance, December 31, 1991		32,101,139	$529,339
Sale of Stock	$24.000	2,000,000	48,000
Automatic Dividend Reinvestment and Stock Purchase Plan	$21.325–$24.850	584,854	13,338
Savings Plus Plan	$22.063–$25.188	110,666	2,590
Capital Stock Expense			(1,735)
Balance, December 31, 1992		34,796,659	$591,532

Note 9. Short Term Debt

At December 31, 1992 and December 31, 1991, the Company had short term debt outstanding of $50.8 million and $59.5 million, respectively. The weighted average interest rate on short term debt outstanding at year end 1992 was 3.99% and was 4.28% for borrowings during the year. For 1991, the weighted average interest rate on short term debt outstanding at year end was 5.09% and was 6.43% for borrowings during the year.

On December 1, 1988 the Company renewed its $90 million revolving credit facility for a period of three years. In January of 1993 the Company was granted a one-year extension of the commitment termination date to December 31, 1995. Commitment fees related to this facility amounted to $169,000 in 1992, $149,000 in 1991 and $164,000 in 1990.

The Company's Charter provides that unsecured debt may not exceed 15 percent of the Company's total capitalization (excluding unsecured debt). As of December 31, 1992, the Company would be able to incur $45.2 million of additional unsecured debt under this provision. In order to be able to use its revolving credit agreement, the Company has created a subordinate mortgage which secures borrowings under its revolving credit agreement that might otherwise be restricted by this provision of the Company's Charter.

Since June 1990 the Company has had a credit agreement with a domestic bank providing for up to $20 million of short term debt. Borrowings under this agreement, which has been extended to December 31, 1993, are secured by the Company's accounts receivable.

Also, beginning in August 1992, additional unsecured short term borrowing capacity of up to $25 million is available from a domestic bank, at its discretion.

Note 10. Commitments and Other Matters

Capital Expenditures.

The Company's 1993 construction expenditures program is currently estimated at $143 million, including $4 million of carrying charges. The Company has entered into certain commitments for purchase of materials and equipment in connection with that program.

Nuclear-Related Matters.

Decommissioning Trust. Under accounting procedures approved by the PSC, the Company has been collecting in its electric rates amounts for the eventual decommissioning of its Ginna Plant and for its 14% share of the decommissioning of Nine Mile Two. The Company has collected approximately $52.4 million through December 31, 1992.

In June 1988 the Nuclear Regulatory Commission (NRC) issued new regulations establishing criteria for various facets of decommissioning including acceptable alternative methods, planning, funding and environmental review. The NRC regulations establish a minimum external funding level determined by formula. The NRC minimum represents only the cost of removing the radioactive plant structures. The Company's depreciation rates reflect a 5% cost of removal factor for Ginna non-radioactive plant structures; however, they do not currently reflect a cost of removal factor for the Company's 14% share of Nine Mile Two non-radioactive plant structures. Since March 1990, the Company has deposited $28.3 million into an external decommissioning trust fund. In July 1990 the Company, in compliance with the NRC regulations, submitted a funding plan to the NRC.

In connection with the Company's rate case completed in June 1992, the PSC approved the collection during the rate year ending June 30, 1993 of an aggregate $8.9 million for decommissioning, covering both nuclear units. The amount allowed in rates is based on estimated ultimate decommissioning costs of $145.8 million for Ginna and $33.5 million for the Company's 14% share of Nine Mile Two (1991 dollars). The Company intends to fund the external decommissioning trust in the amount of the NRC minimum funding requirement. The difference between the amount to be collected and the NRC minimum will be held in an internal reserve.

Uranium Enrichment Decontamination and Decommissioning Fund. As a result of the National Energy Act (Act) passed in October 1992, U.S. Utilities with Nuclear generating facilities will be assessed an annual Decontamination and Decommissioning fee payable to the DOE. This annual fee will be in place for 15 years and could be assessed as early as 1993. The Company's annual fee is approximately $1.8 million for the Ginna Nuclear Plant and the estimated amount for its share of Nine Mile Two is approximately $.1 million. Although a noncash transaction, the aggregate amount of $28.6 million (see Note 1) has been recognized as a liability at December 31, 1992, together with a corresponding deferred debit based on the language of the Act. The Company believes it will receive the ultimate recovery of this deferral through its fuel adjustment clause.

Insurance Program. The Price-Anderson Act establishes a federal program, providing indemnification and insurance against public liability, applicable in the event of a nuclear accident at a licensed U.S. reactor. Amendments to the Act in 1988 increased the public liability limit to approximately $7.4 billion, expanded coverage to include precautionary evacuations and extended the Act's effectiveness until the year 2002. Under the program, claims would first be met by insurance which licensees are required to carry in the maximum amount available (currently $200 million). If claims exceed that amount, licensees are subject to a retrospective assessment up to $63 million per licensed facility for each nuclear incident, payable at a rate not to exceed $10 million per year. Those assessments are subject to periodic inflation-indexing and to a 5% surcharge if funds prove insufficient to pay claims. The Company's interests in two nuclear units could thus expose it to a current potential payment for each accident of $71.8 million through retrospective assessments of $11.4 million per year in the event of a sufficiently serious nuclear accident at its own or another U.S. commercial nuclear reactor.

(Note 10 continued on page 46)

(continued from page 45)

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

The Company is a member of Nuclear Electric Insurance Limited, which provides insurance coverage for the cost of replacement power during certain prolonged accidental outages of nuclear generating units and coverage for property losses in excess of $500 million at nuclear generating units. As of December 31, 1992, the Company is purchasing a weekly indemnity limit of $3.5 million in the NEIL I replacement power expense program and full policy limits of $1.325 billion in the NEIL II Property Insurance Program for the Ginna Nuclear Power Plant. Coverage under the Property Insurance Program includes the shortfall in the NRC required external trust fund resulting from the premature decommissioning of a nuclear power plant following an accident with property damage in excess of $500 million. The Company currently has designated $169 million as a sublimit for this coverage at the Ginna Nuclear Power Plant. For its share in the generation of Nine Mile Two, the Company purchases a weekly indemnity limit of $.5 million in the NEIL I replacement power expense program. The owners at Nine Mile Two purchase the full policy limit of $1.325 billion in the NEIL II Property Insurance Program and the Company pays its proportionate share of those premiums. The owners at Nine Mile Two have selected the maximum available sublimit of $200 million for premature decommissioning. If an insuring program's losses exceeded its other resources available to pay claims, the Company could be subject to maximum assessments in any one policy year of approximately $5.2 million and $13.7 million in the event of losses under the replacement power and property damage coverages, respectively.

Environmental Matters.

On November 15, 1990 the Federal Clean Air Act Amendments of 1990 (Amendments) became law. The Amendments will affect air emissions and quality control measures primarily at the Company's fossil-fueled electric generating facilities. The Amendments consist of several Titles. Three of them are of particular importance to the Company. Title IV addresses Acid Deposition and incorporates a two-phased emissions reduction program for sulfur and nitrogen oxides. The first phase becomes effective in 1995, while the second phase, which contains more stringent provisions, will become effective in the year 2000. The Company is not affected by the first phase of Title IV of the Act. Title I addresses ambient ozone non-attainment and is also divided into two phases. Rochester is included in the Northeast Ozone Transport Region which is required to reduce nitrogen oxide emissions significantly in order to assist downwind receptors in achieving their ozone standards. The first phase of Title I becomes effective in 1995 and will require the installation of low nitrogen oxide burners on the Company's fossil-fuel plants. Phase Two of Title I has not yet been defined, but could require flue gas cleanup for nitrogen oxide removal. Title III of the Act has not yet been defined but could require the control of various air toxics of the Company's fossil-fuel plants if Environmental Protection Agency studies to be completed by 1994 show that these substances are present in specific concentrations. Capital costs between $30 million and $50 million (1992 dollars) have been estimated for the implementation of several potential compliance scenarios under the Amendments. Such capital costs would be incurred between 1993 and 2000, if the Company elected to go forward with any such scenario.

In 1985, the New York State Department of Environmental Conservation (NYSDEC) identified property in the vicinity of the Lower Falls of the Genesee River (the Lower Falls) in Rochester as an inactive hazardous waste disposal site. The Company owns, and was the prior owner or operator of a number of locations within the Lower Falls. In mid-1991, NYSDEC advised the Company that it had delisted the Lower Falls Site, i.e., removed it from its Registry of Inactive Hazardous Waste Sites. The effect of delisting is to terminate the Company's status as a potentially responsible party for the Lower Falls Site, to discontinue the pending NYSDEC review of a joint Company/City of Rochester proposal for a limited further investigation of the Lower Falls, and to defer (and perhaps end) the prospect of remedial action and any Company sharing of the cost thereof. However, NYSDEC also stated its intention to consider listing individual coal gasification sites within the larger, original site once the State of New York adopts new federal procedures under which such individual sites will be compared to new hazardous waste criteria. There is at least some material at one of the individual coal gasification sites that could trigger relisting. The Company is unable to predict what further listing action NYSDEC may take, but regards the announced delisting as a positive development.

The Company and its predecessors formerly owned and operated coal gasification facilities within the Lower Falls. In September 1991 the Company proactively initiated a study of subsurface conditions in the vicinity of retired facilities at its West Station property and has since commenced interim remedial measures there in order to minimize any potential long-term exposure risks.

On a portion of the Company's property in the Lower Falls, and elsewhere in the general area, the County of Monroe has installed and operates sewer lines. During sewer installation, the County constructed over Company property, pursuant to an easement the Company granted the County, certain retention ponds which were reportedly used to recover from the sewer construction area certain fossil-fuel-based materials (the materials) found there. In July 1989 the Company received a letter from the County asserting that activities of the Company left the County unable to effect a regulatorily-approved closure of the retention pond area. The County's letter takes the position that it intends to seek reimbursement for its additional costs in recovering the materials once the NYSDEC identifies the generator thereof and that any further cleanup action which the NYSDEC may require at the retention pond site is the Company's responsibility. In the course of discussions over this matter, the County has claimed, without offering any evidence, that the Company was the original generator of the materials. It asserts that it will hold the Company liable for all County costs—presently estimated at $1.5 million—associated both with the materials' excavation, treatment and disposal and with effecting a regulatorily-approved closure of the retention pond area. The Company could incur costs as yet undetermined if it were to be found liable for such closure and materials handling, although provisions of the easement afford the Company rights which may serve to offset all or a portion of any such County claim.

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

At another location along the River where the Company owns property, a boring taken in Fall 1988 for a sewer system project showed a layer containing a black viscous material. The Company undertook an investigation to determine the extent of contamination. The study found that some soil and ground water contamination existed on-site, but evidence was inadequate to determine whether the contamination had migrated off-site. The matter was reported to the NYSDEC and, in September 1990, the Company also provided the agency with a risk assessment for its review. If the NYSDEC requires remediation of this location, the Company may be fully or partially responsible for the costs of investigation and any site remediation. The Company cannot at this time predict what may result from the NYSDEC review of information on the material from the boring, what future studies may be performed, and what remediation measures may be directed.

(Note 10 continued on page 48)

(continued from page 47)

Gas Cost Recovery.

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

The PSC instituted a proceeding in October 1988 to determine the extent to which the gas distribution companies in New York State would be permitted to recover in rates the take-or-pay costs imposed upon them. That proceeding is ongoing, and the issues raised include the legal authority of the PSC to deny recovery of such costs. However, in October 1989, the PSC approved a settlement between the Staff of the PSC and the Company providing for the Company to recover in rates 87.5% of the first $12 million of the pipeline take-or-pay costs imposed upon it. The recovery of any take-or-pay costs incurred in excess of $12 million would be subject to future determination.

In March 1992 the Company began providing for recovery, on an interim basis, of 65% of take-or-pay costs in excess of $12 million, subject to refund pending permanent disposition of such costs. In November 1992 the Company and the Staff of the PSC entered into, and subsequently filed with the PSC, a supplemental settlement under which the Company would recover all take-or-pay costs imposed upon it in excess of $12 million, except for an amount which would not exceed $562,500. The PSC must approve the supplemental settlement for it to become effective.

The Company is presently unable to estimate the amount of take-or-pay costs which ultimately may be included in its pipeline suppliers' charges. As of December 31, 1992 the Company had been billed for $16.4 million of take-or-pay costs and has thus far recovered $10.6 million from its customers. In addition, $4.1 million has been deferred for recovery.

The FERC is in the process of developing policies and rules which will enable natural gas purchasers, such as the Company, to choose their gas suppliers and to receive non-discriminatory services from interstate pipelines. A major component of this policy permits natural gas purchasers to convert their purchase contracts with interstate pipelines into transportation contracts. These contract conversions will require the pipelines to reduce their purchase commitments to natural gas producers. The costs of such conversions will be allocated among the pipelines' customers. The allocation methodologies are being developed in individual rate cases at this time. The Company cannot predict the dollar cost of such conversions to its customers or what action the PSC may ultimately take regarding this matter.

Other Matters.

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

Nuclear Fuel Enrichment Services. The Company has a contract with the DOE for nuclear fuel enrichment services which assures provision of 70% of the Ginna Nuclear Plant's requirements throughout its service life or 30 years, whichever is less. No payment obligation accrues unless such enrichment services are needed. Annually, the Company is permitted to decline DOE-furnished enrichment for a future year upon giving ten years' notice. Consistent with that provision, the Company has terminated its commitment to DOE for the years 2000, 2001 and 2002. The Company has secured the remaining 30% of its Ginna requirements for the reload

years 1993 through 1995 under different arrangements with DOE. The Company plans to meet its enrichment requirements for years beyond those already committed by making further arrangements with DOE or by contracting with third parties. The cost of DOE enrichment services utilized for the next seven reload years (priced at the most current rate) ranges from $4 million to $7 million per year.

Anticipated Assertion of Tax Liability. The Company's federal income tax returns for 1987 and 1988 have been examined by the Internal Revenue Service (IRS). Based on the progress of the examination to date, in the first half of 1993, the Company anticipates receiving proposed adjustments which, if sustained, could significantly increase its tax liability.

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

The Company expects to protest adjustments the IRS may propose to its 1987-88 tax liability and to pursue the protest vigorously. The Company believes it has sound bases on which to make such a challenge, but cannot predict the outcome thereof. Generally, the Company would expect to receive rate relief to the extent it was unsuccessful in its protest except for that part of the IRS assessment stemming from the Nine Mile Two disallowed costs, although no such assurance can be given.

REPORT OF INDEPENDENT ACCOUNTANTS

Price Waterhouse

1900 Lincoln First Tower
Rochester, New York 14604
January 22, 1993

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

In our opinion, the accompanying balance sheets and the related statements of income, retained earnings and cash flows present fairly, in all material respects, the financial position of Rochester Gas and Electric Corporation at December 31, 1992 and 1991, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1992 in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

As discussed in Note 1 to the financial statements, the Company adopted the provisions of Statement of Financial Accounting Standard No. 106, "Accounting for Postretirement Benefits Other than Pensions" in 1992.

Price Waterhouse

REPORT OF MANAGEMENT

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

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

The Company's financial statements have been examined by Price Waterhouse, independent accountants, in accordance with generally accepted auditing standards. Their examination includes a review of the Company's system of internal accounting control and such tests and other procedures necessary to express an opinion as to whether the Company's financial statements are presented fairly in all material respects in conformity with generally accepted accounting principles. The report of Price Waterhouse is presented on page 49.

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

Management believes that, at December 31, 1992, the Company maintained an effective system of internal control over the preparation of its published financial statements.

Roger W. Kober

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

Robert C. Henderson

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

January 22, 1993

INTERIM FINANCIAL DATA

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

	(Thousands of Dollars)				
Quarter Ended	Operating Revenues	Operating Income	Net Income	Earnings on Common Stock	Earnings per Common Share (in dollars)
December 31, 1992	$244,290	$41,744	$29,146	$27,073	$ .77
September 30, 1992	198,341	33,006	17,507	15,435	.45
June 30, 1992**	195,154	16,460	(4,579)	(6,651)	(.20)
March 31, 1992	257,747	42,735	28,365	26,293	.81
December 31, 1991*	$229,331	$38,578	$14,911	$12,467	$ .38
September 30, 1991	195,629	31,752	17,262	15,756	.49
June 30, 1991	182,637	17,230	1,538	32	—
March 31, 1991	245,673	37,198	24,286	22,780	.72
December 31, 1990	$220,360	$32,878	$18,136	$16,630	$ .53
September 30, 1990	187,508	30,218	15,593	14,087	.45
June 30, 1990	182,216	16,541	2,068	562	.01
March 31, 1990	240,807	37,781	24,084	22,578	.72

*Includes recognition of $6.6 million net-of-tax fuels audit disallowance.
**Includes recognition of $5.4 million net-of-tax ice storm disallowance.

Earnings	1992	1991	1990
Earnings per weighted average share	$1.86	$1.60	$1.72

Shares	1992	1991	1990
Number of shares (000's)			
Weighted average	33,258	31,794	31,293
Actual number at December 31	34,797	32,101	31,421

Tax Status of Cash Dividends

Cash dividends paid in 1992, 1991 and 1990 were 100 percent taxable for Federal income tax purposes.

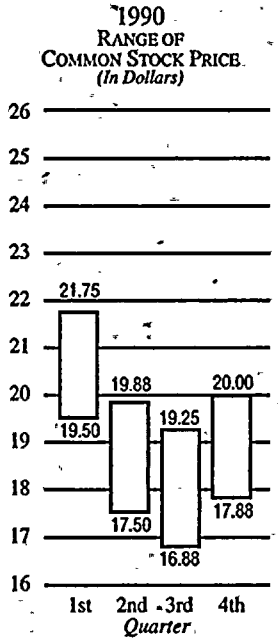
Dividend Policy

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

Quarterly dividends on Common Stock are generally paid on the twenty-fifth day of January, April, July and October. In January 1993, the Company paid a cash dividend of $.43 per share on its Common Stock, up $.01 from the prior quarterly dividend payment of $.42. The January 1993 dividend payment is equivalent to $1.72 on an annual basis.

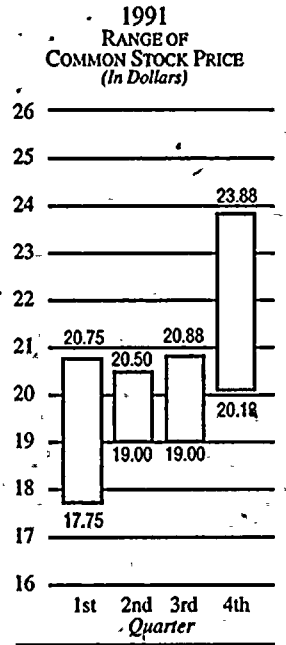
Common Stock Trading

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



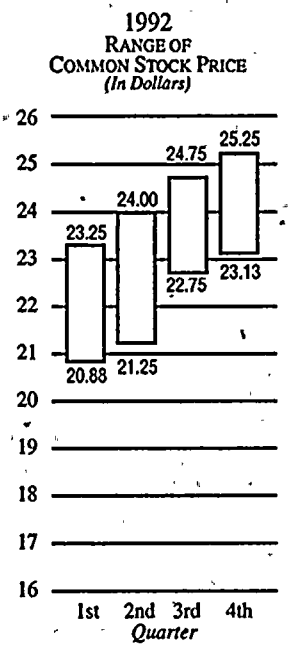
DIVIDENDS PAID per SHARE, 1990 per QUARTER
(In Dollars)

0.39 0.39 0.39 0.39



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

0.405 0.405 0.405 0.405



DIVIDENDS PAID per SHARE, 1992 per QUARTER
(In Dollars)

0.42 0.42 0.42 0.42

(Thousands of Dollars) Year Ended December 31	1992	1991	1990	1989	1988	1987
Summary of Operations						
Operating Revenues						
Electric	$608,267	$588,930	$551,930	$543,096	$514,637	$489,366
Gas	261,724	235,728	236,496	264,573	231,217	218,408
	869,991	824,658	788,426	807,669	745,854	707,774
Electric sales to other utilities	25,541	28,612	42,465	38,028	29,966	26,215
Total Operating Revenues	895,532	853,270	830,891	845,697	775,820	733,989
Operating Expenses						
Fuel Expenses						
Electric fuels	48,376	65,105	76,420	75,873	65,787	61,443
Purchased electricity	29,706	27,683	34,264	39,645	30,299	26,467
Gas purchased for resale	141,291	129,779	132,512	152,623	129,596	124,086
Total Fuel Expenses	219,373	222,567	243,196	268,141	225,682	211,996
Operating Revenues Less Fuel Expenses	676,159	630,703	587,695	577,556	550,138	521,993
Other Operating Expenses						
Operations excluding fuel expenses	226,624	208,440	194,594	173,764	159,689	159,170
Maintenance	62,720	65,415	62,391	64,316	52,575	46,124
Depreciation and Amortization	85,028	84,181	77,767	75,063	69,703	55,530
Taxes—local, state and other	124,252	113,649	101,035	95,341	88,635	82,869
Federal income tax—current	35,299	28,766	20,661	20,509	20,363	32,781
—deferred	8,292	5,493	13,829	17,330	20,299	23,144
Total Other Operating Expenses	542,215	505,944	470,277	446,323	411,264	399,618
Operating Income	133,944	124,759	117,418	131,233	138,874	122,375
Other Income and Deductions						
Allowance for other funds used during construction	164	675	2,689	2,261	2,047	5,030
Federal income tax	4,195	4,580	2,459	1,439	1,683	17,520
Regulatory disallowances	(8,215)	(10,000)	—	(2,100)	—	(55,860)
Other, net	6,155	6,078	4,062	8,328	6,901	8,831
Total Other Income and Deductions	2,299	1,333	9,210	9,928	10,631	(24,479)
Income Before Interest Charges	136,243	126,092	126,628	141,161	149,505	97,896
Interest Charges						
Long term debt	60,810	63,918	64,873	68,628	72,270	73,489
Short term debt	1,950	2,623	1,070	—	—	129
Other, net	5,228	4,459	3,523	3,115	2,898	2,685
Allowance for borrowed funds used during construction	(2,184)	(2,905)	(2,719)	(2,026)	(1,777)	(2,696)
Total Interest Charges	65,804	68,095	66,747	69,717	73,391	73,607
Income from Continuing Operations, Before Cumulative Effect of Accounting Change	70,439	57,997	59,881	71,444	76,114	24,289
Cumulative Effect for Years Prior to 1987 of Accounting Change for Disallowed Costs	—	—	—	—	—	(193,000)
Net Income (Loss)	70,439	57,997	59,881	71,444	76,114	(168,711)
Dividends on Preferred Stock, at Required Rates	8,290	6,963	6,025	6,025	7,348	8,147
Earnings (Loss) Applicable to Common Stock	$ 62,149	$ 51,034	$ 53,856	$ 65,419	$ 68,766	$(176,858)
Weighted Average Number of Shares Outstanding in Each Period (000's)	33,258	31,794	31,293	31,090	30,513	29,728
Earnings (Loss) per Common Share—Total	$1.86	$1.60	$1.72	$2.10	$2.25	$(5.95)
Earnings per Common Share—Continuing Operations	$1.86	$1.60	$1.72	$2.10	$2.25	$ 0.54
Cash Dividends Paid per Common Share	$1.68	$1.62	$1.56	$1.50	$1.50	$2.025

Condensed Balance Sheet

(Thousands of Dollars) At December 31	1992	1991	1990	1989	1988	1987
Assets						
Utility Plant	$2,798,581	$2,706,554	$2,310,294	$2,208,158	$2,122,922	$1,559,848
Less: Accumulated depreciation and amortization	1,253,117	1,178,649	812,994	730,621	653,876	586,840
	1,545,464	1,527,905	1,497,300	1,477,537	1,469,046	973,008
Construction work in progress	83,832	76,848	82,663	68,784	41,044	501,738
Net utility plant	1,629,296	1,604,753	1,579,963	1,546,321	1,510,090	1,474,746
Current Assets	209,621	189,009	176,045	190,321	213,626	184,472
Deferred Debits	210,525	160,034	108,451	102,729	102,015	131,526
Total Assets	$2,049,442	$1,953,796	$1,864,459	$1,839,371	$1,825,731	$1,790,744
Capitalization and Liabilities						
Capitalization						
Long term debt	$ 658,880	$ 672,322	$ 721,612	$ 764,627	$ 792,976	$ 845,326
Preferred stock redeemable at option of Company	67,000	67,000	67,000	67,000	67,000	67,000
Preferred stock subject to mandatory redemption	54,000	60,000	30,000	30,000	30,000	50,797
Common shareholders' equity						
Common stock	591,532	529,339	516,388	513,560	504,907	494,018
Retained earnings	66,968	61,515	62,542	57,983	39,710	17,617
Total common shareholders' equity	658,500	590,854	578,930	571,543	544,617	511,635
Total Capitalization	1,438,380	1,390,176	1,397,542	1,433,170	1,434,593	1,474,758
Long Term Liabilities (Department of Energy)	94,602	63,626	59,989	55,502	51,016	47,773
Current Liabilities	267,277	267,601	183,720	137,899	126,661	89,308
Deferred Credits and Other Liabilities	249,183	232,393	223,208	212,800	213,461	178,905
Total Capitalization and Liabilities	$2,049,442	$1,953,796	$1,864,459	$1,839,371	$1,825,731	$1,790,744

Financial Data

At December 31	1992	1991	1990	1989	1988	1987
Capitalization Ratios (a) (percent)						
Long term debt	48.2	50.6	53.6	55.1	56.8	58.7
Preferred stock	8.0	8.7	6.7	6.5	6.5	7.7
Common shareholders' equity	43.8	40.7	39.7	38.4	36.7	33.6
Total	100.0	100.0	100.0	100.0	100.0	100.0
Book Value per Common Share—Year End	$18.92	$18.41	$18.42	$18.28	$17.69	$16.98
Rate of Return on Average Common Equity (percent)	9.98	8.60	9.29	11.56(b)	12.68	12.45(b)
Embedded Cost of Senior Capital (percent)						
Long term debt	7.91	8.32	8.59	8.74	8.71	8.90
Preferred stock	6.98	6.97	6.72	6.72	6.72	7.09
Effective Federal Income Tax Rate (percent)	35.9	33.9	34.8	33.8	33.9	61.3
Depreciation Rate (percent)—Electric	2.69	3.05	3.33	3.25	3.56	3.50
—Gas	2.78	2.94	2.94	2.96	2.96	2.98
Interest Coverages (b)(c)						
Before federal income taxes (incld. AFUDC)	2.74	2.38	2.32	2.53	2.53	2.55
(excld. AFUDC)	2.70	2.33	2.25	2.47	2.48	2.45
After federal income taxes (incld. AFUDC)	2.12	1.91	1.86	2.02	2.01	1.93
(excld. AFUDC)	2.08	1.86	1.78	1.96	1.96	1.83

(a)Includes Company's long term liability to the Department of Energy (DOE) for nuclear waste disposal. Excludes DOE long term liability for uranium enrichment decommissioning and amounts due or redeemable within one year.
(b)Excludes disallowed Nine Mile Two plant costs written off in 1989 and 1987.
(c)The recognition by the Company in 1991 of a fuel procurement audit approved by the New York State Public Service Commission (PSC) has been excluded from 1991 coverages. Likewise, recognition by the Company in 1992 of disallowed ice storm costs as approved by the PSC has been excluded from 1992 coverages.

Year Ended December 31	1992	1991	1990	1989	1988	1987
Electric Revenue (000's)						
Residential	$220,866	$212,327	$197,612	$191,732	$188,451	$178,933
Commercial	184,815	181,561	165,445	155,076	149,663	146,138
Industrial	142,392	141,001	130,012	124,634	120,490	118,479
Other (Includes Unbilled Revenue)	60,194	54,041	58,861	71,654	56,033	45,816
Electric revenue from our customers	608,267	588,930	551,930	543,096	514,637	489,366
Other electric utilities	25,541	28,612	42,465	38,028	29,966	26,215
Total electric revenue	633,808	617,542	594,395	581,124	544,603	515,581
Electric Expense (000's)						
Fuel used in electric generation	48,376	65,105	76,420	75,873	65,787	61,443
Purchased electricity	29,706	27,683	34,264	39,645	30,299	26,467
Other operation	183,118	168,610	155,289	137,458	124,871	126,320
Maintenance	53,714	57,032	53,880	55,915	44,060	37,641
Depreciation and Amortization	73,213	72,746	67,302	65,287	60,444	46,776
Taxes—local, state and other	94,841	86,925	77,323	71,361	66,426	61,504
Total electric expense	482,968	478,101	464,478	445,539	391,887	360,151
Operating Income before Federal Income Tax	150,840	139,441	129,917	135,585	152,716	155,430
Federal income tax	38,046	31,390	30,670	29,887	34,093	48,788
Operating Income from Electric Operations (000's)	$112,794	$108,051	$ 99,247	$105,698	$118,623	$106,642
Electric Operating Ratio %	49.7	51.6	53.8	53.2	48.7	48.9
Electric Sales—KWH (000's)						
Residential	2,084,466	2,085,429	2,075,072	2,072,047	2,051,808	1,970,345
Commercial	1,937,950	1,928,730	1,897,583	1,832,521	1,792,162	1,732,939
Industrial	1,929,498	1,917,796	1,931,633	1,906,429	1,869,417	1,782,223
Other	503,330	507,765	490,077	491,905	483,730	463,256
Total billed	6,455,244	6,439,720	6,394,365	6,302,902	6,197,117	5,948,763
Unbilled sales	742	7,657	(25,421)	33,406	—	—
Total customer sales	6,455,986	6,447,377	6,368,944	6,336,308	6,197,117	5,948,763
Other electric utilities	1,062,738	1,034,370	1,316,379	1,255,282	1,149,900	1,047,654
Total electric sales	7,518,724	7,481,747	7,685,323	7,591,590	7,347,017	6,996,417
Electric Customers at December 31						
Residential	300,344	298,440	296,110	293,418	290,037	285,988
Commercial	29,339	28,856	28,804	28,386	27,888	27,383
Industrial	1,386	1,388	1,428	1,422	1,392	1,381
Other	2,605	2,558	2,553	2,512	2,326	2,281
Total electric customers	333,674	331,242	328,895	325,738	321,643	317,033
Electricity Generated and Purchased—KWH (000's)						
Fossil	2,197,757	2,146,664	2,505,110	2,578,006	2,214,588	1,877,922
Nuclear	4,191,035	4,391,480	4,016,721	3,659,185	3,884,884	3,793,021
Hydro	278,318	174,239	244,539	175,085	169,002	223,958
Pumped storage	226,391	240,206	269,966	290,582	292,305	246,925
Less energy for pumping	(344,245)	(364,520)	(405,966)	(429,895)	(430,401)	(387,546)
Other	811	1,269	20,408	54,893	2,195	4,554
Total generated—Net	6,550,067	6,589,338	6,650,778	6,327,856	6,132,573	5,758,834
Purchased	1,389,875	1,451,208	1,498,089	1,757,413	1,705,755	1,703,411
Total electric energy	7,939,942	8,040,546	8,148,867	8,085,269	7,838,328	7,462,245
System Net Capability—KW at December 31						
Fossil	541,000	541,000	541,000	541,000	541,000	541,000
Nuclear	617,000	622,000	621,000	621,000	621,000	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	348,000	354,000	356,000	369,000	360,000	363,000
Total system net capability	1,582,000	1,593,000	1,594,000	1,607,000	1,598,000	1,450,000
Net Peak Load—KW	1,252,000	1,297,000	1,208,000	1,249,000	1,275,000	1,205,000
Annual Load Factor—Net %	62.5	61.7	64.6	62.4	59.7	60.8

Year Ended December 31	1992	1991	1990	1989	1988	1987
Gas Revenue (000's)						
Residential	$ 6,456	$ 6,354	$ 6,508	$ 6,770	$ 6,439	$ 6,436
Residential spaceheating	183,405	157,458	159,501	165,832	150,383	138,552
Commercial	44,274	40,196	43,534	46,897	44,781	43,311
Industrial	6,418	6,761	9,674	9,371	9,859	10,842
Municipal and other (Includes Unbilled Revenue)	21,171	24,959	17,279	35,703	19,755	19,267
Total gas revenue	261,724	235,728	236,496	264,573	231,217	218,408
Gas Expense (000's)						
Gas purchased for resale	141,291	129,779	132,512	152,623	129,596	124,086
Other operation	43,506	39,830	39,307	36,306	34,818	32,850
Maintenance	9,006	8,383	8,510	8,401	8,515	8,483
Depreciation	11,815	11,435	10,465	9,776	9,259	8,754
Taxes—local, state and other	29,411	26,724	23,711	23,980	22,209	21,365
Total gas expense	235,029	216,151	214,505	231,086	204,397	195,538
Operating Income before Federal Income Tax	26,695	19,577	21,991	33,487	26,820	22,870
Federal income tax	5,545	2,869	3,820	7,952	6,569	7,137
Operating Income from Gas Operations (000's)	$ 21,150	$ 16,708	$ 18,171	$ 25,535	$ 20,251	$ 15,733
Gas Operating Ratio %	74.1	75.5	76.3	74.6	74.8	75.7
Gas Sales—Therms (000's)						
Residential	8,780	9,068	9,644	10,321	10,374	10,255
Residential spaceheating	287,614	253,655	262,458	277,267	267,697	244,655
Commercial	78,993	71,509	77,617	84,152	86,413	83,167
Industrial	12,437	13,000	18,536	17,873	20,174	22,033
Municipal	11,410	10,580	13,350	12,319	15,514	17,985
Total billed	399,234	357,812	381,605	401,932	400,172	378,095
Unbilled sales	13	3,291	(22,840)	20,320	—	—
Total gas sales	399,247	361,103	358,765	422,252	400,172	378,095
Transportation of customer-owned gas	127,196	109,835	101,985	105,303	83,594	67,496
Total gas sold and transported	526,443	470,938	460,750	527,555	483,766	445,591
Gas Customers at December 31						
Residential	19,114	21,448	22,410	23,321	24,139	24,834
Residential spaceheating	228,096	222,918	219,242	215,120	210,710	206,458
Commercial	18,378	18,151	17,920	17,677	17,213	16,771
Industrial	932	921	960	1,095	1,042	1,035
Municipal	1,010	983	984	1,067	1,039	1,026
Transportation	424	423	401	367	270	147
Total gas customers	267,954	264,844	261,917	258,647	254,413	250,271
Gas—Therms (000's)						
Purchased for resale	360,493	384,643	366,684	426,941	408,044	381,632
Gas from storage	53,757	16,755	—	—	—	—
Other	1,059	1,140	2,525	1,764	1,967	2,317
Total gas available	415,309	402,538	369,209	428,705	410,011	383,949
Cost of gas per therm (excluding gas from storage)	32.67¢	33.43¢	36.03¢	35.74¢	31.76¢	32.51¢
*Total Daily Capacity—Therms at December 31**	4,485,000	4,485,000	4,485,000	4,485,000	4,485,000	4,485,000
Maximum daily throughput—Therms	3,768,470	3,539,260	3,539,820	3,719,050	3,744,500	3,443,240
Degree Days (Calendar Month)						
For the period	6,981	6,146	5,924	7,109	6,862	6,423
Percent colder (warmer) than normal	3.4	(8.4)	(11.8)	5.9	1.6	(4.3)

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

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General Counsel
Age 49, Years of Service, 1

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

Form 10-K Annual Report
Shareholders may obtain a copy of the Company's 1992 annual report on Form 10-K, as filed with the Securities and Exchange Commission, without charge, by writing to the Secretary.

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

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

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

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

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

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

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