RGS ENERGY GROUP, INC.

1999 ANNUAL REPORT

RGS ENERGY GROUP, INC. GROWING TOWARDS THE FUTURE

RGS Energy Group, Inc. is a holding company formed in 1999 in response to the restructuring of the energy utility industry. It conducts its regulated energy business through Rochester Gas and Electric Corporation (RG&E) and its unregulated energy business through Energetix, Inc. The RGS Energy Group vision is to be the premier energy provider in the region. Our mission is to provide energy and energy-related services to the people of this region with the highest level of customer satisfaction and quality.

RG&E supplies regulated electric and gas service in a service territory of about one million people. The service territory is well diversified among residential, commercial and industrial customers. The City of Rochester is the third largest in New York State and a major industrial center. Multi-national commerce in the Greater Rochester Region accounts for 40 percent of all exports from New York State and makes our area the number one per-capita exporting community in the nation. Our territory also has a substantial suburban area with commercial growth and large, prosperous farming regions.

Energetix, Inc. and its subsidiary, Griffith Energy, Inc., are unregulated companies offering a full line of energy products including electricity, natural gas, home heating oil, propane and a variety of energy services throughout the region. This allows RGS Energy Group to be a successful competitor in the emerging energy marketplace that is driven by consumer energy supplier choice and an expanded array of energy services.

RGE AND

ENERGETIX

GO GRIFFITH ENERGY AN ENERGETIX COMPANY

RGS DEVELOPMENT CORPORATION

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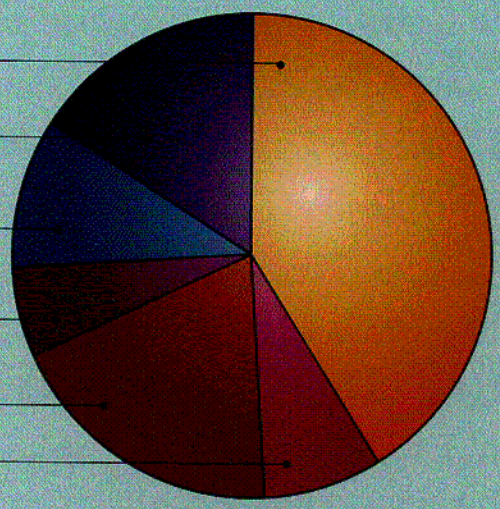
1999 Revenue Dollar

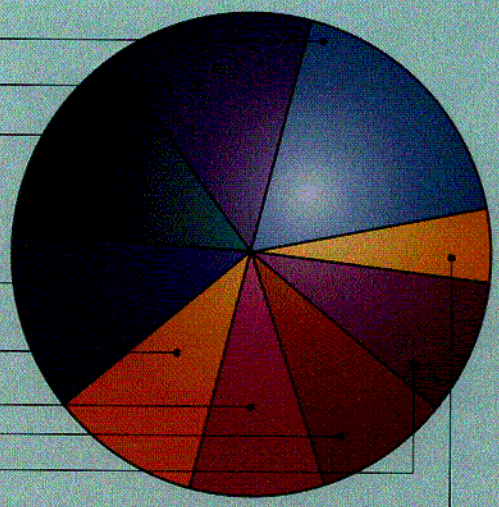
Source of 1999 Revenue Dollar

Residential (23¢ Electric, 18¢ Gas)	41¢
Commercial (14¢ Electric, 2¢ Gas)	16¢
Industrial (9¢ Electric, 1¢ Gas)	10¢
Other (4¢ Electric, 2¢ Gas)	6¢
Unregulated Operations	19¢
Wholesale Electric	8¢



Use of 1999 Revenue Dollar

Unregulated Operations	18¢
Taxes	14¢
Other Operations	14¢
Purchased Gas	12¢
Wages & Benefits	10¢
Depreciation & Amortization	10¢
Electric Fuel & Purchased Electricity	9¢
Dividends & Reinvested Earnings	8¢
Interest	5¢



RGS ENERGY GROUP, INC.

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FINANCIAL HIGHLIGHTS—RGS

	1999	1998	% Change
FINANCIAL DATA (Thousands)			
Operating revenues: Electric	$ 702,751	$ 687,622	2
Gas	$ 284,476	$ 274,657	4
Other	$ 220,310	$ 71,212	209
Total	$1,207,537	$1,033,491	17
Operating expenses	$1,066,498	$ 905,425	18
Operating income	$ 141,039	$ 128,066	10
Net income applicable to common stock	$ 89,497	$ 89,296	—
Rate of return on average common equity	11.53%	11.22%	3
COMMON STOCK DATA			
Weighted average number of shares outstanding (Thousands)			
—Basic	36,665	38,462	(5)
—Diluted	36,757	38,600	(5)
Per common share:			
Earnings—Basic	$2.44	$2.32	5
Earnings—Diluted	$2.44	$2.31	6
Dividends Paid	$1.80	$1.80	—
Book Value (year end)	$21.43	$20.94	2
Year-end market price	$20.56	$31.25	(34)
Number of Registered Common Stock Shareholders at December 31	27,258	28,995	(6)
OPERATING DATA			
Sales (Thousands)			
Kilowatt-hours to retail customers	6,319,259	6,586,186	(4)
Kilowatt-hours to wholesale customers	1,874,927	1,673,345	12
Therms of gas sold and transported	535,850	474,096	13
Net additions to utility plant, less allowance for funds used during construction (thousands)	$ 108,339	$129,286	(16)
Employees (year end)	2,354	2,333	1

Dear Shareholder,

When I last wrote to you in an annual report, the name on the cover was Rochester Gas and Electric Corporation. This year it is RGS Energy Group, Inc., a change that is characteristic of the transition that is occurring in our industry. We are moving from regulated monopoly to reduced regulation and customer choice. It's a journey that leads less to a destination than to a state of continual change. Our progress should be measured, not by how near we are to a fixed location, but by our ability to successfully adapt to and prosper in a changing environment. That's what we have been doing, and that's the substance of this annual report.

We're on a journey that leads less to a destination than to a state of continual change. So our progress should be measured, not by how near we are to a fixed location, but by our ability to successfully adapt to and prosper in a changing environment.

As the journey began with the Competitive Opportunities Regulatory Settlement in 1997, we identified the challenges that we had to meet in this changing environment as:

- Keep the lights on and the gas flowing for everyone for a lower cost
- Create the systems and facilities for a new competitive system
- Develop a profitable, growing, unregulated business
- Maintain our financial performance
- Balance them all

I want to share with you some examples of how we met these challenges in 1999.

Keep the lights on and the gas flowing for everyone for a lower cost

We have continued to honor our commitment to lower electric prices during the five-year transition period. Residential electric customers are seeing about a ten percent rate reduction over the period and commercial and industrial electric customers will realize savings of between ten and 15 percent.

Last year we closed Beebee Station as part of our strategy to eliminate generating facilities that could no longer be profitable. Beebee dates back more than 100 years on the Genesee River in downtown Rochester. Many generations of RG&E employees provided dedicated service to the plant in meeting the ever-growing needs of the community. We are working with the City of Rochester and others to determine an appropriate future for the site.

As part of our settlement with an independent power producer we took ownership of a gas-fired power plant south of Rochester. Its capacity of about 60 megawatts largely offsets the loss from the Beebee plant closure.

Despite the cost pressures that are created by the changes in our industry, we need to continue our commitment to energy reliability. We recognize that our customers depend on us and we have actually increased our investment in the reliability of our energy delivery systems.

And in the midst of these changes in1999 came the much publicized Y2K issue.

We remediated 6.8 million lines of computer code, checked 12,000 digital devices and upgraded about 100, and verified the readiness of several hundred vendors. Leading up to and including New Year's Eve, we worked closely with other utilities, government and industry oversight agencies, customers and media. We had almost 300 response personnel on duty just in case anything unexpected happened. The result? Three years of dedicated effort paid off, the stroke of midnight Dec. 31 was like the stroke of midnight any other night.

Create the systems and facilities for a new competitive system

To make way for open electric retail access and to reduce our dependency on our own generating resources, we completed what we call a load pocket project in 1999. The work centered around our Russell Station coal-fired plant. By redesigning the electric transmission and distribution system we now have much more flexibility in delivering electricity

and can more easily import power when we need it. This clears the way for more effective retail access in our system.

The "New York Independent System Operator" (NYISO) began full operation on November 18, 1999. The ISO took charge of the operation and cost of the electric system in the New York Control Area from the New York Power Pool which was formerly operated by the utility members of New York State.

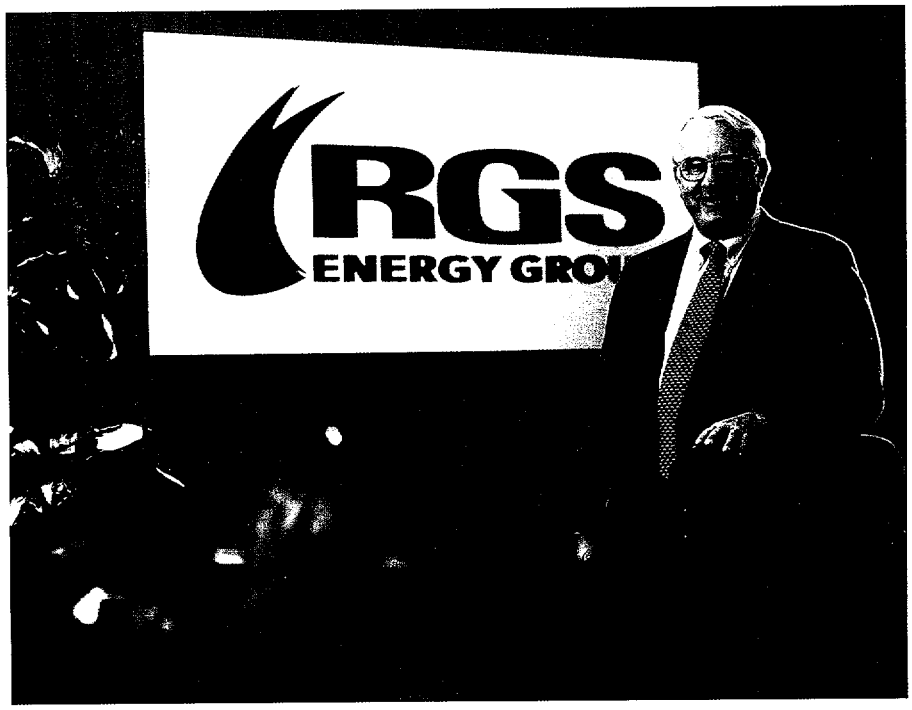
The ISO is designed to independently run the wholesale electric marketplace in New York State. The products include electric energy, transmission services and associated services. The ISO provides a clearing mechanism for trading in wholesale electric energy and related services. This means that RG&E will buy the necessary electricity for its customers in a competitive marketplace, and sell the output of its generating plants into the same competitive marketplace.

Already there are eight qualified electric energy service companies operating in our service territory and 16 natural gas energy service companies. They are presently providing the commodity for 38 percent of our natural gas system sales and 15 percent of our electric system sales.

One of our regulatory charges is to raise consumer awareness of energy choice. Through direct mail and paid advertising we have made remarkable strides in this effort. Our year-end 1999 survey shows that nearly eight out of ten of our customers are aware of electric choice and more than 60 percent are aware of gas choice. Those levels are up substantially from year-end 1998 when about half of our customers were aware of choice. You can visit our website at www.rgs-energy.com for more information on energy choice.

Develop a profitable, growing unregulated business Energetix

On the unregulated side, we have our own energy service company called Energetix. It is developing quickly and is making great strides in the energy marketplace both within our service territory and well beyond. At year's end 1999, Energetix posted a modest loss, but is well ahead of our projections, and is expected to be profitable this year.



Thomas S. Richards

In 1999 Energetix had signed up over 14,000 gas and electric customers, and expanded east into Syracuse and Albany and south to the Corning and Elmira area. It's also wrapping up implementation of performance contracts for energy efficiency improvements with business customers worth over $1.8 million. And Energetix's subsidiary, Griffith Energy, which serves 70,000 customers across the state, acquired two oil and propane companies to strategically grow the business.

We have continued to honor our commitment to reduce energy prices during the five-year transition period.

Maintain our financial performance

The Company's earnings per share for 1999 were $2.44 compared to $2.32 for 1998, a five percent increase. This was achieved despite the reduction in revenue due to lower rates and the significant changes that have accompanied the transition to competitive customer choice.

It's not enough to focus on any one challenge that faces us. We need to balance them all to a successful conclusion.

The operating performance of Energetix, our unregulated subsidiary, resulted in a modest pre-tax loss that reflects the positive earnings contribution of its subsidiary Griffith Energy. This was offset by the development expenses related to building a successful new unregulated electric and natural gas business.

Balance them all

It's not enough to focus on any one of these challenges. We need to balance them all to a successful conclusion. As you will note from the examples I've given we are working hard to achieve that balance. The creation of the RGS holding company in 1999 will help us strike this balance, particularly between our regulated and unregulated businesses.

Stock Value

Despite the success we have had in moving along the journey to a new industry and in meeting the changing challenges along the way, the performance of our stock has been a disappointment. RGS Energy's price decline mirrored the weak performance of the utility sector that was driven by the traditional factors of changing market conditions and rising interest rates that were compounded by regulatory and nuclear uncertainty.

As an industry, utility stock valuations reflect the impact of lower-than-expected growth rates during this period of transition to competition and substantially higher returns that have been provided in other market sectors. As a result there has been selling pressure created by investors rotating out of utility stocks and into other sectors that were providing premium return opportunities.

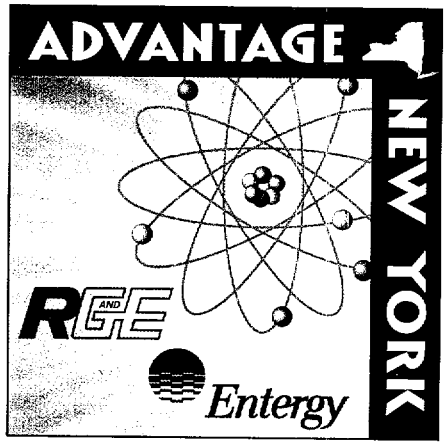
Historically, increases in interest rates have led to declines in utility stock prices and this trend was evident again last year. As interest rates rose, investors required higher dividend yields which further contributed to a decline in utility stock prices.

Regulatory changes and the uncertainties surrounding the industry have contributed to investor concerns in the late 1990's. Regulation of the utility industry is in a state of transition and uncertainty in general, and, particularly with respect to the future of nuclear power plants. In New York State, the Public Service Commission continues to exert considerable influence over all aspects of our business and none of the New York State electric and gas utility stocks performed well in 1999.

The combination of these factors is preventing the recognition of the true value of our company in the stock market. I don't like it and the management of the company is strongly focused on dealing with those factors that we can influence. That includes running the regulated business well, growing the unregulated business and continuing to deal with the changing regulatory environment with flexibility and creativity. I firmly believe that this will make your investment in RGS a profitable one and appreciate your support as we implement this strategy.

Advantage New York

As I wrote to you in a recent letter there have been some significant developments in connection with the future of the nuclear plants in New York State. Although the Public Service Commission proceeding to determine the future of nuclear plants in a restructured industry was only partly completed, Niagara Mohawk Power Corporation and New York State Electric & Gas jointly announced their intention to sell their majority interests in the Nine Mile Point Two plant to AmerGen, which is a joint venture of Pennsylvania-based PECO and British Energy.



This proposal then presented us with an opportunity to sell our existing 14 percent interest in the plant, retain that interest or exercise our right of first refusal to acquire the interests being offered for sale, which included the Nine Mile Point One plant wholly owned by Niagara Mohawk. We elected to exercise our right of first refusal.

We call our proposal "Advantage New York." The rationale has been discussed in some detail in previous correspondence and is further covered in the Management Discussion and Analysis Section of this report immediately following this letter.

The PSC is now conducting proceedings to determine whether to approve the terms of the sale proposed by Niagara Mohawk and NYSEG in the context of its continuing consideration of the future role of nuclear plants. These proceedings raise a number of issues, including the value of the plants, who should own them, and the consequences of the loss of control over the price and quantity of the energy supplied from them. There's also the question as to who should bear the shortfall between the value of the plants on the books of the utilities and the sale price. As this letter is being written it is not clear on what terms the PSC would approve the sale of the plants, if at all.

This is likely to be an evolving situation right through the date of our annual meeting. Throughout the process, we have some clear goals.

- Safe and efficient operation of the plants
- Recovery of our investment in the plants
- Adequate supply of energy at a stable cost to meet our continuing obligation to serve customers
- Reliance on our ability to run the business profitably. This includes our ability to recover our nuclear investment from operations, rather than depending on regulatory assurances of loss recovery from customers.

We have made a proposal that meets those goals while providing substantial protection and benefits to our customers. While we would consider other proposals, we will continue to work toward our goals because we're convinced our plan works to the benefit of all concerned. We'll keep you informed as the process unfolds.

Making the Company

As you read further in this report, you will be introduced to our newest Board member, Jean Howard. Jean brings experience as an accomplished executive in the not-for-profit sector and has already become a valued member of the Board. We are very pleased that she was willing to join us.

Energetix, our unregulated energy service company, is making great strides in the marketplace both within our service territory and well beyond.

You will also notice that we have appointed a number of new officers in our principal subsidiary, RG&E. These appointments were made as part of the reorganization that accompanied the formation of the RGS holding company. In most cases they represent a recognition of roles already being filled by these people, and in all cases they're fine people who are working hard to make your company a success. I am pleased that we have been able to recognize their contributions.

I have been saying to people that in this time of change we have a chance to do more than work for the company. We can "Make the Company." All of us are working hard to "make a company" of which you will be proud to be an owner. We appreciate your support as we work toward this goal.

Thomas S. Richards
February 1, 2000
Chairman of the Board,
President and Chief
Executive Officer

Management's Discussion and Analysis

Of Financial Condition and Results of Operations

Introduction

The following is Management's assessment of certain significant factors affecting the financial condition and operating results of RGS Energy Group, Inc. and its subsidiaries over the past three years. The Consolidated Financial Statements and the Notes thereto contain additional data. For the twelve months ended December 31, 1999, 58 percent of the Company's operating revenues were derived from electric service, 23 percent from natural gas service, and 19 percent from unregulated businesses.

Selected Abbreviations and Glossary

Cooling degree days: The extent to which the daily outdoor average temperature exceeds a base of 65 degrees Fahrenheit. One degree day is counted for each degree day falling above the assumed base for each calendar day.

Company or RGS: RGS Energy Group Inc., a holding company formed August 2, 1999,which is the parent company of Rochester Gas and Electric Corporation, RGS Development Corporation, and Energetix, Inc.

FERC: Federal Energy Regulatory Commission

Ginna Plant: Ginna Nuclear Plant wholly owned by the Company

Heating degree days: The extent to which the daily outdoor average temperature falls below a base of 65 degrees Fahrenheit. One degree day is counted for each degree day falling below the assumed base for each calendar day.

Nine Mile Two: Nine Mile Point Nuclear Plant Unit No. 2 of which the Company currently owns a 14% share

PSC: New York State Public Service Commission

RG&E: Rochester Gas and Electric Corporation, a wholly-owned subsidiary of the Company

Settlement: Competitive Opportunities Case Settlement among the Company, PSC and other parties which provides the framework for the development of competition in the electric energy marketplace through June 30, 2002

SFAS: Statement of Financial Accounting Standards

Forward Looking Statements

The discussion presented below contains statements which are not historic fact and which can be classified as forward looking. These statements can be identified by the use of certain words which suggest forward looking information, such as "believes," "will," "expects," "projects," "estimates" and "anticipates". They can also be identified by the use of words which relate to future goals or strategies. In addition to the assumptions and other factors referred to specifically in connection with the forward looking statements, some of the factors that could have a significant effect on whether the forward looking statements ultimately prove to be accurate include:

1. uncertainties related to the regulatory treatment of nuclear generation facilities including the proposed sale of the Nine Mile Point nuclear generating facilities by Niagara Mohawk Power Corporation (Niagara Mohawk) and New York State Electric and Gas Corporation and the exercise of RG&E's right of first refusal;
2. any state or federal legislative or regulatory initiatives (including the results of negotiations between RG&E and the PSC regarding certain gas restructurings) that affect the cost or recovery of investments necessary to provide utility service in the electric and natural gas industries. Such initiatives could include, for example, changes in the regulation of rate structures or changes in the speed or degree to which competition occurs in the electric and natural gas industries;
3. any changes in the ability of RG&E to recover environmental compliance costs through increased rates;
4. the determination in the nuclear generation proceeding initiated by the PSC, including any changes in the regulatory status of nuclear generating facilities and their related costs, including recovery of costs related to spent fuel and decommissioning;
5. any changes in the rate of industrial, commercial and residential growth in RG&E's and RGS's service territories;
6. the development of any new technologies which allow customers to generate their own energy or produce lower cost energy;
7. any unusual or extreme weather or other natural phenomena;
8. the ability of RGS to manage profitably new unregulated operations;

9. certain unknowable risks involved in operating unregulated businesses in new territories and new industries;
10. the timing and extent of changes in commodity prices and interest rates; and
11. any other considerations that may be disclosed from time to time in the publicly disseminated documents and filings of RGS and RG&E.

Shown below is a listing of the principal items discussed.

RGS Energy Group, Inc.

On August 2, 1999, RG&E was reorganized into a holding company structure pursuant to an Agreement and Plan of Share Exchange (Exchange Agreement) between RG&E and RGS. As part of the reorganization, all of the outstanding shares of RG&E common stock were exchanged on a share-for-share basis for shares of RGS and RG&E became a subsidiary of RGS. Certificates for shares of RG&E common stock are automatically valid as certificates for RGS and do not have to be replaced. The transfer does not affect the value of the stock or RGS's dividend policy. RGS trades on the New York Stock Exchange under the symbol "RGS". RG&E shareholders approved the Exchange Agreement on April 29, 1999.

The holding company structure was formed so that RGS could respond quickly to changes in the evolving competitive energy utility industry. The new structure permits the use of financing techniques that are better suited to the particular requirements, characteristics and risks of non-utility operations without affecting the capital structure or creditworthiness of RG&E. This increases RGS's financial flexibility by allowing it to establish different debt-to-equity ratios for each of its individual lines of business.

RGS is not an operating entity. RGS's operations are being conducted through its subsidiaries which include RG&E, and two unregulated subsidiaries –RGS Development Corporation and Energetix, Inc.

RG&E Ginna's simulator control room, an exact replica of the 'live' control room, is used for rigorous training and certification programs for RG&E personnel.

RG&E will continue to offer regulated electric and natural gas utility service in its franchise territory. Energetix, Inc. provides energy products and services throughout upstate New York. RGS Development Corporation offers energy systems development and management services.

Unregulated Subsidiaries. It is part of RGS's financial strategy to seek growth by entering into unregulated businesses. The Settlement allowed RG&E to provide the funding for RGS to invest up to $100 million in unregulated businesses. The first step in this direction was the formation and operation of Energetix, Inc. (Energetix) effective January 1, 1998. Energetix is an unregulated subsidiary that brings energy products and services to the marketplace both within and outside of RG&E's regulated franchise territory. Energetix markets electricity, natural gas, oil, gasoline, and propane fuel energy services in an area extending in approximately a 150-mile radius around Rochester.

In August 1998, Energetix announced the acquisition of Griffith Oil Company, Inc. (Griffith), the second largest oil and propane distribution company in New York State. This $31.5 million acquisition was accounted for using purchase accounting and the results of Griffith's operations are reflected in the consolidated financial statements of RGS since its acquisition on August 2, 1998.

Griffith gives Energetix access to 70,000 new customers, 65,000 of which are outside of RG&E's regulated franchise territory. Griffith has approximately 350 employees and operates 18 customer service centers.

In September 1999, Griffith acquired Bobbett Gas Service, a provider of propane gas and service in the Central New York area. The acquisition adds 2,600 customers to the current Griffith customer base. The acquisition was accounted for using purchase accounting and their results of operations are reflected in the consolidated financial statements of RGS since acquisition.

In December 1999, Griffith acquired Clark Oil, a provider of fuel oil in the Central New York area. This acquisition adds 600 customers to the Griffith customer base. The acquisition was accounted for using purchase accounting and their results of operations are reflected in the consolidated financial statements of RGS since acquisition.

Additional information on Energetix operations (including Griffith) is presented under the headings Operating Revenues and Sales, Operating Expenses, and is contained in Note 4 of the Notes to Financial Statements.

During the second quarter of 1998, the Company formed RGS Development to pursue unregulated business opportunities in the energy marketplace. Through December 31, 1999, RGS Development operations have not been material to RGS's results of operations or its financial condition.

Rochester Gas And Electric Corporation

Competition

PSC Competitive Opportunities Case Settlement.

During 1996 and 1997, RG&E, the staff of the PSC and several other parties negotiated an agreement which was approved by the PSC in November 1997 (the "Settlement"). The Settlement sets the framework for the introduction and development of open competition in the electric energy marketplace and lasts through June 30, 2002. Over this time, the way electricity is provided to customers will fundamentally change. In phases, RG&E will allow customers to purchase electricity, and later capacity commitments, from sources other than RG&E through its retail access program, Energy Choice. These energy service companies will compete to package and sell energy and related services to customers. The competing energy service companies will purchase distribution services from RG&E who will remain the sole provider of distribution services, and will be responsible for maintaining the distribution system and for responding to emergencies.

The Settlement sets RG&E's electric rates for each year during its five-year term. Over the five-year term of the Settlement, the cumulative rate reductions for the bundled service will be as follows: Rate Year 1 (July 1, 1997 to June 30, 1998) $3.5 million; Rate Year 2 $12.8 million; Rate Year 3 $27.6 million; Rate Year 4 $39.5 million; and Rate Year 5 $64.6 million.

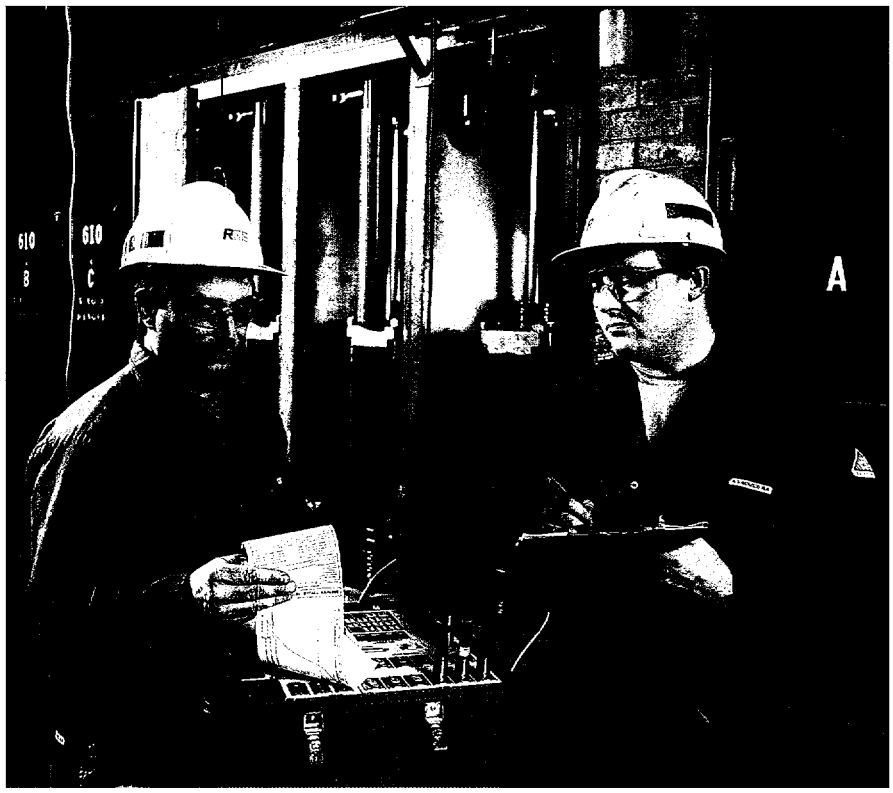
In the event that RG&E earns a return on common equity in its regulated electric business in excess of an effective rate of 11.50 percent over the entire five-year term of the Settlement, 50 percent of such excess will be used to write down deferred costs accumulated during the term. The other 50 percent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

The Settlement requires unregulated energy retailing operations be structurally separate from the regulated utility functions. Although the Settlement provides incentives for the sale of generating assets, it does not require RG&E to divest generating or other assets or write-off stranded costs. Additionally, RG&E will be given a reasonable opportunity to recover substantially all of its prudently incurred costs, including those pertaining to generation and purchased power.

RG&E believes that the Settlement has not adversely affected its eligibility to continue to apply certain accounting rules applicable to regulated industries. In particular, RG&E believes it continues to be eligible for the treatment provided by SFAS-71 which allows RG&E to include assets on its balance sheet based on its regulated ability to recoup the cost of those assets. However, this may not be the case with respect to certain operational costs associated with non-nuclear generation (see Note 10 of the Notes to Financial Statements under the heading Other Matters, EITF Issue 97-4, Deregulation of the Pricing of Electricity).

RG&E's retail access program, Energy Choice, was approved by the PSC as part of the Settlement and went into effect on July 1, 1998. Details of the Energy Choice program are discussed below.

One party to the Settlement negotiations has commenced an action for declaratory and injunctive relief as to certain provisions of the Settlement and the PSC's approval of it. RG&E is unable, at this time, to predict the outcome of this action.



RG&E employees measuring the speed of circuit breakers at station #5.

Energy Choice.

On July 1, 1998, RG&E officially began implementation of its full-scale electric retail access Energy Choice program. As of July 1, 1999, RG&E entered its second year of this program. There are five basic components of the sale of energy: (1) the sale of electricity which is the amount of energy actually used by the consumer, (2) the sale of capacity which is the ability through generating facilities or otherwise, to provide electricity when it is needed, (3) the sale of transmission services, which is the physical transportation of electricity to RG&E's distribution system, (4) the sale of distribution services, which is the physical delivery of electricity to the consumer, and (5) retail services such as billing and metering. Historically, RG&E has sold all five components bundled together for a fixed rate approved by the PSC. The implementation of the Energy Choice program included a four year phase-in process to allow RG&E and other parties to manage the transition to electric competition in an orderly fashion. During the first year of the program, participation

in Energy Choice was limited to no more than 10 percent of RG&E's total annual retail electric kilowatt-hour sales (670,000 annualized megawatt-hours). Essentially, until this 10 percent limit was achieved, RG&E's electric retail customers could seek out or be approached by alternative energy service companies for electricity to be resold and then delivered over RG&E's distribution system. By February 1, 1999, only six months into the Energy Choice program, this 10 percent limit was achieved by qualified competitive energy service companies in RG&E's service territory. For the second year of the program, beginning July 1, 1999, this limit increased from 10 percent to approximately 20 percent. By December 31, 1999, approximately 14.8 percent of total RG&E sales had shifted to competitive energy service companies. On July 1, 2001, all retail customers will be eligible to purchase energy from alternative energy service companies. The phase-in of the Energy Choice program over the next few years eventually will give retail electric customers the opportunity to purchase energy, capacity and retailing services from competitive energy service companies. Existing RG&E customers may also continue to purchase fully bundled electric service from RG&E.

RG&E welders fabricating a length of gas pipeline.

Energy Choice adopted the single-retailer model for the relationship between RG&E as the distribution provider, qualified energy service companies, and retail (end-use) customers. In this model, retail customers have the opportunity for choice in their energy service company and receive only one electric bill from the company that serves them. Except for providing emergency services, satisfying requests for distribution services, and scheduling outages, which remain RG&E's responsibility, the retail customer's primary point of contact for billing questions, technical advice and other energy-related needs, is with their chosen energy service company.

Under the single-retailer model, energy service companies are responsible for buying or otherwise providing the electricity their retail customers will use, paying regulated rates for transmission and distribution, and selling electricity to their retail customers (the price of which would include the cost of the electricity itself and the cost to transport electricity through RG&E's distribution system).

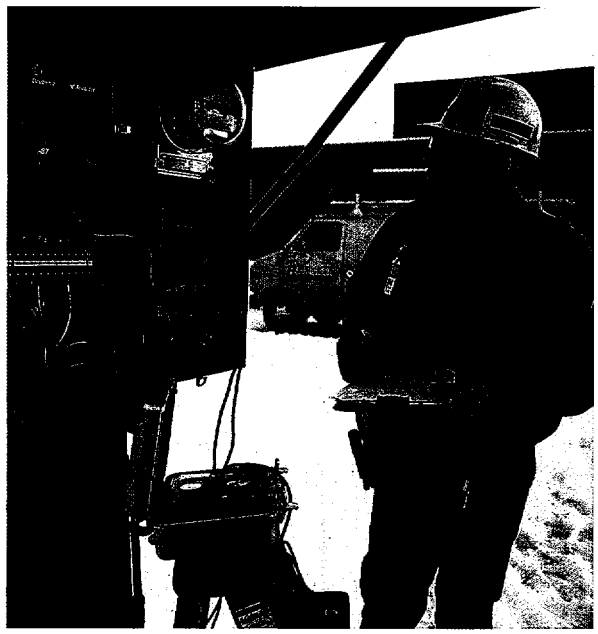
Throughout the term of the Settlement, RG&E will continue to provide regulated and fully bundled electric service under its retail service tariff to customers who choose to continue with such service.

During the initial "Energy-Only" stage of the Energy Choice program, energy service companies were able to choose their own sources of energy supply, while RG&E continued to provide to them, through its bundled distribution rates, the generating capacity (installed reserve) needed to serve their retail customers. In addition, during the "Energy-Only" stage, energy service companies had the option of purchasing "full-requirements" (i.e. delivery services plus energy) from RG&E.

The "Energy and Capacity" stage, the second stage of the phase-in, was scheduled to begin this past Fall. In this stage, energy service companies may purchase both energy and capacity in the open market. As a result of a delay in establishing an Independent System Operator entity in New York State, RG&E, with the consent of the energy service companies participating in the retail access program, reserved capacity for the 1999-2000 winter capability period and will provide energy and capacity for the energy service companies through that period. Essentially, energy service companies will purchase "full-requirements" (delivery services plus energy and capacity) from RG&E.

During the initial "Energy Only" stage of the retail access program, RG&E's distribution rate was set by deducting 2.305 cents per kilowatt-hour from its full service ("bundled") rates. The 2.305 cents per kilowatt-hour was comprised of 1.905 cents per kilowatt-hour (an estimate of the wholesale market price of electricity) plus 0.4 cents per kilowatt-hour for its avoided cost of retailing services. During the "Energy and Capacity" stage, RG&E's distribution rates will equal the bundled rate less RG&E's cost of the electric commodity and RG&E's non-nuclear generating capacity. During this stage of the program, RG&E's distribution rates will be set by deducting 3.0712 cents per kilowatt-hour from its full service ("bundled") rates. The 3.0712 cents per kilowatt-hour is comprised of 2.6712 cents per kilowatt-hour (an estimate of the wholesale market price of electric energy and capacity) plus 0.4 cents per kilowatt-hour for its avoided cost of retailing services.

As of December 31, 1999, eight energy service companies, including Energetix, the Company's unregulated subsidiary, are qualified by RG&E to serve retail customers under the Energy Choice program. In addition to Energetix, these companies are Columbia Energy Power Marketing Corporation, DukeSolutions, Inc., Northeast Energy Services, Inc. (NORESCO), North American Energy, NYSEG Solutions, Inc., Select Energy Inc., and TXU Energy Services, Inc. In addition, the County of Monroe has been qualified to act as its own energy service company to service its own facilities. As of December 31, 1999, all energy service companies had opted to purchase "full-requirements" from RG&E to serve their retail customers.



An RG&E employee doing metering inspection.

With the commencement of the "Energy and Capacity" stage and the implementation of the New York Independent System Operator on November 18, 1999 (see FERC Open Access Transmission Orders and Company Filings), the responsibility for purchasing not only energy, but also capacity, shifted to the energy service companies. However, these energy service companies, as "full-requirements" customers of RG&E during the winter capability period, will be purchasing energy and capacity from RG&E at 2.6712 cents per kilowatt-hour. The cost impact on RG&E of providing "full requirements" energy and capacity for this time period will be determined by prices in the New York State wholesale market. The PSC has approved a request by RG&E to extend "full requirements" availability to November 1, 2000.

Once RG&E no longer provides "full requirements" to the energy service companies, they will assume responsibility for obtaining their own supplies. There will be a revenue decrease when RG&E no longer collects the 2.6712 cents per kilowatt-hour for energy and capacity. This will be offset to some extent by decreased costs resulting from no longer acquiring energy and capacity for the energy service companies. The extent of this offset will be determined by market prices.

On December 3, 1999, New York State Electric and Gas Corporation (NYSEG) petitioned the PSC to accelerate the implementation of retail access in RG&E's service territory. NYSEG filed the petition pursuant to the terms of its electric restructuring agreement, whereby NYSEG may petition the PSC to deny permission to a New York State utility-affiliated competitive energy service company to participate in NYSEG's retail access program if the service area of the energy service company's affiliated utility is not comparably open to retail access. However, NYSEG does not seek to deny RG&E's affiliate, Energetix, the ability to participate in NYSEG's retail access program, stating that such a motion would be inconsistent with the PSC's efforts to create competitive opportunities in the electric industry. Instead, NYSEG requests the PSC to order RG&E to accelerate its retail access implementation schedule, claiming that RG&E's introduction of retail access is occurring at an extremely slow rate. RG&E's retail access program and implementation schedule was approved by the PSC in November 1997, as part of a comprehensive electric restructuring agreement. RG&E is in the process of preparing a response to NYSEG's petition, and cannot determine at this time what course of action the PSC may take.

On December 14, 1999, a group of marketers and energy service companies submitted a petition to the PSC to initiate an inquiry into the effectiveness of RG&E's retail access program. The petitioners are NYSEG Solutions, Inc., Advantage Energy, Leveraged Energy Purchasing Corporation, Empire Natural Gas Corporation, and Salerni & Boyd,

Inc. The petitioners make the following claims concerning RG&E's retail access program: (1) RG&E's operating agreement creates significant obstacles to development of retail competition in RG&E's territory because of the obligations the energy service companies now have to serve the retail customers. The petitioners have asked the PSC to exercise its authority to investigate the effectiveness of the terms and conditions of RG&E's operating agreement, and order RG&E to either reduce the customer service obligations or offer a higher backout credit or other reasonable economic incentives to offset the costs of these obligations, and (2) the shopping credit (i.e., backout rate) offered by RG&E inhibits retail access and competition. The petitioners ask the PSC to order RG&E to provide additional credits, to at least 3.7 cents per kilowatt-hour, while maintaining the price of energy to the energy service companies at 2.8 cents per kilowatt-hour in order to provide a reasonable opportunity for the energy service companies to enter and compete in RG&E's territory, and (3) the phase-in approach to retail access in RG&E's relatively small service area discriminates against energy service companies and marketers and inhibits competition. The petitioners request the PSC to order RG&E to open its service territory to full retail access as soon as possible, but no later than July 1, 2000. RG&E is in the process of preparing a response to this petition, and cannot determine at this time what course of action the PSC may take.

RG&E employee isolating breaker for testing at Station #29

The PSC is conducting proceedings that are intended to bring more administrative consistency among New York State utilities and potentially offer additional services for energy service companies to provide. These proceedings include uniform business practices, standardized billing and competitive metering. RG&E continues to assess the scope and impact of such changes on its operations.

Proposed Purchase of Nuclear Plants.

On June 24, 1999, Niagara Mohawk and NYSEG announced their intention to sell their interests in the Nine Mile Two nuclear plant to AmerGen Energy Company, L.L.C.(AmerGen), a joint venture of PECO Energy of Philadelphia and British Energy. Niagara Mohawk owns 41 percent and NYSEG owns 18 percent of Nine Mile Two. The financial terms of the transaction include purchase prices to be paid to Niagara Mohawk of $63.6 million and to NYSEG of $27.9 million.

RG&E's 14 percent interest in Nine Mile Two was not included in the current proposal. As an original part owner, RG&E generally had three options: the first option was to retain its ownership interest on the same basis that it does now; the second option was to sell its 14 percent interest in Nine Mile Two to AmerGen on substantially the same terms as Niagara Mohawk and NYSEG; and the third option was to exercise its right-of-first-refusal and buy the Niagara Mohawk and/or NYSEG interests on terms at least as favorable as those offered by AmerGen. Niagara Mohawk took the position that an exercise of the right to buy its interest in Nine Mile Two must necessarily include matching the terms of the agreement between AmerGen and Niagara Mohawk ($72 million) to buy the Nine Mile Point One Nuclear Plant (Nine Mile One), which is 100 percent owned by Niagara Mohawk.

On December 22, 1999, RG&E announced it had exercised its legal right-of-first-refusal to acquire a controlling interest in Nine Mile Two and to acquire the interests of Niagara Mohawk in Nine Mile One. As a result of the regulatory process discussed below, the status of RG&E's acquisition pursuant to its right-of-first-refusal is in question.

RG&E has contracted with Entergy Nuclear Nine Mile, L.L.C. (Entergy Nine Mile) to operate and maintain the plants upon RG&E's acquisition under its right-of-first-refusal. Under the terms of an operating agreement, Entergy Nine Mile will be responsible for operating the plants, for certain operating costs and risks during a transition period and most operating costs and risks thereafter. RG&E will be responsible for substantial operating costs and risks during the transition period and these costs and risks will be significantly reduced after the transition period. RG&E will pay Entergy Nine Mile a fixed price (periodically adjusted by certain appropriate price indices) per kilowatt-hour of power actually generated and delivered to RG&E. The contract with Entergy Nine Mile expires in September 2009.

RG&E intends to finance its acquisition through the issuance of long-term debt. Depending on when transfer of ownership takes place, RG&E currently expects to pay between $180 million and $210 million, including the cost of fuel at the plants. The transfer of ownership of the plants to RG&E and transfer of operation of the plants to Entergy Nine Mile will require State and federal regulatory approvals, including the PSC, the Nuclear Regulatory Commission (NRC) and the FERC.

In this transaction, RG&E will continue to own the rights to its original approximately 160 megawatts of electric generating capacity from Nine Mile Two and acquire the rights to approximately an additional 670 megawatts of capacity from that plant. At the conclusion of its purchase, RG&E would own 73% of Nine Mile Two. The Long Island Lighting Company, which is wholly-owned by the Long Island Power Authority, and Central Hudson Gas & Electric Corporation are the other non-operating owners of Nine Mile Two and will retain their interests in the plant. RG&E would also acquire the entire capacity from Nine Mile One, about 615 megawatts.

Niagara Mohawk and NYSEG will purchase the power produced by their previous ownership shares in the Nine Mile Point plants from RG&E under long-term contracts that run for a period of three to five years. These terms are the same as those agreed to by AmerGen. After that period of time, available power is expected to be sold into the wholesale energy market.

"Always At Your Service"—an RG&E lineman battles the elements and minus 20° wind-chill factor to make repairs.

Under the terms of a decommissioning agreement, Entergy Nuclear, Inc. will be responsible for decommissioning the plants at a fixed price after they are both taken out of service. For Nine Mile One, Niagara Mohawk, as the former sole owner, will contribute the entire present cost of decommissioning to a fund. For Nine Mile Two, Niagara Mohawk and NYSEG will contribute payments proportionate to their former ownership interests.

At December 31, 1999 the net book value of RG&E's 14 percent interest in the Nine Mile Two generating facility was approximately $376 million.

On August 30, 1999 the PSC began a proceeding to review the proposed sale of the Nine Mile Point nuclear facilities by Niagara Mohawk and NYSEG to AmerGen to determine if the sale would be in the public interest. RG&E has intervened in that proceeding. In early January 2000, at the request of PSC Trial Staff, that proceeding was suspended to give the interested parties time for settlement negotiations. In late January 2000, the PSC Trial Staff expressed its intention to move to dismiss the proceeding since it believes that the sale to AmerGen, as filed, is not consistent with the public interest standard in Public Service Law Section 70; Trial Staff said that it intends to immediately explore, in conjunction with the utilities and interested parties, other scenarios for future ownership and operation of the Nine Mile nuclear plants; and Trial Staff proposed that the parties dispense with formal evidentiary hearings in this proceeding. AmerGen has asked that the Judge reject Staff's request to dispense with formal evidentiary hearings and instead set a schedule for testimony and hearings in this proceeding.

A separate proceeding to consider RG&E's acquisition of the Nine Mile nuclear facilities has not yet been commenced. At this time, RG&E is uncertain what the outcome of the PSC regulatory process will be but expects that it will continue for some time. RG&E intends to continue to pursue all of its alternatives and evaluate any modifications to the current proposed transaction and any new proposed transaction.

PSC Proceeding on Nuclear Generation.

On March 20, 1998, the PSC initiated a proceeding to examine a number of issues raised by a Staff position paper on nuclear generation and the comments received in response to it. In reviewing the Staff paper and parties' comments, the PSC:

(1) adopted as a rebuttable presumption the premise that nuclear power should be priced on a market basis to the same degree as power from other sources, with parties challenging that premise having to bear a substantial burden of persuasion;

(2) characterized the proposals in the Staff paper as by and large consistent in concept with the PSC's goal of a competitive, market-based electricity industry;

(3) questioned Staff's position that would leave funding and other decommissioning responsibilities with the sellers of nuclear power interests and;

(4) indicated interest in the potential for a New York Nuclear Operating Company (NYNOC) proposal to benefit customers through efficiency gains and directed pursuit of that matter in this nuclear generating proceeding or separately upon the filing of a formal NYNOC proposal.

RG&E has worked with other New York nuclear generation operators on the development of a NYNOC but no substantial further work on its implementation is anticipated until completion of this proceeding and the outcome of any proposed sales by current New York nuclear plant owners is determined.

RG&E' s potentially strandable assets in nuclear plant could be impacted by the outcome of this proceeding. The initial collaborative conference for this proceeding was held on January 20, 1999. The parties in this proceeding developed a collaborative, non-binding interim report entitled"Nuclear Generation and the Competitive Electric Market" which was issued in July 1999. RG&E is actively involved in this proceeding which is continuing. RG&E is unable to determine when this proceeding may conclude.

On site 'Tailboard' conferences take place as part of RG&E's operating procedures and commitment to OSHA safety standards.

Fossil Units Status.

In 1999, RG&E ceased operations at and retired its Beebee Station (80 Megawatt) generating facility. The retirement of Beebee Station did not have a material effect on the financial position or results of operations of RGS or RG&E. The Competitive Opportunities Settlement provides that all prudently incurred incremental costs associated with the retirement and decommissioning of the plant are recoverable through RG&E' s distribution access rates.

In early June 1999 the Allegany Station, a combined-cycle unit fueled by natural gas, began generating electricity. The 63 megawatt capacity unit is expected to generate electricity during the peak demand summer months and when the economics of producing electricity for sale are favorable. The plant is being operated and maintained for RG&E by Bell Harbert Energy L.L.C. Allegany Station, which was built as a co-generation facility in the early 1990s, was obtained by RG&E as part of a legal settlement in December 1998 with General Electric Capital Corporation, Kamine/Besicorp Allegany L.P. (Kamine) and other Kamine affiliates.

Oswego Unit Sale. On October 22, 1999, RG&E and Niagara Mohawk sold their respective 12% and 88% interests in the Oswego Generation Facility to Oswego Harbor Power L.L.C., a wholly-owned affiliate of NRG Energy, Inc. (collectively, the Buyer) for approximately $91 million. Additionally, the Buyer agreed to assume RG&E's obligations under a June 8, 1998 transmission services agreement (Exit Agreement) as it pertains to the Oswego Generation Facility. This assumption represents a net present value of approximately $25 million, which was deducted from RG&E's approximately $11 million share of the sale proceeds. Accordingly, upon closing, RG&E was required to make a net payment of approximately $14 million to Niagara Mohawk. Under the terms of the Competitive Opportunities Settlement, RG&E is permitted to recover any losses and related costs on a sale of generation through distribution rates. Pursuant to an October 21, 1999 PSC order, RG&E was required to file with the PSC a detailed calculation of its net book loss after tax impacts. RG&E made this filing with the PSC on December 21, 1999.

Including the impact of the $25 million relating to the Exit Agreement, RG&E's net loss and associated costs are approximately $79 million. In the filing, RG&E indicated that $2.2 million of depreciation charges and $4.3 million of transmission contract payments, currently included in rates, will be used to amortize the net loss during the remaining term of the Competitive Opportunities Settlement.

An RG&E lineman prepares to energize a primary cable.

FERC Open Access Transmission Orders and Company Filings.

On January 31, 1997, the New York electric utilities filed a "Comprehensive Proposal To Restructure the New York Wholesale Electric Market" with the FERC. As proposed, the New York Power Pool (NYPP) then in effect would be dissolved and an independent system operator (NYISO) would administer a Statewide open access tariff and provide for the reliable operation of the bulk power system in the State.

On June 30, 1998, the FERC issued an Order that conditionally authorized the establishment of the NYISO by the member systems of the NYPP (Member Systems). The order addressed areas of governance, standards of conduct and reliability. On April 30, 1999, the FERC issued an order which addressed several issues, including its rejection of the Member Systems' settlement on governance issues, and its acceptance of the Section 203 filing to transfer jurisdictional transmission facilities to the NYISO. On September 15, 1999, the FERC issued an Order approving the agreement on governance.

On January 27, 1999 the FERC issued an Order conditionally accepting the proposed NYISO tariff and the proposed market rules of the NYISO. The Order also granted the Member Systems' request for market-based rates for energy, ancillary services and installed capacity sold through the NYISO. On July 29, 1999, the FERC issued an Order, approving the NYISO Open Access Transmission Tariff, the NYISO Services Tariff, and each of the related ISO Agreements submitted by the Member Systems.

On November 18, 1999 the NYISO implemented a competitive wholesale market for the sale, purchase and transmission of electricity and ancillary services in New York State. After a two-week cutover period, the NYISO officially assumed control and operation of the New York State electric transmission system from the NYPP. With the implementation of day-ahead and real-time markets, RG&E is provided with additional flexibility, beyond bilateral contracts, in marketing its excess generation and in purchasing energy to supply retained retail load.

A settlement proceeding was established during 1999 to resolve an issue involving the disposition of certain pre-ISO transmission agreements. On June 17, 1999, the Member Systems and other intervenors filed a Settlement Agreement with FERC. On July 21, 1999, the presiding administrative law judge certified the uncontested settlement to the Commission. On November 26, 1999, the Commission approved the settlement. On January 5, 2000, the Commission certified a partial uncontested settlement that included changes to the revenue requirement as well as the divisor used to compute the transmission service charge, setting the rate that RG&E and the other New York State utilities will charge under the NYISO.

Currently, it is unclear what effect the above changes may have once other regulatory changes in New York State are implemented. At the present time, RG&E cannot predict what effects regulations ultimately adopted by FERC will have, if any, on future operations or the financial condition of RGS or RG&E.

Competition and the Company's Prospective Financial Position.

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

In a competitive electric market, strandable assets would arise when investments are made in facilities, or costs are incurred to service customers, and such costs are not fully recoverable in market-based rates. Estimates of strandable assets are highly sensitive to the competitive wholesale market price assumed in the estimation. In a competitive natural

gas market, strandable assets would arise where customers migrate away from dependence on RG&E for full service, leaving RG&E with surplus pipeline and storage capacity, as well as natural gas supplies under contract. A discussion of strandable assets is presented in Note 10 of the Notes to Financial Statements.

At December 31, 1999 RG&E believes that its regulatory assets are probable of recovery. The Settlement in the Competitive Opportunities Proceeding does not impair the opportunity of RG&E to recover its investment in these assets. However, the PSC issued an Opinion and Order Instituting Further Inquiry on March 20, 1998 to address issues surrounding nuclear generation. The initial meeting in this Inquiry was held in January 1999 (see PSC Proceeding on Nuclear Generation). The ultimate determination in this proceeding or any proceeding to consider RG&E's proposed purchase of nuclear plants as discussed under Proposed Purchase of Nuclear Plants could have an impact on strandable assets and the recovery of nuclear costs.

Removing electric cables in preparation for replacing a transformer.

Rates and Regulatory Matters

PSC Gas Restructuring Policy Statement.

On November 3, 1998, the PSC issued a gas restructuring policy statement ("Gas Policy Statement") announcing its conclusion that, among other things, the most effective way to establish a competitive gas supply market is for gas distribution utilities to cease selling gas. The PSC established a transition process in which it plans to address three groups of issues: (1) individual gas utility plans to implement the PSC's vision of the market; (2) key generic issues to be dealt with through collaboration among gas utilities, marketers, pipelines and other stakeholders, and (3) coordination of issues that are common to both the gas and the electric industries. The PSC has encouraged settlement negotiations with each gas utility pertaining to the transition to a fully competitive gas market. RG&E, the PSC Staff and other interested parties have been participating in settlement discussions in response to the specific requirements of the Policy Statement.

Gas Proposal and Interim Settlement.

In August 1998, prior to issuance of the PSC's Gas Policy Statement (see PSC Gas Restructuring Policy Statement above), RG&E had commenced negotiations with the PSC staff and other parties to develop a comprehensive multi-year settlement of various issues, including rates and the structure of RG&E's gas business. Because the negotiation of a comprehensive settlement was not anticipated to conclude until mid-1999, the parties to the negotiations agreed to an Interim Settlement, effective November 1998 through June 1999, that dealt with such issues as rates, transportation and storage capacity costs, assignment of capacity, and retail access. Significant features of the Interim Settlement include a freeze on base rates at the current levels (which were fixed at July 1994 levels), the imputation of $11.9 million in revenues from the remarketing of capacity and a limit on RG&E's exposure to costs associated with the migration of customers from RG&E to marketers for sales and service.

Discussions following the expiration of the Interim Settlement resulted in a September 14, 1999 filing to address issues pertaining to the cost of upstream capacity and other matters pertaining to restructuring pursuant to the PSC's Policy Statement. The proposal calls for: (1) a continued reduction in capacity costs of $11.9 million, comprised of $10.2 million relating to upstream capacity release transactions for the period September 1, 1999 through August 31, 2000 and $1.7 million from the expiration of a Texas Eastern capacity contract; (2) a report to PSC staff, within 60 days of approval of the proposal, of the plans and progress RG&E has made to reduce its upstream capacity costs; (3) a resumption of the multi-year settlement discussions calling for RG&E to make a public filing addressing the rate and restructuring issues addressed in the PSC's Policy Statement within 120 days of approval of the proposal; and (4) RG&E continuing to work on retail access program improvements. The proposal was subsequently approved by the PSC and RG&E began implementation of its proposal in the fourth quarter of 1999. As required, the report on upstream capacity costs was submitted on November 29, 1999, under trade secret status. The public filing addressing the rate and restructuring issues was made on January 28, 2000. This filing is intended to provide the

basis for negotiations with the PSC and other interested parties on RG&E's proposal to implement a fully competitive marketplace for natural gas. Settlement negotiations pertaining to RG&E's gas rate and restructuring proposal will begin as early as 30 days after filing pursuant to the Gas Policy Statement. RG&E is unable to predict the ultimate outcome from this proceeding, or when the PSC will issue a final order.

Under a March 1996 Order, the PSC permitted RG&E and other gas distribution companies to assign to marketers the pipeline and storage capacity held by RG&E to serve their customers. In its Gas Policy Statement issued in November 1998, the PSC ordered that the mandatory assignment of capacity, permitted by the March 1996 Order, be terminated effective April 1, 1999. According to the Gas Policy Statement, however, the utilities are to be afforded a reasonable opportunity to recover resulting strandable costs, if any. On March 24, 1999, the PSC issued an Order Concerning Assignment of Capacity for all gas utilities in the State of New York, generally requiring the removal of restrictions on customer migration from utility service to service from marketers. RG&E has complied with the PSC's directives.

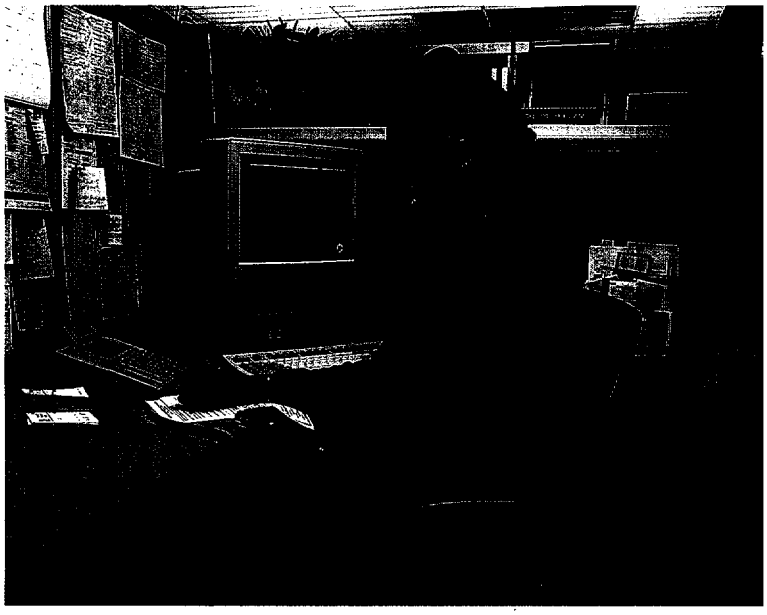
A team of RG&E cable splicers and crane operators switch out a large pad-mounted transformer at an RG&E commercial customer job site.

Flexible Pricing Tariff.

Under its flexible pricing tariff for major industrial and commercial electric customers, RG&E may negotiate competitive electric rates at discount prices to compete with alternative power sources, such as customer-owned generation facilities. Pursuant to the terms of the Settlement under the Competitive Opportunities Proceeding, RG&E will absorb, as it has done since the inception of these rates, the difference between the discounted rates paid under these individual contracts and the rates that would otherwise apply. Approximately 24 percent of all regulated electric sales to customers are made under long-term contracts, primarily to large industrial customers. These contracts represent approximately 49 percent of RG&E's revenues from its commercial and industrial customers.

Liquidity and Capital Resources

During 1999, RGS's and RG&E's cash flow from operations (see Statements of Cash Flows) provided the funds for construction expenditures and the payment of dividends and short-term debt. In addition, RG&E completed a long-term financing in October 1999 (see "Financing" below). Cash used for investing activities in 1999 was lower due to the acquisition of Griffith in August 1998 and there were no acquisitions of comparable size in 1999. Cash used in financing activities for 1999 was higher due mainly to the redemption of short-term debt. Capital requirements of the Company during 2000 are anticipated to be satisfied from the combination of internally generated funds and short-term credit arrangements. In addition, RG&E expects to issue long-term debt to finance its proposed acquisition of the Nine Mile Two facilities (see Proposed Purchase of Nuclear Plants). RG&E may also refinance long-term securities obligations during 2000 depending on prevailing financial market conditions.



An RG&E Telephone Service department employee utilizes state-of-the-art data systems in response to customer calls.

Capital and Other Requirements.

RGS's and RG&E's capital requirements relate primarily to expenditures for energy delivery, including electric transmission and distribution facilities and gas mains and services as well as nuclear fuel, electric production, the repayment of existing debt and the repurchase of outstanding shares of Common Stock. Additional baseload generation is expected to be available once RG&E completes its acquisition of the Nine Mile Two facilities as discussed above. RG&E has no further plans to install additional baseload generation.

1998 Labor Day Storm. At approximately midnight, Monday morning, September 7, 1998, a severe lightning and windstorm struck RG&E's franchise area. The storm damaged RG&E's electrical system at several hundred different locations. Several counties within RG&E's franchise area were declared State and federal disaster areas.

RG&E has deferred approximately $8.5 million of costs and carrying charges associated with this storm. Under the Competitive Opportunities Settlement with the PSC, if incremental costs resulting from a "catastrophic event" exceed $2.5 million, such costs could be deferred. RG&E submitted a petition to the PSC for deferral of costs associated with this storm and this petition is currently pending.

Settlement with Co-generator. In May 1998 RG&E entered into a Global Settlement Agreement regarding the termination of a power purchase contract with Kamine/Besicorp Allegany L.P. (Kamine). In August 1998 the PSC approved the Global Settlement Agreement, and on December 1, 1998, the Agreement became effective. Under the terms of the Global Settlement Agreement, the Power Purchase Agreement was terminated in consideration of payment by RG&E of $168 million over 16 years, without interest, with an initial payment of $10 million. Also, under the terms of the Global Settlement Agreement, RG&E paid an additional $15 million for the purchase of the Kamine generation facility. In June 1999 the plant began generating electricity (see Fossil Units Status). RG&E does not expect the terms of the Global Settlement Agreement to have any material effect on its earnings or the earnings of RGS. Pursuant to a PSC order approving the terms of the Global Settlement Agreement, regulatory assets have been established by RG&E to account for the initial payment, the facility purchase, and future payments. RG&E has no other long-term obligations to purchase energy from other cogeneration facilities.

Capital Requirements—Summary. Excluding the potential acquisition by RG&E of Nine Mile One and the additional investment in Nine Mile Two as discussed above, capital requirements for the Company over the three-year period 1997 to 1999 and the current estimate of capital requirements through 2002 are summarized in the Capital Requirements table. RG&E's portion of total construction requirements as presented in the Capital Requirements table for 2000, 2001, and 2002 are $151 million, $137 million, and $112 million, respectively.

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

Financing.

On October 27, 1999 RG&E issued $100 million of 7.60% First Mortgage Bonds, Designated Secured Medium-Term Notes, Series B. The net proceeds from this financing were used to repay short-term debt and pay for capital expenditures.

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

Capital Requirements—RGS

Type of Facilities	Actual 1997	Actual 1998	Actual 1999	Projected 2000	Projected 2001	Projected 2002
	(Millions of Dollars)					
Electric Property						
Production	$ 9	$ 16	$ 14	$ 14	$ 14	$ 15
Energy Delivery	28	41	42	67	80	50
Subtotal	37	57	56	81	94	65
Nuclear Fuel	19	14	14	25	9	19
Total Electric	56	71	70	106	103	84
Gas Property	22	21	19	25	23	17
Common Property	9	21	20	22	13	13
Total	87	113	109	153	139	114
Carrying Costs						
Allowance for Funds Used During Construction	1	1	2	1	1	1
Total Construction Requirements	88	114	111	154	140	115
Securities Redemptions, Maturities and Sinking Fund Obligations*	182	66	10	30	—	100
Total Capital Requirements	$270	$180	$121	$184	$140	$215

** Excludes prospective refinancings.*

Redemption of Securities.

In addition to first mortgage bond maturities and mandatory sinking fund obligations over the past three years, discretionary redemption of securities totaled $152 million in 1997 and $25.5 million in 1998. Included in discretionary redemptions for 1997 and 1998 were over $127 million of tax-exempt securities, which were refinanced with tax-exempt debt. There were no discretionary redemptions of securities in 1999.

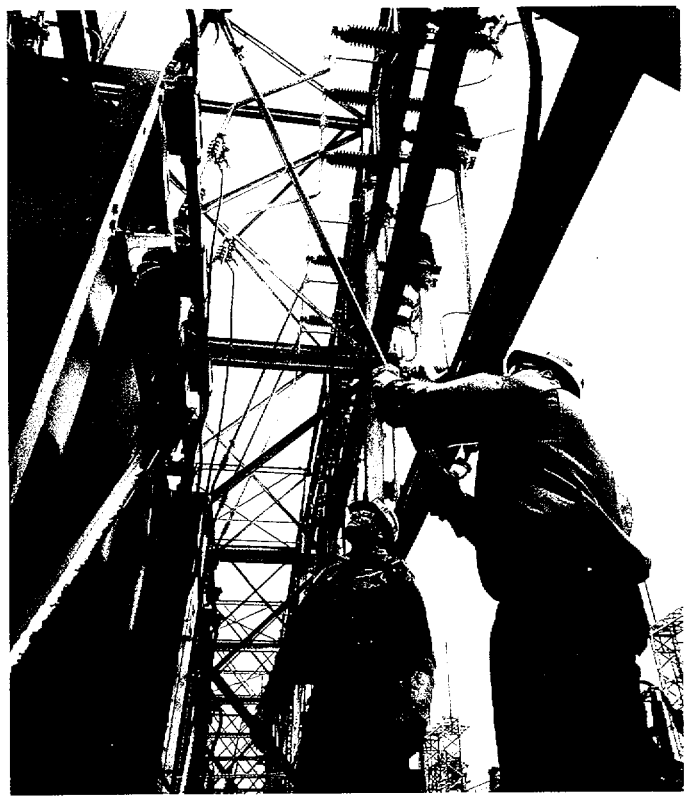
Stock Purchase Plan.

In April 1998, the PSC approved a Stock Repurchase Plan for RG&E providing for the repurchase of Common Stock having an aggregate market value not to exceed $145 million. RG&E began the repurchase program in May 1998 and 2,942,600 shares of Common Stock have been repurchased for approximately $83.3 million through December 31, 1999. The average cost per share purchased during 1999 was $25.65.

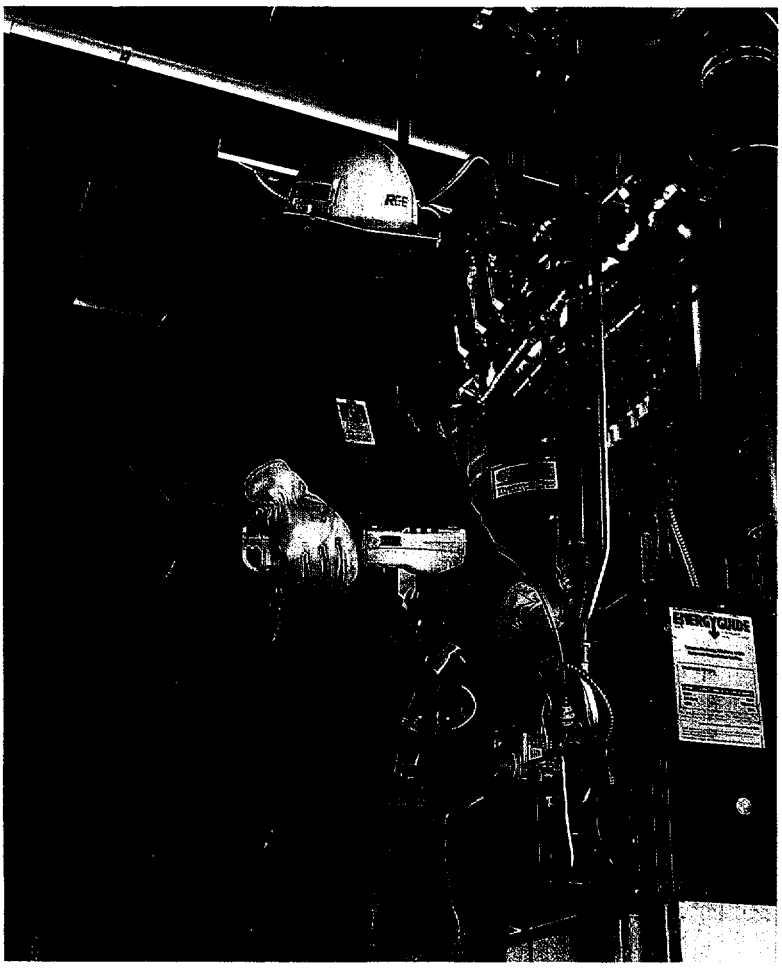
Environmental Issues.

The production and delivery of energy are necessarily accompanied by the release of by-products subject to environmental controls. RGS and RG&E have taken a variety of measures (e.g., self-auditing, recycling and waste minimization, training of employees in hazardous waste management) to reduce the potential for adverse environmental effects from its energy operations.

RGS and RG&E have recorded liabilities to reflect specific issues where remediation activities are currently deemed to be probable and where the cost of remediation can be estimated. Estimates of the extent of the Company's degree of responsibility at a particular site and the method and ultimate cost of remediation require a number of assumptions for which the ultimate outcome may differ from current estimates. While RGS and RG&E do not anticipate that any adjustment would be material to its financial statements, it is reasonably possible that the result of ongoing and/or



At station #29 an RG&E crew installs personal safety grounds.



An RG&E Energy Services gas serviceman using an Ultra Trac 2000 combustible gas indicator to ensure that a customer's gas fired boiler installation is free of gas leaks and carbon monoxide.

future environmental studies or other factors could alter this expectation and require the recording of additional liabilities. The extent or amount of such events, if any, cannot be estimated at this time.

Additional information concerning RGS's and RG&E's environmental matters can be found in Note 10 of the Notes to Financial Statements.

Year 2000 Readiness Information.

As the year 2000 (Y2K) approached, RGS and RG&E, like most companies, faced potentially serious information and operational systems (computer and microprocessor-based devices) problems because many software applications and embedded systems programs created in the past would not properly recognize calendar dates beginning with the year 2000 or that the year 2000 is a "leap-year".

On and after January 1, 2000, the Company and RG&E have experienced normal operations of their computer and microprocessor-based devices with no loss or interruption of energy generation or delivery and no operating difficulties of its mission critical internally developed applications or critical devices. RG&E's two major electric power plants, Ginna and Russell Station, performed without any difficulties. Likewise, operations at the Nine Mile Two electric power plant proceeded normally and there has been no major impact on gas service. RG&E is not aware of any regional or statewide power systems that failed to perform as the result of Y2K-related problems. The Company has experienced no major problems related to applications and devices of critical external parties. The Company will continue to monitor the operation of its computers and microprocessor-based devices for any Y2K-related problems.

RG&E funded its Y2K Project internally and has incurred $9.3 million of incremental costs through December 31, 1999 associated with making the necessary modifications identified to applications and devices. Energetix, including Griffith Oil, incurred less than $100,000 of incremental costs. Neither RGS or RG&E have deferred any major corporate information technology projects due to this effort.

Earnings Summary

The impact of developing competition in the energy marketplace may affect future earnings. The Competitive Opportunities Settlement allows for a phase-in to open electric markets while lowering customer prices and establishing an opportunity for competitive returns on shareholder investments. The nature and magnitude of the potential impact of the Settlement on the business of RG&E will depend on several factors, including the availability of qualified energy suppliers in RG&E's service territory, the degree of customer participation and ultimate selection of an alternative energy supplier, RG&E' s ability to be competitive by controlling its operating expenses, and RGS' s ultimate success in the development of its unregulated business opportunities as permitted under the Settlement.

Although RG&E does not earn a return on the gas commodity it acquires for distribution, under the current regulatory environment future earnings may be affected, in part, by the ultimate outcome of implementation of the November 1998 Gas Policy Statement (see Rates and Regulatory Matters). That policy statement concludes that the most effective way to establish a robust competitive gas supply in New York State is for local gas distribution companies (LDCs), such as RG&E, to exit the merchant function of acquiring gas, as well as transportation and storage capacity to serve retail customers. LDCs ceased assigning transportation capacity to customers migrating from sales

to transportation service by April 1, 1999. The nature and magnitude of the potential impact of these policies will depend on individual negotiations that RG&E is undertaking with the PSC Staff and other interested parties on RG&E specific restructuring, as well as a number of Statewide collaborative efforts that will deal with such issues as provider of last resort, reliability, recovery of stranded costs, and market power as the transition is made to a more competitive gas business.

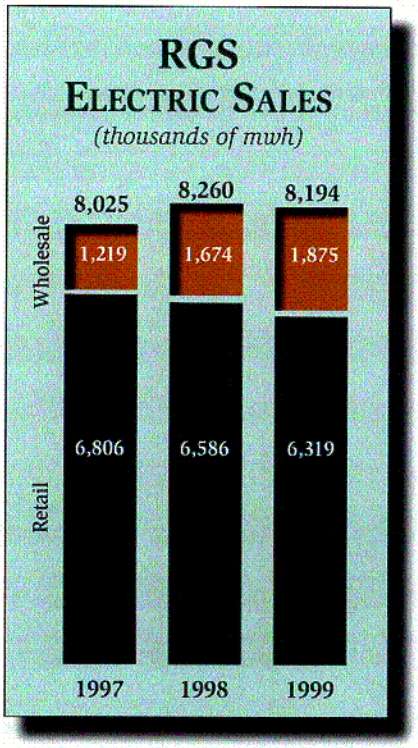
RGS. RGS reported consolidated earnings of $2.44 per share in 1999 compared to $2.32 in 1998. RGS's earnings per share in 1999 were positively affected by increased electric sales to a combination of marketers and retail customers during the summer months when the weather was 25% warmer than a year ago (cooling degree day basis) and by higher gas sales in the first quarter of 1999 driven by 19% colder weather (heating degree day basis) as compared to 1998. Sales and revenues in 1999 also reflect a one-time adjustment during the second quarter of the year in the methodology of calculating unbilled sales and revenues which increased electric revenues by $7.1 million and gas revenues by $6.1 million. In addition, non-fuel operating expenses for RGS include a $4.8 million drop in RG&E welfare expense from 1998 as discussed below. RGS's share buy-back program also contributed to higher earnings per share in 1999 adding $.11 per share. Having a negative effect on earnings in 1999 was a 57-day scheduled refueling and ten-year in-service inspection outage at the Ginna plant (there was no outage in 1998) and a 30-day unscheduled outage at the Nine Mile Two plant. These outages contributed to increased purchased power expenses and decreased sales of electricity to other utilities during the year. A scheduled electric rate reduction effective July 1 and a one-time adjustment of approximately $7 million in the second quarter of 1999 to increase RG&E's allowance for uncollectible accounts also had an unfavorable effect on 1999 earnings.

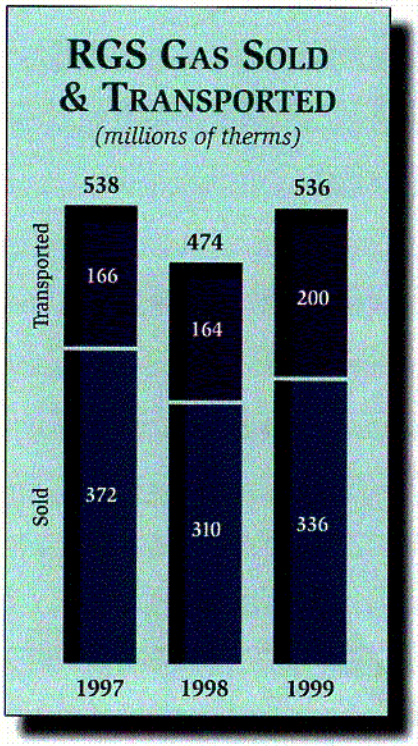
Braving blizzard conditions, an RG&E splicer prepares to cut an underground cable in a manhole.

RGS continues to grow its unregulated business through its subsidiary, Energetix, which provides electric, natural gas, and petroleum-based energy products and services throughout the upstate New York region. Energetix's unconsolidated operating revenues were $275 million in 1999, of which sales from Griffith's heating oil, gasoline and propane gas contributed approximately $220 million. These revenues from Griffith are included under "Other Revenues" on RGS's and RG&E's Income Statements. Energetix, including Griffith, on a consolidated basis, had a pre-tax loss of $0.1 million for 1999. These results reflect the development expenses related to building a successful unregulated electric and natural gas business in an open and competitive market. Energetix's revenues for 2000 from electric and gas operations are expected to increase over 1999 levels as Energetix expands its customer base, although no assurance may be given that Energetix will achieve a net operating gain in 2000.

RG&E. Earnings for RG&E in 1999 reflect the same issues discussed above for RGS except that discussions relating to Energetix and Griffith are not applicable. The 1999 RG&E Income Statement reflects the consolidated operations of RG&E and its former subsidiaries, Energetix and RGS Development, through August 2, 1999 at which time the holding company RGS was formed and RG&E, Energetix and RGS Development then became subsidiaries of RGS. Subsequent to that date, the RG&E Income Statement reflects only the operating results of RG&E.

Basic earnings per share for RG&E were $2.32 in 1998, compared with $2.30 in 1997. For both 1998 and 1997, these results reflect the consolidated operations of RG&E and its subsidiaries at that time, Energetix and RGS Development Corporation. Operating performance of RG&E's generating plants, expense control, the sale of electric energy to wholesale customers, and the recognition of $17.4 million of non-recurring income during the year (see "1998 Compared to 1997", Other Statement of Income Items) allowed RG&E to keep 1998 earnings applicable to Common Stock at about the same level as 1997, despite rate decreases and warmer temperatures during the 1998 heating seasons. Earnings per share in 1998 were improved by approximately $.02 per share resulting from the buyback of Common Stock under the Company's Stock Repurchase Program.





For the twelve month period ending December 31, 1998, RG&E's unregulated subsidiary, Energetix, had a pretax operating loss of $4.1 million, which reduced consolidated earnings by approximately $0.06 per basic share. This loss is primarily due to initial start-up and marketing costs. Moreover, while Energetix was formed January 1, 1998, the first revenues were not received until April of 1998. In addition, revenues from Griffith Oil Co., Inc., a company acquired by Energetix, only reflect sales since acquisition in August 1998.

Results of Operations

The following financial review identifies the causes of significant changes in the amounts of revenues and expenses for RGS (regulated and unregulated business) and RG&E (regulated business), comparing 1999 to 1998 and 1998 to 1997. The operating results of the regulated business reflect RG&E's electric and gas sales and services and the operating results of the unregulated business reflect Energetix operations. In 1999, the majority of RGS's operating results reflect the operating results of RG&E and the factors that affect operating results for RG&E are the significant factors that affect comparable operating results for RGS, unless otherwise noted. The Notes to Financial Statements contain additional information.

1999 Compared to 1998

Operating Revenues and Sales.

Increased electric revenues for RGS and RG&E reflect the warmer summer weather as discussed above to meet the demand for air conditioning usage partially offset by a base rate reduction and lower regulated electric sales due largely to RG&E's reduced capacity to sell power to other electric utilities because of the refueling and in-service inspection outage at the Ginna Plant and the unscheduled outage at Nine Mile Two as discussed above under "Earnings Summary". Regulated sales and revenues for this period compared to last year also reflect a one-time adjustment to reflect a change in the estimating process for unbilled sales and revenues. This adjustment increased regulated electric revenues by $7.1 million and increased regulated gas revenues by $6.1 million. Regulated electric sales increased by 74,000 megawatt-hours and regulated gas sales were higher by 7,610,000 therms as a result of this one-time adjustment. A drop in commercial and industrial regulated electric sales reflects, in part, the opening of the electric market under the terms of the Competitive Opportunities Settlement. RG&E, however, sells electric energy, as well as distribution services, to qualified energy marketers in its franchise territory which has the effect of increasing wholesale sales to energy marketers. Included in RGS's electric operating revenues for 1999 are $65.2 million of revenues from electric sales to energy marketers and $ 25.3 million of revenues from wholesale sales to other utilities. Revenues in 1999 from energy marketers were up $50.2 million compared with 1998 reflecting the opening of the electric marketplace and increased sales of electricity and distribution services. Revenues from the sales of electric energy to other utilities dropped $3.7 million from 1998 due mainly to the availability of RG&E's generating plants as discussed above, partially offset by an increase in the average revenue per unit sold. Fluctuations in revenues from electric sales to other utilities are generally related to RG&E's customer energy requirements, the wholesale energy market, availability of transmission, and the availability of electric generation from RG&E's facilities.

Regulated gas margins (revenues less cost of purchased gas) were up over $12 million reflecting 11% cooler weather (based on heating degree days) for the year and the change in unbilled sales methodology discussed above. Therms of gas sold and transported for the regulated business were up 10.7 percent in 1999. The transportation of gas

C2

for customers who are able to purchase natural gas from sources other than RG&E is an important component of RG&E's marketing mix. In 1999, RG&E's small customer aggregate transportation market appeared as a significant addition to RG&E's marketing mix. Company facilities are used to distribute this gas, which in total amounted to 20.0 million dekatherms in 1999 and 16.4 million dekatherms in 1998. These purchases by eligible customers have caused decreases in RG&E's retail gas customer revenues, with offsetting decreases in purchased gas expenses and, in general, do not adversely affect earnings because transportation customers are billed at rates which, except for the cost of buying and transporting gas to RG&E's city gate, are the same as the rates charged RG&E's retail gas service customers. Moreover, under the current regulatory environment, RG&E does not earn a return on the gas commodity it acquires for distribution. Gas supplies transported in this manner are not included in RG&E's therm sales, depressing reported gas sales to non-residential customers.

Eighty percent of Energetix total operating revenues in 1999 were from the sale of heating oil, propane and gasoline by Griffith (see discussion under "Earnings Summary"). For heating oil and propane, Griffith experiences seasonal fluctuations due to the dependence on spaceheating sales during the heating season. In addition, gasoline sales reflect seasonal fluctuations due to increased consumer driving during the warmer months. Unregulated sales reflect Griffith's operations since its acquisition by Energetix on August 2, 1998 and the migration of electric and gas customers from the regulated to the unregulated business.

An RG&E welder gets down and dirty to make repairs in the trenches at a construction site.

Operating Expenses

Higher regulated electric fuel expenses reflect increased purchased electricity costs driven by the effect from lower generation from the Ginna nuclear plant, hydro plants, and the closing of Beebee Station on April 30, 1999, in addition to an increase in the cost per unit purchased. The cost of purchased power may fluctuate depending on the availability of electric generation from RG&E's facilities, the wholesale energy market and the total availability of energy, and the availability of transmission facilities. Fuel expense for electric generation was down in 1999 reflecting lower generation from RG&E's facilities. Since July 1996, Common Stock shareholders have assumed the full benefits and detriments realized from actual electric fuel costs and generation mix compared with PSC-approved forecast amounts. RG&E normally purchases electric power to supplement its own generation when needed to meet load or reserve requirements, and when such power is available at a cost lower than RG&E's production cost. Despite an increase in retail regulated gas therm sales, gas purchased for resale expense declined in 1999 reflecting a lower average cost per unit due, in part, to reduction in pipeline costs. Other fuel expense on both RGS's and RG&E's Income Statements reflect mainly the cost of purchased fuel for Griffith's operations since its acquisition by Energetix.

The decrease in non-fuel operating expenses for RGS and RG&E includes a $4.8 million drop in RG&E welfare expense from 1998 due mainly to the performance of pension assets and a change in the discount rate used to value the aggregate pension liability (see Note 3 of the Notes to Financial Statements), elimination in the first quarter of 1999 of property insurance and storm reserves no longer required totaling $2.1 million, lower non-fuel net expenses of $1.5 million associated with Ginna Station refueling outages, a decrease of $2.8 million due primarily to the completion in 1998 of the amortization of costs of RG&E's billing system, insurance dividends of $1.8 million, and lower employee performance incentive program costs of $1.1 million. Offsetting these declines was a June 1999 increase in the allowance for uncollectible accounts of approximately $7 million to better match RG&E's actual collection history, the establishment in the fourth quarter of 1999 of a $3.0 million liability for anticipated Nine Mile Two inventory losses due to a change in the expected ownership of that facility, and Y2K costs of $6.0 million.

An RG&E employee power factoring at RG&E's substation #29

The variance in unregulated non-fuel operating expenses reflects primarily an increase in payroll expenses ($5.6 million), other operating expenses for Griffith ($2.6 million), and general and administrative expenses ($2.1 million). The increase in these expenses reflects twelve months of Griffith's operations in 1999 compared with only five months of operations in 1998 following its acquisition in August 1998.

Depreciation expense for both RGS and RG&E in 1999 includes an incremental one-time charge in the second quarter of approximately $2.1 million associated with the closing of Beebee Station in April 1999. Depreciation and amortization expense for unregulated operations in 1999 was $3.2 million, up $2.1 million from 1998.

Local, State and other taxes for RGS and RG&E declined reflecting a New York State use tax audit refund, lower tax rates for State and local revenue taxes, and lower assessments for property taxes. These results were partially offset by higher unbilled revenue taxes resulting from an increase in unbilled revenues. For unregulated operations, local, State and other taxes increased $2.9 million to $4.0 million compared to 1998.

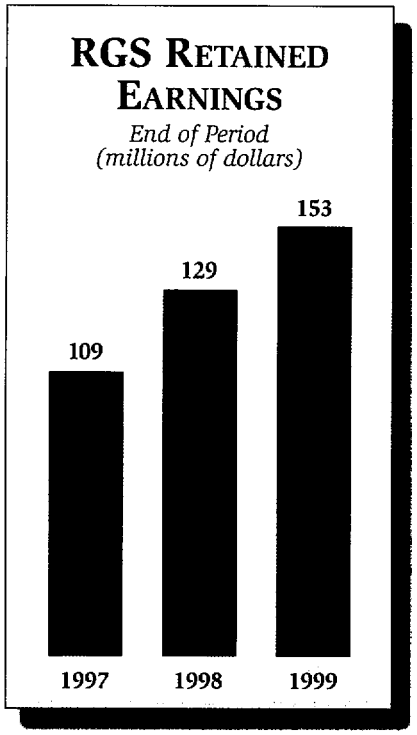
The difference in federal income tax expense for RGS and RG&E reflects pre-tax earnings and, regarding RG&E, the settlement of RG&E audits in the first quarter of 1998 and a tax reserve increase for potential disputed issues of $4.8 million in the fourth quarter of 1999.

Other Statement of Income Items.

The change in non-operating federal income taxes for both RGS and RG&E results from variances in non-operating earnings before federal income taxes.

The change in RGS's and RG&E's Other Income and Deductions, Other-net reflects mainly the recognition of income in 1998 due to the elimination of certain pension and other post-employment benefit deferred credits and Nine Mile Two operating and maintenance expenses in accordance with the Competitive Opportunities Settlement (see "1998 Compared to 1997", Other Statement of Income Items). This variance in Other Income and Deductions, Other-net was partially offset by non-cash carrying charges of $8.6 million related to deferral of Kamine (Allegany Station) facility costs in 1999 for the regulated business. These carrying charges, which are primarily associated with the deferred recovery of costs associated with the Kamine settlement (see following paragraph), were allowed under the Competitive Opportunities and Kamine settlements. In addition, expenses associated with RG&E management performance awards were down $4.4 million in 1999 compared with 1998.

The increase in RGS's interest charges reflects mainly an increase in long-term debt outstanding, resulting mainly from the Kamine settlement, the acquisition of Griffith by Energetix, and the issuance of $50 million of long term debt by RG&E in December 1998. The increase in RG&E's interest charges reflects the same issues exclusive of the debt incurred for the Griffith acquisition. To a lesser extent, interest expense for both RGS and RG&E reflects the interest on $100 million of first mortgage bonds issued in October 1999 (see "Financing").



1998 Compared to 1997

Operating Revenues and Sales.

Regulated electric revenues for 1998 were down compared to a year earlier resulting from a decrease in electric base rates effective July 1, 1998 and July 1, 1997 and the effect of the migration of approximately 10% of RG&E's electric load to competitive suppliers, including Energetix. Making a positive contribution to 1998 electric revenues was an increased demand for air conditioning load during the summer months when the

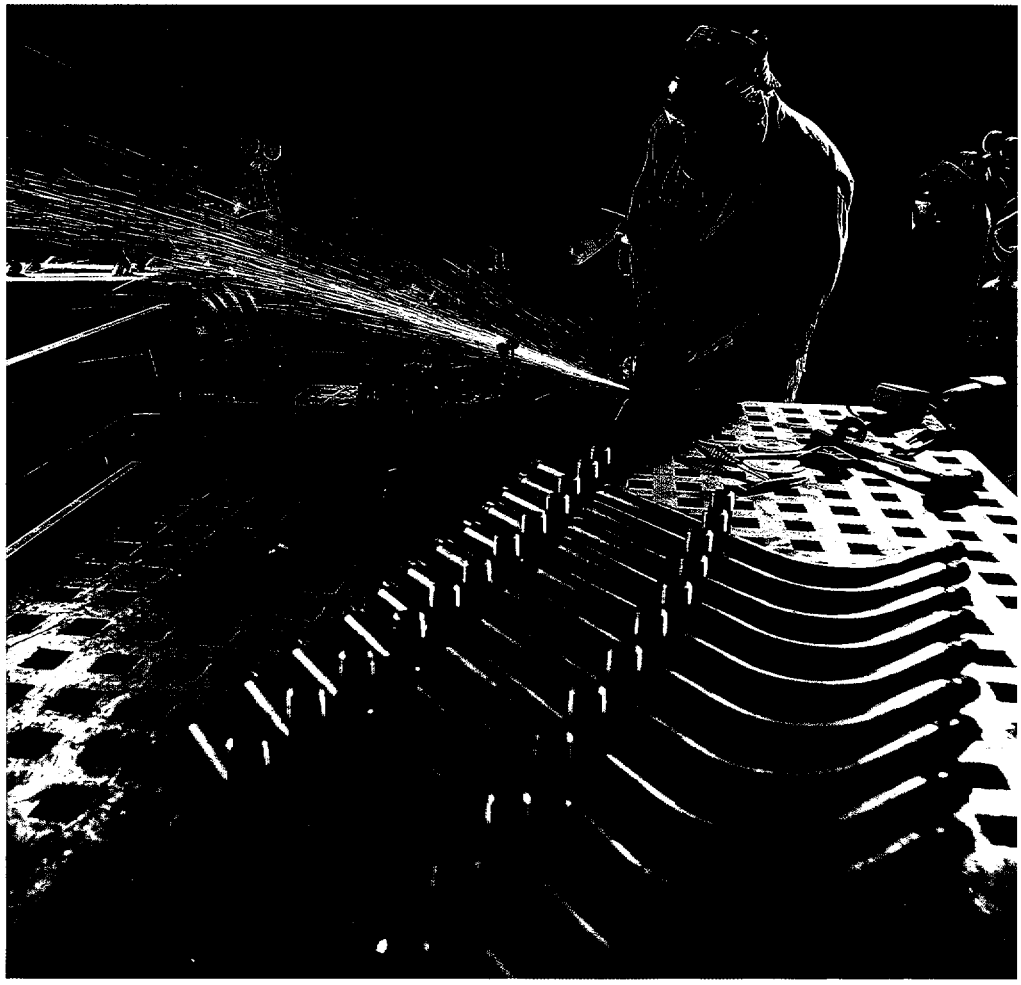
weather was 70% warmer (on a cooling degree day basis) in contrast to the summer of 1997 which was 35% cooler than normal. Electric revenues from sales to other electric utilities was up largely due to the increased availability of the Ginna Plant. The Ginna Plant experienced a 31 day scheduled refueling outage in 1997 compared with no outage in 1998. The drop in commercial and industrial regulated electric sales reflects, in part, the opening of the electric market on July 1, 1998 under the terms of the Competitive Opportunities Settlement. RG&E, however, sells electric energy, as well as distribution services, to qualified energy marketers in its franchise territory which has the effect of increasing wholesale sales to energy marketers. Included in electric operating revenues for 1998 are $15.0 million of revenues from electric sales to energy marketers.

Regulated gas margins (revenues less cost of purchased gas) were down over $20 million reflecting 18% warmer weather (based on heating degree days). Therms of gas sold and transported for the regulated business were down 12.1 percent in 1998.

Included in total operating revenues for 1998 are $10.6 million of electric and gas operating revenues received by Energetix and $71.2 million of Griffith operating revenues. Griffith's operating revenues are reported under Other Revenues on both RGS's and RG&E's Income Statements. Prior year comparisons for the Company's unregulated subsidiary, Energetix, are not relevant because formal operations began in the first quarter of 1998 and Griffith was acquired in August 1998.

Operating Expenses.

Higher fuel expenses in 1998 reflect higher fuel expenses for electric generation resulting from increased generation to support higher electric sales. For the 1998 comparison period, increased fuel expense also reflects relatively more generation from RG&E's costlier fossil-fueled units. Compared with 1997, purchased electric power expense declined in 1998 driven primarily by the effect of greater availability of RG&E's generating facilities. The cost per unit purchased for electric energy was up about 8% in 1998 compared with a year earlier. Gas purchased for resale expense declined in 1998 driven by a reduced volume of purchased gas resulting from a warmer heating season. Other fuel expense on both RGS's and RG&E's Income Statements reflects mainly the cost of purchased fuel for Griffith operations since its acquisition in August 1998 by Energetix.



An RG&E welder fabricating some gas meter manifolds.

The decrease in non-fuel operating expenses for RGS and RG&E includes lower expense of $5.3 million associated with RG&E's uncollectible accounts and a $7.9 million drop in RG&E's welfare expenses due to a favorable adjustment in pension expense (see Note 3 to the Notes to Financial Statements). The decrease in uncollectible accounts expense was driven by the increased level of collection activity. Partially offsetting these lower costs were increased payroll costs of $2.2 million. Approximately $1.6 million of Year 2000 costs were charged to operating expenses in 1998, up $0.4 million from 1997.

The variance in unregulated non-fuel operating expenses reflects primarily a change in payroll expenses, other operating expenses for Griffith, and general and administrative expenses. Prior year comparisons for the Company's unregulated subsidiary, Energetix, are not relevant because formal operations began in the first quarter of 1998 and Griffith was acquired in August 1998.

Depreciation expense for both RGS and RG&E in 1998 remained relatively flat compared to 1997 due to the completion of depreciation expense on certain fully depreciated computer equipment. Depreciation and amortization expense in 1998 includes $1.1 million for unregulated operations.

Local, State and other taxes for RGS and RG&E declined reflecting mainly lower State revenue taxes due to decreased regulated revenues. This decline was partially offset by an additional $1.5 million of local and State taxes associated with unregulated operations.

The difference in federal income tax expense for RGS and RG&E reflects pre-tax earnings and, regarding RG&E, the settlement of RG&E audits in the first quarter of 1998.

Other Statement of Income Items.

The change in non-operating federal income taxes for both RGS and RG&E results from variances in non-operating earnings before federal income taxes, as well as a $1.7 million RG&E reserve for deferred taxes subsequent to a review of the historic balances.

The change in RGS's and RG&E's Other Income and Deductions, Other-net reflects the recognition of income due to the reversal of certain deferred credits in accordance with the Competitive Opportunities Settlement. In prior years, the PSC had required RG&E to establish deferred credits to account for certain pension and other post-employment benefit charges and Nine Mile Two operating and maintenance expenses. In 1998, these deferred credits totaling $17.4 million were eliminated consistent with the terms of the Settlement and discussions with the PSC. An amount of $8.8 million associated with certain pension charges was reflected on RG&E's books in the first quarter of 1998, after RG&E received the written order associated with the Competitive Opportunities Settlement. An amount of $6.0 million associated with certain Nine Mile Two operating and maintenance expenses was reflected ratably over each of the four quarters of 1998, consistent with Nine Mile Two accounting practices. The remainder associated with certain other post-employment benefits was reflected in the second quarter of 1998, after RG&E had concluded discussions with the PSC. This income was partially offset by expenses associated with the gas interim settlement agreement.

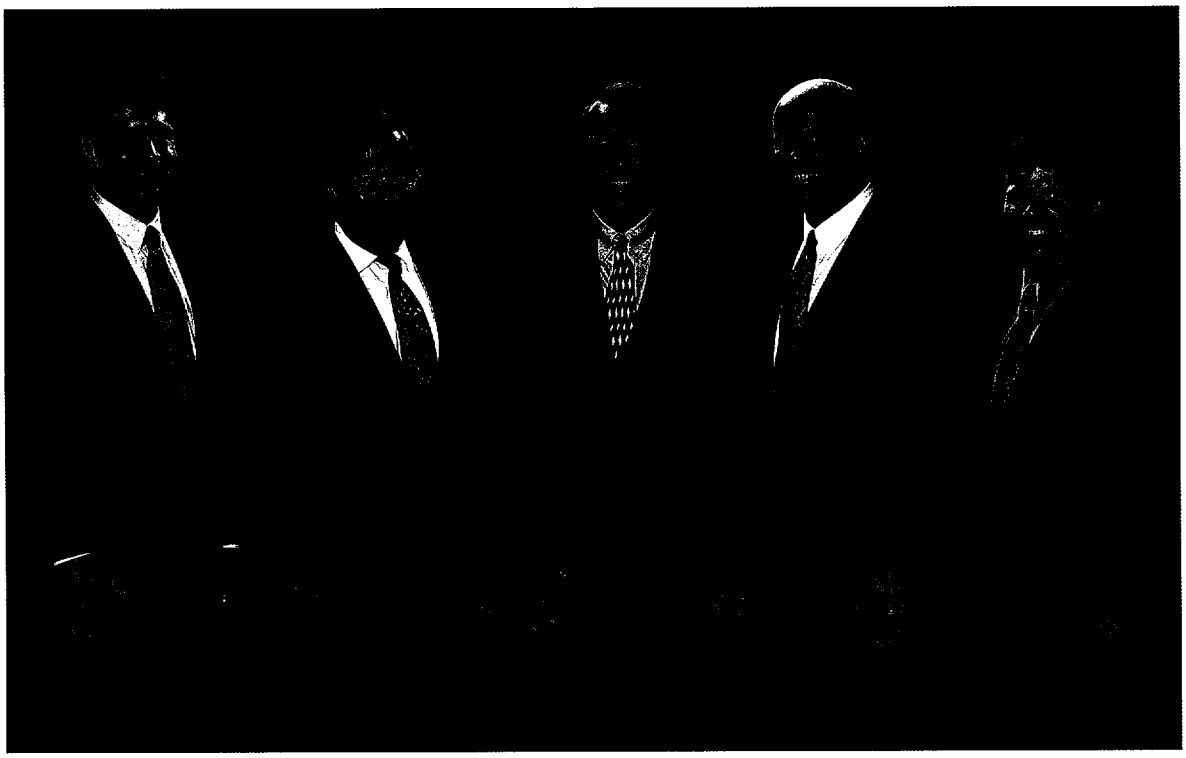
The decrease in RGS's and RG&E's interest charges reflects both mandatory and optional redemptions of long term debt undertaken by RG&E during 1998 and 1997. In addition, other interest decreased in 1998 due to lower miscellaneous interest charges on RG&E pension and other post-employment benefits. The decline in interest charges was partially offset by an additional $1.0 million of interest expense associated mainly with the acquisition of Griffith by Energetix.

Dividend Policy

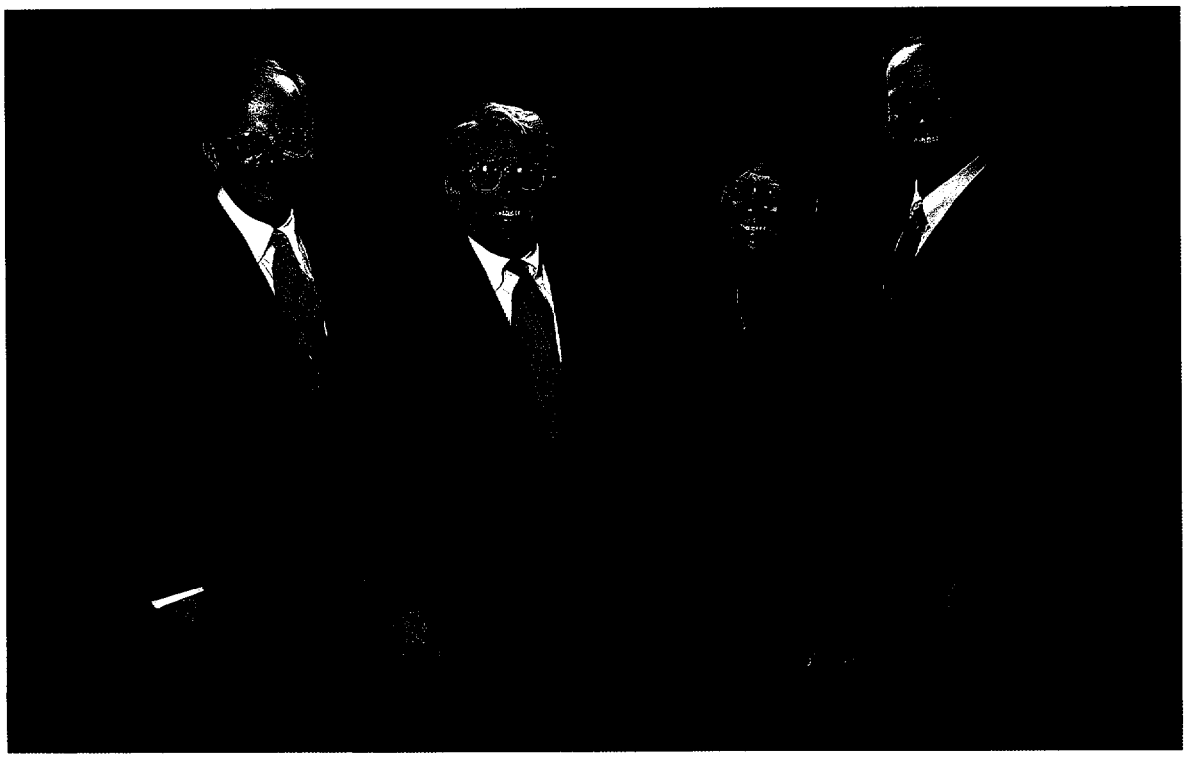
The ability of RGS to pay common stock dividends is governed by the ability of RGS' s subsidiaries to pay dividends to RGS. Because RG&E is by far the largest of the subsidiaries, it is expected that for the foreseeable future the funds required by RGS to enable it to pay dividends will be derived predominantly from the dividends paid to RGS by RG&E. In the future, dividends from subsidiaries other than RG&E may also be a source of funds for dividend payments by RGS. RG&E's ability to make dividend payments to RGS will depend upon the availability of retained earnings and the needs of its utility business. In addition, pursuant to the PSC order approving the formation of RGS, RG&E may pay dividends to RGS of no more than 100% of RG&E's net income calculated on a two-year rolling basis. The calculation of net income for this purpose excludes non-cash charges to income resulting from accounting changes or certain PSC required charges as well as charges that may arise from significant unanticipated events. This condition does not apply to dividends that would be used to fund the remaining portion of the $100 million authorized for RG&E's unregulated operations (about $42 million at December 31, 1999). The level of future cash dividend payments on Common Stock will be dependent upon RGS's future earnings, its financial requirements, and other factors.

New Management Appointments

In conjunction with the restructuring of its business, Rochester Gas and Electric Corporation, has appointed nine new vice-presidents.



From left to right: David Irish, Vice President, Fossil-Hydro Operations, Clifton Olson, Vice President, Energy Supply, Michael Whitcraft, Vice President, Energy Delivery, William Reddy, Vice President and Controller, Joseph Widay, Vice President and Plant Manager, Ginna Station



From left to right: Paul Ruganis, Vice President, Information Services, Mark Keogh, Vice President and Treasurer, Jessica Raines, Vice President, Support Services, Louis Bellina, Vice President, Customer Relations

Financial Reports

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Report of Independent Accountants

PRICEWATERHOUSECOOPERS

1100 Bausch & Lomb Place
Rochester, New York 14604-2705
February 1, 2000

To the Shareholders and Board of Directors of
RGS Energy Group, Inc and the
Shareholders and Board of Directors of
Rochester Gas and Electric Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, retained earnings and cash flows present fairly, in all material respects, the financial position of RGS Energy Group, Inc. and its subsidiaries ("RGS") at December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999 and 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 ("RG&E") at December 31, 1999 and 1998, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1999 in conformity with accounting principles generally accepted in the United States. These financial statements are the responsibility of the RGS and RG&E 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 auditing standards generally accepted in the United States, 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.

PricewaterhouseCoopers LLP

RGS ENERGY GROUP, INC.

CONSOLIDATED STATEMENT OF INCOME

(Thousands of Dollars) Year Ended December 31,	1999	1998*	1997
OPERATING REVENUES			
Electric	$ 702,751	$ 687,622	$ 700,329
Gas	284,476	274,657	336,309
Other	220,310	71,212	—
Total Operating Revenues	1,207,537	1,033,491	1,036,638
OPERATING EXPENSES			
Fuel Expenses			
Fuel for electric generation	49,297	53,954	47,665
Purchased electricity	54,337	27,024	28,347
Gas purchased for resale	151,458	155,497	196,579
Unregulated fuel expenses	189,465	59,490	—
Total Fuel Expenses	444,557	295,965	272,591
Operating Revenues Less Fuel Expenses	762,980	737,526	764,047
Other Operating Expenses			
Operations and maintenance excluding fuel expenses	297,890	301,625	315,109
Unregulated operating and maintenance expenses excluding fuel	26,464	13,524	—
Depreciation and amortization	118,695	116,102	116,522
Taxes—local, state and other	114,639	117,973	121,796
Federal income tax	64,253	60,236	65,279
Total Other Operating Expenses	621,941	609,460	618,706
Operating Income	141,039	128,066	145,341
OTHER (INCOME) AND DEDUCTIONS			
Allowance for other funds used during construction	(657)	(408)	(351)
Federal income tax	(1,134)	1,665	(3,704)
Other, net	(8,178)	(13,370)	3,308
Total Other (Income) and Deductions	(9,969)	(12,113)	(747)
INTEREST CHARGES			
Long term debt	53,681	43,306	44,615
Other, net	4,798	3,388	6,676
Allowance for borrowed funds used during construction	(1,051)	(653)	(563)
Total Interest Charges	57,428	46,041	50,728
Preferred Stock Dividend Requirements	4,083	4,842	5,805
Net Income Applicable to Common Stock	$ 89,497	$ 89,296	$ 89,555
Earnings per Common Share—Basic	$2.44	$2.32	$2.30
Earnings per Common Share—Diluted	$2.44	$2.31	$2.30

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(Thousands of Dollars) Year Ended December 31,	1999	1998*	1997*
Balance at Beginning of Period	$129,484	$109,313	$ 90,540
Add			
Net Income	89,497	89,296	89,555
Total	218,981	198,609	180,095
Deduct			
Dividends declared on Common Stock	65,594	68,927	69,936
Other Adjustments	201	198	846
Total	65,795	69,125	70,782
Balance at End of Period	$153,186	$129,484	$109,313
Cash Dividends Declared per Common Share	$1.80	$1.80	$1.80

The accompanying notes are an integral part of the financial statements.
**Reclassified for comparative purposes.*

RGS ENERGY GROUP, INC.

CONSOLIDATED BALANCE SHEET

(Thousands of Dollars) At December 31	1999	1998
ASSETS		
Utility Plant		
Electric	$2,399,532	$2,477,077
Gas	453,634	435,318
Common	130,118	158,038
Nuclear	270,447	256,562
	3,253,731	3,326,995
Less: Accumulated depreciation	1,636,955	1,640,645
Nuclear fuel amortization	239,243	222,830
	1,377,533	1,463,520
Construction work in progress	95,862	98,554
Net Utility Plant	1,473,395	1,562,074
Current Assets		
Cash and cash equivalents	8,288	6,523
Accounts receivable, net of allowance for doubtful accounts: 1999—$34,026; 1998—$26,554	90,239	89,291
Unbilled revenue receivable	58,005	37,922
Materials, supplies and fuels	38,206	43,024
Prepayments	24,576	25,950
Other current assets	523	253
Total Current Assets	219,837	202,963
Intangible Assets		
Goodwill, net	13,894	14,681
Other Intangible Assets	7,338	6,381
Total Intangible Assets	21,232	21,062
Deferred Debits and Other Assets		
Nuclear generating plant decommissioning fund	220,815	183,502
Nine Mile Two deferred costs	28,206	29,258
Unamortized debt expense	17,984	17,241
Other deferred debits	13,137	18,531
Regulatory assets	466,231	416,320
Other assets	2,037	1,984
Total Deferred Debits and Other Assets	748,410	666,836
Total Assets	$2,462,874	$2,452,935

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

(Thousands of Dollars) At December 31	1999	1998
CAPITALIZATION AND LIABILITIES		
Capitalization		
Long term debt—mortgage bonds	$ 580,070	$ 510,002
—promissory notes	235,395	248,224
Preferred stock redeemable at option of Company	47,000	47,000
Preferred stock subject to mandatory redemption	25,000	25,000
Common shareholders' equity:		
Common stock		
Authorized 50,000,000 shares; 38,885,813 shares issued at December 31, 1999 and at December 31, 1998	700,268	699,730
Retained earnings	153,186	129,484
	853,454	829,214
Less: Treasury stock at cost (2,942,600 shares at December 31,1999 and 1,507,000 shares at December 31, 1998)	83,252	46,433
Total Common Shareholders' Equity	770,202	782,781
Total Capitalization	1,657,667	1,613,007
Long Term Liabilities		
Nuclear waste disposal	91,743	87,566
Uranium enrichment decommissioning	10,911	12,197
Site remediation	23,698	24,157
	126,352	123,920
Current Liabilities		
Long term debt due within one year	37,643	427
Preferred stock redeemable within one year	—	10,000
Short term debt	10,500	57,000
Accounts payable	54,221	52,454
Dividends payable	17,078	17,937
Equal payment plan	10,529	11,025
Other	39,385	34,526
Total Current Liabilities	169,356	183,369
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes	318,694	326,972
Pension costs accrued	48,628	58,677
Kamine deferred costs	58,738	65,799
Post employment benefits	48,653	42,909
Other	34,786	38,282
Total Deferred Credits and Other Liabilities	509,499	532,639
Commitments and Other Matters	—	—
Total Capitalization and Liabilities	$2,462,874	$2,452,935

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

RGS ENERGY GROUP, INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

(Thousands of Dollars) Year Ended December 31	1999	1998*	1997*
CASH FLOW FROM OPERATING ACTIVITIES			
Net Income	$ 93,580	$ 94,138	$ 95,360
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation & amortization	135,094	135,289	133,942
Deferred recoverable fuel costs	1,401	(3,565)	489
Income taxes deferred	9,901	(9,141)	(10,064)
Allowance for funds used during construction	(1,708)	(1,061)	(914)
Power contract termination costs	—	(10,000)	—
Electric transmission contract termination costs	(26,935)	—	—
Unbilled revenue	(20,083)	10,516	4,823
Post employment benefit/pension costs	4,911	2,798	2,791
Provision for doubtful accounts	7,472	(372)	5,078
Changes in certain current assets and liabilities:			
Accounts receivable	(8,420)	27,549	3,049
Materials, supplies and fuels	4,818	141	(41)
Taxes accrued	4,095	(1,448)	347
Payroll accrued	712	54	433
Accounts payable	1,767	(7,031)	3,733
Other current assets and liabilities, net	1,299	(817)	6,911
Other, net	(14,553)	(13,527)	9,246
Total Operating	193,351	223,523	255,183
CASH FLOW FROM INVESTING ACTIVITIES			
Net additions to utility plant	(108,339)	(129,286)	(84,068)
Nuclear generating plant decommissioning fund	(20,736)	(20,827)	(20,331)
Acquisitions, net of cash	(3,152)	(30,977)	—
Proceeds from sale of Oswego #6	10,920	—	—
Other, net	(147)	484	(1)
Total Investing	(121,454)	(180,606)	(104,400)
CASH FLOW FROM FINANCING ACTIVITIES			
Proceeds from:			
Sale/Issuance of common stock	—	586	272
Issuance of long term debt	100,000	99,422	101,900
Short term borrowings, net	(46,500)	30,500	6,000
Retirement of long term debt	—	(55,500)	(151,568)
Retirement of preferred stock	(10,000)	(10,000)	(30,000)
Repayment of promissory notes	(5,958)	(7,790)	—
Dividends paid on preferred stock	(4,274)	(5,031)	(6,366)
Dividends paid on common stock	(66,262)	(69,592)	(69,933)
Payment for treasury stock	(36,819)	(46,433)	—
Equal Payment Plan	(495)	2,090	3,385
Other, net	176	(51)	(369)
Total Financing	(70,132)	(61,799)	(146,679)
Increase (Decrease) in cash and cash equivalents	$ 1,765	$ (18,882)	$ 4,104
Cash and cash equivalents at beginning of year	$ 6,523	$ 25,405	$ 21,301
Cash and cash equivalents at end of year	$ 8,288	$ 6,523	$ 25,405

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

(Thousands of Dollars) Year Ended December 31	1999	1998	1997
CASH PAID DURING THE PERIOD			
Interest paid (net of capitalized amount)	$ 54,059	$ 43,793	$ 50,681
Income taxes paid	$ 58,750	$ 75,600	$ 70,500
TRANSFER FROM UTILITY PLANT TO REGULATORY ASSET, NET	$ 54,255	$ —	$ —

Reclassified for comparative purposes.

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

ROCHESTER GAS AND ELECTRIC CORPORATION

STATEMENT OF INCOME

(Thousands of Dollars) Year Ended December 31,	1999	1998*	1997
OPERATING REVENUES			
Electric	$ 700,194	$ 687,622	$ 700,329
Gas	281,555	274,657	336,309
Other	108,699	71,212	—
Total Operating Revenues	1,090,448	1,033,491	1,036,638
OPERATING EXPENSES			
Fuel Expenses			
Fuel for electric generation	49,297	53,954	47,665
Purchased electricity	53,046	27,024	28,347
Gas purchased for resale	148,983	155,497	196,579
Unregulated fuel expenses	91,505	59,490	—
Total Fuel Expenses	342,831	295,965	272,591
Operating Revenues Less Fuel Expenses	747,617	737,526	764,047
Other Operating Expenses			
Operations and maintenance excluding fuel expenses	297,890	301,625	315,109
Unregulated operating and maintenance expenses excluding fuel	14,236	13,524	—
Depreciation and amortization	117,289	116,102	116,522
Taxes—local, state and other	112,613	117,973	121,796
Federal income tax	64,454	60,236	65,279
Total Other Operating Expenses	606,482	609,460	618,706
Operating Income	141,135	128,066	145,341
OTHER (INCOME) AND DEDUCTIONS			
Allowance for other funds used during construction	(657)	(408)	(351)
Federal income tax	(1,144)	1,665	(3,704)
Other, net	(8,111)	(13,370)	3,308
Total Other (Income) and Deductions	(9,912)	(12,113)	(747)
INTEREST CHARGES			
Long term debt	53,067	43,306	44,615
Other, net	4,543	3,388	6,676
Allowance for borrowed funds used during construction	(1,051)	(653)	(563)
Total Interest Charges	56,559	46,041	50,728
Net Income	94,488	94,138	95,360
Dividends on Preferred Stock	4,083	4,842	5,805
Net Income Applicable to Common Stock	$ 90,405	$ 89,296	$ 89,555

STATEMENT OF RETAINED EARNINGS

(Thousands of Dollars) Year Ended December 31,	1999	1998*	1997*
Balance at Beginning of Period	$ 129,484	$ 109,313	$ 90,540
Add			
Net Income	94,488	94,138	95,360
Total	223,972	203,451	185,900
Deduct			
Dividends declared on capital stock			
Cumulative preferred stock - at required rates	4,083	4,842	5,805
Common Stock	65,594	68,927	69,936
Adjustment Associated with RGS Energy Group Formation	16,243	—	—
Other Adjustments	198	198	846
Total	86,118	73,967	76,587
Balance at End of Period	$ 137,854	$ 129,484	$ 109,313

The accompanying notes are an integral part of the financial statements.
**Reclassified for comparative purposes.*

ROCHESTER GAS AND ELECTRIC CORPORATION

BALANCE SHEET

(Thousands of Dollars) At December 31	1999	1998
ASSETS		
Utility Plant		
Electric	$2,399,532	$2,477,077
Gas	453,634	435,318
Common	107,469	158,038
Nuclear	270,447	256,562
	3,231,082	3,326,995
Less: Accumulated depreciation	1,634,334	1,640,645
Nuclear fuel amortization	239,243	222,830
	1,357,505	1,463,520
Construction work in progress	95,862	98,554
Net Utility Plant	1,453,367	1,562,074
Current Assets		
Cash and cash equivalents	6,443	6,523
Accounts receivable, net of allowance for doubtful accounts: 1999—$33,365; 1998—$26,554	70,388	89,291
Affiliate receivable	13,197	—
Unbilled revenue receivable	55,661	37,922
Materials, supplies and fuels	33,378	43,024
Prepayments	23,294	25,950
Other current assets	145	253
Total Current Assets	202,506	202,963
Intangible Assets		
Goodwill, net	—	14,681
Other Intangible Assets	—	6,381
Total Intangible Assets	—	21,062
Deferred Debits and Other Assets		
Nuclear generating plant decommissioning fund	220,815	183,502
Nine Mile Two deferred costs	28,206	29,258
Unamortized debt expense	17,984	17,241
Other deferred debits	13,760	18,531
Regulatory assets	466,231	416,320
Other assets	—	1,984
Total Deferred Debits and Other Assets	746,996	666,836
Total Assets	$2,402,869	$2,452,935

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

(Thousands of Dollars) At December 31	1999	1998
CAPITALIZATION AND LIABILITIES		
Capitalization		
Long term debt—mortgage bonds	$ 580,070	$ 510,002
—promissory notes	215,930	248,224
Preferred stock redeemable at option of Company	47,000	47,000
Preferred stock subject to mandatory redemption	25,000	25,000
Common shareholders' equity:		
Common stock		
Authorized 50,000,000 shares; 38,885,813 shares issued at December 31, 1999 and at December 31, 1998	700,268	699,730
Retained earnings	137,854	129,484
	838,122	829,214
Less: Treasury stock at cost (2,942,600 shares at December 31,1999 and 1,507,000 shares at December 31, 1998)	83,252	46,433
Total Common Shareholders' Equity	754,870	782,781
Total Capitalization	1,622,870	1,613,007
Long Term Liabilities		
Nuclear waste disposal	91,743	87,566
Uranium enrichment decommissioning	10,911	12,197
Site remediation	22,357	24,157
	125,011	123,920
Current Liabilities		
Long term debt due within one year	33,781	427
Preferred stock redeemable within one year	—	10,000
Short term debt	—	57,000
Accounts payable	42,263	52,454
Affiliate payable	12,961	—
Dividends payable	17,078	17,937
Equal payment plan	10,529	11,025
Other	33,243	34,526
Total Current Liabilities	149,855	183,369
Deferred Credits and Other Liabilities		
Accumulated deferred income taxes	314,683	326,972
Pension costs accrued	48,628	58,677
Kamine deferred costs	58,738	65,799
Post employment benefits	48,653	42,909
Other	34,431	38,282
Total Deferred Credits and Other Liabilities	505,133	532,639
Commitments and Other Matters	—	—
Total Capitalization and Liabilities	$2,402,869	$2,452,935

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

ROCHESTER GAS AND ELECTRIC CORPORATION

STATEMENT OF CASH FLOWS

(Thousands of Dollars) Year Ended December 31	1999	1998*	1997*
CASH FLOW FROM OPERATING ACTIVITIES			
Net Income	$ 94,488	$ 94,138	$ 95,360
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation & amortization	131,903	135,289	133,942
Deferred recoverable fuel costs	1,401	(3,565)	489
Income taxes deferred	5,889	(9,141)	(10,064)
Allowance for funds used during construction	(1,708)	(1,061)	(914)
Power contract termination costs	—	(10,000)	—
Electric transmission contract termination costs	(26,935)	—	—
Unbilled revenue	(17,739)	10,516	4,823
Post employment benefit/pension costs	4,911	2,798	2,791
Provision for doubtful accounts	7,066	(372)	5,078
Changes in certain current assets and liabilities:			
Accounts receivable	(10,248)	27,549	3,049
Materials, supplies and fuels	7,164	141	(41)
Taxes accrued	2,822	(1,448)	347
Payroll accrued	(2)	54	433
Accounts payable	(3,298)	(7,031)	3,733
Other current assets and liabilities, net	1,160	(817)	6,911
Other, net	(12,687)	(13,527)	9,246
Total Operating	184,187	223,523	255,183
CASH FLOW FROM INVESTING ACTIVITIES			
Net additions to utility plant	(106,359)	(129,286)	(84,068)
Nuclear generating plant decommissioning fund	(20,736)	(20,827)	(20,331)
Acquisitions, net of cash	—	(30,977)	—
Proceeds from sale of Oswego #6	10,920	—	—
Other, net	467	484	(1)
Total Investing	(115,708)	(180,606)	(104,400)
CASH FLOW FROM FINANCING ACTIVITIES			
Proceeds from:			
Sale/Issuance of common stock	—	586	272
Issuance of long term debt	100,000	99,422	101,900
Short term borrowings, net	(50,500)	30,500	6,000
Retirement of long term debt	—	(55,500)	(151,568)
Retirement of preferred stock	(10,000)	(10,000)	(30,000)
Repayment of promissory notes	(2,449)	(7,790)	—
Dividends paid on preferred stock	(4,274)	(5,031)	(6,366)
Dividends paid on common stock	(66,262)	(69,592)	(69,933)
Payment for treasury stock	(36,819)	(46,433)	—
Equal Payment Plan	(495)	2,090	3,385
Corporate restructuring to establish holding company	(6,824)	—	—
Other, net	9,064	(51)	(369)
Total Financing	(68,559)	(61,799)	(146,679)
(Decrease) Increase in cash and cash equivalents	$ (80)	$ (18,882)	$ 4,104
Cash and cash equivalents at beginning of year	$ 6,523	$ 25,405	$ 21,301
Cash and cash equivalents at end of year	$ 6,443	$ 6,523	$ 25,405

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

(Thousands of Dollars) Year Ended December 31	1999	1998	1997
CASH PAID DURING THE PERIOD			
Interest paid (net of capitalized amount)	$ 53,061	$ 43,793	$ 50,681
Income taxes paid	$ 58,750	$ 75,600	$ 70,500
TRANSFER FROM UTILITY PLANT TO REGULATORY ASSET, NET	$ 54,255	$ —	$ —

*Reclassified for comparative purposes.

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

note 1

SUMMARY OF ACCOUNTING PRINCIPLES

Holding Company Formation.

On August 2, 1999, RG&E was reorganized into a holding company structure in accordance with the Agreement and Plan of Exchange between RG&E and RGS Energy. RG&E's common stock was exchanged on a share-for-share basis for RGS Energy's common stock. RG&E's preferred stock was not exchanged as part of the share exchange and will continue as shares of RG&E.

General.

The Company supplies regulated electric and gas services wholly within the State of New York. The unregulated portion of the Company provides products and services as discussed in Note 4. The Company is subject to regulation by the Public Service Commission of the State of New York (PSC) under New York statutes and by the Federal Energy Regulatory Commission (FERC) as a licensee and public utility under the Federal Power Act. The Company's accounting policies conform to generally accepted accounting principles as applied to New York State public utilities giving effect to the ratemaking and accounting practices and policies of the PSC.

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

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

Basis of Presentation.

This is a combined report of RGS Energy and RG&E, a regulated Electric and Gas subsidiary. The Notes to Financial Statements apply to both RGS Energy and RG&E. RGS Energy's Consolidated Financial Statements include the accounts of RGS Energy and its wholly owned subsidiaries, including RG&E, and two non-utility subsidiaries, RGS Development and Energetix. RGS Energy's prior period consolidated financial statements have been prepared from RG&E's prior period consolidated financial statements, except that accounts have been reclassified to reflect RGS Energy's structure. RG&E's financial statements reflect the operations of RG&E, Energetix and RGS Development prior to August 1, 1999. Subsequent to that date only RG&E operations are reflected.

Principles of Consolidation.

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries RG&E, Energetix, Energyline and RGS Development. All intercompany balances and transactions have been eliminated. Energetix's financial statements are consolidated with its wholly-owned subsidiary Griffith.

Energyline was dissolved in January 2000. It was formed as a gas pipeline corporation to fund the Company's investment in the Empire State Pipeline project. In late 1996, Energyline sold its investment in the Empire State Pipeline.

During the second quarter of 1998, the Company formed a new unregulated subsidiary, RGS Development Corporation ("RGS Development"). RGS Development was formed to pursue unregulated business opportunities in the energy marketplace. Through December 31, 1999, RGS Development operations have not been material to the Company's results of operation or its financial condition.

Summary of Significant Accounting Policies.

Goodwill and Other Intangible Assets.

Goodwill presented on the consolidated balance sheet, represents the excess of cost over the net tangible and identifiable intangible assets of acquired businesses. It is stated at cost and is amortized, principally on a straight-line basis, over the estimated future periods to be benefited (20 years). On an annual basis the Company reviews the recoverability of goodwill based primarily upon an analysis of undiscounted cash flows from the acquired businesses. Other intangible assets include dealer improvements and are being amortized over varying periods. Accumulated amortization amounted to $1.7 million and $0.7 million at December 31, 1999 and December 31, 1998 respectively.

Acquisitions.

In August 1998, Energetix acquired Griffith Oil, Co., Inc. ("Griffith"), for $31.5 million. Griffith sells oil, propane, electricity, gasoline, natural gas and other services offered by Energetix to its existing customers. The acquisition was accounted for as a purchase resulting in goodwill as reflected on the consolidated financial statements. The principal tangible assets acquired were vehicles, tanks, pumps, buildings and commodity inventory.

Rates and Revenue.

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

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

The Company continues to use gas cost deferral accounting. A reconciliation of recoverable gas costs with gas revenues is done annually as of August 31, and the excess or deficiency is refunded to or recovered from the customers during a subsequent period.

Utility Plant, Depreciation and Amortization.

The cost of additions to utility plant and replacement of retirement units of property is capitalized. Cost includes labor, material, and similar items, as well as indirect charges such as engineering and supervision, and is recorded at original cost. The Company capitalizes an Allowance for Funds Used During Construction (AFUDC) approximately equivalent to the cost of capital devoted to plant under construction that is not included in its rate base. AFUDC is segregated into two components and classified in the Consolidated Statement of Income as Allowance for Borrowed Funds Used During Construction, an offset to Interest Charges, and Allowance for Other Funds Used During Construction, a part of Other Income. The rate approved by the PSC for purposes of computing AFUDC was 5.0% during the three-year period ended December 31, 1999. 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 an annual regulated depreciation provision of 3.2% in the three-year period ended December 31, 1999. The annual depreciation provision of Energetix is 7.6% and 8.0% for 1999 and 1998 respectively.

Cash and Cash Equivalents.

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

Investments in Debt and Equity Securities.

The Company's accounting policy, as prescribed by the PSC, with respect to its nuclear decommissioning trusts is to reflect the trusts' assets at market value and reflect unrealized gains and losses as a change in the corresponding accrued decommissioning liability. The Company has no other debt or equity securities.

Financial/Commodity Instruments.

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

Energetix has entered into electric and natural gas purchase commitments with numerous suppliers. These commitments support fixed price offerings to retail electric and gas customers. Griffith is in the business of purchasing various petroleum-related commodities for resale to its customers. In order to manage the risk associated with market price fluctuations Griffith enters into various exchange-traded futures and option contracts and over-the-counter contracts with third parties. The commodity instruments are designated at the inception as a hedge where there is a direct relationship to the price risk associated with Griffith's inventory or future purchases and sales of commodities used in Griffith's operation. These contracts are closely monitored on a daily basis to manage the price risk associated with the company's inventory and future product commitments. All hedge contracts are accounted for under the deferral method with gains and losses from the hedging activity included in the cost of sales as inventories are sold or as the hedge transaction occurs. Commodity instruments not designated as effective hedges are marked to market at the end of the reporting period, with the resulting gains or losses recognized in cost of sales. At December 31, 1999 and 1998 Griffith's net deferred gains on open hedge contracts were immaterial.

Research and Development Costs.

Research and Development costs were charged to expense as incurred. Expenditures for the years 1999, 1998, and 1997 were $2.9 million, $3.4 million and $4.5 million respectively.

Environmental Remediation Costs.

The Company accrues for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as further information develops or circumstances change.

Materials, Supplies and Fuels.

Materials and supplies inventories are valued at the lower of cost or market using the first-in, first-out method. Regulated fuel inventories are valued at average cost. Griffith fuel inventories are valued at the lower of cost or market, using the first-in, first-out method.

Nuclear Outage Costs.

The Company levelizes estimated incremental non-fuel expenses due to planned refueling outages at its two nuclear power plants. Such costs are levelized between refueling outages.

Stock-Based Compensation.

The Company accounts for its stock-based compensation using the fair value method in accordance with SFAS-123. The aggregate amount charged to expense as a result of the Company's stock-based compensation plans for the years 1999, 1998 and 1997 approximates $2.2 million, $5.9 million and $8.2 million respectively. Additional information on the PSOP is included in Note 8.

Earnings Per Share.

SFAS-128, Earnings Per Share, was adopted by the Company in the fourth quarter of 1997. This statement replaces the presentation of primary earnings per share (EPS) with basic EPS, and also requires presentation of diluted EPS. Basic EPS is computed by dividing income available to common shareholders by the weighted average number of common shares outstanding for the period. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock that then shared in the earnings of the Company.

The following table illustrates the calculation of both basic and diluted EPS for the year ended December 31,:

(Thousands of Dollars except Per Share Amounts)	1999	1998	1997
Basic EPS:			
Net Income available to Common Shareholders	$89,497	$89,296	$89,555
Shares	36,665	38,462	38,853
Per-Share Amount	$2.44	$2.32	$2.30
Diluted EPS:			
Effect of Dilutive Securities Stock Option Plan	92	138	56
Income available to Common Shareholders	$89,497	$89,296	$89,555
Shares	36,757	38,600	38,909
Per-Share Amount	$2.44	$2.31	$2.30

At December 31, 1999 RGS had 177,322 of antidilutive stock options.

Comprehensive Income.

There were no items of comprehensive income during the two-year period ended December 31, 1999; therefore, net income is equivalent to total comprehensive income.

Reclassifications.

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

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 RGS Energy Group, Inc. Amounts for Rochester Gas and Electric Corporation are not materially different.

(Thousands of Dollars)	1999	1998	1997
Charged (Credited) to operating expense:			
Current	$ 72,137	$ 70,541	$ 69,812
Deferred	(7,884)	(4,533)	(4,533)
Total	64,253	61,385	65,279
Charged (Credited) to other income:			
Current	(2,614)	(1,614)	1,828)
Deferred	5,703	4,562	(3,100)
Deferred investment tax credit	(4,223)	(2,432)	(2,432)
Total	(1,134)	516	(3,704)
Total federal income tax expense	$ 63,119	$ 61,901	$ 61,575

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

(Thousands of Dollars)	1999	1998	1997
Net income prior to preferred stock dividend requirements	$ 93,580	$ 94,138	$ 95,360
Add: federal income tax expense	63,119	61,901	61,575
Income before federal income tax	$156,699	$156,039	$156,935
Computed tax expense at statutory tax rate	$ 54,845	$ 54,614	$ 54,927
Increases (decreases) in tax resulting from:			
Difference between tax depreciation and amount deferred	7,103	9,366	10,772
Deferred investment tax credit	(4,223)	(2,432)	(2,432)
Miscellaneous items, net	5,394	353	(1,692)
Total federal income tax expense	$ 63,119	$ 61,901	$ 61,575

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

(Thousands of Dollars)	1999	1998	1997
Nuclear decommissioning	$ (28,811)	$ (24,849)	$ (20,807)
Accelerated depreciation	218,001	214,521	216,704
Deferred investment tax credit	23,023	25,768	27,981
Depreciation previously flowed through	127,448	146,953	157,538
Pension	(21,503)	(20,161)	(23,166)
Other	536	(15,260)	(13,281)
Total	$318,694	$326,972	$344,969

SFAS-109 "Accounting for Income Taxes" requires that a deferred tax liability must be recognized on the balance sheet for tax differences previously flowed through to customers. Substantially all of these flow-through adjustments relate to property, plant and equipment and related investment tax credits of Rochester Gas and Electric Corporation and will be amortized consistent with the depreciation of these accounts. The net amount of the additional liability at December 31, 1999 and 1998 was $129 million and $148 million, respectively. In conjunction with the recognition of this liability, a corresponding regulatory asset was also recognized.

note 3

Pension and Other Postretirement Benefit Plans

The following table shows reconciliations of the domestic pension plan and other post-retirement plan benefits as of December 31, 1999 and 1998:

	(Millions)			
	Pension Benefits		Other Benefits	
	1999	1998	**1999**	1998
Change in benefit obligation				
Benefit obligation at beginning of year	$516.8	$499.3	$99.0	$89.0
Service cost	6.9	7.0	1.1	1.1
Interest cost	32.7	32.9	5.5	6.0
Plan Amendments	(0.5)	0.0	0.9	4.3
Actuarial (gain) loss	(48.7)	10.7	(22.0)	2.7
Benefits paid	(38.3)	(32.9)	(4.3)	(4.1)
Benefit obligation at end of year	$468.9	$516.8	$80.2	$99.0
Change in plan assets				
Fair value of plan assets at beginning of year	$706.4	$638.4	$0.0	$0.0
Actual return on plan assets	99.5	100.0	0.0	0.0
Company contribution	0.7	0.9	4.3	4.1
Benefits paid	(38.3)	(32.9)	(4.3)	(4.1)
Fair value of plan assets at end of year	$768.3	$706.4	$0.0	$0.0
Funded status	$294.5	$189.5	$(80.2)	$(99.0)
Unrecognized actuarial (gain) loss	(352.5)	(259.4)	(10.8)	11.2
Unrecognized prior service cost	8.6	9.9	12.6	12.6
Unrecognized net transition obligation	0.8	1.3	29.8	32.3
Accrued benefit	$(48.6)	$(58.7)	$(48.6)	$(42.9)
Weighted-average assumptions as of December 31				
Discount rate	7.50%	6.50%	7.50%	6.50%
Expected return on plan assets	8.50%	8.50%		
Rate of compensation increase	5.00%	5.00%		

	(Millions)					
	Pension Benefits			Other Benefits		
	1999	1998	1997	**1999**	1998	1997
Components of net periodic benefit cost						
Service cost	$6.9	$7.0	$6.2	$1.1	$1.1	$0.9
Interest cost	32.7	32.9	33.1	5.5	6.0	5.8
Expected return on plan assets	(49.6)	(44.8)	(39.6)	0.0	0.0	0.0
Unrecognized transition obligation	0.5	0.5	0.5	2.5	2.8	2.9
Amortization of prior service	0.8	0.9	0.9	1.0	0.6	0.6
Recognized actuarial loss	(5.5)	(4.3)	(3.1)	0.0	0.0	0.0
Net periodic (benefit) cost	$(14.2)	$(7.8)	$(2.0)	$10.1	$10.5	$10.2

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits on a defined dollar basis. In 1999, the health care benefit consists of a contribution of up to $220 per retiree per month towards the cost of a group health policy provided by the Company. The life insurance benefit consists of a Basic Group Life benefit, covering substantially all employees, providing a death benefit equal to one-half of the retiree's final pay.

In addition to the above plans, employees are eligible to contribute to a 401(k) plan. The Company matches a portion of these contributions. Contributions charged to income for this plan for 1999, 1998, and 1997 were $2.8 million, $2.5 million, and $2.3 million, respectively.

During 1999, a generation plant was shut down creating a staff reduction of 36 employees, resulting in a net curtailment charge of $4.9 million, including $8.4 million cost of special termination benefits provided to affected employees offset by a curtailment gain of $3.5 million. Pursuant to the Company's settlement agreement, this charge has been deferred.

note 4

Operating Segment Financial Information

Under SFAS-131, information pertaining to operating segments is required to be reported. Upon adoption of SFAS-131, the Company identified three operating segments, driven by the types of products and services offered and regulatory environment under which the Company primarily operates. The three segments are Regulated Electric, Regulated Gas, and Unregulated. The Regulated segments' financial records are maintained in accordance with generally accepted accounting principles (GAAP) and Public Service Commission (PSC) accounting policies. The Unregulated segment's financial records are maintained in accordance with GAAP.

During the reported periods, substantially all revenues are from United States sources, and all assets are located in the United States. No single customer represents more than 10% of the overall Company revenue.

The Regulated Electric segment supplies electric distribution services wholly within New York State. It produces electricity, and distributes and sells electricity to retail customers within a franchise area centering about the City of Rochester. It also sells electricity on a wholesale basis to other electric utilities throughout the Northeast and to energy marketers who resell that electricity to retail customers.

The Regulated Gas segment supplies gas services wholly within New York State. Gas is purchased and distributed to retail customers and distributed on behalf of other large or aggregated customers who purchase their own gas supply.

The Unregulated segment includes Energetix, RGS Development Corporation and Energyline. Energetix brings energy products and services to the marketplace both within and outside of the Company's regulated franchise area. These energy products and services include electricity, gasoline, natural gas, oil, propane, and appliance warranty and repair. RGS Development Corporation was formed to pursue unregulated business opportunities in the energy marketplace.

(Thousands of dollars)	1999	1998*	1997*
Regulated Electric			
Operating Income	$ 120,599	$ 119,937	$ 121,699
Revenues from External Customers	$ 698,745	$ 687,100	$ 700,329
Revenues from Intersegment Transactions	$ 44,510	$ 8,974	$ —
Interest Revenue	$ 10,799	$ 1,694	$ 3,379
Depreciation and Amortization	$ 102,946	$ 102,123	$ 103,395
Regulatory Amortization	$ 14,287	$ 15,080	$ 23,409
Nuclear Fuel Amortization	$ 15,622	$ 18,138	$ 17,419
Interest Expense	$ 45,653	$ 36,122	$ 40,583
Operating Income Tax Expense	$ 55,752	$ 61,477	$ 61,837
Capital Expenditures, net	$ 78,599	$ 96,206	$ 58,522
Total Identifiable Assets	$1,925,809	$1,941,622	$1,783,825

(Thousands of dollars)	1999	1998*	1997*
Regulated Gas			
Operating Income	$ 19,343	$ 10,393	$ 23,642
Revenues from External Customers	$278,659	$274,540	$336,309
Revenues from Intersegment Transactions	$ 420	$ 594	$ —
Interest Revenue	$ 315	$ 424	$ 845
Depreciation and Amortization	$ 12,548	$ 12,867	$ 13,127
Regulatory Amortization	$ 220	$ 1,461	$ 1,337
Interest Expense	$ 9,648	$ 9,030	$ 10,145
Operating Income Tax Expense/(Benefit)	$ 8,580	$ (92)	$ 3,442
Capital Expenditures, net	$ 24,746	$ 28,075	$ 25,546
Total Identifiable Assets	$438,290	$433,029	$441,849

(Thousands of dollars)	1999	1998*	1997*
Unregulated			
Operating Income/(Loss)	$ 543	$ (2,460)	$ 618
Revenues from External Customers	$275,063	$ 81,419	$ —
Interest Revenue	$ 398	$ 158	$ 1,016
Depreciation and Amortization	$ 2,450	$ 834	$ —
Goodwill Amortization	$ 751	$ 278	$ —
Interest Expense	$ 2,171	$ 916	$ —
Operating Income Tax Expense/(Benefit)	$ (50)	$ (1,255)	$ 333
Capital Expenditures, net	$ 4,994	$ 5,005	$ —
Total Assets	$ 90,580	$ 59,946	$ 18,508

There are intersegment transactions which occur between the Regulated segments and the Unregulated segment. These transactions are governed by guidelines established in the Competitive Opportunities Settlement and other PSC proceedings. The Unregulated segment is charged for the provision of services and for an allocation of other corporate costs by the Regulated Segments on a fully loaded cost basis. The Unregulated segment buys electricity from the Regulated Electric segment at rates established through PSC proceedings. The Unregulated segment also pays the Regulated segments for electric and gas distribution services at rates established through PSC proceedings. The total amount of the revenues identified by operating segment do not equal the total Company consolidated amounts as shown in the Consolidated Statement of Income. This is due to the elimination of certain intersegment revenues during consolidation. Additionally, the operations of RGS Development Corporation and Energyline are included in Other (Income) and Deductions in the RGS Energy Group, Inc. Consolidated Statement of Income. The total assets identified by operating segment do not equal the total Company consolidated amounts as shown in the Consolidated Balance Sheet. This is due to the elimination of certain intersegment transactions during consolidation, and certain common assets unidentifiable by segment. A reconciliation follows:

(Thousands of dollars)	1999	1998*	1997
Revenues			
Regulated Electric	$ 698,745	$ 687,100	$ 700,329
Regulated Gas	278,659	274,540	336,309
Unregulated	275,063	81,419	—
Total	$1,252,467	$1,043,059	$1,036,638
Reported on Consolidated Income Statement	1,207,537	1,033,491	1,036,638
Difference to reconcile	$ 44,930	$ 9,568	$ —
Intersegment Revenues			
Regulated Electric from Unregulated	$ 44,510	$ 8,974	$ —
Regulated Gas from Unregulated	$ 420	$ 594	$ —
Total Intersegment	$ 44,930	$ 9,568	$ —

(Thousands of dollars)	1999	1998
Assets		
Regulated Electric	$1,925,809	$1,941,622
Regulated Gas	438,290	433,029
Unregulated	90,580	59,946
Cash and Cash Equivalents, Regulated Operations	6,443	5,375
Unamortized Debt Expense	17,984	17,241
Other	367	266
Intersegment eliminations	(16,599)	(4,544)
Total Assets	$2,462,874	$2,452,935

** Some items have been restated for comparative purposes.*

note 5

Jointly-Owned Facilities

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

	Nine Mile Point Nuclear Unit No.2
Net megawatt capability (summer)	1,128
RG&E's share—megawatts	158
—percent	14
Year of completion	1988

	(Millions of Dollars) at December 31, 1999
Plant In Service Balance	$882.4
Accumulated Provision For Depreciation	$504.8
Plant Under Construction	$ 1.5

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

note 6

Long-Term Debt

First Mortgage Bonds of RG&E

%	Series	Due	(Thousands of Dollars) Principal Amount December 31 1999	1998
9⅜	PP	Apr. 1, 2021	$100,000	$100,000
8¼	QQ(a)	Mar. 15, 2002	100,000	100,000
6.35	RR(b)	May 15, 2032	10,500	10,500
6.50	SS(b)	May 15, 2032	50,000	50,000
7.00	(a)(c)	Jan. 14, 2000	30,000	30,000
7.15	(a)(c)	Feb. 10, 2003	39,000	39,000
7.13	(a)(c)	Mar. 3, 2003	1,000	1,000
7.64	(c)	Mar. 15, 2023	33,000	33,000
7.66	(c)	Mar. 15, 2023	5,000	5,000
7.67	(c)	Mar. 15, 2023	12,000	12,000
6.375	(a)(c)	July 30, 2003	40,000	40,000
7.45	(c)	July 30, 2023	40,000	40,000
5.84	(a)(d)	Dec. 22, 2008	50,000	50,000
7.60	(a)(d)	Oct. 27, 2009	100,000	—
			$610,500	$510,500
Net bond discount			(430)	(498)
Less: Due within one year			30,000	—
Total			$580,070	$510,002

(a) The Series QQ First Mortgage Bonds and the 7%, 7.15%, 7.13%, 6.375%, 5.84% and 7.60% medium-term notes described below are generally not redeemable prior to maturity.

(b) The 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 Refunding Revenue Bonds, Series 1992 A, Series 1992 B (Rochester Gas and Electric Corporation Projects), respectively, issued by the New York State Energy Research and Development Authority (NYSERDA) through a participation agreement with the Company. Payments of the principal of, and interest on the Series 1992 A and Series 1992 B Bonds are guaranteed under a Bond Insurance Policy by MBIA Insurance Corporation.

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

(d) RG&E issued $50 million in 1998 and $100 million in 1999 under a medium-term note program entitled "First Mortgage Bonds, Designated Secured Medium-Term Notes, Series B" with maturities that range from seven years to thirty years.

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

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

On December 1, 1998 RG&E redeemed all its outstanding First Mortgage 8⅜% Bonds, due December 1, 2028, Series OO.

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

	(Thousands of Dollars) 2000	2001	2002	2003	2004
7% Series	$30,000				
Series QQ			$100,000		
7.15% Series				$39,000	
7.13% Series				1,000	
6.375% Series				40,000	
	$30,000	$ —	$100,000	$80,000	$ —

Promissory Notes and Other

Issued	Due	(Thousands of Dollars) December 31 1999	1998
September 2, 1998(e)	September 1, 2033	$ 25,500	$ 25,500
August 19, 1997(f)	August 1, 2032	101,900	101,900
December 1, 1998(g)	March 31, 2014	92,311	94,761
August 3, 1998(h)	August 3, 2005	—	24,563
Other Long Term Debt of Subsidiaries		—	1,500
Total		$219,711	$248,224
Less: RG&E Due within one year		3,781	—
Total RG&E		$215,930	$248,224
August 3, 1998(h)	August 3, 2005	21,054	—
Other Long Term Debt of Subsidiaries		2,273	—
Total		$239,257	$248,224
Less: RGS Due within one year		3,862	—
Total RGS		$235,395	$248,224

(e) The $25.5 million Promissory Note was issued in connection with NYSERDA's 5.95% Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), 1998 Series A. Payment of the principal of, and interest on the Series A Bonds is guaranteed under a Bond Insurance Policy by MBIA Insurance Corporation.

(f) Multi-mode pollution control notes totaling the principal amount of $101.9 million were issued in connection with NYSERDA's Pollution Control Revenue Bonds (Rochester Gas and Electric Corporation Project), $34,000,000 1997 Series A, $34,000,000 1997 Series B and $33,900,000 1997 Series C. The Multi-mode Revenue Bonds have a structure that enables the Company to optimize the use of short-term rates by allowing for the interest rates to be based on a daily rate, a weekly rate, a commercial paper rate, an auction rate or a multi-year fixed rate. Payment of the principal of, and interest on the Multi-mode Revenue Bonds is guaranteed under Bond Insurance Policies by MBIA Insurance Corporation. At December 31, 1999 and December 31, 1998, the Multi-mode Revenue Bonds bore interest at the weekly rate and the average annual interest rate for all three series was 3.09% and 3.21%, respectively.

RG&E is obligated to make payments of principal, premium and interest on each Promissory Note which corresponds to the payments of principal, premium, if any, and interest on certain Pollution Control Revenue Bonds issued by NYSERDA as described above.

(g) The Promissory Note was issued in connection with the Kamine Global Settlement Agreement, which resolved all litigation, released all claims and terminated all electricity purchase obligations under a power purchase agreement. The Promissory Note is secured by a mortgage, the lien for which is subordinate to the lien of the First Mortgage. The liability represents the present value at December 31, 1999 and December 31, 1998 of future obligations under the Note assuming a discount rate of 7.5 percent. This balance will decrease as payments are made over the term of the Note. At December 31, 1999 and December 31, 1998 RG&E made payments totaling $9.6 million and $7.8 million, respectively. The Company expects to make future payments totaling $10.6 million per year.

(h) The $24.6 million Promissory Note was issued in connection with the acquisition of Griffith Oil, Inc. by Energetix and is secured by a pledge of the stock of Griffith Oil, Inc. RGS has made a financial guarantee on behalf of Energetix which obligates RGS in the event of a default by Energetix in payments under the Note. Beginning in 1998 payments of principal are made in seven annual installments and interest for the first three years accrues at the rate of 7% per year and thereafter at rates varying between 7%-8½% per year.

Based on an estimated borrowing rate at year-end 1999 of 7.60% for long-term debt with similar terms and average maturities (11 years), the fair value of the Company's long-term debt outstanding (including Promissory Notes as described above) is approximately $829 million at December 31, 1999.

Based on an estimated borrowing rate at year-end 1998 of 5.84% for long-term debt with similar terms and average maturities (12 years), the fair value of the Company's long-term debt outstanding (including Promissory Notes as described above) is approximately $844 million at December 31, 1998.

note 7

Preferred and Preference Stock of RG&E

Type by Order of Seniority	Par Value	Shares Authorized	Shares Outstanding
Preferred Stock (cumulative)	$100	2,000,000	720,000*
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, 1999	1999	(Thousands) December 31, 1998	Optional Redemption (per share)#
4	F	120,000	$12,000	$12,000	$105
4.10	H	80,000	8,000	8,000	101
4 3/4	I	60,000	6,000	6,000	101
4.10	J	50,000	5,000	5,000	102.5
4.95	K	60,000	6,000	6,000	102
4.55	M	100,000	10,000	10,000	101
Total		470,000	$47,000	$47,000	

#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, 1999	1999	(Thousands) December 31, 1998	Optional Redemption (per share)
7.65	U	—	$ —	$10,000	Not applicable
6.60	V	250,000	25,000	25,000	Not Before 3/1/04 +
Total		250,000	$25,000	$35,000	
Less: Due within one year		—	—	10,000	
Total		250,000	$25,000	$25,000	

+ Thereafter at $100.00

Mandatory Redemption Provisions

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

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

Based on an estimated dividend rate at year-end 1999 of 6.40% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (8.25 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $26 million at December 31, 1999.

Based on an estimated dividend rate at year-end 1998 of 4.75% for Preferred Stock, subject to mandatory redemption, with similar terms and average maturities (6.61 years), the fair value of the Company's Preferred Stock, subject to mandatory redemption, is approximately $39 million at December 31, 1998.

note 8

Common Stock and Stock Options

Repurchase Plan

In December 1997, the Board of Directors of the Company authorized the repurchase of up to 4.5 million shares of the Company's Common Stock on the open market. A total of 1,435,600 and 1,507,000 of the shares were purchased in 1999 and 1998 respectively.

Common Stock

At December 31, 1999, there were 50,000,000 shares of $5 par value Common Stock authorized, of which 35,943,213 were outstanding. No shares of Common Stock are reserved for warrants, conversions, or other rights. There were 1,954,767 shares of Common Stock reserved and unissued for employees under the 1996 Performance Stock Option Plan, as further described below.

	Shares Outstanding	Amount (Thousands)
Balance, December 31, 1997	38,862,347	$699,031
Shares Issued through Stock Plans	23,466	586
Additional Paid in Capital		99
Repurchase Plan	(1,507,000)	(46,433)
Decrease (Increase) in Capital Stock Expense		14
Balance, December 31, 1998	37,378,813	$653,297
Shares Issued through Stock Plans	—	—
RG&E Shares	(38,885,813)	
RGS Shares	38,885,813	
Additional Paid in Capital		486
Repurchase Plan	(1,435,600)	(36,819)
Decrease (Increase) in Capital Stock Expense		52
Balance, December 31, 1999	35,943,213	$617,016

Performance Stock Option Plan

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

In 1999, the Board of Directors granted 177,322 options at an exercise price of $29.689 per share. These options are exercisable for a period of 10 years, and vest three years after the options are granted. The average grant date option fair value and exercise prices are $3.17 and $29.689 respectively. None of these options were exercised during 1999, and are included in the summary of stock option activity presented on the following page.

In 1998, the Board of Directors granted 27,984 options at an exercise price of $33.9065 per share and 15,157 options at an exercise price of $31.0005 per share. These options are vested at 25% when the stock closes at $35 per share, 50% at $40 per share, 75% at $45 per share and 100% at $50 per share. These options are exercisable for a period of 10 years. The weighted average grant date option fair value is $5.56.

In 1997, the Board of Directors granted 504,700 options at an exercise price of $19.0625 per share. These options are vested at 50% when the stock closes at $25 per share, 75% at $30 per share and 100% at $35 per share. Also in 1997, the Board of Directors granted 50,159 options at an exercise price of $24.75 per share. These options are vested at 25% when the stock closes at $25 per share, 50% at $30 per share, 75% at $35 per share and 100% at $40 per share. These options are exercisable for a period of 10 years. The weighted average grant date option fair value is $4.60.

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

The weighted average contractual remaining life for all options issued is 7.02 years and exercise prices range from $19.063 to $33.907 at December 31, 1999.

Since the Company adopted SFAS-123, compensation expense associated with the options granted is reflected in 1999, 1998 and 1997 net income. The compensation expense recorded was $485,300 in 1999, $239,800 in 1998 and $2,399,000 in 1997. The compensation expense was calculated using the shorter of the anticipated or actual vesting period. In applying SFAS-123, the fair value of each option granted is estimated on the date of the grant using the Black-Scholes option pricing model with the following assumptions: risk-free rate of return ranging from 4.61% to 5.16% for 1999, 5.54% to 5.65% for 1998, and 6.39% to 6.56% for 1997, expected dividend yield of 0% for 1999, 1998 and 1997 and expected stock volatility of 19% for 1999 and 17% for 1998 and 1997.

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

	Options	Weighted Average Exercise Price
Options granted 1997	554,859	$19.577
Options exercised	(10,883)	$19.063
Outstanding at 12/31/97	543,976	$19.587
Vested at 12/31/97	392,722	$19.426
Available for future grant at 12/31/97	1,445,141	
Options granted 1998	43,141	$32.886
Options exercised	(23,466)	$19.063
Outstanding at 12/31/98	563,651	$20.627
Vested at 12/31/98	369,256	$19.449
Available for future grant at 12/31/98	1,402,000	
Options granted 1999	177,322	$29.689
Options forfeited	(10,884)	$19.063
Outstanding at 12/31/99	730,089	$22.85
Vested at 12/31/99	369,256	$19.45
Available for future grant at 12/31/99	1,224,678	

note 9

Short-Term Debt

On December 31, 1999, RGS had total short-term debt outstanding of $10.5 million, comprised entirely of Energetix short-term debt. At December 31, 1998, RG&E and Energetix had short-term debt outstanding of $50.5 million and $6.5 million, respectively. The weighted average interest rate on short-term debt outstanding at year-end 1999 for Energetix was 6.74%. The weighted average interest rates for borrowings during the year for RG&E and Energetix were 5.44% and 5.95%, respectively. The weighted average interest rates on short-term debt borrowed during 1998 were 5.51% and 6.31%, respectively.

RG&E's $90 million revolving credit agreement terminates on December 31, 2001. Griffith Oil Co., Inc., a subsidiary of Energetix, has a $15 million revolving credit agreement terminating July 31, 2002. Borrowings under this agreement are secured by personal property of Griffith. Energetix has made a financial guarantee on behalf of Griffith that obligates Energetix in the event of a Griffith default.

RG&E's Charter provides that it may not issue unsecured debt if immediately after such issuance the total amount of unsecured debt outstanding would exceed 15 percent of its total secured indebtedness, capital, and surplus without the approval of at least a majority of the holders of outstanding Preferred Stock. As of December 31, 1999, RG&E would be able to incur approximately $114.5 million of additional unsecured debt under this provision. RG&E has unsecured lines of credit totaling $27 million available from several banks, at their discretion.

In order to be able to use its $90 million revolving credit agreement, RG&E has created a subordinate mortgage which secures borrowings under its revolving credit agreement that might otherwise be restricted by this provision of its Charter. In addition, RG&E has a Loan and Security Agreement to provide for borrowings up to $30 million as needed from time to time for other working capital needs. Borrowings under this agreement, which can be renewed annually, are secured by a lien on RG&E's accounts receivable.

note 10

Commitments and Other Matters

Regulatory Assets

With PSC approval RG&E has deferred certain costs rather than recognize them on its books when incurred. Such deferred costs are then recognized as expenses when they are included in rates and recovered from customers. Such deferral accounting is permitted by SFAS-71, Accounting for the Effects of Certain Types of Regulation. These deferred costs are shown as Regulatory Assets on the Company's and RG&E's Balance Sheets. Such cost deferral is appropriate under traditional regulated cost-of-service rate setting, where all prudently incurred costs are recovered through rates. In a purely competitive pricing environment, such costs might not have been incurred and could not have been deferred. Accordingly, if RG&E was no longer allowed to defer some or a portion of these costs under SFAS-71, these assets would be adjusted accordingly, up to and including the entire amount being written off.

Below is a summarization of the Regulatory Assets as of December 31, 1999 and 1998:

	Millions of Dollars	
	1999	1998
Kamine Settlement	$187.5	$192.8
Income Taxes	129.5	147.6
Oswego Plant Sale	78.6	—
Deferred Environmental SIR costs	20.5	20.9
Uranium Enrichment Decommissioning Deferral	13.9	15.1
Deferred Fuel-Gas	9.3	10.7
Labor Day 1998 Storm Costs	8.5	7.2
Other, net	18.4	22.0
Total—Regulatory Assets	$466.2	$416.3

- **Kamine Settlement:** This amount results from a settlement resolving all litigation, releasing all claims and terminating all electricity purchase obligations under a power purchase agreement. Recovery will be at the rate of approximately $10.5 million per year through June 30, 2002 and is subject to modification, thereafter.
- **Income Taxes:** This amount represents the unrecovered portion of tax benefits from accelerated depreciation and other timing differences which were used to reduce tax expense in past years. The recovery of this deferral is anticipated over the remaining life of the related property, which varies from one to thirty years, when the effect of the past deductions reverses in future years.
- **Oswego Plant Sale:** This amount results from the sale of RG&E's interest in the Oswego generation facility including closing costs and the Buyer's assumption of RG&E's obligations under a transmission services agreement. RG&E is currently amortizing this amount at the rate of approximately $6.5 million per year.
- **Deferred Environmental Site Investigation/Remediation Costs:** These costs represent RG&E's share of the estimated costs to investigate and perform certain remediation activities at both RG&E-owned and non-owned sites with which it may be associated. RG&E has recorded a regulatory asset representing the remediation obligations to be recovered from ratepayers, subject to the terms of the Competitive Opportunities Settlement.
- **Uranium Enrichment Decommissioning Deferral:** The Energy Policy Act of 1992 requires utilities to contribute such amounts based on the amount of uranium enriched by the United States Department of Energy (DOE) for each utility. This amount is mandated to be paid to DOE through the year 2007. The recovery of these costs is through base rates of fuel.
- **Gas Deferred Fuel:** These costs result from a PSC-approved annual reconciliation of recoverable gas costs with gas revenues in which the excess or deficiency is refunded to or recovered from customers during a subsequent period.
- **Labor Day 1998 Storm Costs:** These costs result from a 1998 Labor Day storm. Under the Competitive Opportunities Settlement, RG&E is entitled to defer, for later recovery in rates, certain costs, including those caused by "catastrophic events", when any single event results in costs exceeding $2.5 million. RG&E filed a petition with the PSC notifying them of the deferral of these storm costs.

In a competitive electric market, strandable assets would arise when investments are made in facilities, or costs are incurred to service customers, and such costs are not fully recoverable in market-based rates. An example includes high cost generating assets. Estimates of strandable assets are highly sensitive to the competitive wholesale market price assumed in the estimation. The amount of potentially strandable assets at December 31, 1999 depends on market prices and the competitive market in New York State which is still under development and subject to continuing changes which are not yet determinable, but the amount could be significant.

Strandable assets, if any, could be written down for impairment of recovery based on SFAS-121, which requires write-down of long-lived assets whenever events or circumstances occur which indicate that the carrying amount of a long-lived asset may not be recoverable.

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

At December 31, 1999 RG&E believes that its regulatory assets are probable of recovery. The Settlement in the Competitive Opportunities Proceeding does not impair the opportunity of RG&E to recover its investment in these assets. However, the PSC issued an Opinion and Order Instituting Further Inquiry on March 20, 1998 to address issues surrounding nuclear generation. The initial meeting in this Inquiry was held in January 1999. RG&E is unable to determine when this proceeding may conclude (see PSC Proceeding on Nuclear Generation under Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations). The ultimate determination in this proceeding or the proceeding to consider RG&E's proposed purchase of nuclear plants as discussed under "Nuclear-Related Matters" could have an impact on strandable assets and the recovery of nuclear costs.

Capital Expenditures

The Company's 2000 construction expenditures program is currently estimated at $154 million for RGS of which $151 million is for RG&E. These amounts exclude provision for the proposed purchase of the Nine Mile nuclear generating facilities (see below). The Company has entered into certain commitments for purchase of materials and equipment in connection with that program.

Nuclear-Related Matters

Proposed Purchase of Nuclear Plants. On June 24, 1999, Niagara Mohawk and New York State Electric and Gas (NYSEG) announced their intention to sell their interests in the Nine Mile Two nuclear plant to AmerGen Energy Company, L.L.C.(AmerGen), a joint venture of PECO Energy of Philadelphia and British Energy. Niagara Mohawk owns 41 percent and NYSEG owns 18 percent of Nine Mile Two. The financial terms of the transaction include purchase prices to be paid to Niagara Mohawk of $63.6 million and to NYSEG of $27.9 million.

RG&E's 14 percent interest in Nine Mile Two was not included in the current proposal. As an original part owner, RG&E generally had three options: the first option was to retain its ownership interest on the same basis that it does now; the second option was to sell its 14 percent interest in Nine Mile Two to AmerGen on substantially the same terms as Niagara Mohawk and NYSEG; and the third option was to exercise its right-of-first-refusal and buy the Niagara Mohawk and/or NYSEG interests on terms at least as favorable as those offered by AmerGen. Niagara Mohawk took the position that an exercise of the right to buy its interest in Nine Mile Two must necessarily include matching the terms of the agreement between AmerGen and Niagara Mohawk ($72 million) to buy the Nine Mile Point One Nuclear Plant (Nine Mile One), which is 100 percent owned by Niagara Mohawk.

On December 22, 1999, RG&E announced it had exercised its legal right-of-first-refusal to acquire a controlling interest in Nine Mile Two and to acquire the interests of Niagara

Mohawk in Nine Mile One. As a result of the regulatory process discussed below, the status of RG&E's acquisition pursuant to its right-of-first-refusal is in question.

RG&E has contracted with Entergy Nuclear Nine Mile, L.L.C. (Entergy Nine Mile) to operate and maintain the plants upon RG&E's acquisition under its right-of-first-refusal. Under the terms of an operating agreement, Entergy Nine Mile will be responsible for operating the plants, for certain operating costs and risks during a transition period and most operating costs and risks thereafter. RG&E will be responsible for substantial operating costs and risks during the transition period and these costs and risks will be significantly reduced after the transition period. RG&E will pay Entergy Nine Mile a fixed price (periodically adjusted by certain appropriate price indices) per kilowatt-hour of power actually generated and delivered to RG&E. The contract with Entergy Nine Mile expires in September 2009.

RG&E intends to finance its acquisition through the issuance of long-term debt. Depending on when transfer of ownership takes place, RG&E currently expects to pay between $180 million and $210 million, including the cost of fuel at the plants. The transfer of ownership of the plants to RG&E and transfer of operation of the plants to Entergy Nine Mile will require State and federal regulatory approvals, including the PSC, the Nuclear Regulatory Commission (NRC) and the FERC.

In this transaction, RG&E will continue to own the rights to its original approximately 160 megawatts of electric generating capacity from Nine Mile Two and acquire the rights to approximately an additional 670 megawatts of capacity from that plant. At the conclusion of its purchase, RG&E would own 73% of Nine Mile Two. The Long Island Lighting Company, which is wholly-owned by the Long Island Power Authority, and Central Hudson Gas & Electric Corporation are the other non-operating owners of Nine Mile Two and will retain their interests in the plant. RG&E would also acquire the entire capacity from Nine Mile One, about 615 megawatts.

Niagara Mohawk and NYSEG will purchase the power produced by their previous ownership shares in the Nine Mile Point plants from RG&E under long-term contracts that run for a period of three to five years. These terms are the same as those agreed to by AmerGen. After that period of time, available power is expected to be sold into the wholesale energy market.

Under the terms of a decommissioning agreement, Entergy Nuclear, Inc. will be responsible for decommissioning the plants at a fixed price after they are both taken out of service. For Nine Mile One, Niagara Mohawk, as the former sole owner, will contribute the entire present cost of decommissioning to a fund. For Nine Mile Two, Niagara Mohawk and NYSEG will contribute payments proportionate to their former ownership interests.

At December 31, 1999 the net book value of RG&E's 14 percent interest in the Nine Mile Two generating facility was approximately $376 million.

On August 30, 1999 the PSC began a proceeding to review the proposed sale of the Nine Mile Point nuclear facilities by Niagara Mohawk and NYSEG to AmerGen to determine if the sale would be in the public interest. RG&E has intervened in that proceeding. In early January 2000, at the request of PSC Trial Staff, that proceeding was suspended to give the interested parties time for settlement negotiations. In late January 2000, the PSC Trial Staff expressed its intention to move to dismiss the proceeding since it believes that the sale to AmerGen, as filed, is not consistent with the public interest standard in Public Service Law Section 70; Trial Staff said that it intends to immediately explore, in conjunction with the utilities and interested parties, other scenarios for future ownership and operation of the Nine Mile nuclear plants; and Trial Staff proposed that the parties dispense with formal evidentiary hearings in this proceeding. AmerGen has asked that the Judge reject Staff's request to dispense with formal evidentiary hearings and instead set a schedule for testimony and hearings in this proceeding.

A separate proceeding to consider RG&E's acquisition of the Nine Mile nuclear facilities has not yet been commenced. At this time, RG&E is uncertain what the outcome of the PSC regulatory process will be but expects that it will continue for some time. RG&E intends to continue to pursue all of its alternatives and evaluate any modifications to the current proposed transaction and any new proposed transaction.

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

Under accounting procedures approved by the PSC, RG&E has collected decommissioning costs of approximately $160.6 million through December 31, 1999 and is authorized to collect approximately $22 million annually through June 30, 2002 for decommissioning, covering both nuclear units. The amount allowed in rates is based on estimated ultimate decommissioning costs of $296.3 million for Ginna and $112.8 million for the RG&E's 14% share of Nine Mile Two (1995 dollars). These estimates are based on site specific cost studies for each plant completed in 1995. Site specific studies of the anticipated costs of actual decommissioning are required to be submitted to the NRC at least five years prior to the expiration of the license.

The NRC requires reactor licensees to submit funding plans that establish minimum NRC external funding levels for reactor decommissioning. RG&E's plan, filed in 1990, consists of an external decommissioning trust fund covering both its Ginna Plant and its Nine Mile Two share. Since 1990, RG&E has contributed $128.0 million to this fund and, including realized and unrealized investment returns, the fund has a balance of $220.8 million as of December 31, 1999. The amount attributed to the allowance for removal of non-contaminated structures is being held in an internal reserve. The internal reserve balance as of December 31, 1999 is $32.6 million. NRC regulations require biennial reports on the status of Decommissioning Trust funds and RG&E reported to the NRC that both the Ginna and Nine Mile Two decommissioning trusts exceed the NRC minimum funding amounts required as of December 31, 1999.

The NRC has issued a policy statement relating to industry restructuring which addresses, in part, the prospects of joint and several liability of co-owners for nuclear decommissioning costs, such as co-owners of Nine Mile Two. The NRC recognizes that co-owners generally divide costs and output from their facilities by using a contractually-defined, pro rata share standard. The NRC has implicitly accepted this practice in the past and believes that it should continue to be the operative practice, but reserves the right, in highly unusual situations where adequate protection of public health and safety would be compromised if such action were not taken, to consider imposing joint and several liability on co-owners when one or more co-owners have defaulted.

On March 20, 1998 the PSC issued an Opinion and Order Instituting Further Inquiry. In December 1998 the PSC issued a Notice of Collaborative Conference to further examine the future treatment of nuclear generation. The initial collaborative conference in this proceeding was held in January, 1999. RG&E's potentially strandable assets in nuclear plant could be impacted by the outcome of this proceeding. The parties in this proceeding developed a collaborative, non-binding interim report entitled "Nuclear Generation and the Competitive Electric Market" which was issued in July 1999. RG&E is actively involved in this proceeding which is continuing. RG&E is unable to determine when this proceeding may conclude.

The Staff of the Financial Accounting Standards Board is studying the recognition, measurement and classification of certain liabilities related to the closure or removal of long lived assets. This could affect the accounting for the decommissioning costs of RG&E's nuclear generating stations. If current accounting practices for such costs were changed, the annual provisions

for decommissioning costs could increase, the estimated cost for decommissioning could be reclassified as a liability rather than as accumulated depreciation, the liability accounts and corresponding plant asset accounts could be increased and trust fund income from the external decommissioning trusts could be reported as investment income rather than as a reduction to decommissioning expense.

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

Uranium Enrichment Decontamination and Decommissioning Fund. On June 12, 1998, 16 electric utilities from across the country, including RG&E, filed multi-count complaints against the United States government in the United States District Court for the Southern District of New York. The suits challenge the constitutionality of a $2.25 billion retroactive assessment imposed by the federal government on domestic nuclear power companies to pay for the clean up of the federal government's three uranium enrichment plants. Those plants are located at Oak Ridge, Tennessee, Paducah, Kentucky, and Portsmouth, Ohio. The Oak Ridge plant went into operation in 1945, and the other two plants began operation during the 1950s. The Government has moved to dismiss the utilities' complaints. A decision on the Government's motion is expected in early 2000.

The assessments for Ginna and RG&E's share of Nine Mile Two are estimated to total $22.1 million, excluding inflation and interest. Installments aggregating approximately $12.9 million have been paid through 1999. A liability has been recognized on the financial statements along with a corresponding regulatory asset. For the two facilities RG&E's liability at December 31, 1999 is $12.6 million ($10.9 million as a long-term liability and $1.7 million as a current liability). RG&E is recovering these costs in rates.

Nuclear Fuel Disposal Costs. The Nuclear Waste Policy Act (Nuclear Waste Act) of 1982, as amended, requires the DOE to establish a nuclear waste disposal site and to take title to nuclear waste. A permanent DOE high-level nuclear waste repository is not expected to be operational before the year 2010. In December 1996 the DOE notified RG&E that the DOE would not start accepting Ginna spent fuel in 1998. The Nuclear Waste Act provides for a determination of the fees collectible by the DOE for the disposal of nuclear fuel irradiated prior to April 7, 1983 and for three payment options. The option of a single payment to be made at any time prior to the first delivery of fuel to the DOE was selected by RG&E in June 1985. RG&E estimates the fees, including accrued interest, owed to the DOE to be $91.7 million at December 31, 1999. RG&E is allowed by the PSC to recover these costs in rates. The estimated fees are classified as a long-term liability and interest is accrued at the current three-month Treasury bill rate, adjusted quarterly. The Nuclear Waste Act also requires the DOE to provide for the disposal of nuclear fuel irradiated after April 6, 1983, for a charge of approximately one mill ($.001) per KWH of nuclear energy generated and sold. This charge (approximately $4.3 million per year) is currently being collected from customers and paid to the DOE pursuant to PSC authorization. RG&E expects to utilize on-site storage for all spent or retired nuclear fuel assemblies until an interim or permanent nuclear disposal facility is operational.

There are presently no facilities in operation in the United States available for the reprocessing of spent nuclear fuel from utility companies. In RG&E's determination of nuclear fuel costs it has taken into account that nuclear fuel would not be reprocessed and has provided for disposal costs in accordance with the Nuclear Waste Act. In November 1998 RG&E completed installation of seven high-capacity spent fuel racks in the Ginna spent fuel pool. This will allow interim storage capacity of all spent fuel discharged from the Ginna Plant through the end of its Operating License in the year 2009.

Environmental Matters

The Company is subject to federal, state and local laws and regulations dealing with air and water quality and other environmental matters. Environmental matters may expose the Company to potential liabilities which, in certain instances, may be imposed without regard to fault or historical activities which were lawful at the time they occurred. The Company continually monitors its activities in order to determine the impact of its activities on the environment and to ensure compliance with various environmental requirements. RGS has recorded a total liability of approximately $23.7 million in connection with Site Investigation and/or Remediation (SIR) efforts where disposal of certain waste products may have occurred. Estimates of the SIR costs for each of these sites range from preliminary to highly refined. RG&E and Energetix expect to pay these SIR costs over the next ten years. These estimates could change materially, based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations. Liability may be joint and several for certain of these sites. There may be additional costs with respect to these and possibly other sites, the materiality of which is not presently determinable.

RG&E-Owned Electric and Gas Waste Site Activities. RG&E is conducting proactive SIR efforts at seven RG&E-owned sites where past waste handling and disposal may have occurred. Remediation activities at five of these sites are in various stages of planning or completion and RG&E is conducting a program to restore the other two sites. RG&E has recorded a liability of approximately $21.9 million for SIR efforts at the seven Company-owned sites in the Rochester, NY area.

Superfund and Non-Owned Other Sites. RG&E has been or may be associated as a potentially responsible party at eight sites not owned by it and has recorded estimated liabilities of approximately $.5 million in connection with SIR efforts at these sites. RG&E has signed orders on consent for five of these sites.

Griffith Facilities. RGS's subsidiary, Energetix, acquired Griffith Oil, Inc. in 1998. A review and audit was conducted of all Griffith facilities by a nationally recognized engineering firm as part of the due diligence acquisition process by Energetix. As a result of this review 35 sites were identified which are currently undergoing evaluation and/or remediation. Using historical New York State Department of Environmental Conservation (NYSDEC) remedial actions as a guide, Energetix estimates the accrual of aggregate cleanup costs discounted at 6.8% over the future five-year period for all active sites approximates $1.3 million.

New York Initiatives. The New York Attorney General sent a letter to certain New York utilities in October, 1999 requesting historic information regarding certain upgrades, modifications and maintenance activities at coal fired power plants under their control. RG&E received such a letter requesting data covering a period back to 1977 for its Russell and (the now closed) Beebee Stations. The letter suggests that those upgrades, modifications and improvements may have required permission from the NYSDEC prior to their occurrence. RG&E and other letter recipients are involved in discussions with the Attorney General's office to clarify the scope and timing of the request and establish the role of the Attorney General and the DEC in the information gathering effort and any subsequent potential action. On January 13, 2000, RG&E received a formal request from the NYSDEC pursuant to its investigatory powers under the New York Environmental Conservation Law which seeks essentially the same documents covered by the Attorney General's letter. Commencing January 21, 2000, RG&E is providing responsive documents to the State through NYSDEC. RG&E cannot assess the potential impact of this initiative in these early stages of its development.

On October 14, 1999, the Governor of New York publicly proposed modifications of the state's oxides of nitrogen (NOx) and sulfur dioxide (SO2) control programs. The Governor's proposal suggests extending the existing NOx control program under which RG&E's Russell Station operates to a year-round program (it is currently in effect only for the five month ozone season). The proposal suggests such a change should take effect in October, 2003. In addition, the Governor is also proposing that there be a targeted reduction of some 50% in SO2 emissions below the existing Acid Rain Phase II limits that are required under the 1990 Clean Air Act Amendments. The proposal suggests a phase-in period from 2003 through 2007. Since this is only a proposed rule change and subject to review, comment and modification; no estimate of the future economic impact on RG&E of a change in the rules can be made at this time because the nature of the change is uncertain.

Gas Cost Recovery

PSC Gas Restructuring Policy Statement. On November 3, 1998, the PSC issued a gas restructuring policy statement ("Gas Policy Statement") announcing its conclusion that, among other things, the most effective way to establish a competitive gas supply market is for gas distribution utilities to cease selling gas. The PSC established a transition process in which it plans to address three groups of issues: (1) individual gas utility plans to implement the PSC's vision of the market; (2) key generic issues to be dealt with through collaboration among gas utilities, marketers, pipelines and other stakeholders, and (3) coordination of issues that are common to both the gas and the electric industries. The PSC has encouraged settlement negotiations with each gas utility pertaining to the transition to a fully competitive gas market. RG&E, the PSC Staff and other interested parties have been participating in settlement discussions in response to the specific requirements of the Policy Statement.

Gas Proposal and Interim Settlement. In August 1998, prior to issuance of the PSC's Gas Policy Statement (see PSC Gas Restructuring Policy Statement above), RG&E had commenced negotiations with the PSC staff and other parties to develop a comprehensive multi-year settlement of various issues, including rates and the structure of RG&E's gas business. Because the negotiation of a comprehensive settlement was not anticipated to conclude until mid-1999, the parties to the negotiations agreed to an Interim Settlement, effective November 1998 through June 1999, that dealt with such issues as rates, transportation and storage capacity costs, assignment of capacity, and retail access. Significant features of the Interim Settlement include a freeze on base rates at the current levels (which were fixed at July 1994 levels), the imputation of $11.9 million in revenues from the remarketing of capacity and a limit on RG&E's exposure to costs associated with the migration of customers from RG&E to marketers for sales service.

Discussions following the expiration of the Interim Settlement resulted in a September 14, 1999, filing to address issues pertaining to the cost of upstream capacity and other matters pertaining to restructuring pursuant to the PSC's Policy Statement. The proposal calls for: (1) a continued reduction in capacity costs of $11.9 million, comprised of $10.2 million relating to upstream capacity release transactions for the period September 1, 1999 through August 31, 2000 and $1.7 million from the expiration of a Texas Eastern capacity contract; (2) a report to PSC staff, within 60 days of approval of the proposal, of the progress RG&E has made to reduce its upstream capacity costs; (3) a resumption of the multi-year settlement discussions calling for RG&E to make a public filing addressing the rate and restructuring issues addressed in the PSC's Policy Statement within 120 days of approval of the proposal; and (4) RG&E continuing to work on retail access program improvements. The proposal was subsequently approved by the PSC and RG&E began implementation of its proposal in the fourth quarter of 1999. RG&E has

proceeded to implement the proposal as approved. As required, the report on upstream capacity costs was submitted on November 29, 1999, under trade secret status. The public filing addressing the rate and restructuring issues was made on January 28, 2000. This filing is intended to provide the basis for negotiations with the PSC and other interested parties on RG&E's proposal to implement a fully competitive marketplace for natural gas. Settlement negotiations pertaining to RG&E's gas rate and restructuring proposal will begin as early as 30 days after the filing pursuant to the Policy Statement.

Under a March 1996 Order, the PSC permitted RG&E and other gas distribution companies to assign to marketers the pipeline and storage capacity held by RG&E to serve their customers. In its Gas Policy Statement issued in November 1998, the PSC ordered that the mandatory assignment of capacity, permitted by the March 1996 Order, be terminated effective April 1, 1999. According to the Gas Policy Statement, however, the utilities are to be afforded a reasonable opportunity to recover resulting strandable costs, if any. On March 24, 1999, the PSC issued an Order Concerning Assignment of Capacity for all gas utilities in the State of New York, generally requiring the removal of restrictions on customer migration from utility sales service to service from marketers. RG&E has complied with the PSC's directives.

Litigation

Spent Nuclear Fuel Litigation. The federal Nuclear Waste Act obligated DOE to accept for disposal spent nuclear fuel (SNF) from utilities' powerplants by January 31, 1998 (statutory deadline). Since the mid-1980s RG&E and other nuclear plant owners and operators have paid substantial fees to DOE to fund that obligation (Nuclear Waste Fund). That the DOE would not meet its obligation was evident well prior to 1998; DOE admitted as much as the statutory deadline approached.

DOE's failure to meet its statutory deadline has given rise to numerous lawsuits in both the U.S. Court of Appeals for the District of Columbia and the U.S. Court of Federal Claims.

Although the DOE has been found to have breached its obligations, it is not possible to predict the outcome of these cases, the future course of the DOE obligation or the resolution of the spent nuclear fuel movement and storage concern that underlies it. Similarly, the ultimate outcome of nuclear waste legislation in Congress, that could address these and related concerns, is uncertain. The court rulings on the DOE's default in meeting its obligation to remove SNF by the statutory deadline, and on its contractual liability therefor, have been promising. The current court rulings appear to have prompted greater DOE effort to complete site investigations at its Yucca Mountain, NV, site for SNF disposal and to focus greater Congressional attention on the inappropriateness of continuing to house SNF around the nation at short-term SNF facilities of nuclear powerplants. These developments have not yet led, however, either to a firm schedule for DOE's movement of SNF from plant facilities to a permanent repository or to the authorization of plant owners and operators to withhold their Nuclear Waste Fund payments to DOE until that schedule is established. RG&E and other nuclear utilities continue to work toward those objectives in judicial, legislative and administrative initiatives.

Other Matters

Other Statement of Income Items. The change in RGS's and RG&E's Other Income and Deductions, Other-net reflects mainly the recognition of income in 1998 due to the elimination of certain pension and other post-employment benefit deferred credits and Nine Mile Two operating and maintenance expenses in accordance with the Competitive Opportunities Settlement. This variance in Other Income and Deductions, Other-net was partially offset by non-cash carrying charges of $8.6 million related to deferral of Kamine (Allegany Station)

facility costs in 1999 for the regulated business. These carrying charges, which are primarily associated with the deferred recovery of costs associated with the Kamine settlement, were allowed under the Competitive Opportunities and Kamine settlements. In addition, expenses associated with RG&E management performance awards were down $4.4 million in 1999 compared with 1998.

EITF Issue 97-4—Deregulation of the Pricing of Electricity. In July 1997, the Financial Accounting Standards Board's EITF reached a consensus on accounting rules for utilities' transition plans for moving to more competitive environments and provided guidance on when utilities with transition plans will need to discontinue the application of SFAS-71.

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

RG&E's application of the EITF 97-4 consensus has not affected its financial position or results of operations because any above-market generation costs, regulatory assets and regulatory liabilities associated with the generation portion of its business will be recovered by the regulated portion of RG&E through its distribution rates, given the Settlement provisions. The Settlement provides for recovery of all prudently incurred sunk costs (all investment in electric plant and electric regulatory assets) as of March 1, 1997 by inclusion in rates charged pursuant to RG&E's distribution access tariff. The Settlement also states that "the Parties intend that the provisions of this Settlement will allow RG&E to continue to recover such costs, during the term of the Settlement, under SFAS-71", and that "such treatment shall be consistent with the principle that RG&E shall have a reasonable opportunity beyond July 1, 2002 to recover all such costs". The fixed portion of the non-nuclear generation to-go costs sometime after July 1, 1999 and the variable portion of the non-nuclear generation to-go costs after July 1, 1998 are subject to market forces and would no longer be able to apply SFAS-71. These costs have been below prevailing market prices. RG&E's net investment at December 31, 1999 in nuclear generating assets is $634.3 million and in non-nuclear generating assets is $58.4 million. (See "Proposed Sale of Nuclear Plant" for information concerning RG&E's proposed acquisition of the interests in Nine Mile Two owned by two co-owners.)

Lease Agreements. RG&E and Energetix lease a total of 15 properties for administrative offices, operating activities and vehicles. The total lease obligations charged to operations was $5.4 million, $4.8 million and $4.2 million in 1999, 1998 and 1997, respectively, including $1.5 million in 1999 and $.5 million in 1998 for Energetix. RG&E's estimated annual lease obligations for the years 2000-2004 will be $4.0 million, $2.5 million, $2.5 million, $2.7 million and $2.7 million, respectively. Energetix estimated annual lease obligations for the years 2000-2004 will be $1.3 million, $1.0 million, $.6 million, $.4 million and $.2 million, respectively. Commitments under capital leases after 2004 are not significant.

Purchase Commitments. The Company has entered into electric and natural gas purchase commitments with numerous suppliers. Certain of these commitments support fixed price offerings to retail electric and gas customers.

REPORT OF MANAGEMENT

The management of RGS Energy Group, Inc. (RGS) and its subsidiaries has prepared and is responsible for the consolidated 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 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.

Financial statements have been examined by PricewaterhouseCoopers LLP, independent accountants, in accordance with generally accepted auditing standards. Their examination includes a review of the system of internal accounting control and such tests and other procedures necessary to express an opinion as to whether the financial statements are presented fairly in all material respects in conformity with generally accepted accounting principles. The report of PricewaterhouseCoopers LLP is presented on page 28.

The Audit Committee of the RGS Board of Directors is responsible for reviewing and monitoring the 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, 1999, RGS and its subsidiaries maintained an effective system of internal control over the preparation of their published financial statements.

Thomas S. Richards
Chairman of the Board, President and
Chief Executive Officer—RGS

J. Burt Stokes
Senior Vice President,
Chief Financial Officer—RGS

INTERIM FINANCIAL DATA

In the opinion of the Company, the following quarterly information includes all adjustments, consisting of normal recurring adjustments, necessary for a fair statement of the results of operations for such periods. The variations in operations reported on a quarterly basis are a result of the seasonal nature of the Company's business and the availability of surplus electricity. The sum of the quarterly earnings per share may not equal the fiscal year earnings per share due to rounding.

	(Thousands of Dollars)					
					Earnings Per Common Share (in dollars)	
Quarter Ended	Operating Revenues	Operating Income	Net Income	Earnings on Common Stock	Basic	Diluted
RGS						
December 31, 1999	$325,788	$34,103	$ 23,681	$23,681	$ .65	$ .65
September 30, 1999[1]	279,853	29,528	15,964	15,964	.44	.44
June 30, 1999	275,805	27,219	13,706	13,706	.37	.37
March 31, 1999[1]	326,091	50,189	36,146	36,146	.97	.97
RG&E						
December 31, 1999	$249,204	$33,737	$ 24,696	$23,394		
September 30, 1999[1]	239,348	29,990	17,708	17,159		
June 30, 1999	275,805	27,219	14,822	13,706		
March 31, 1999[1]	326,091	50,189	37,262	36,146		
December 31, 1998[1]	$286,507	$22,173	$ 15,015	$14,088	$ .37	$ .37
September 30, 1998[1]	253,750	35,128	25,213	23,908	.62	.62
June 30, 1998[1]	210,724	22,620	15,655	14,350	.37	.37
March 31, 1998[1]	282,510	48,145	38,255	36,950	.95	.95
December 31, 1997	$271,089	$24,406	$14,031	$12,726	$ .32	$ .32
September 30, 1997	221,335	34,616	21,724	20,419	.52	.52
June 30, 1997	229,419	31,125	18,172	16,681	.42	.42
March 31, 1997	314,845	55,194	41,433	39,729	1.02	1.02

[1]*Reclassified for comparative purposes.*

COMMON STOCK AND DIVIDENDS

Earnings/Dividends	RGS 1999	1998	1997
Earnings per share			
—basic	$2.44	$2.32	$2.30
—diluted	$2.44	$2.31	$2.30
Dividends paid per share	$1.80	$1.80	$1.80

Shares/Shareholders	1999	1998	1997
Number of shares (000's)			
Weighted average			
—basic	36,665	38,462	38,853
—diluted	36,757	38,600	38,909
Actual number at December 31	35,943	37,379	38,862
Number of shareholders at December 31	27,258	28,995	31,337

RGS ENERGY GROUP, INC.

On August 2, 1999, Rochester Gas and Electric Corporation (RG&E) was reorganized into a holding company structure pursuant to an Agreement and Plan of Share Exchange (Exchange Agreement) between RG&E and RGS Energy Group, Inc. (RGS). As part of the reorganization, all of the outstanding shares of RG&E common stock were exchanged on a share-for-share basis for shares of RGS and RG&E became a subsidiary of RGS. Certificates for shares of RG&E common stock are automatically valid as certificates for RGS and do not have to be replaced. The transfer does not affect the value of the stock or RGS's dividend policy. RGS trades on the New York Stock Exchange under the symbol "RGS". RG&E shareholders approved the Exchange Agreement on April 29, 1999.

TAX STATUS OF CASH DIVIDENDS

Cash dividends paid in 1999, 1998 and 1997 were 100 percent taxable for federal income tax purposes.

DIVIDEND POLICY

RG&E has paid cash dividends quarterly on its Common Stock without interruption since it became publicly held in 1949. Since its formation in August 1999, RGS has continued this historic trend of dividend payments.

The ability of RGS to pay common stock dividends is governed by the ability of RGS's subsidiaries to pay dividends to RGS. Because RG&E is by far the largest of the subsidiaries, it is expected that for the foreseeable future the funds required by RGS to enable it to pay dividends will be derived predominantly from the dividends paid to RGS by RG&E. In the future, dividends from subsidiaries other than RG&E may also be a source of funds for dividend payments by RGS. RG&E's ability to make dividend payments to RGS will depend upon the availability of retained earnings and the needs of its utility business. RG&E's Certificate of Incorporation provides for the payment of dividends on Common Stock out of the surplus net profits (retained earnings) of the Company. In addition, pursuant to the PSC order approving the formation of RGS, RG&E may pay dividends to RGS of no more than 100% of RG&E's net income calculated on a two-year rolling basis. The calculation of net income for this purpose excludes non-cash charges to income resulting from accounting changes or certain PSC required charges as well as charges that may arise from significant unanticipated events. This condition does not apply to dividends that would be used to fund the remaining portion of the $100 million authorized for RG&E's unregulated operations (about $42 million at December 31, 1999). The level of future cash dividend payments on Common Stock will be dependent upon RGS's future earnings, its financial requirements, and other factors.

Quarterly dividends on Common Stock are generally paid on the twenty-fifth day of January, April, July and October. In January 2000, RGS paid a cash dividend of $.45 per share on its Common Stock. The January 2000 dividend payment is equivalent to $1.80 on an annual basis.

	1999	1998	1997
Common Stock—Price Range			
High			
1st quarter	31 9/16	33 1/4	20 3/8
2nd quarter	28 7/16	32 3/4	21 7/16
3rd quarter	27 5/16	32 7/16	24 15/16
4th quarter	25 1/2	33 1/4	34 1/2
Low			
1st quarter	25 7/16	29 1/2	18 7/8
2nd quarter	25 1/4	29 5/16	18
3rd quarter	24 1/16	28 3/8	20 5/8
4th quarter	20	28 9/16	23 3/4
At December 31	20 9/16	31 1/4	34

SELECTED FINANCIAL DATA

CONSOLIDATED SUMMARY OF OPERATIONS

(Thousands of Dollars) Year Ended December 31	RGS Consolidated 1999	RG&E 1999	1998*	1997*	1996*	1995*
Operating Revenues						
Electric	$ 702,751	$ 700,194	$ 687,622	$ 700,329	$ 707,768	$ 722,465
Gas	284,476	281,555	274,657	336,309	346,279	293,863
Other	220,310	108,699	71,212	—	—	—
Total Operating Revenues	1,207,537	1,090,448	1,033,491	1,036,638	1,054,047	1,016,328
Operating Expenses						
Fuel Expenses						
Fuel for electric generation	49,297	49,297	53,954	47,665	40,938	44,190
Purchased electricity	54,337	53,046	27,024	28,347	46,484	54,167
Gas purchased for resale	151,458	148,983	155,497	196,579	202,297	167,762
Unregulated fuel expenses	189,465	91,505	59,490	—	—	—
Total Fuel Expenses	444,557	342,831	295,965	272,591	289,719	266,119
Operating Revenues Less Fuel Expenses	762,980	747,617	737,526	764,047	764,328	750,209
Other Operating Expenses						
Operations and maintenance excluding fuel expenses	297,890	297,890	301,625	315,109	313,157	308,433
Unregulated operating and maintenance expenses excluding fuel	26,464	14,236	13,524	—	—	—
Depreciation and amortization	118,695	117,289	116,102	116,522	105,614	91,593
Taxes—local, state and other	114,639	112,613	117,973	121,796	126,868	133,895
Federal income tax—current	72,873	73,074	69,392	69,812	65,757	65,368
—deferred	(8,620)	(8,620)	(9,156)	(4,533)	3,744	847
Total Other Operating Expenses	621,941	606,482	609,460	618,706	615,140	600,136
Operating Income	141,039	141,135	128,066	145,341	149,188	150,073
Other (Income) and Deductions						
Allowance for other funds used during construction	(657)	(657)	(408)	(351)	(684)	(585)
Federal income tax	(1,134)	(1,144)	1,665	(3,704)	(3,450)	(16,948)
Regulatory disallowances	—	—	—	—	—	26,866
Other, net	(8,178)	(8,111)	(13,370)	3,308	(712)	9,631
Total Other (Income) and Deductions	(9,969)	(9,912)	(12,113)	(747)	(4,846)	18,964
Interest Charges						
Long term debt	53,681	53,067	43,306	44,615	48,618	53,026
Other, net	4,798	4,543	3,388	6,676	9,328	9,056
Allowance for borrowed funds used during construction	(1,051)	(1,051)	(653)	(563)	(1,423)	(2,901)
Total Interest Charges	57,428	56,559	46,041	50,728	56,523	59,181
Preferred Stock Dividend Requirements	4,083	4,083	4,842	5,805	7,465	7,465
Net Income Applicable to Common Stock	$ 89,497	$ 90,405	$ 89,296	$ 89,555	$ 90,046	$ 64,463
Earnings per Common Share—Basic	$2.44		$2.32	$2.30	$2.32	$1.69
Earnings per Common Share—Diluted	$2.44		$2.31	$2.30	$2.32	$1.69
Cash Dividends Declared per Common Share	$1.80		$1.80	$1.80	$1.80	$1.80

Reclassified for comparative purposes.

Condensed Consolidated Balance Sheet

(Thousands of Dollars) At December 31	RGS Consolidated 1999	RG&E 1999	1998	1997*	1996*	1995*
Assets						
Utility Plant	$3,253,731	$3,231,082	$3,326,995	$3,234,077	$3,159,759	$3,068,103
Less: Accumulated depreciation and amortization	1,876,198	1,873,577	1,863,475	1,714,368	1,569,078	1,518,878
	1,377,533	1,357,505	1,463,520	1,519,709	1,590,681	1,549,225
Construction work in progress	95,862	95,862	98,554	74,018	69,711	121,725
Net Utility Plant	1,473,395	1,453,367	1,562,074	1,593,727	1,660,392	1,670,950
Current Assets	219,837	202,506	202,963	242,371	250,461	292,596
Investment in Empire	—	—	—	—	—	38,879
Intangible Assets	21,232	—	21,062	—	—	—
Deferred Debits and Other Assets	748,410	746,996	666,836	432,191	450,623	453,726
Total Assets	$2,462,874	$2,402,869	$2,452,935	$2,268,289	$2,361,476	$2,456,151
Capitalization and Liabilities						
Capitalization						
Long term debt	$ 815,465	$ 796,000	$ 758,226	$ 587,334	$ 646,954	$ 716,232
Preferred stock redeemable at option of Company	47,000	47,000	47,000	47,000	67,000	67,000
Preferred stock subject to mandatory redemption	25,000	25,000	25,000	35,000	45,000	55,000
Common shareholders' equity:						
Common stock	700,268	700,268	699,730	699,031	696,019	687,518
Retained earnings	153,186	137,854	129,484	109,313	90,540	70,330
Less: Treasury stock at cost	83,252	83,252	46,433	—	—	—
Total common shareholders' equity	770,202	754,870	782,781	808,344	786,559	757,848
Total Capitalization	$1,657,667	$1,622,870	$1,613,007	$1,477,678	$1,545,513	$1,596,080
Long Term Liabilities	126,352	125,011	123,920	110,352	106,578	101,561
Current Liabilities	169,356	149,855	183,369	175,691	145,391	171,664
Deferred Credits and Other Liabilities	509,499	505,133	532,639	504,568	563,994	586,846
Total Capitalization and Liabilities	$2,462,874	$2,402,869	$2,452,935	$2,268,289	$2,361,476	$2,456,151

**Reclassified for comparative purposes.*

Financial Data

At December 31	RGS Consolidated 1999	RG&E 1999	1998	1997	1996	1995
Capitalization Ratios(a) (percent)						
Long-term debt	51.9	51.8	49.8	43.0	44.7	47.4
Preferred Stock	4.1	4.2	4.2	5.2	6.9	7.3
Common shareholders' equity	44.0	44.0	46.0	51.8	48.4	45.3
Total	100.0	100.0	100.0	100.0	100.0	100.0
Book Value per Common Share—Year End	$21.43	$21.00	$20.94	$20.80	$20.24	$19.71
Rate of Return on Average Common Equity(b) (percent)	11.53	11.76	11.22	11.00	11.41	8.37
Embedded Cost of Senior Capital (percent)						
Long-term debt	7.20	7.21	7.20	7.32	7.33	7.38
Preferred stock	5.24	5.24	5.56	5.80	6.26	6.26
Effective Federal Income Tax Rate (percent)	40.3	40.1	39.7	39.2	40.4	40.7
Depreciation Rate (percent)—Electric	3.14	3.14	3.09	3.12	2.99	2.76
—Gas	2.54	2.54	2.64	2.60	2.60	2.59
Interest Coverages						
Before federal income taxes (incld. AFUDC)	3.68	3.74	4.41	4.06	3.82	2.95
(excld. AFUDC)	3.65	3.71	4.38	4.04	3.79	2.90
After federal income taxes (incld. AFUDC)	2.60	2.64	3.06	2.86	2.68	2.16
(excld. AFUDC)	2.57	2.61	3.03	2.84	2.65	2.10
Interest Coverages Excluding Non-Recurring Items(c)						
Before federal income taxes (incld. AFUDC)	3.68	3.74	4.41	4.06	3.82	3.66
(excld. AFUDC)	3.65	3.71	4.38	4.04	3.79	3.61
After federal income taxes (incld. AFUDC)	2.60	2.64	3.06	2.86	2.68	2.62
(excld. AFUDC)	2.57	2.61	3.03	2.84	2.65	2.57

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

(b) The return on average common equity for 1995 excluding effects of the 1995 Gas Settlement is 12.10%.

(c) Coverages in 1995 exclude the economic effect of the 1995 Gas Settlement ($44.2 million, pretax).

ELECTRIC DEPARTMENT STATISTICS

At December 31	RGS 1999	RG&E 1999	1998*	1997	1996	1995
Electric Revenue (000's)						
Residential	$ 282,391	$ 282,391	$ 250,073	$ 252,464	$ 254,885	$ 256,294
Commercial	166,410	166,410	203,316	210,643	215,763	215,696
Industrial	112,390	112,390	130,778	144,305	153,337	157,464
Municipal and Other	47,098	47,098	58,889	72,061	66,898	67,128
Electric revenue—retail customers	608,289	608,289	643,056	679,473	690,883	696,582
Energy Marketers	65,204	65,204	15,049	—	—	—
Other Electric Utilities	25,251	25,251	28,995	20,856	16,885	25,883
Other unregulated electric revenues	4,007	1,450	522	—	—	—
Total electric revenues	702,751	700,194	687,622	700,329	707,768	722,465
Electric Expense (000's)						
Fuel for electric generation	49,297	49,297	53,954	47,665	40,938	44,190
Purchased electricity	53,013	53,013	27,024	28,347	46,484	54,167
Other unregulated fuel expense	1,324	33	—	—	—	—
Operation and maintenance	233,845	233,845	233,422	246,275	246,175	243,556
Unregulated operation and maintenance	2,233	1,046	1,997	—	—	—
Depreciation and amortization	103,000	102,970	102,133	103,395	92,615	78,812
Taxes—local, state and other	84,492	83,922	89,600	91,111	95,010	102,380
Total electric expense	527,204	524,126	508,130	516,793	521,222	523,105
Operating Income before Federal Income Tax	175,547	176,068	179,492	183,536	186,546	199,360
Federal income tax	55,203	55,527	61,477	61,837	61,901	59,500
Operating Income from Electric Operations (000's)	$ 120,344	$ 120,541	$ 118,015	$ 121,699	$ 124,645	$ 139,860
Electric Sales—KWH (000's)						
Residential	2,269,005	2,269,005	2,119,846	2,139,064	2,132,902	2,144,718
Commercial	1,783,128	1,783,128	2,036,144	2,118,991	2,061,625	2,064,813
Industrial	1,762,369	1,762,369	1,913,611	2,010,613	2,010,963	1,964,975
Municipal and Other	481,610	481,610	516,585	537,051	520,885	531,311
Total retail sales	6,296,112	6,296,112	6,586,186	6,805,719	6,726,375	6,705,817
Energy Marketers (including Energetix)	762,999	762,999	174,676	—	—	—
Other electric utilities	1,111,928	1,111,928	1,498,669	1,218,794	994,842	1,484,196
Other unregulated sales	23,147	2,372	—	—	—	—
Total electric sales	8,194,186	8,173,411	8,259,531	8,024,513	7,721,217	8,190,013
Electric Customers at December 31						
Residential	310,861	310,861	310,045	308,909	307,181	306,601
Commercial	30,178	30,178	30,483	30,940	30,620	30,426
Industrial	1,026	1,026	1,128	1,300	1,325	1,347
Municipal and Other	2,324	2,324	2,689	2,824	2,688	2,711
Unregulated electric customers	6,937	—	830	—	—	—
Total electric customers	351,326	344,389	345,175	343,973	341,814	341,085
Electricity Generated and Purchased—KWH (000's)						
Fossil	1,692,605	1,692,605	1,962,889	1,664,914	1,512,513	1,631,933
Nuclear	4,734,703	4,734,703	5,323,639	5,119,544	4,094,272	4,645,646
Hydro	133,317	133,317	189,512	227,867	248,990	171,886
Pumped storage	233,279	233,279	232,927	238,900	246,726	237,904
Less energy for pumping	(349,836)	(349,836)	(348,438)	(358,350)	(370,097)	(361,144)
Other	1,334	1,334	195	890	936	1,565
Total generated—net	6,445,402	6,445,402	7,360,724	6,893,765	5,733,340	6,327,790
Purchased	2,088,761	2,067,986	1,465,797	1,301,636	2,437,433	2,343,484
Total electric energy	8,534,163	8,513,388	8,826,521	8,195,401	8,170,773	8,671,274
RGE System Net Capability—KW at December 31						
Total system net capability	1,382,000	1,382,000	1,588,000	1,614,000	1,617,000	1,619,000
RGE Net Peak Load—KW	1,433,000	1,433,000	1,388,000	1,421,000	1,305,000	1,425,000

Reclassified for comparative purposes.

RGS ENERGY GROUP, INC.

GAS DEPARTMENT STATISTICS

Year Ended December 31	RGS 1999	RG&E 1999	1998*	1997	1996	1995
Gas Revenue (000's)						
Residential	$ 5,658	$ 5,658	$ 2,944	$ 5,852	$ 6,010	$ 4,081
Residential spaceheating	212,786	212,786	201,686	249,101	246,945	230,934
Commercial	31,134	31,134	40,196	51,893	52,073	51,117
Industrial	3,016	3,004	4,222	5,800	6,175	6,686
Municipal and other	26,077	26,077	25,492	23,663	35,076	1,045
Other unregulated gas revenues	5,805	2,896	117	—	—	—
Total gas revenue	284,476	281,555	274,657	336,309	346,279	293,863
Gas Expense (000's)						
Gas purchased for resale	146,985	146,985	155,497	196,579	202,297	167,762
Other unregulated fuel expense	4,473	1,998	—	—	—	—
Operation and maintenance	64,045	64,045	68,202	68,834	66,982	64,878
Unregulated operation and maintenance	2,842	1,331	2,541	—	—	—
Depreciation	12,601	12,571	12,876	13,127	12,999	12,781
Taxes—local, state and other	28,358	27,788	28,108	30,685	31,858	31,514
Total gas expense	259,304	254,718	267,224	309,225	314,136	276,935
Operating Income before Federal Income Tax	25,172	26,837	7,433	27,084	32,143	16,928
Federal income tax	8,032	8,356	(92)	3,442	7,600	6,715
Operating Income from Gas Operations (000's)	$ 17,140	$ 18,481	$ 7,525	$ 23,642	$ 24,543	$ 10,213
Gas Sales—Therms (000's)						
Residential	5,887	5,887	3,599	5,773	6,455	7,167
Residential spaceheating	264,047	264,047	239,740	285,395	299,085	280,763
Commercial	43,179	43,179	53,552	65,675	70,543	68,380
Industrial	4,541	4,541	6,079	7,828	9,334	9,560
Municipal	5,749	5,749	6,388	7,331	8,086	8,219
Total retail sales	323,403	323,403	309,358	372,002	393,503	374,089
Transportation of customer-owned gas	199,997	199,997	163,575	166,060	167,779	146,149
Other unregulated sales	12,450	7,101	1,163	—	—	—
Total gas sold and transported	535,850	530,501	474,096	538,062	561,282	520,238
Gas Customers at December 31						
Residential	16,341	16,341	16,944	16,265	16,718	17,443
Residential spaceheating	240,308	240,308	249,684	243,264	240,685	238,267
Commercial	15,904	15,904	18,633	19,118	19,045	18,978
Industrial	586	586	778	829	857	879
Municipal	739	739	965	1,117	961	981
Transportation	11,190	11,190	1,900	836	744	655
Unregulated gas customers	8,717	—	821	—	—	—
Total gas customers	293,785	285,068	289,725	281,429	279,010	277,203
RGE, Gas—Therms (000's)						
Purchased for resale	200,036	200,036	203,677	274,430	279,353	237,728
Gas from storage	126,158	126,158	111,164	104,317	122,843	152,852
Other	2,151	2,151	1,496	1,410	1,082	1,800
Total gas available—RGE	328,345	328,345	316,337	380,157	403,278	392,380
Total Daily Capacity—RGE Therms at December 31 **	4,493,000	4,493,000	4,380,000	4,380,000	4,480,000	5,230,000
Max. daily throughput, Therms—RGE	4,008,200	4,008,200	3,583,500	4,114,290	4,022,600	3,980,000
Degree Days (Calendar Month)						
For the period	6,289	6,289	5,666	6,916	6,998	6,535
Percent colder (warmer) than normal	(6.6)	(6.6)	(15.9)	2.8	3.9	(3.0)

*Reclassified for comparative purposes.

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

BUSINESS AND FINANCIAL INFORMATION

RGS business and financial information is now available on line as well as by phone.

RGS by Phone
Access RGS from anywhere in the United States or Canada by calling our automated investor communications system at (800) 724-8833. You will be greeted with a brief message, then given a menu of options. Among other things, you can hear RGS's quarterly earnings announcement or request a copy, including financial statements, by fax or by mail.

RGS on Line
RGS's web site features the latest news and financial information, including quarterly dividend and earnings announcements, financial statements and press releases. Visit us on line at http://www.rgs-energy.com.

RGS Financial Information
Earnings results are typically released around the 23rd of January, April, July and October. Dividend announcements are made in March, June, September and December at mid-month.

Security Analyst Contact
Security analysts and others requesting information about RGS should contact Mark J. Graham, Manager of Investor Relations at (716) 724-8176.

Corporate Address
RGS Energy Group, Inc.
89 East Avenue
Rochester, NY 14649-0001
(716) 771-4444

SHAREHOLDER SERVICES

Shareholder services representatives are available weekdays from 9 a.m. to 6 p.m. eastern standard time through EquiServe at (800) 736-3001. Among other things, they can provide dividend information, enroll you in our dividend reinvestment program and handle requests for ownership or account changes.

Stock Transfer Agent
BankBoston, N.A.
c/o EquiServe
P.O. Box 8040
Boston, MA 02266-8040
(800) 736-3001

Telecommunication Device for the Deaf (TDD)
(800) 952-9245

DIVIDENDS

Dividend Payment Dates
Dividends on RGS Common Stock are paid quarterly around the 25th of January, April, July and October. Dividends on the RG&E 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 stock transfer agent.

Dividend Reinvestment
RGS offers a dividend reinvestment plan as a service to Common Stock shareholders who wish to purchase additional shares. In addition to full or partial reinvestment of dividends, the plan gives shareholders the opportunity to make direct cash investments ranging from $50 to $5,000 as often as once a month. To enroll, you need to have ten shares of RGS Common Stock and the shares have to be held in your name, meaning they can't be in a broker street name account.

RG&E FIRST MORTGAGE BOND TRUSTEE

Bankers Trust Company
c/o BT Services Tennessee Inc.
Securities Payment Unit
P.O. Box 291207
Nashville, TN 37229-1207
(800) 735-7777

ANNUAL MEETING

RGS's 2000 annual meeting of shareholders will be held at the Hyatt Regency Rochester, on Wednesday, April 26, 2000 at 11 am.

STOCK LISTINGS

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

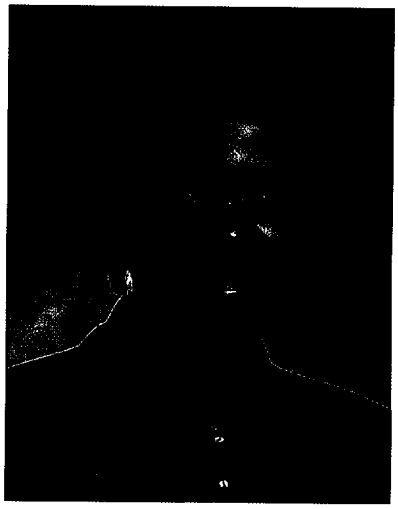
FORM 10-K ANNUAL REPORT

Shareholders may obtain a copy of RGS's 1999 annual report on Form 10-K, as filed with the Securities and Exchange Commission, without charge, by calling (800) 724-8833 or writing to Investor Services at RGS.

Directors and Officers

As of January 1, 2000

Director Appointment



G. Jean Howard

G. Jean Howard was elected a director in April 1999. She is executive director of Wilson Commencement Park, a human service and housing management agency empowering low-income, single-parent families to become socially and economically self-sufficient.

RGS Energy Group, Inc. and Rochester Gas and Electric Corporation ~ Directors

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FJF Architects, LLP

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Executive Vice President,
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Xerox Corporation

Mark B. Grier †‡
Executive Vice President,
Corporate Governance,
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Susan R. Holliday √
President and Publisher,
Rochester Business Journal

Jay T. Holmes *√
Attorney and Business Consultant

G. Jean Howard †
Executive Director, Wilson
Commencement Park

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& Sherwood Associates, Inc.

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William E. Simon Graduate School
of Business Administration,
University of Rochester

Thomas S. Richards *
Chairman of the Board, President
and Chief Executive Officer, RGS
Energy Group, Inc. and Rochester
Gas and Electric Corporation

* Member of Executive and Finance Committee
† Member of Audit Committee
‡ Member of Committee on Management
√ Member of Committee on Directors

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Michael T. Tomaino, *General Counsel*
Michael J. Bovalino
Paul C. Wilkens

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Treasurer: Mark Keogh
Controller: William J. Reddy
Assistant Treasurer: Sean T. Higman
Assistant Controller: Joseph J. Syta

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Michael T. Tomaino, *General Counsel*
Paul C. Wilkens, *Generation*

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William J. Reddy, *Controller*
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Wilfred J. Schrouder, Jr., *Human Resource Services*
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Joseph A. Widay, *Plant Manager, Ginna Station*

Assistant Treasurer: Sean T. Higman
Assistant Controller: Joseph J. Syta

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Vice Presidents:
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