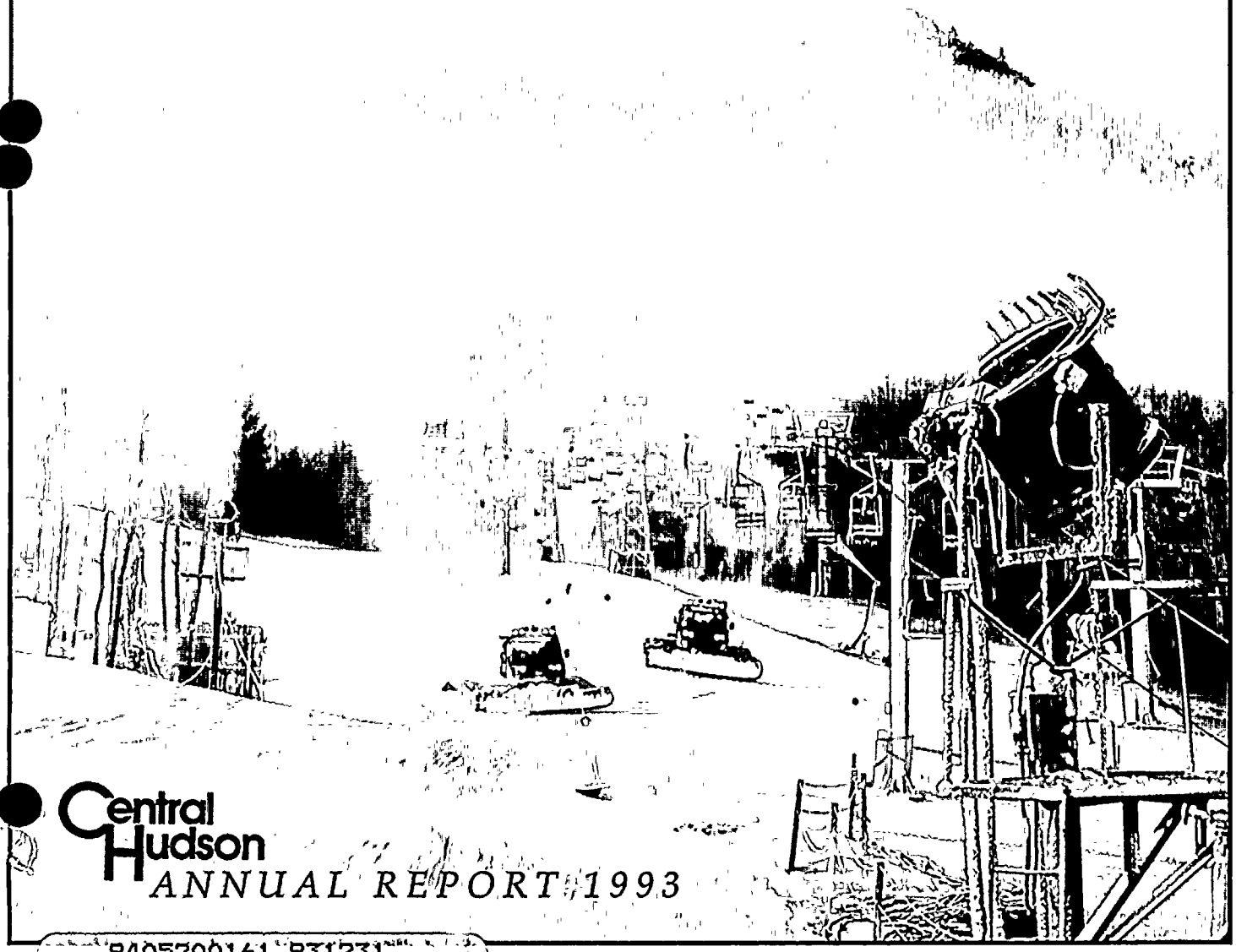
ENERGY SOLUTIONS



Central Hudson

ANNUAL REPORT 1993

An Energy Solution for Hunter Mountain, the "Snowmaking Capitol of the World"

The cover photograph shows state-of-the-art equipment making snow at Hunter Mountain, which is celebrating its 35th season as a major ski center in the Northeast. Central Hudson worked with Hunter Mountain, located in Greene County, to help the ski center introduce new electric snowmaking technology to produce more snow, operate more efficiently, and reduce costs. Industrial and large commercial customers throughout the Mid-Hudson Valley are being encouraged to contact Central Hudson to become familiar with electric and gas "Energy Solutions" which can help them improve productivity, become more efficient and control costs.

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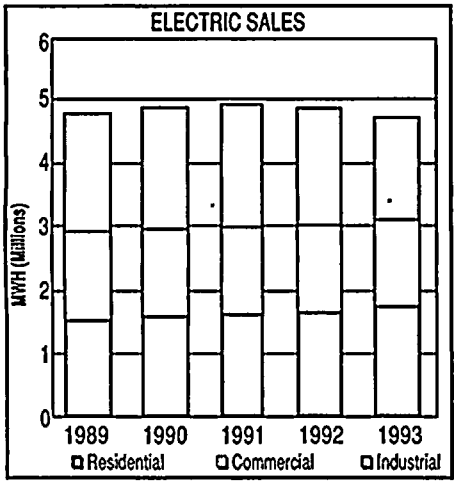
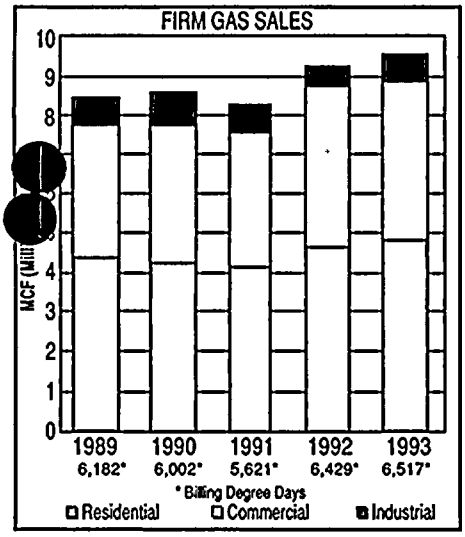
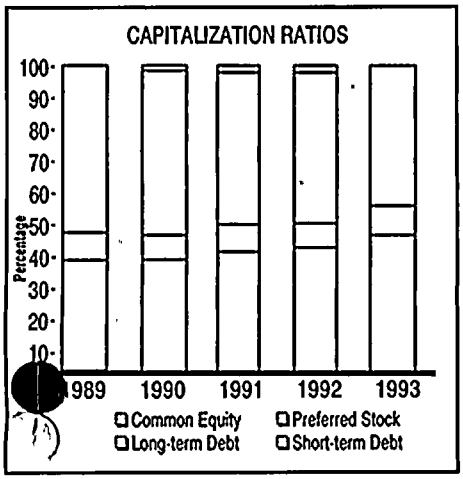
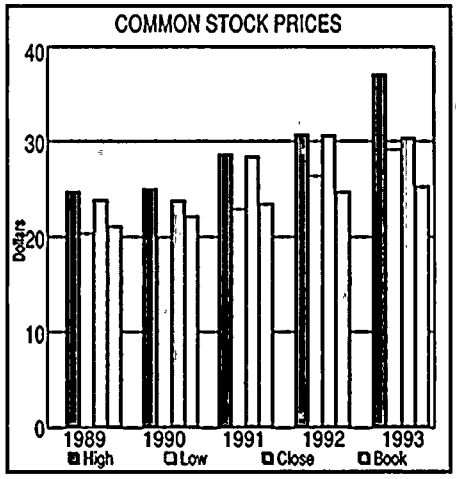


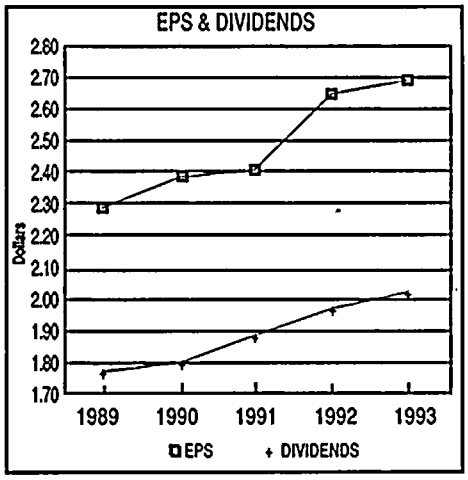


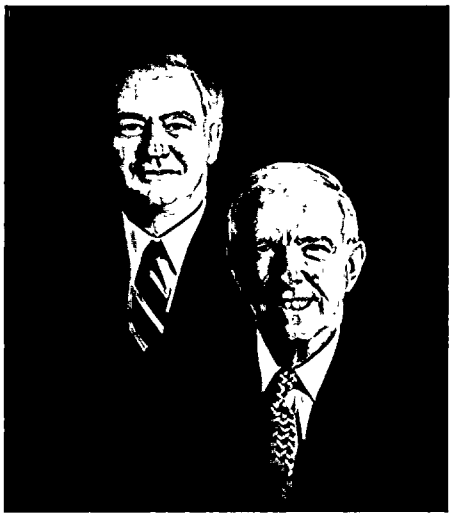
Financial Highlights

	1993	1992	Change
Operating Revenues	$517,373,000	$523,557,000	(1)%
Net Income	$50,390,000	$47,688,000	6 %
Earnings Per Share	$2.68	$2.65	1 %
Average Shares Outstanding	16,725,000	15,901,000	5 %
Dividends Declared Per Share	$2.045	$1.98	3 %
Total Assets	$1,328,235,000	$1,211,276,000	10 %
Electric Sales - Own Territory (kWh)	4,703,754,000	4,840,244,000	(3)%
Natural Gas Firm Sales (thousands of cubic feet)	9,554,000	9,379,000	2 %
Electric Customers - Own Territory (average)	259,650	256,503	1 %
Firm Gas Customers (average)	59,168	58,038	2 %









Left, Paul J. Ganci, President and Chief Operating Officer; John E. Mack III, Chairman and Chief Executive Officer.

Chairman's Report

Over the years, Central Hudson has been committed to a business philosophy which places the highest priority on providing customers with safe, reliable, quality service at competitive prices.

Our philosophy recognizes that our business is market-driven, and that we must manage and conduct our business in a way which enables us to do better than our competition.

In this context, I am pleased to report that during 1993 your Company reached a milestone: our average electric prices were the lowest among electric companies in New York State and among the lowest in the Northeast.

I can assure you that our commitment remains strong and that we will remain competitive as the electric and natural gas industries undergo major changes which are increasing competitive pressures.

Looking at 1993, there were a number of challenges, ranging from a devastating fire at the Roseton Electric Generating Plant to a substantial reduction in employment in the Mid-Hudson Valley by IBM, which is Central Hudson's largest customer.

Not withstanding these and other challenges, 1993 was a good year for our shareholders.

- Earnings per share increased 1.1 percent, from $2.65 in 1992 to $2.68 in 1993. Dividends paid to shareholders increased 3.6 percent, from $1.96 in 1992 to $2.03 in 1993. During the last five years, the average annual increase in the dividend was 3.7 percent.
- The sale of 700,000 shares of common stock was undertaken successfully at a price of $33.75 per share.
- Book value per share increased 4.4 percent, from $23.60 at year-end 1992 to $24.65 at the end of 1993.
- The successful refinancing of $40 million of First Mortgage Bonds will reduce interest expense by approximately $2.7 million over the life of the debt.
- Two series of preferred stock were refinanced as part of a program to reduce the cost of the Company's preferred stock, reducing future dividend requirements by $200,000 annually.
- The credit ratings on our First Mortgage Bonds have been maintained at "A" by one rating agency and at "A-" or equivalent by three other agencies.

Overall, the financial results for the year are very good and especially gratifying considering two unexpected developments early in the year.

First, as part of a world-wide reduction in the size of its workforce, IBM reduced employment at three work locations in our service area by 8,400 workers. As a result, total IBM employment in the Mid-Hudson Valley dropped 57 percent in eight years, from 30,700 in 1985 to 13,100 at the end of 1993.

As you might expect, these reductions are having a major effect on the economy of the Valley, and our industrial sales and revenues. However, as you will see in this report, we are participating in a number of programs at the county, region and state levels to help create jobs and stimulate the economy of the region.

With respect to the fire at Roseton in March, we were fortunate that there were no personal injuries, no interruption of electric service to our customers, and no harm to the environment.

Generating Unit #1 was restarted and placed in service in a matter of weeks. Unit # 2, however, was more severely damaged and was not returned to service until December. Fortunately, insurance will cover

almost all of the damage, estimated to be $32 million. During the period of restoration, we were able to provide electric service to our customers, and purchase replacement power at prices comparable to the generating costs at Roseton.

Being the lowest-cost electric provider in New York State is the result of ongoing efforts by the entire Central Hudson organization to control costs and work productively. While we take pride in this accomplishment, having the lowest electric prices was not, in itself, enough to keep IBM from significantly reducing the size of its workforce in the Valley. Our electric prices compare very favorably with the price of electricity at any IBM facility in the nation. However, IBM's competitive problems overwhelmed any benefit provided by our low electric prices.

After years of having very low unemployment and high per capita income levels, largely due to the presence of IBM, the region is experiencing high unemployment. As a result, both the private and public sectors are re-evaluating economic development activities, identifying strengths and weaknesses, and setting out to re-establish the economic health of the region.

From the viewpoint of Central Hudson, there are two important considerations. First, the availability of low-cost electricity makes the region attractive to businesses which are seeking to relocate. Low electric prices also help our existing customers become more competitive and help make it possible for them to expand their businesses.

Second, we believe that the Mid-Hudson Valley is the "gem" of New York State. The region is strategically located in the Northeast region with respect to population centers, transportation networks, the availability of modern manufacturing facilities and a skilled labor force.

The region has a rich historical heritage, scenic beauty, cultural and recreational attractions, and an attractive quality of life. Taken together, we believe the region has the resources and the commitment to create new jobs and re-establish a first-rate economy.

Providing solutions to energy problems is the focus of this year's Annual Report and the keystone of our efforts to help our customers become more productive and competitive.

Just as the economy of the Valley is in transition, so too are highly efficient electric and gas technologies which are being introduced to cut costs and improve productivity while protecting our environment and improving the overall quality of life.

The photographs in this report depict innovative solutions to energy problems, how new energy technologies are boosting productivity, and how Central Hudson has established partnerships with its customers to find new ways to use energy efficiently.

I want to acknowledge another important partnership: the one between the Company and its employees. I am proud of the contributions made by Central Hudson employees during a very challenging period. Their efforts and support are greatly appreciated.

Looking to the future, competition resulting from the deregulation of the electric and gas industries will create new challenges for Central Hudson.

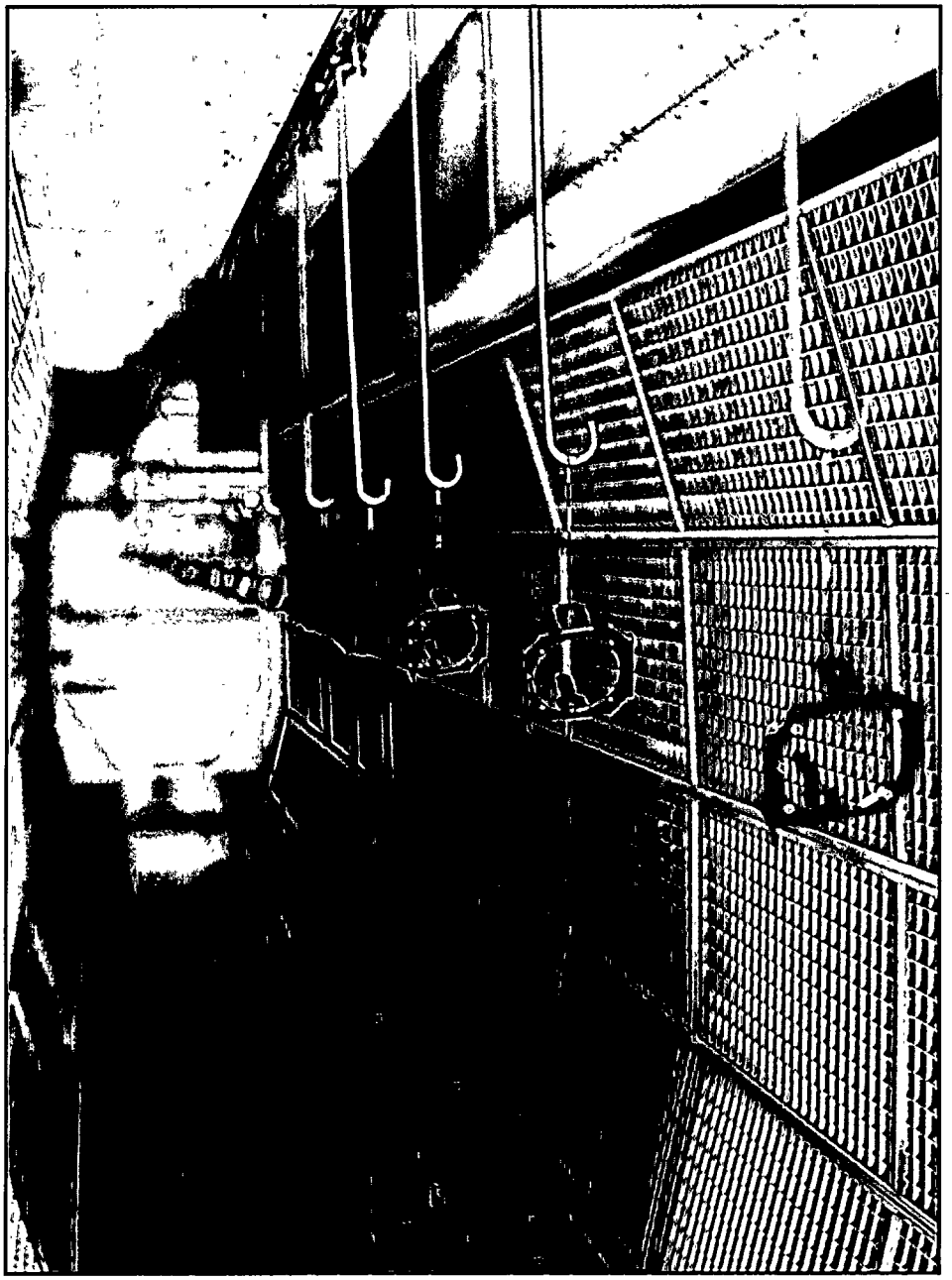
New technologies, service, quality, price and value will continue to be important to our success, but our future existence will depend upon maintaining and strengthening the trust that exists between our Company and our shareholders, customers and employees.

Over the years, principles and values have been developed to guide the employees of Central Hudson, from top to bottom. High standards of integrity, teamwork, ethical behavior, professionalism, leadership and respect for others are qualities which characterize our Company and our employees. They are the qualities which represent our heritage, and our future.

Very truly yours,

John E Mack III

Chairman of the Board
and Chief Executive Officer



Electricity can be substituted for other fuels to improve productivity and improve our environment

Infrared technologies provide fast and efficient heating, drying and curing capabilities in a wide range of applications. On the left, light fixture parts are shown in an infrared curing oven at Staff Lighting, located in Highland, which produces high-quality lighting fixtures. Compared with fossil-fuel convection ovens, infrared is faster, more energy efficient, environmentally friendly, and produces a higher-quality product. Central Hudson is meeting with customers to educate them about new energy technologies which can help them improve efficiency and productivity, thereby making them more competitive.

State-Of-The-Art Facilities Improve Reliability, Customer Service

Early in the year, two state-of-the-art facilities were opened: an Energy Control Center and a Computer Center.

The Energy Control Center, located at the Company's General Offices in Poughkeepsie, coordinates the generation and transmission of electricity by using some of the most sophisticated computer software in the electric utility industry. This Center, which also coordinates the transmission and distribution of natural gas, is helping the Company maintain a high degree of reliability and cost savings for its customers.

The Computer Center, also located at the General Offices, features the largest IBM mainframe computer in the Mid-Hudson Valley outside of IBM's own facilities. The computer, which is capable of executing 32 million instructions per second, is processing 3.3 million customer transactions annually and helping to provide a high level of service and rapid response to the needs of customers.

Competitive Pricing: The Company's Prices For Electricity Were The Lowest In New York State

Continuing its program of keeping prices competitive, the Company's prices for electricity during the year were the lowest among the seven investor-owned electric companies serving New York State.

The average electric bills for the Company's residential, commercial and industrial customers not only were the lowest in the State, in many cases they were lower by a wide margin. Based on the average price per kilowatt-hour, the Company's prices also were lower than the average prices of all the states in New England and the average price of the Mid-Atlantic region, which includes New York, New Jersey and Pennsylvania.

The Public Service Commission authorized an electric revenue increase of $5.1 million annually. The increase is being partially offset by $3.5 million in net proceeds from the litigation involving the construction of the Nine Mile 2 Nuclear Plant, in which the Company has a nine percent interest.

Even with an electric price increase which became effective on December 21, 1993, the Company's electric prices remained the lowest in New York State.

As a result of the electric price increase, the bill for a residential customer using 500 kilowatt-hours per month has increased from $57.55 to $58.26, an increase of 1.2 percent.

At the time of the price change, the new typical residential electric bill was 16 percent below the average typical bills of all other electric companies in the State. It also was nearly six percent below the typical monthly bill for a Central Hudson residential customer back in May of 1985.

The average electric bills for the Company's commercial and industrial customers also remained the lowest in the State, even with the price adjustment in December.

Central Hudson Provides Leadership In Restoring The Economy Of The Mid-Hudson Valley

A major commitment has been made by the Company to allocate both human and financial resources to the economic development of the Mid-Hudson Valley and New York State.

Chairman and CEO John E. Mack is representing the Company in The Alliance for a New, New York, which is a major partnership between the state's utility companies and the government of New York State.

This five-year, $5 million program is designed to position New York State as a strong competitor for new domestic and international investments, and to help create and retain jobs in targeted industries.

President and Chief Operating Officer Paul J. Ganci is Chairman of Dutchess County's External Marketing Council, which is implementing a $1 million program to promote the county as a center of laboratory research and high-tech manufacturing.

Competitive Pricing: Energy Prices Make The Region Attractive For New Business And Economic Development

As the public and private sectors organize to strengthen the economy of the Mid-Hudson Valley, among the region's principal assets are the competitive prices for energy.

The availability of low-cost electricity helps make the region attractive to businesses which are seeking to relocate. Low electric prices also help the Company's existing customers be more competitive in their markets or expand their operations.

As part of the Company's economic development program for the Valley, a new electric incentive rate has been developed which provides reduced electric rates to businesses which move into vacant space in the Company's service area.

The incentive rate, which provides as much as a 25 percent discount for up to five years, also is available to existing businesses which expand their operations in vacant space.

In addition, the Company's Economic Development Office is participating in a variety of economic development programs with local, county and state organizations to promote the Mid-Hudson Valley as the "Heart of the Northeast."

Competitive Pricing Results From Controlling Costs, Especially The Purchase And Efficient Use Of Fuel

Providing customers with low electric prices did not happen overnight.

It is the result of unrelenting efforts to control costs; negotiating the best prices for fuel, equipment, supplies and services; increasing productivity in all areas of the business; and applying automated solutions where feasible to save time and money.

As you might expect, the cost of fuel and purchased electricity is the Company's largest single expense: more than $122 million during 1993. During the past decade, the Company made major capital expenditures to diversify its fuel options and to convert oil-fired generating plants to burn a variety of fuels efficiently. As a result of this fuel diversification program, the Company is able to take advantage of fluctuations in fuel prices and utilize the fuels — such as coal, oil, natural gas and uranium — which are the lowest in price at any given time.

Taxes are the Company's next largest expense: more than $94 million in 1993. Unfortunately, taxes on utility companies in New York State are double the national utility average. Efforts are being made to make the tax burden more equitable. In the meantime, however, utility taxes make New York State less competitive than other states with respect to energy pricing.

Controlling the size of the work force also is important in controlling costs. During the period 1982 through 1992, the number of customers served by the Company increased by 20 percent. During the same period of time, however, the number of employees increased by only two percent. Quality and productivity initiatives are enabling the Company and its highly skilled work force to introduce new services and products which provide added value and increase the quality of service to customers.

Employees Took Decisive Action During A Devastating Fire At Roseton

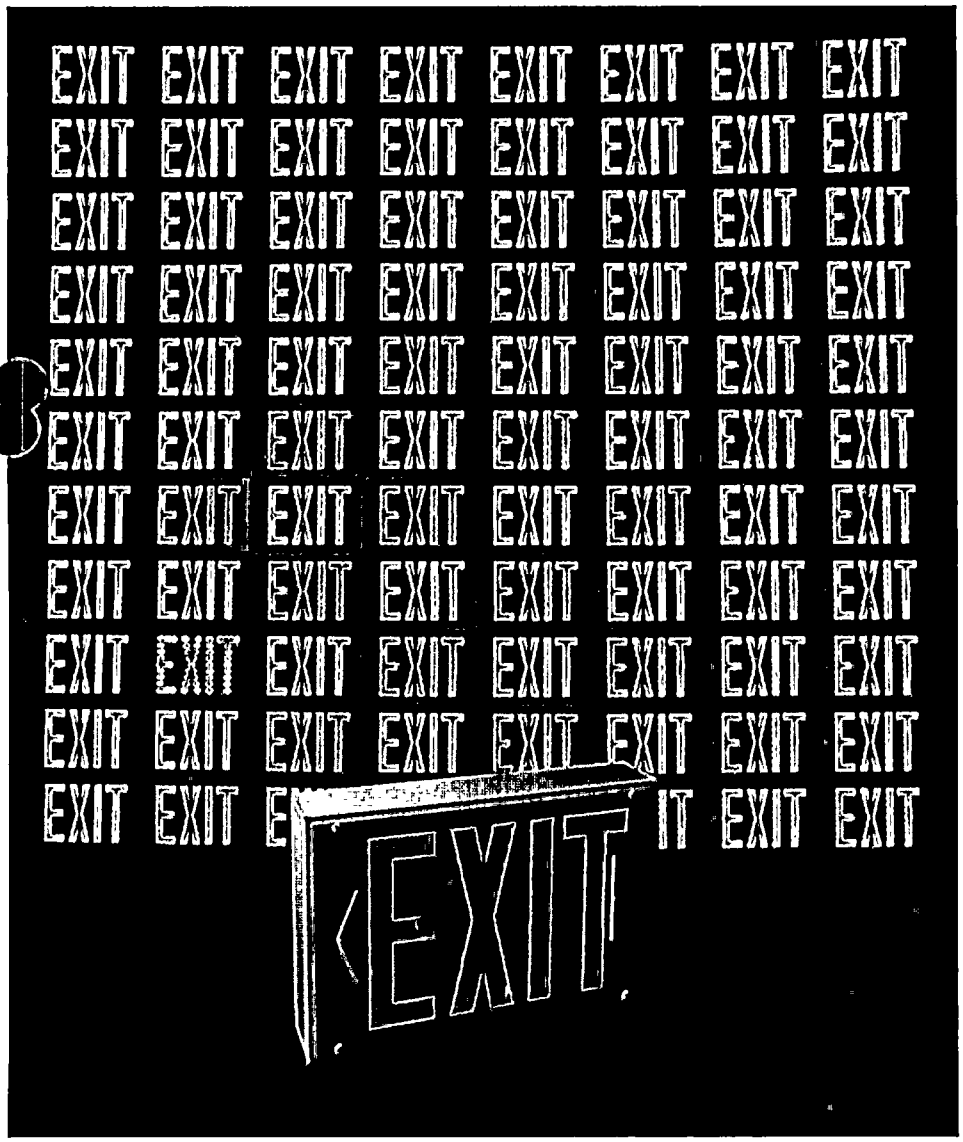
In March, a major fire occurred when a transformer failed catastrophically at the Roseton Electric Generating Plant causing $32 million in damages, most of which will be recovered through insurance. The plant is located north of Newburgh.

As a result of the quick and effective response by employees at the plant, no one was injured, electric service was not interrupted to any customers, and there were no significant effects on the environment.

In reporting to shareholders at last year's Annual Meeting, President Paul J. Ganci said, "In more than 35 years, I have never seen greater dedication, effective teamwork and decisive action."

A team of employees and contractors restarted Generating Unit #1 by the end of April, but Unit #2 was not returned to service until December 20 due to severe and extensive damage.

Central Hudson is helping one of its electronics customers expand into new and larger markets



There are two things which make LED exit signs attractive: first, they use only one watt of electricity compared with 40 watts normally; second, they are guaranteed by the manufacturer for 25 years compared with incandescent bulbs which may need changing several times each year. LED stands for Light Emitting Diodes. The exit signs shown to the left were made by Cavalier Electronics, located in Dutchess County. Central Hudson, as part of its Energy Efficiency Services program, encourages its customers to install these exit signs. Due to lower operating and maintenance costs, the signs pay for themselves in less than two years. Central Hudson also is helping Cavalier by making electric companies across the country aware of this new, energy-saving product. Helping Cavalier expand its market is an example of how Central Hudson is helping its customers become more competitive and make an even larger contribution to the economy of the region.

We are developing new markets for clean, efficient natural gas as an alternative fuel

The United States Military Academy at West Point is using a fleet of natural gas-powered pick-up trucks as part of a federal program to utilize clean alternative fuels. Central Hudson has provided the Academy with a natural gas refueling station to assist in the development of natural gas vehicle technology. Natural gas offers many benefits as an alternative fuel for vehicles. It is economical, and reduces engine maintenance and harmful emissions.

Central Hudson is developing another new market by promoting the use of forklifts which use compressed natural gas. Most forklifts use propane which produces high levels of harmful emissions and poor air quality. Clean natural gas, however, provides an attractive option to provide better working conditions for employees. A natural gas forklift is being used by KTB Associates, a printer located in Saugerties, to demonstrate the advantages of natural gas technology.

Customer Services Group Reorganized To Meet The Needs Of Customers

During the year, the Customer Services Group was reorganized to improve the effectiveness of communications and the productivity of the work force, thus improving the Company's ability to meet the needs of customers.

The improvement has resulted from the consolidation of customer relations and operating functions under a Customer Services Manager in each of the Company's five operating divisions: Catskill, Fishkill, Kingston, Newburgh and Poughkeepsie.

As part of the reorganization, a Customer Quality and Services Division was formed to support the five divisions. In addition, the Community Relations and Consumer Outreach office was integrated in the Customer Services Group to serve customers with special needs.

Analysis Of Corporate Culture Shows Focus On Customer Service

The Company is implementing 37 recommendations which it developed in response to conclusions contained in a "Management Audit." The audit, which is mandated by Public Service Law, is conducted every five years by an independent consultant selected by the Public Service Commission.

This review process, which took more than one year, provided the Company with a positive, constructive view of six areas of the business: Human Resources, Construction Program Planning, Corporate Budgeting, Consumer Services, Computerized Information Systems, and Economic Development.

The audit was very thorough. More than 250 documents were provided to the auditors, who also conducted 186 interviews before preparing their findings and conclusions.

The action plan developed by the Company in response to the audit provides for improvements or further evaluation of some existing processes and practices, or improved documentation, record keeping and information sharing.

It is noteworthy that as part of an analysis of Central Hudson's "corporate culture," the auditors found that employees throughout the organization are dedicated to and focused on customer service.

Quality Control Program Being Implemented For Gas Operations

The Company is implementing a Quality Control Program to enhance the safe and efficient operation of its gas system.

The program has been approved by the Public Service Commission as part of an agreement which was developed by the Company and the Commission staff following an explosion which occurred on November 6, 1992 in a house in the Company's service territory in Catskill.

As part of the agreement, the Company also will establish an expanded training program, create four training centers and implement an expanded program to evaluate and replace cast iron and steel pipeline facilities.

Starting in 1994, the Company will invest, as shareholder expense, $500,000 per year for three years and up to $500,000 for the fourth year, all in connection with these new programs. Under the agreement, the Company will not pay any fines or penalties related to the Catskill incident.

Nine Mile Point Two Nuclear Plant Sets Operating Record

The Nine Mile Point Two Nuclear Plant set a record by operating 327 consecutive days before it was shut down for a refueling in October.

Starting on November 8, 1992, the plant had operated at an overall capacity factor of 90 percent, which was a very strong operating performance. Overall performance also continues to improve. Based on a Systematic Assessment of Licensee Performance Report issued by the U.S. Nuclear Regulatory Commission in September 1993, ".... improved program performance and effectiveness were demonstrated in operations, maintenance and engineering, self assessment, quality assurance and quality control activities were comprehensive and effective in identifying strengths and opportunities for improvement."

Central Hudson has a nine percent ownership in the Nine Mile Point Two Plant, which is located on Lake Ontario near Oswego and operated by Niagara Mohawk Power Corporation.

Capital Structure Improved; Refinancings Reduce Interest Expense

As part of the Company's program to strengthen its capital structure, common equity ratio and credit ratings, 700,000 shares of common stock were sold in March at a price of $33.75 per share.

In August, the Company sold $20 million of secured Medium Term Notes. The sale consisted of $10 million of seven-year First Mortgage Bonds bearing an annual interest rate of 6.10 percent and $10 million of ten-year First Mortgage Bonds bearing an annual interest rate of 6.46 percent.

In October, the Company sold $20 million of five-year unsecured Medium Term Notes bearing an annual interest rate of 5.38 percent. The proceeds from the August and October sales were used to redeem $40 million of First Mortgage Bonds carrying higher interest rates. The refinancing will reduce the Company's interest expense by approximately $2.7 million over the life of the debt.

Also in October, the Company issued two new series of serial preferred stock: 150,000 shares of 6.80 percent Cumulative Preferred Stock and 200,000 shares of 6.20 percent Cumulative Preferred Stock, each of $100 par value.

The proceeds were used to redeem all of the Company's outstanding shares of Adjustable Rate Redeemable Cumulative Preferred Stock, Series A, and all outstanding shares of 8.40 percent Redeemable Cumulative Preferred Stock, thereby reducing the cost of the Company's preferred stock.

At the end of the year, the credit ratings on the Company's First Mortgage Bonds were an "A" rating by Fitch Investors Service and an "A-" or equivalent by Moody's Investor Service, Duff & Phelps Inc., and Standard & Poor's Corporation.

Natural Gas Made Available To Customers In New Paltz

In keeping with the Company's program of providing customers with energy options, natural gas service was extended to the Village and Town of New Paltz in Ulster County.

Prior to the construction of ten miles of pipe, an information program was conducted to solicit opinions from customers on the routing of the pipeline and to familiarize them with the uses and advantages of natural gas.

At the same time, a five-year marketing program was initiated with a goal to convert existing alternate fuel customers to natural gas, and to have all new construction in the village and township utilize natural gas.

New Paltz, which is located near the New York State Thruway and is the site of the State University of New York at New Paltz, also has the potential for future economic development.

Incentives Provided To Customers To Install Efficient Equipment

The Company continues to promote the efficient use of energy, especially with respect to lighting. During 1993, the Company paid $2,800,000 in rebates to 939 commercial and industrial customers who installed more efficient lighting equipment. The Company also provides rebates to customers who install more efficient motors or air conditioning.

Pipeline Crossing Of The Hudson Wins Outstanding Engineering Award

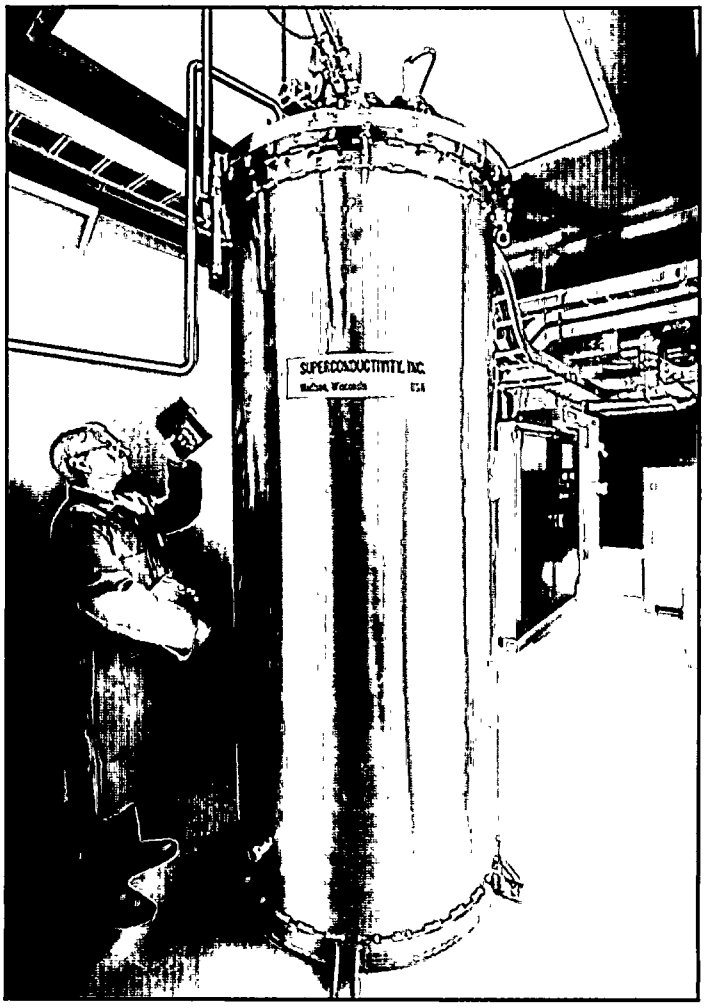
The New York State Society of Professional Engineers named the Company's gas pipeline crossing of the Hudson River as the 1993 Outstanding Engineering Achievement.

The 3,500-foot bore below the bed of the river created a path for a gas pipeline which now supplies natural gas to the Roseton Electric Generating Plant. The engineering project was the first horizontally controlled, directionally drilled crossing of the Hudson River and the longest drilled crossing ever undertaken in the Northeast.

Boring under the Hudson was an environmentally preferable alternative to laying the pipeline on the bottom of the river, which may have disturbed indigenous fish or potentially PCB-contaminated sediments.

By burning clean natural gas at the Roseton plant, the Company not only is helping to control fuel costs, it is also helping to improve air quality.

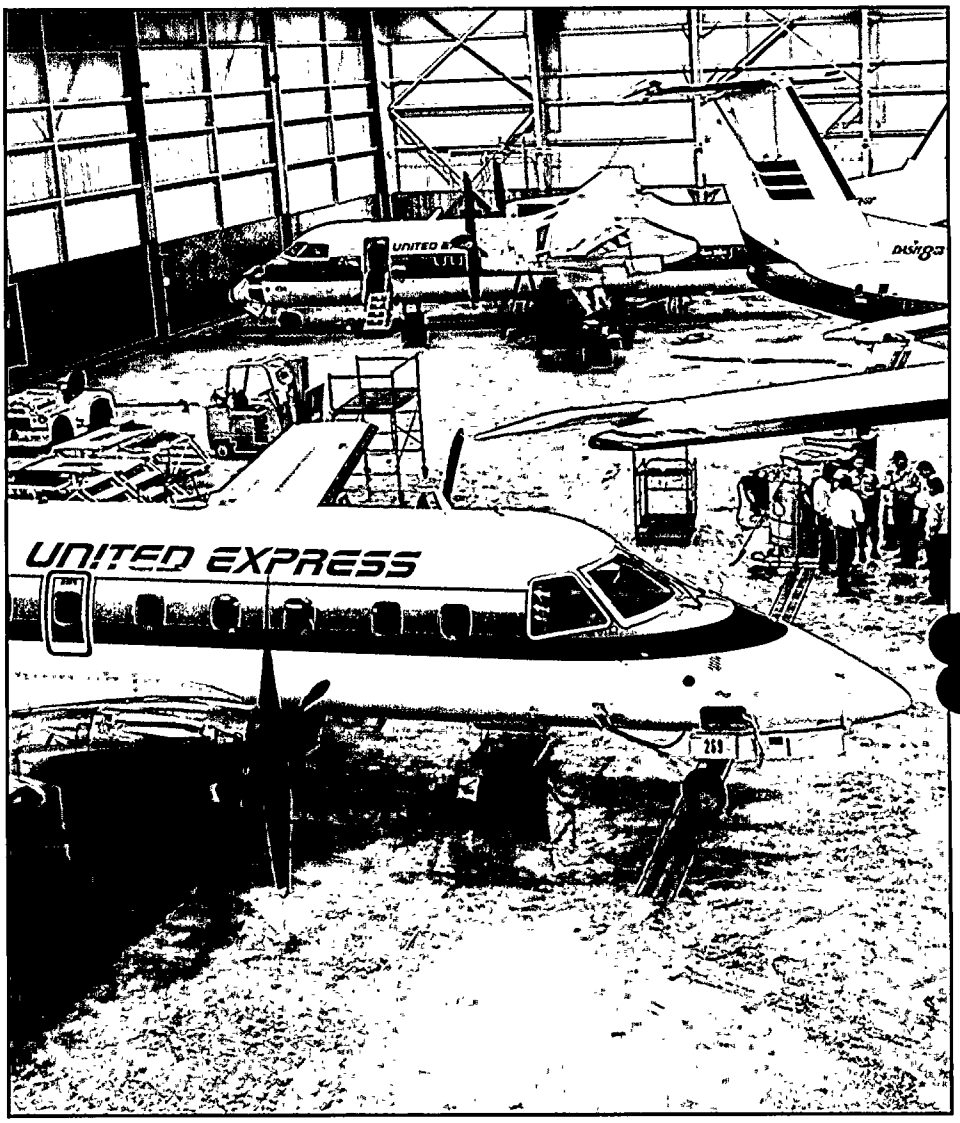
Central Hudson is helping to develop a Superconducting Magnetic Energy Storage System to improve reliabilty and power quality



For the last three years, Central Hudson has been participating in the development of a superconducting magnetic energy storage device (SSD) to improve the quality of power delivered to high-tech customers. An SSD protects critical electrical loads by sensing momentary electric power disruptions and instantly providing supplementary power. Working with Superconductivity, Inc., Central Hudson successfully field tested an SSD unit at one of IBM's semiconductor test facilities in Fishkill over a period of 16 months. Central Hudson is continuing to support commercial testing at other locations, including an Air Force base in Florida and a Motorola facility in Texas. SSD technology represents another aspect of Central Hudson's commitment to developing and providing Energy Solutions to improve the quality of electric service.

Our economic incentive rate for electricity is designed to encourage businesses to relocate in the Mid-Hudson Valley

To help businesses relocate in the Mid-Hudson Valley, Central Hudson is offering an Economic Incentive Rate which provides for a discount of up to 25% for electricity. In order to qualify, a business must move into a building of 25,000 square feet or more which has been vacant for at least six months. The special electric rate also is available to existing Central Hudson customers which move into vacant buildings and increase their load by 100 kilowatts. One customer which is benefiting from the Economic Incentive Rate is Atlantic Coast Airlines, a regional airline which operates United Express. The airline transferred 70 aircraft maintenance employees from Pennsylvania to a facility at Stewart International Airport, located in Newburgh.



Company And Customers Reach Out To Those In Need

Recognizing the difficult times many people are having as a result of the economy, the Company introduced the "Extend A Hand" program to educate customers about the programs and services which are available to help them pay their utility bills.

As a result, customers are taking advantage of "The Good Neighbor Fund," which provides a "last resort" grant when all other forms of assistance have been exhausted. This program is funded by Central Hudson's customers and shareholders and is administered by The Salvation Army.

Customers also have been making deferred payment arrangements, signing up for budget billing, and shifting their electric use to lower-price, off peak periods.

The Company also has been promoting a variety of energy efficiency services, including free home energy audits, low-cost financing for energy improvements, and free weatherization.

Company Education Program Receives National Recognition

Central Hudson and the Poughkeepsie Middle School received recognition from the Edison Electric Institute (EEI) for an educational program which enabled sixth grade students to realize how science, math and language skills they learn in the classroom are used in real world contexts.

The Institute, which is a national organization comprised of the nation's investor-owned electric companies, is sponsoring "EEI 2000" to help meet the national goal of revitalizing education in America. The Company is a charter member of "EEI 2000." Company employees worked with school officials to organize the educational program, which helped students learn about gas and electric energy and understand how to run a business.

By forming their own energy company, the students became involved in a variety of activities, such as negotiating rights-of-way, forecasting future energy needs, exploring environmental issues, writing news releases and obtaining stock in the company.

Subsidiaries Implement Energy Efficiency & Cogeneration Projects

Two of the Company's unregulated subsidiaries continue to expand their role in implementing energy efficiency and cogeneration projects in the Northeast.

Although the economy in the Northeast is not strong, there are many end users of electricity and steam who desire to reduce their energy costs through more efficient operations. This provides an attractive market for both subsidiaries.

In 1993, Central Hudson Enterprises Corporation (CHEC) completed more than 2.4 megawatts of lighting retrofit projects throughout New Jersey under a special award program with Public Service Electric & Gas Corporation (PSE&G). CHEC financed $4.7 million of energy efficiency projects which will produce another 5 megawatts of energy efficiency projects in the PSE&G service area.

CHEC also continues to provide technical, administrative and management services to reduce energy costs in several school districts throughout New York State. This is a developing market that is expected to expand during 1994.

Central Hudson Cogeneration, Inc. continues to expand its portfolio of cogeneration projects with three completed during 1993. One 4.3 megawatt gas turbine is operating at Montclair State College, located in Upper Montclair, N.J., and another is operating at the Edna Mahan Correctional Facility, located in Clinton, N.J.

In addition, a 1.2 megawatt reciprocating engine is operating at Plymouth State College, which is in New Hampshire. The market for cogeneration to meet the electric and steam needs of hospitals, colleges and correctional facilities promises to provide investment opportunities for several years to come.

Marjorie S. Brown, Director Since 1979, Resigns From Board

Marjorie S. Brown, who had been a member of the Company's Board of Directors since 1979, resigned as a Director, effective January 1, 1994.

Mrs. Brown had been a member of the Board's Retirement Committee since 1980. She became an officer of the Board in 1987 when she was appointed Chairwoman of the Committee on Compensation and Succession, a position she held until April of 1993. At the time of her resignation, she was serving as a member of the Committee on Finance.

Speaking on behalf of the Board, John E. Mack, Chairman and Chief Executive Officer, said, "Mrs. Brown initially served as a Director during a crucial period when the Board faced challenging decisions to undertake major financing and construction programs to diversify our fuel mix and control fuel costs.

"More recently, she has participated in deliberations and decisions which have prepared the Company to compete in the world of deregulation. Her contributions to the Board and to the progress of Central Hudson are greatly appreciated."

President Of Vassar College Elected To The Board Of Directors

Dr. Frances D. Fergusson, President of Vassar College in Poughkeepsie, was elected to the Board of Directors in September. She is a member of the Board of Trustees of the Ford Foundation and the Chair of the Foundation's Education and Culture Committee.

Dr. Fergusson, who has been President of Vassar since 1986, is a Trustee of the Mayo Foundation and Historic Hudson, and a Director of the Marine Midland Bank and the National Association of Independent Colleges and Universities.

She received a B.A. degree from Wellesley College, and M.A. and Ph.D. degrees in Fine Arts from Harvard University.

Steven Lant Promoted To Treasurer

Steven Lant was promoted to the position of Treasurer of the Company in April. Mr. Lant joined Central Hudson in 1980 and held a number of management positions in the Cost & Rate Division before being promoted to Assistant Treasurer in 1990, and to Assistant Treasurer and Assistant Secretary in 1991.

H. Clifton Wilson, Former President, Died At Age 68

H. Clifton Wilson, who served as President of Central Hudson from 1975 to 1982, died on March 23, 1993. At the time of Mr. Wilson's death, Chairman John E. Mack said, "Cliff Wilson joined Central Hudson as an experienced utility executive, and his contributions to our Company and to the community were significant. His leadership set an example for all of us."

Mr. Wilson joined Central Hudson as a Vice President in 1972. He was named Senior Vice President in 1973 and Executive Vice President and a Director of the Company in 1974. He was elected President in 1975. Prior to joining Central Hudson, Mr. Wilson served as President of Ebasco International Corporation.

Board of Directors

The Directors are shown in Central Hudson's new Energy Control Center, which opened during 1993. For more information about this state-of-the-art center, please see page 5.

Front row, from left: Marjorie S. Brown; Richard H. Eyman; John E. Mack, III, Chairman and Chief Executive Officer; Howard C. St. John, Vice Chairman; and Jack Effron.

Back row, from left: Edward F.X. Gallagher; Charles LaForge; Paul J. Ganci, President and Chief Operating Officer; Dr. Frances D. Fergusson; Heinz K. Fridrich; Edward P. Swyer; and L. Wallace Cross. Information about the Directors is on the inside back cover.

Corporate & Stock Information

Annual Meeting

The annual meeting of holders of common stock will be held on Tuesday, April 5, 1994 at 10:30 a.m. at the Corporation's General Offices, 284 South Avenue, Poughkeepsie, NewYork.

The management welcomes the personal attendance of shareholders at this meeting. A summary report of the meeting will be mailed to all shareholders of record at a later date.

Financial and Statistical Report

A comprehensive ten-year financial and statistical supplement to this Annual Report will be available to shareholders attending the Annual Meeting. Copies may also be obtained by writing or calling Steven V. Lant, Treasurer and Assistant Secretary, 284 South Avenue, Poughkeepsie, N.Y. 12601; telephone (914) 486-5254.

Annual Report to the SEC; Form 10-K

Shareholders may obtain without charge a copy of Central Hudson's annual report to the Securities and Exchange Commission, on Form 10-K, by writing or calling Ellen Ahearn, Assistant Secretary, 284 South Avenue, Poughkeepsie, N.Y., 12601; telephone (914) 486-5757. The copy provided will be without exhibits; these may be purchased for a specified fee.

Shareholder Information

First Chicago Trust Company of New York; telephone (800) 428-9578 between 9 a.m. and 5 p.m. weekdays.

Security Analysts and Institutional Investors

Steven V. Lant, Treasurer and Assistant Secretary; telephone (914) 486-5254.

Dividend Reinvestment Plan

Central Hudson offers a Dividend Reinvestment Plan under which all holders of common stock may reinvest dividends and/or make direct cash investments to obtain additional shares. All brokerage and other fees to acquire shares are paid by the Corporation. To participate, call Janet M. Horvat, Director of Risk Management & Shareholder Relations, at (914) 486-5204 or First Chicago Trust Company of New York at (800) 428-9578.

Transfer Agent & Registrar, Common and Preferred Stock

First Chicago Trust Company of New York, P.O. Box 2550, Jersey City, N.J. 07303-2550.

Stock Exchange Listings

Common: *New York Stock Exchange*

Stock Trading Symbol: CNH

Multiple Copies of this Annual Report

Shareholders who receive multiple copies of this Annual Report may, if they choose, reduce the number received by calling First Chicago Trust Company of New York at (800) 428-9578.

General Counsel

Gould & Wilkie
One Chase Manhattan Plaza
New York, N.Y. 10005

Independent Accountants

Price Waterhouse
1177 Avenue of the Americas
New York, N.Y. 10036

Central Hudson

Keeping The Customer In Focus

Common Stock
Market Price and Dividends Paid Per Share

	1993			1992		
	High	Low	Dividend	High	Low	Dividend
1st Quarter	$34 1/4	$30 5/8	$.50	$28 7/8	$25 7/8	$.48
2nd Quarter	34 1/2	30 5/8	.50	29 1/2	26	.48
3rd Quarter	35 5/8	34	.515	30 1/4	28 1/4	.50
4th Quarter	34 3/8	28 3/8	.515	31 1/4	28 7/8	.50

FINANCIAL SECTION

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FINANCIAL HIGHLIGHTS

Earnings Per Share: (Page 23)
Earnings per share of common stock were $2.68 in 1993, an increase of 3 cents, or 1% from 1992.

Dividends Per Share: (Page 30)
The quarterly dividend rate was increased to $.515 per share, effective August 1, 1993. This represented an increase of 3% over the previous quarterly rate of $.50 per share. Dividends paid to shareholders in 1993 were $2.03 per share as compared to $1.96 per share in 1992. No portion of the 1993 dividend constitutes a return of capital.

Economy:
While the Company continued to feel the effects of the reduction in employment by IBM in early 1993, the local economy has begun to rebound. The local unemployment rates are now below the New York State average and approximately equal to the National average. The Company's economic development efforts coupled with the State and local efforts helped to attract some new manufacturing companies throughout the region. It is hoped that this trend will continue through 1994.

Electric Sales: (Page 25)
Sales of electricity within the Company's service territory decreased 3% in 1993. Sales of electricity to residential customers increased 3% due to the combined effect of a 2% increase in usage per customer and a 1% increase in the number of customers. Commercial sales increased 4% resulting from the combined effect of a 2% increase in usage per customer and a 2% increase in the number of customers. Electric sales to industrial customers decreased 13% due primarily to a 20% decline in usage by IBM.

Gas Sales: (Page 25)
Firm sales of natural gas increased 2% in 1993. Sales of gas to residential customers increased 1% due to the net effect of a 2% increase in the number of customers and a 1% decrease in usage per customer. Sales to commercial customers increased 3% resulting from the net effect of a 4% increase in the number of customers and a 1% decrease in usage per customer. Firm gas sales to industrial customers remained stable compared to 1992.

Rate Proceeding - Electric: (Page 21)
By Order Adopting Revenue Requirement and Rate Design (Order), issued and effective December 16, 1993, the Public Service Commission of the State of New York (PSC) permitted the Company to increase its electric base rates by $5.133 million (or approximately 1.3% on an annual basis), based on a 10.6% return on common equity, an 8.5% return on total invested capital, a resultant cash coverage of total interest charges during the Rate Year of 3.17 times, a recognized revenue requirement deficiency of $14.330 million and the use of $6 million (after-tax) of Mirror CWIP as a rate moderator, which reduced such deficiency to the $5.133 million authorized increase. The Order also directed that such rates be designed to produce such revenues for the period November 22, 1993 through November 21, 1994.

Rate Proceeding - Gas: (Page 22)
By said Order, the PSC authorized no increase in the Company's base gas rates. The Order in effect recognized a $1.237 million revenue requirement deficiency, but eliminates it by applying $537,000 of previously retained profits from sales of gas to interruptible customers as a rate moderator, and by imputing an increase of $700,000 net revenues from interruptible gas sales of the Company. The Order also bases such revenue requirement on a 10.6% return on common equity.

Common Stock: (Note 5)
Issuances under a 700,000 share stock offering, the Dividend Reinvestment Plan and Customer Stock Purchase Plan increased the number of common shares outstanding to 16,953,147. At December 31, 1993 a share of common stock was selling at $30.375 while the book value per share was $24.65. At December 31, 1993 the Company's shares were held approximately 38% by individuals registered with the Registrar and Transfer Agent, 10% by institutional investors and 52% in "street name."

Financing Program: (Notes 5 & 6)
In 1993, the Company optionally redeemed two series of First Mortgage Bonds, totaling $40 million and two series of preferred stock totaling $34.2 million. These securities were refunded with similar securities of similar maturity bearing lower interest rates or dividend rates. In March 1993, the Company issued 700,000 additional shares of common stock, through a public offering, and issued 224,578 shares of common stock in 1993 through the Company's Automatic Dividend Reinvestment and Customer Stock Purchase Plans realizing net proceeds of $30.1 million to fund working capital requirements and reduce outstanding short-term debt.

Taxes: (Page 28)
In 1993, the Company incurred $94.2 million for operating taxes levied by federal, state and local governments.

FIVE-YEAR SUMMARY OF CONSOLIDATED OPERATIONS AND SELECTED FINANCIAL DATA*

(Thousands of Dollars)

	1993	1992	1991	1990	1989
Operating Revenues					
Electric	$ 422,925	$ 427,436	$ 424,121	$ 433,859	$ 403,235
Gas	94,448	96,121	70,615	69,749	66,767
Total	517,373	523,557	494,736	503,608	470,002
Operating Expenses					
Operations	274,477	283,787	267,339	279,602	263,104
Maintenance	34,486	34,226	31,504	30,364	23,939
Depreciation and amortization	39,682	39,596	37,230	36,134	35,344
Operating taxes	65,564	66,339	60,554	57,234	51,240
Federal and deferred income tax	28,603	25,111	22,613	22,456	19,828
Total	442,812	449,059	419,240	425,790	393,455
Operating Income	74,561	74,498	75,496	77,818	76,547
Other Income and Deductions					
Allowance for equity funds used during construction	934	596	921	785	463
Federal and deferred income tax	1,445	748	1,252	2,082	910
Other - net	5,167	4,427	854	1,505	3,419
Total	7,546	5,771	3,027	4,372	4,792
Income before Interest Charges	82,107	80,269	78,523	82,190	81,339
Interest Charges	31,717	32,581	35,582	41,155	42,222
Net Income	50,390	47,688	42,941	41,035	39,117
Dividends on Preferred Stock	5,562	5,544	5,659	5,681	5,698
Income Available for Common Stock	44,828	42,144	37,282	35,354	33,419
Dividends Declared on Common Stock	34,497	31,545	29,800	27,067	25,825
Amount Retained in the Business	10,331	10,599	7,482	8,287	7,594
Retained Earnings - beginning of year	58,692	48,093	40,611	32,324	24,730
Retained Earnings - end of year	$ 69,023	$ 58,692	$ 48,093	$ 40,611	$ 32,324
Common Stock					
Average shares outstanding (000s)	16,725	15,901	15,530	14,850	14,657
Earnings per share on average shares outstanding	$2.68	$2.65	$2.40	$2.38	$2.28
Dividends declared per share	$2.045	$1.98	$1.90	$1.82	$1.76
Book value per share (at year-end)	$24.65	$23.60	$22.84	$22.31	$21.76
Total Assets	$1,328,235	$1,211,276	$1,184,548	$1,134,503	$1,113,430
Long-term Debt	391,810	441,096	416,030	407,638	447,440
Cumulative Preferred Stock	81,030	81,030	81,030	81,030	81,030
Common Equity	417,846	378,214	360,203	333,587	320,709

*This summary should be read in conjunction with the consolidated financial statements and notes thereto included in the "Financial Section" of this Annual Report.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CAPITAL RESOURCES AND LIQUIDITY

CONSTRUCTION PROGRAM

As shown in the Consolidated Statement of Cash Flows, the cash expenditures related to the Company's construction program amounted to $53.1 million in 1993, an $8.0 million decrease from the $61.1 million expended in 1992. As shown in the table below, cash construction expenditures for 1994 are estimated to be $82.1 million, an increase of $29.0 million over 1993 expenditures. Internal sources funded 100% of the 1993 cash construction expenditures and are presently estimated to fund approximately 71% of the forecasted expenditures for 1994.

Estimates of construction expenditures, internal funds, mandatory redemption of long-term securities, and working capital requirements for the five-year period 1994-1998 are set forth by year in the following table:

	1994	1995	1996	1997	1998	Total 1994-1998
			(Thousands of Dollars)			
Construction Expenditures *:						
Electric	$48,900	$40,100	$38,400	$45,300	$43,600	$216,300
Gas	11,400	8,500	8,600	8,400	8,500	45,400
Common	11,600	10,200	10,600	10,700	11,100	54,200
Roseton buy-back **	7,300	7,100	7,000	6,800	6,600	34,800
Nuclear fuel	2,900	100	5,000	3,700	1,300	13,000
Total	82,100	66,000	69,600	74,900	71,100	363,700
Internal Funds Available:						
Depreciation accruals	41,400	43,200	44,600	46,000	47,600	222,8[illegible]
Deferred income tax - net	10,600	11,300	11,200	2,700	2,300	38,100
Other	5,900	5,600	6,000	7,500	7,200	32,200
Total	57,900	60,100	61,800	56,200	57,100	293,100
Excess of Construction Expenditures over Internal Funds	24,200	5,900	7,800	18,700	14,000	70,600
Mandatory Redemption of Long-term Securities:						
Long-term debt	50,100	2,600	—	100	100	52,900
Working Capital Requirements	14,600	10,000	10,000	10,000	10,000	54,600
Total Cash Requirements	$88,900	$18,500	$17,800	$ 28,800	$ 24,100	$ 178,100

* Excluding the equity portion of Allowance for Funds used During Construction (AFDC), a noncash item.
** Described in Note 9 of the Notes to Consolidated Financial Statements (Notes), under the subcaption "Roseton Plant."

Estimates of construction expenditures are subject to continuous review and adjustment, and actual expenditures may vary from such estimates. The depreciation accrual for the Nine Mile 2 Plant (as described in Note 2 of the Notes), is based on the remaining life method. The assumed amortization rate for the Danskammer Plant coal reconversion investment is 5%. The deferred income tax projections are based on current federal income tax law.

Included in the construction expenditures are expenditures which are required to comply with the Clean Air Act Amendments of 1990. The Company estimates such required expenditures will cost approximately $14 million. A discussion of the Clean Air Act Amendments is included in Note 9 of the Notes.

As shown in the table above, it is presently estimated that funds available from internal sources will finance 81% of the Company's cash construction expenditures for the five-year period 1994-1998. During this same five-year period, total external financing requirements are projected to amount to $178.1 million, of which $52.9 million is related to the redemption of long-term securities.

CAPITAL STRUCTURE

In an effort to increase its common equity ratio and improve its bond rating, the Company issued, through a public sale, 600,000 additional shares of common stock in 1991. In March 1993, the Company accelerated the rate of increase in its common equity ratio through the public sale of 700,000 additional shares of common stock. One result of these recent increases in its common equity ratio has been a significant improvement in its interest coverage ratios, which have also been improved by the refinancing of debt at lower interest rates. As a result of the improving trend in the Company's financial indices, the Company received credit rating upgrades in 1991 and 1992 by Standard & Poor's Corporation, Moody's Investor Service and Duff & Phelps Inc., to the "A-" level, or equivalent, and by Fitch Investors Service to the "A" level, and thereby moved closer to its longer-term goal of attaining an "A" credit rating.

	Year-end Capital Structure		
	1991	1992	1993
Long-term debt	47.8%	48.3%	47.0%
Short-term debt	2.2	1.6	—
Preferred stock	9.2	8.8	8.6
Common equity	40.8	41.3	44.4
	100.0%	100.0%	100.0%

FINANCING PROGRAM

In 1993, the Company optionally redeemed two series of First Mortgage Bonds totaling $40 million and two series of preferred stock totaling $34.2 million. These securities were refunded with similar securities of similar maturity bearing lower interest rates or dividend rates. In March 1993, the Company issued 700,000 additional shares of common stock, through a public offering, and issued 224,578 shares of common stock in 1993 through its Automatic Dividend Reinvestment and Customer Stock Purchase Plans. These funds were used to reduce short-term debt outstanding and to fund working capital requirements.

In 1994, the Company intends to refinance $50 million of maturing First Mortgage Bonds, and fund any external funding requirements related to its construction program and working capital requirements through its Automatic Dividend Reinvestment and Customer Stock Purchase Plans and by issuing a small amount of new debt securities. The Company continues to monitor the market for opportunities to refinance debt or preferred stock at lower cost.

SHORT-TERM DEBT AND SALE OF RECEIVABLES

As more fully discussed in Note 4 of the Notes, the Company has a revolving credit agreement with four commercial banks for borrowing up to $50 million through December 14, 1997. In addition, the Company continues to maintain confirmed lines of credit totaling $2 million with three regional banks.

As discussed in Note 8 of the Notes, the Company also has the ability to accelerate its cash flow by selling its accounts receivable from retail sales, when deemed desirable.

RATE PROCEEDING — ELECTRIC

On November 12, 1992, the Company filed a request with the Public Service Commission of the State of New York (PSC) to increase its base rates for electric service to produce additional annual net revenues of $15.728 million based on projected operations during the rate year comprised of the period November 1, 1993 - October 31, 1994 (Rate Year).

In its filing, the Company requested an 11.75% return on common equity and a 9.15% return on total invested capital.

By Order Adopting Revenue Requirement and Rate Design (Order), issued and effective December 16, 1993, the PSC permitted the Company to increase its electric base rates by $5.133 million (or approximately 1.3% on an annual basis), based on a 10.6% return on common equity, an 8.5% return on total invested capital, a resultant cash coverage of total interest charges during the Rate Year of 3.17 times, a recognized revenue requirement deficiency of $14.330 million and the use of $6 million (after-tax) of Mirror CWIP as a rate moderator, which reduced such deficiency to the $5.133 million authorized increase. The Order also directed that such rates be designed to produce such revenues for the period November 22, 1993 through November 21, 1994.

As a result of the application of Mirror CWIP under the Order, the balance of Mirror CWIP (available for utilization) on the Company's Consolidated Balance Sheet was reduced resulting from the application of: (1) $6.0 million of Mirror CWIP as a rate moderator, (2) $5.2 million of additional Mirror CWIP to offset deferred balance sheet items, and (3) $300,000 of Mirror CWIP to offset the revenues the Company would otherwise be entitled to collect for the period November 22, 1993 through December 20, 1993.

In addition, the PSC directed the refund (through the Company's electric fuel cost adjustment clause) to ratepayers of $3.542 million during the 12 months beginning December 21, 1993. This refund represents the ratepayers' portion of the net proceeds received from litigation with respect to the construction of the Nine Mile 2 Plant.

RATE PROCEEDING — GAS

On November 12, 1992, the Company filed a request with the PSC to increase its base rates for firm natural gas service to produce additional annual net revenues of $1.838 million based on projected operations during the Rate Year. This represented an overall increase in firm gas revenues of 2.52%.

In its filing, the Company requested an 11.75% return on common equity and a 9.15% return on total invested capital.

By the Order, the PSC authorized no increase in the Company's base gas rates. The Order in effect recognized a $1.237 million revenue requirement deficiency, but eliminated it by applying $537,000 of previously retained profits from sales of gas to interruptible customers as a rate moderator, and by imputing an increase of $700,000 net revenues from interruptible gas sales of the Company. The Order also based such revenue requirement on a 10.6% return on common equity.

OTHER DEVELOPMENTS

Electric Sales to IBM: The Company's largest customer is International Business Machines Corporation (IBM), which accounted for approximately 14% of the Company's total electric revenues for the year ended December 31, 1993. Published reports indicate that IBM reduced its employment by 45,000 worldwide to 256,000 in 1993 from 301,000 in 1992. Such reports indicate that IBM has reduced its employment in the Company's service territory by up to 8,400 employees in 1993. Such reductions would bring the total number employed in the Company's service territory to approximately 13,100, as compared to the peak level of IBM employment in excess of 30,000 in 1985. During 1993, IBM phased out its semiconductor manufacturing operations at its East Fishkill, New York facility, which is in the Company's service territory. This downsizing of IBM has resulted in a decline of electric sales to IBM by 20% in 1993. The Company cannot assess at this time the effect, if any, of such IBM employment reductions on the Company's future results of operations.

New Accounting Standards: The Company adopted SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other than Pensions" (SFAS 106), in the first quarter of 1993. As discussed in Note 7 of the Notes, this new accounting standard did not have a material impact on the Company's results of operations.

The Company adopted SFAS No. 109, "Accounting for Income Taxes" (SFAS 109), in the first quarter of 1993. As discussed in Note 3 of the Notes, this new accounting standard did not have a material impact on the Company's results of operations.

In November 1992, the Financial Accounting Standards Board (FASB) issued SFAS No. 112, "Employers' Accounting for Postemployment Benefits" (SFAS 112), which the Company will adopt in the first quarter of 1994. As discussed in Note 7 of the Notes, the adoption of SFAS 112 will not have a material impact on the Company's results of operations.

In May 1993, the FASB issued SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS 115), which the Company will adopt in the first quarter of 1994. As discussed in Note 11 of the Notes, the adoption of SFAS 115 will not have a material impact on the Company's results of operations.

Environmental Issues: On an ongoing basis, the Company assesses environmental issues which could impact the Company and its ratepayers. Notes 2 and 9 of the Notes discuss current environmental issues affecting the Company, including the Clean Air Act Amendments of 1990, which require control of emissions from fossil-fueled electric generating units.

RESULTS OF OPERATIONS

The following discussion and analysis includes an explanation of significant changes in revenues and expenses during the years 1991, 1992 and 1993. Additional information relating to changes between these years is provided in the Notes on pages 36 through 52 of this Report.

EARNINGS

Earnings per share of common stock are shown after provision for dividends on preferred stock and are computed on the basis of the average number of common shares outstanding during the year.

The number of common shares, the earnings per share, the percentage change and the rate of return earned on average common equity are as follows:

	1991	1992	1993
Average shares outstanding (000s)	15,530	15,901	16,725
Earnings per share	$ 2.40	$ 2.65	$ 2.68
% increase over prior year	1%	10%	1%
Return earned on common equity per books*	10.6%	11.4%	11.1%

* Return on equity for regulatory purposes differs from these figures.

The 1% increase in the 1991 earnings per share reflects the following favorable results: reduced interest charges resulting from the refinancing of high interest rate debt, increased electric base rates which became effective May 24, 1990 and favorably impacted the first half of 1991, and increased gas base rates which became effective July 8, 1991 and favorably impacted the second half of 1991. Also contributing to the increase were a reduction in the amount of fuel cost increases absorbed by the Company, an increase in the incentive provided to the Company for successful participation in its energy efficiency program and a marked improvement in the relationship between the actual cost of operating the Nine Mile 2 Plant and the amount provided for in the rate-making process. While actual costs exceeded those provided for in rates by $4.8 million in 1990, actual costs for 1991 were $520,000 less than those provided for in rates.

These favorable variations were partially offset, however, by decreased gas sales, a slowdown in the rate of growth in electric sales, higher expenses related to tree-trimming work, increased payroll and related fringe benefits and higher property taxes.

The 25-cent per share increase in the 1992 earnings versus 1991 earnings resulted primarily from increased firm gas sales, increased electric base rates which became effective April 15, 1992, and increased firm gas base rates which became effective July 8, 1991. In addition, lower interest charges resulting from the refinancing of high interest rate debt in 1992 and an increase in the amortization to income of Mirror CWIP as a rate moderator favorably impacted earnings in 1992. The one-time inclusion in income of 50% of the Nine Mile 2 Plant net litigation proceeds of $2.3 million, as more fully discussed in Note 2 of the Notes, accounted for 10-cents of the increase in the 1992 per share earnings.

These favorable variations were partially offset, however, by increased maintenance on the Company's fossil-fuelled electric generating plant, increased payroll costs, an increase in operating reserve provisions, and higher depreciation expense.

The 3-cent per share increase in 1993 earnings versus 1992 earnings includes the effect of one-time items on earnings per share in both 1992 and 1993. The effect of the one-time inclusion of the Nine Mile 2 Plant net litigation proceeds (which increased 1992 earnings by $.10 per share) was partially offset by the effect of a one-time gain from the sale of long-term investments (which increased 1993 earnings per share by $.03). Thus, excluding these two one-time items, income from operations increased $.10 per share in 1993 as compared to 1992. The increase in earnings from operations of $.10 per share is due primarily to higher electric base rates, an increase in the amortization to income of Mirror CWIP as a rate moderator, and lower interest charges on the Company's outstanding debt resulting from the additional refinancing of high interest rate debt in 1993.

These increases were partially offset, however, by a decrease in industrial electric sales (primarily attributable to the operational cutbacks by IBM described above) and higher federal income taxes.

OPERATING REVENUES

Total operating revenues decreased $8.9 million (2%) in 1991, increased $28.8 million (6%) in 1992 and decreased $6.2 million (1%) in 1993. As shown in the table below, the 1991 decrease in revenues was due primarily to decreased revenues collected pursuant to the electric fuel cost adjustment clause and decreased sales of electricity to other utilities, which were partially offset by higher electric base rates. The 1992 increase in revenues was due primarily to increased sales of natural gas, higher electric and gas base rates, and higher gas costs included in revenues, which were partially offset by decreased revenues from sales of electricity to other utilities. The 1993 decrease in revenues was due to a decrease in sales of natural gas, and a decrease in industrial electric sales which was partially offset by increases in electric residential and commercial sales. Also contributing to the overall decrease in operating revenues in 1993 were a decrease in sales to other utilities, the net effect of an increase in electric fuel cost adjustments refunded to customers and an increase in amounts collected from customers through the gas cost adjustment clause. Operating revenues were also affected in 1993 by higher electric base rates.

Details of the revenue changes are as follows:

	Increase or (Decrease) from Prior Year					
	1991		1992		1993	
	Electric	Gas	Electric	Gas	Electric	Gas
	(Thousands of Dollars)					
Customer sales	$ 2,503	$ (2,812)	$(1,515)	$16,957	$(5,818)	$(5,146)
Sales to other utilities	(4,413)	—	(5,353)	—	(2,407)	—
Increase in base rates	5,811	1,157	11,455	3,618	7,605	—
Fuel cost changes reflected in base rates	—	2,499	—	6,850	—	—
Fuel cost adjustment	(11,123)	(2,015)	(2,774)	(2,518)	(4,202)	2,806
Deferred revenues	(2,927)	2,293	770	(2,255)	322	1,628
Miscellaneous	411	(256)	732	2,854	(11)	(961)
Total	$(9,738)	$ 866	$ 3,315	$25,506	$(4,511)	$(1,673)

The Company's electric fuel cost adjustment clause provides for a partial sharing of fuel cost variations, pursuant to an incentive/penalty formula. The PSC requires a sharing between the customers and the Company of variations in actual fuel costs from the forecasted amounts which have been approved by the PSC for a specific twelve-month period, whereby the Company bears 20% of the first $10 million of variation and 10% of the second $10 million of variation. Any variations in excess of $20 million are credited or charged, as appropriate, in total to the customers. See subcaption "Deferred Electric Fuel Costs" of Note 1 of the Notes. The following table sets forth the variation in actual electric fuel costs from the targeted amounts approved by the PSC, the amount charged or credited to retail customers through the electric fuel cost adjustment clause, and the amount retained by the Company and recognized in the results of operations:

	1991	1992	1993
	(Thousands of Dollars)		
Variation in actual electric fuel costs from targeted amounts	$852	$(1,067)	$1,345
Customer (charge) credit	682	(854)	1,076
Income (expense) recognized by the Company	$170	$ (213)	$ 269

The Company's base rates for electricity include an imputed amount of net revenue (gross revenues less incremental costs, principally fuel) from sales of electricity to other utilities. The PSC requires an 80%/20% sharing between customers and the Company, respectively, of any variations from the imputed amount, either higher or lower. The Company reflects any credits or charges to its customers resulting from these provisions through the electric fuel cost adjustment clause.

The following table sets forth the variation in actual net revenue realized from the amounts imputed, the amount charged or credited to retail customers through the electric fuel cost adjustment clause, and the amount of such net revenues retained by the Company and recognized in the results of operations:

	1991	1992	1993
	(Thousands of Dollars)		
Variation in actual net revenue from imputed amounts	$(785)	$(3,118)	$889
Customer (charge) credit	(628)	(2,494)	7[illegible]
Income (expense) recognized by the Company	$(157)	$ (624)	$1[illegible]

Prior to November 22, 1993, the treatment established by the PSC regarding net revenues from interruptible gas sales was to impute in gas base rates an annual level of $1.2 million. Firm gas customers were to receive 100% of any net revenues between $1.2 million and $1.8 million, and any net revenues in excess of $1.8 million were to be shared 80%/20% between the Company's firm gas customers and the Company, respectively.

Pursuant to the Order, the PSC changed said treatment regarding net revenues from interruptible gas sales. First, the PSC assumed that prior interruptible customers would convert to firm transportation service. Second, the PSC increased the level of such net revenues imputed in gas base rates from $1.2 million to $1.9 million. Finally, the incentive sharing mechanism was changed from 80%/20% between the Company's gas customers and the Company to 90%/10%. This mechanism will apply to all net revenues above $1.9 million received between November 22, 1993 and November 21, 1994 from the Company's ten largest firm transportation customers, and all net revenues received between November 22, 1993 and November 21, 1994 from all other interruptible sales and transportation customers, interdepartmental sales, and other firm transportation customers.

The following table sets forth the actual net revenue from interruptible gas sales, the amount credited to firm gas customers, and the amount of such net revenues retained by the Company and recognized in the results of operations:

	1991	1992	1993
	(Thousands of Dollars)		
Actual net revenue from interruptible gas sales	$3,028	$4,515	$3,278
Customer credit	1,550	2,771	1,725
Income recognized by the Company	$1,478	$1,744	$1,553

SALES

Sales of electricity within the Company's service territory increased .7% in 1991, decreased 2.0% in 1992, and decreased 2.8% in 1993. The decline in the growth rate in 1991 and the decrease in sales in 1992 primarily reflected the effect of a general slowdown in the region's economy. The decrease in 1993 largely reflected a decline in usage by IBM. Firm sales of natural gas, excluding sales to the Company's electric department, decreased 2.3% in 1991, increased 11.3% in 1992 and increased 1.9% in 1993. The 1991 decrease resulted primarily from the unusually warm weather which occurred in the winter periods and the transfer of a large industrial customer from firm service to interruptible service. The increase in 1992 was due primarily to the much colder weather experienced in 1992 as heating degree days increased 14%. The 1993 increase was largely attributable to an increase in the number of residential and commercial customers. Heating degree days increased 1% in 1993. Changes in sales by major customer classification are set forth below (parentheses denote decrease):

	Electric %		
	1991	1992	1993
Residential	—	—	3
Commercial	1	—	4
Industrial	1	(6)	(13)

	Gas %		
	1991	1992	1993
Residential	(4)	14	1
Commercial	2	14	3
Industrial	(10)	(19)	—

Residential electric sales: Residential electric sales are primarily affected by the growth in the number of customers and the change in kwh. usage per customer. Customer usage is also sensitive to weather. Changes in these components are set forth in the table below (parentheses denote decrease):

	Residential Sales %		
	1991	1992	1993
Growth in number of customers	1	1	1
Change in average usage per customer	—	(1)	2

The usage per customer remained stable in 1991, as warmer weather experienced during the winter heating season was offset by the hotter weather experienced during the summer air conditioning months. In 1992, usage per customer decreased due to cooler weather experienced during the summer air conditioning months. Residential cooling degree days decreased 77% in 1992. In 1993, the increased usage per customer was largely attributable to hotter summer weather as cooling degree days increased 280%.

Commercial electric sales: Commercial electric sales increased 1% in 1991. In 1992, commercial sales remained stable and in 1993 commercial sales increased 4%. The components of these changes are set forth in the table below (parentheses denote decrease):

	Commercial Sales %		
	1991	1992	1993
Growth in number of customers	2	2	2
Change in average usage per customer	(1)	(2)	2

Industrial electric sales: The increase in industrial electric sales of 1% in 1991 was due primarily to increased usage by existing customers. In 1992, industrial electric sales decreased 6% due to decreased usage by existing customers, including IBM. In 1993, industrial electric sales decreased by 13%, due primarily to a 20% decline in usage by IBM.

Gas sales-firm: The following tables set forth customer growth, changes in customer usage and heating degree days for the residential and commercial classifications. Although the changes in residential gas sales are primarily weather related, the growth in the number of customers has remained a positive factor. Commercial gas sales are also weather sensitive.

	Residential Sales %		
	1991	1992	1993
Growth in number of customers	1	1	2
Change in average usage per customer	(5)	13	(1)
Change in heating degree days:			
Bimonthly billing cycle	(6)	14	1
Calendar year	3	14	—

	Commercial Sales %		
	1991	1992	1993
Growth in number of customers	5	3	4
Change in average usage per customer	(3)	11	(1)
Change in heating degree days:			
Bimonthly billing cycle	(6)	14	1
Calendar year	3	14	—

Firm gas sales to industrial customers decreased 10% in 1991 and 19% in 1992 primarily from decreased sales to existing customers and the shift of a container manufacturing company located within the Company's service territory to interruptible and transportation gas service. Firm gas sales to industrial customers remained stable in 1993.

Gas sales-Interruptible: Interruptible gas sales decreased 20% in 1991, increased 192% in 1992 and decreased 37% in 1993. The 1991 decrease in interruptible gas sales is attributable primarily to a decrease in customer usage and a shift of several customers from interruptible sales service to interruptible transportation service. Transportation service permits large volume users of natural gas to purchase gas directly from producers and wholesalers, and transport the gas through the Company's distribution system. Net revenues from transportation service are approximately equal to those net revenues from the customers who shifted from interruptible service. The 1992 increase was due primarily to the sale of natural gas to the other cotenants of the Roseton Electric Generating Station (Roseton Plant) for use as a boiler fuel as well as the shift of several customers to interruptible sales service from interruptible transportation service. The 1993 decrease was due to a reduction in the amount of natural gas sold to the other cotenants for use as a boiler fuel at the Roseton Plant which was a result of lower costs of alternate fuels. In addition, Unit 2 of the Roseton Plant was severely damaged by a fire in March 1993 and was not returned to service until December 1993.

NUCLEAR OPERATIONS

Since 1990, there has been improvement in the relationship between the actual cost of operating the Nine Mile 2 Plant and the amount provided for in the rate-making process. In 1993, the relationship between the actual cost of operation and the amount provided for in the rate-making process continued to show improvement, providing a positive impact on 1993 earnings.

The Company has continued to participate actively on the management, operations and accounting committees for the Nine Mile 2 Plant and also the finance committee dealing with regulatory and budgeting issues in an effort to produce better forecasts and control costs.

OPERATING EXPENSES

Changes in operating expenses from the prior year are set forth below:

	Increase or (Decrease) from Prior Year					
	1991		1992		1993	
	Amount	%	Amount	%	Amount	%
	(Thousands of Dollars)					
Operating Expenses:						
Fuel and purchased electricity	$(15,511)	(9.9)	$(7,683)	(5.5)	$(10,555)	(7.9)
Purchased natural gas	979	2.5	15,199	38.1	(1,166)	(2.1)
Other expenses of operation	4,852	6.6	6,347	8.1	1,794	2.1
Maintenance	2,138	8.1	2,916	10.2	6	—
Nine Mile 2 Plant operation and maintenance	(3,581)	(23.7)	2,391	20.8	871	6.3
Depreciation and amortization	1,096	3.0	2,366	6.4	86	0.2
Taxes, other than income tax	3,320	5.8	5,785	9.6	(775)	(1.2)
Federal income tax	157	0.7	2,498	11.0	3,492	13.9
Total	$ (6,550)	(1.5)	$29,819	7.1	$ (6,247)	(1.4)

The most significant elements of cost are fuel and purchased electricity in the Company's electric department and purchased natural gas in the Company's gas department. Approximately 33% in 1991, 31% in 1992 and 29% in 1993 of every revenue dollar billed in the Company's electric department was expended for the combined cost of fuel used in electric generation and purchased electricity. The corresponding figures in the Company's gas department for the cost of purchased gas were 56%, 57% and 57%, respectively. As discussed in Note 9 of the Notes, contracts that the Company has in place for a majority of its gas supply will expire in 1994 and will be replaced with competively bid contracts with third-party gas suppliers.

In 1991, the combined cost of fuel used in electric generation and purchased electricity decreased $15.5 million (10%), resulting primarily from lower fuel prices. In 1992 and 1993, the combined cost of fuel used in electric generation and purchased electricity decreased $7.7 million (6%) and $10.6 million (8%), respectively, resulting primarily from decreased sales of electricity.

The following table shows the average fuel cost per kWh. for the Company's three major generating plants during the last five years:

	Average Cost (¢/kWh.)		
	Danskammer Plant	Roseton Plant	Nine Mile 2 Plant
1989	2.27	2.56	1.17
1990	2.36	2.94	1.21
1991	2.25	2.43	.64*
1992	2.01	2.64	.60
1993	1.95	2.67	.57

* The 1991 decrease in the average cost per kWh. for the Nine Mile 2 Plant was primarily a result of the 1991 revaluation of the Plant's remaining MBTUs in the initial load, as well as lower costs associated with the Plant's first reload which occurred in January 1991.

In an effort to keep the cost of electricity at the lowest reasonable level, the Company purchases energy from other member companies of the New York Power Pool, whenever such energy can be purchased at a unit cost lower than the incremental cost of generating the energy in the Company's plants.

The amount of natural gas purchased, excluding gas burned as boiler fuel at the Danskammer Plant and the Company's share of gas burned as a boiler fuel at the Roseton Plant, and the cost per Mcf. during the last five years are set forth in the following table:

Year	Amount of Gas Purchased-Mcf.	$/Mcf.
1989	12,402,848	3.22
1990	11,813,255	3.37
1991	11,640,289	3.50
1992	16,831,406	3.59
1993	14,968,805	3.79

The large increase in gas purchased in 1992 was due primarily to the increased sales of natural gas to residential and commercial customers and the sale of natural gas to the other cotenant owners of the Roseton Plant for use as a boiler fuel beginning in February 1992. The decrease in gas purchased in 1993 was due primarily to a reduction in gas sold to the other cotenant owners for use as a boiler fuel at the Roseton Plant.

Under FERC Order 636, local distribution companies, such as the Company, are permitted to offer unused firm transportation service to others for a fee; this is known as capacity brokering. This new option gives the Company an opportunity to defray some or all of the monthly fixed charges when firm transportation is not fully utilized. The primary benefit of this program is a reduction of costs billed to the Company's firm gas customers.

In an effort to keep the cost of purchased gas at the lowest reasonable level, the Company brokered excess capacity outside of its service territory during November and December 1993.

The Company has filed with the PSC a capacity brokering program for its service territory, which is expected to be approved in early 1994.

The $4.9 million (7%) increase in other expenses of operation in 1991 was due primarily to higher employee wages and related fringe benefits, an increase in major storm costs, an increase in gas department legal expenses and increased operating expenses related to the New York Power Pool. The $6.3 million (8%) increase in other expenses of operation in 1992 was due primarily to higher employee wages, increased costs associated with the Company's energy efficiency programs, increased electric and gas facilities charges, and an increase in the reserve provisions for injuries and damages and uncollectible customer accounts. The 1993 increase of $1.8 million (2%) in other expenses of operation was a result of increased costs associated with the Company's energy efficiency programs and higher employee wages.

Maintenance expenses increased $2.1 million (8%) in 1991 due primarily to increases in steam production maintenance expenses and tree-trimming costs. The increase in steam production maintenance expense of $900,000 was due primarily to increased costs for routine maintenance of the Danskammer Plant generating units and the costs for a major overhaul of Unit 1 of the Danskammer Plant. The 1991 increase was also attributable to a major overhaul of Unit 2 of the Roseton Plant which began in October 1991. The increased tree-trimming expenses of $1.3 million resulted from the intensified program instituted by the Company in the Spring of 1990 whereby the trimming cycle for all electric distribution lines was reduced from four years to three years. Maintenance expenses increased $2.9 million (10%) in 1992 due primarily to increased costs for a major overhaul of Unit 2 at the Danskammer Plant which began in January 1992. Increased maintenance costs related to Unit 4 at the Danskammer Plant in 1992 were offset by a reduction in

maintenance costs related to Unit 1 at the Danskammer Plant. Maintenance costs for 1993 remained flat compared to 1992 maintenance costs.

The Company's portion of operating expenses, taxes and depreciation pertaining to the operation of the Nine Mile 2 Plant are included in the Company's financial results. In 1991, 1992 and 1993, the amounts provided for in rates exceeded operation and maintenance expenses for the Nine Mile 2 Plant by $520,000, $19,000 and $124,000, respectively.

The Company's total provision for depreciation amounted to 3.23% in 1991, 3.29% in 1992 and 3.17% in 1993 of the original cost of average depreciable property. The ratio of the amount of accumulated depreciation to the cost of depreciable property at December 31 was 30.9% in 1991, 31.4% in 1992 and 32.8% in 1993.

State and local taxes levied on gross revenues increased in 1991 and 1992 by $1.4 million and $4.9 million, respectively, and decreased $1.8 million in 1993. In 1991, the revenue taxes were impacted by an increase in the New York State Gross Receipt Tax Rate from 3.0% to 3.5%. In 1992, the revenue taxes increase was due to the increase in the New York State Gross Receipt Tax Rate as well as the increase in revenues in 1992. The 1993 decrease was due primarily to the inclusion in 1992 cost of a retroactive New York State Gross Receipt Tax, which increased 1992 costs by $1.2 million.

Property taxes, including school taxes, increased $1.4 million, $405,000 and $891,000 in 1991, 1992 and 1993, respectively. Commercial operations of the Nine Mile 2 Plant accounted for $396,000, $259,000 and $90,000, respectively, of such increases. These two categories of taxes accounted for a substantial portion of the total changes in operating taxes.

With the enactment in August 1993 of the Omnibus Budget Reconciliation Act of 1993 (OBRA), the corporate federal income tax rate increased from 34% to 35%, effective January 1, 1993. The PSC authorized deferral of the resultant increase in the corporate federal income tax rate until such costs are collected from customers through rates.

See Note 3 of the Notes for an additional analysis and reconciliation of the federal income tax.

OTHER INCOME AND INTEREST CHARGES

Details of the AFDC are set forth below:

	1991	1992	1993
		(Thousands of Dollars)	
Nine Mile 2 Plant	$ 707	$ 597	$ 7[illegible]
Iroquois Gas Pipeline interconnection	272	201	—
Other	1,231	749	807
Total	$2,210	$1,547	$1,545
AFDC rate	9.00%	6.75%	8.75%

The higher AFDC rate in 1993 was due to construction expenditures being funded primarily by the higher cost of permanent capital as compared to lower cost short-term borrowings in 1992.

See Note 1 of the Notes for additional information on this subject.

Total interest charges (excluding AFDC) decreased $5.2 million (12%) in 1991, $3.3 million (9%) in 1992 and $1.2 million (4%) in 1993. The following table sets forth some of the pertinent data on the Company's outstanding debt:

	1991	1992	1993
		(Thousands of Dollars)	
Long-term debt:			
New debt issued	$100,000	$ 76,000	$ 40,000
Debt retired	89,000	56,000	40,000
Outstanding at year-end:*			
Amount (including current portion)	423,785*	443,618*	443,897*
Effective rate	7.70%	7.05%	6.75%
Short-term debt:			
Average daily amount outstanding	$ 8,281	$ 12,984	$ 330
Weighted average interest rate	7.12%	4.48%	3.9[illegible]

*Including debt of subsidiaries of $4.527 million in 1991, $4.442 million in 1992 and $4.803 million in 1993.

See Notes 4 and 6 of the Notes for additional information on this subject.

In an effort to reduce its cost of debt, the Company refinanced a large portion of its high interest rate debt with lower rest rate debt during the period from December 1990 to November 1993. Details of the 1991, 1992 and 1993 long-term bt redemptions and issuances and sales (excluding issuances and sales under the Company's Medium Term Note ogram) are shown below:

Redemptions:

Series of First Mortgage Bonds	Principal Amount Redeemed	Applicable Redemption Price (% of Principal Amount)	Redemption Date
14 5/8% Series due 1994	$45,000,000	103.250%	June 12, 1991
10 5/8% Series due 2005	20,000,000	105.900%	July 1, 1991
10 3/4% Series due 2009	20,000,000	106.400%	July 1, 1991
11 % Series due 1995	4,000,000*	100.000%	July 2, 1991
11 % Series due 1995	4,000,000*	100.000%	July 2, 1992
11 % Series due 1995	12,000,000	102.445%	July 2, 1992
9 3/8% Series due 2000	25,000,000	102.390%	August 1, 1992
9 1/4% Series due 2004	15,000,000	104.080%	August 1, 1992
7 3/4% Series due 2002	20,000,000	102.630%	September 1, 1993
7 1/8% Series due 1999	20,000,000	101.230%	November 15, 1993

Issuance and Sale:

Series of First Mortgage Bonds	Principal Amount	Proceeds to Company	Issuance and Sale Date
9 1/4% Series due 2021	$70,000,000	98.028%	May 14, 1991
8 3/4% Series due 2001	30,000,000	97.836%	May 14, 1991

inking fund payment.

Details of the issuances and sales in 1992 and 1993 under the Company's Medium Term Note Program under which First Mortgage Bonds and/or unsecured debt can be issued are shown below:

Tranches of Medium Term Notes	Principal Amount	Proceeds to Company	Issuance and Sale Date
7.70% Series due 2000*	$25,000,000	99.400%	June 11, 1992
7.97% Series due 2003*	8,000,000	99.375%	June 11, 1992
7.97% Series due 2003*	8,000,000	99.375%	June 11, 1992
7.85% Series due 2004**	15,000,000	99.375%	July 2, 1992
8.12% Series due 2022*	10,000,000	99.250%	August 31, 1992
8.14% Series due 2022*	10,000,000	99.250%	August 31, 1992
6.10% Series due 2000*	10,000,000	99.400%	August 9, 1993
6.46% Series due 2003*	10,000,000	99.375%	August 9, 1993
5.38% Series due 1999**	20,000,000	99.500%	October 14, 1993

* First Mortgage Bonds.
** Promissory Note.

Under the Company's Medium Term Note Program, the Company has authorization from the PSC by an amended Order effective September 29, 1993, to issue and sell up to $125 million principal amount of Medium Term Notes through December 31, 1994, of which the Company has issued and sold $116 million through December 31, 1993 as detailed above.

FINANCIAL INDICES

Selected financial indices for the last five years are set forth in the following table:

	1989	1990	1991	1992	1993
Pretax coverage of total interest charges:					
Including AFDC*	2.33x	2.43x	2.70x	3.07x	3.29x
Excluding AFDC*	2.25x	2.36x	2.62x	2.95x	3.15x
Pretax coverage of total interest charges and preferred stock dividends*	1.96x	2.04x	2.22x	2.49x	2.65x
Percent of construction expenditures financed from internal funds	100%	100%	88%	100%	100%
AFDC and Mirror CWIP as a percentage of income available for common stock	11%	9%	8%	10%	11%
Effective tax rate	33%	33%	33%	34%	35%

* Prior year amounts have been restated to conform to current year reporting which includes the interest portion of rent expense as a component of interest charges.

COMMON STOCK DIVIDENDS AND PRICE RANGES

The Company and its principal predecessors have paid dividends on its common stock in each year commencing 1903, and the common stock of the Company has been listed on the New York Stock Exchange since 1945. The price ranges and the dividends paid for each quarterly period during the Company's last two fiscal years are indicated on page 16 of this Report.

On June 28, 1991, the quarterly dividend rate was increased to $.48 per share and on June 26, 1992 the Company further increased the quarterly dividend to $.50 per share. On June 25, 1993 the Company increased the quarterly dividends to $.515 per share. While the Board of Directors of the Company intends to continue the practice of paying dividends quarterly, the amounts and dates of such dividends as may be declared will be based on all of the facts and circumstances known at the time of consideration of such declaration.

The number of registered holders of common stock as of December 31, 1993 was 26,761. Of these, 26,458 were accounts in the names of individuals with total holdings of 6,485,132 shares, or an average of 245 shares per account. The 303 other accounts, in the names of institutions or other non-individual holders, for the most part, hold shares for the benefit of individuals.

The Company's 4.85% Promissory Notes due December 1, 1995 contain limitations upon the right of the Company to declare or pay any dividend or make any other distribution on (other than dividends or distributions payable in common stock), or acquire, for a consideration, any shares of its common stock unless the aggregate of all such dividends, distributions and considerations since December 31, 1964 does not exceed an amount determined by a formula. At December 31, 1993, the amount of retained earnings available for dividends on the Company's common stock under the provisions of said 4.85% Promissory Notes was $60.609 million.

Report of Independent Accountants

Price Waterhouse

To the Board of Directors and Shareholders of
Central Hudson Gas & Electric Corporation

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, of retained earnings and of cash flows present fairly, in all material respects, the financial position of Central Hudson Gas & Electric Corporation and its subsidiaries at December 31, 1993 and 1992, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1993, in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these financial statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

As discussed in the Notes to the Consolidated Financial Statements, in 1993 the Company changed its methods of accounting for federal income taxes (Note 3) and postretirement benefits other than pensions (Note 7) to conform with Statements of Financial Accounting Standards No. 109 and No. 106, respectively.

Price Waterhouse

New York, New York
January 28, 1994

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(Thousands of Dollars)

	Year ended December 31,		
	1993	1992	1991
Balance at beginning of year	$ 58,692	$48,093	$ 40,611
Net Income	50,390	47,688	42,941
	109,082	95,781	83,552
Dividends declared:			
On cumulative preferred stock	5,562	5,544	5,659
On common stock ($2.045 per share 1993; $1.98 per share 1992; $1.90 per share 1991)	34,497	31,545	29,800
	40,059	37,089	35,459
Balance at end of year	$ 69,023*	$ 58,692	$ 48,093

* Pursuant to the terms of the 4.85% promissory notes, due 1995, $60,609 is available for payment of dividends on common stock.

The Notes to Consolidated Financial Statements are an integral part hereof.

CONSOLIDATED BALANCE SHEET

(Thousands of Dollars)

ASSETS

	1993	1992
Utility Plant		
Electric	$1,083,491	$1,060,528
Gas	128,093	121,021
Common	80,485	77,870
Nuclear fuel	28,199	25,989
	1,320,268	1,285,408
Less: Accumulated depreciation	427,504	397,893
Nuclear fuel amortization	20,646	17,872
	872,118	869,643
Construction work in progress	42,741	34,930
	914,859	904,573
Other Property and Investments	8,465	9,078
Current Assets		
Cash	6,609	6,787
Temporary cash investments	20,563	4,471
Special deposits	458	1,209
Accounts receivable from customers - net (Note 8)	46,452	46,603
Accrued unbilled utility revenues (Notes 1 and 8)	16,931	15,48[illegible]
Other receivables	2,255	3,2[illegible]
Materials and supplies, at average cost:		
Fuel	20,800	23,79[illegible]
Construction and operating	14,617	14,249
Prepaid taxes and other prepayments	10,910	10,603
	139,595	126,478
Deferred Charges		
Income taxes recoverable (Note 3)	71,121	—
Deferred finance charges approved for amortization (Note 1)	37,868	25,631
Deferred finance charges - Nine Mile 2 Plant (Note 1)	35,181	48,208
Unamortized debt expense	12,707	13,524
Deferred energy efficiency costs (Note 1)	10,316	9,220
Deferred vacation (Note 1)	3,643	3,441
Other	30,485	26,971
	201,321	126,995
Accumulated Deferred Income Tax (Note 3)	63,995	44,152
	$1,328,235	$1,211,276

The Notes to Consolidated Financial Statements are an integral part hereof.

LIABILITIES

	1993	1992
Capitalization		
Common Stock Equity		
Common stock, $5 par value (Note 5)	$ 84,766	$ 80,143
Paid-in capital (Note 5)	270,848	245,349
Retained earnings	69,023	58,692
Capital stock expense	(6,791)	(5,970)
	417,846	378,214
Cumulative Preferred Stock (Note 5)		
Not Subject to Mandatory Redemption	46,030	61,030
Subject to Mandatory Redemption	35,000	19,200
	81,030	80,230
Long-term Debt (Note 6)	391,810	441,096
	890,686	899,540
Current Liabilities		
Current maturities of long-term debt and preferred stock	51,019	2,243
Notes payable	—	15,000
Accounts payable	28,554	27,886
Accrued taxes	249	3,949
Accrued interest	6,361	7,222
Accrued vacation (Note 1)	3,836	3,634
Customer deposits	3,452	3,191
Dividends payable	9,906	9,374
Other	4,716	5,172
	108,093	77,671
Deferred Credits and Other Liabilities		
Income taxes refundable (Note 3)	28,935	—
Deferred finance charges - Nine Mile 2 Plant (Note 1)	35,181	48,208
Deferred finance charges approved for amortization (Note 1)	5,250	1,000
Deferred unbilled gas revenues (Note 1)	5,814	4,870
Deferred Nine Mile 2 Plant litigation proceeds (Note 2)	3,695	3,350
Accrued pension costs (Note 7)	11,733	14,295
Operating reserves	2,346	1,818
Other	4,723	3,807
	97,677	77,348
Accumulated Deferred Income Tax (Note 3)	231,779	156,717
Commitments and Contingencies (Notes 2 and 9)	—	—
	$1,328,235	$1,211,276

The Notes to Consolidated Financial Statements are an integral part hereof.

CONSOLIDATED STATEMENT OF INCOME

(Thousands of Dollars)

	Year ended December 31, 1993	1992	1991
Operating Revenues			
Electric	$411,339	$413,443	$404,775
Gas	94,448	96,121	70,615
Total - own territory	505,787	509,564	475,390
Revenues from electric sales to other utilities	11,586	13,993	19,346
	517,373	523,557	494,736
Operating Expenses			
Operation:			
Fuel used in electric generation	72,291	106,970	121,587
Purchased electricity	49,959	25,835	18,901
Purchased natural gas	53,900	55,066	39,867
Other expenses of operation	98,327	95,916	86,984
Maintenance	34,486	34,226	31,504
Depreciation and amortization (Note 1)	39,682	39,596	37,230
Taxes, other than income tax	65,564	66,339	60,554
Federal income tax (Note 3)	14,502	5,467	10,514
Deferred income tax (Note 3)	14,101	19,644	12,099
	442,812	449,059	419,240
Operating Income	74,561	74,498	75,4[illegible]
Other Income and Deductions			
Allowance for equity funds used during construction (Note 1)	934	596	921
Federal income tax (Note 3)	2,937	(7,789)	2,454
Deferred income tax (Note 3)	(1,492)	8,537	(1,202)
Other - net	5,167	4,427	854
	7,546	5,771	3,027
Income before Interest Charges	82,107	80,269	78,523
Interest Charges			
Interest on mortgage bonds	22,390	23,207	25,236
Interest on other long-term debt	6,487	6,286	7,482
Other interest	1,204	1,954	2,569
Allowance for borrowed funds used during construction (Note 1)	(611)	(951)	(1,289)
Amortization of premium and expense on debt	2,247	2,085	1,584
	31,717	32,581	35,582
Net Income	50,390	47,688	42,941
Dividends on Preferred Stock	5,562	5,544	5,659
Income Available for Common Stock	$ 44,828	$ 42,144	$ 37,282
Common Stock:			
Average shares outstanding (000s)	16,725	15,901	15,53[illegible]
Earnings per share on average shares outstanding	$2.68	$2.65	$2.[illegible]

The Notes to Consolidated Financial Statements are an integral part hereof.

CONSOLIDATED STATEMENT OF CASH FLOWS

(Thousands of Dollars)

	Year ended December 31, 1993	1992	1991
Operating Activities			
Net Income	$50,390	$47,688	$42,941
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization and nuclear fuel amortization	43,887	42,999	41,367
Deferred income taxes, net	15,593	11,107	13,301
Allowance for equity funds used during construction	(934)	(596)	(921)
Nine Mile 2 Plant deferred finance charges, net	(7,987)	(9,951)	95
Provisions for uncollectibles	3,431	3,824	3,536
Accrued pension costs	(2,562)	8,774	2,432
Nine Mile 2 Plant net litigation proceeds	16	(2,328)	—
Gain on sale of long-term investments	(670)	—	—
Other - net	(2,285)	2,009	(3,861)
Changes in current assets and liabilities, net:			
Accounts receivable and unbilled utility revenues	(3,701)	(10,670)	(4,597)
Materials and supplies	2,623	(598)	3,140
Special deposits, prepaid taxes, and other prepayments	444	(949)	(949)
Accounts payable	668	(6,725)	9
Accrued taxes and interest	(4,561)	1,535	(4,318)
Other current liabilities	7	(1,788)	98
Net cash provided by operating activities	94,359	84,331	92,273
Investing Activities			
Additions to Plant	(54,037)	(61,721)	(70,907)
Allowance for equity funds used during construction	934	596	921
Net cash expenditures	(53,103)	(61,125)	(69,986)
Investment activity of subsidiaries	(69)	(204)	(1,751)
Plant retirements, costs of removal and other	(146)	(467)	(753)
Nine Mile 2 Plant decommissioning trust fund	(942)	(917)	(868)
Proceeds from sale of long-term investments	2,212	—	—
Net cash used in investing activities	(52,048)	(62,713)	(73,358)
Financing Activities			
Proceeds from issuance of:			
Long-term debt	41,722	77,630	101,131
Common stock	30,122	7,453	19,326
Preferred stock	35,000	—	—
Net repayments of short-term debt	(15,000)	(4,000)	(9,000)
Retirement and redemption of long-term debt	(41,443)	(57,797)	(90,874)
Retirement and redemption of preferred stock	(35,000)	—	—
Dividends paid on preferred and common stock	(39,527)	(36,691)	(34,801)
Issuance and redemption costs	(2,271)	(2,869)	(7,257)
Net cash used in financing activities	(26,397)	(16,274)	(21,475)
Net Change in Cash and Cash Equivalents	15,914	5,344	(2,560)
Cash and Cash Equivalents at Beginning of Year	11,258	5,914	8,474
Cash and Cash Equivalents at End of Year	$ 27,172	$ 11,258	$ 5,914
Supplemental Disclosure of Cash Flow Information			
Interest paid (net of amounts capitalized)	$30,287	$ 30,413	$ 34,499
Federal income taxes paid	13,000	11,298	10,500

The Notes to Consolidated Financial Statements are an integral part hereof.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General: The Company is subject to regulation by the Public Service Commission of the State of New York (PSC) and the Federal Energy Regulatory Commission (FERC) with respect to its rates for service and the maintenance of its accounting records. The Company's accounting policies conform to generally accepted accounting principles as applied to regulated public utilities and are in accordance with the accounting requirements and rate-making practices of the regulatory authorities having jurisdiction.

For purposes of the Consolidated Statement of Cash Flows, the Company considers temporary cash investments with an original maturity of three months or less to be cash equivalents.

Certain amounts from prior years have been reclassified on the consolidated financial statements to conform with the 1993 presentation.

Principles of Consolidation: The consolidated financial statements include the accounts of the Company and its subsidiaries. All intercompany balances and transactions have been eliminated.

The Company's subsidiaries are wholly owned landholding, cogeneration and energy management companies. Due to immateriality, the net income of the Company's subsidiaries is reflected in the Consolidated Statement of Income as other nonoperating income-net.

Summarized financial data for the Company's subsidiaries, included in the consolidated financial statements, is as follows:

	1993	1992	1991
	(Thousands of Dollars)		
Total Assets (year-end)	$20,097	$17,651	$14,378
Net Assets (year-end)	10,240	9,274	6,140
Revenues	7,368	4,753	5,758
Net Income	966	634	195

Utility Plant: The costs of additions to utility plant and replacements of retirement units of property are capitalized at original cost. The costs of Unit No. 2 of the Nine Mile Point Nuclear Station (Nine Mile 2 Plant) are capitalized at original cost, less the disallowed investment of $169.3 million which was recorded in 1987. Costs include labor, materials and supplies, indirect charges for such items as transportation, certain taxes, pension and other employee benefits and an allowance for the cost of funds used during construction. Replacement of minor items of property is included in maintenance expenses.

The original cost of property, together with removal cost, less salvage, is charged to accumulated depreciation at such time as the property is retired and removed from service.

The Company has a 9% or 97.2 MW interest in the 1,080 MW Nine Mile 2 Plant and a 35% or 420 MW interest in the 1,200 MW Roseton Steam Electric Generating Plant (Roseton Plant). See Note 9 for further discussion of the Roseton Plant.

The Company's shares of the investment in the Nine Mile 2 Plant and the Roseton Plant, as included in its Consolidated Balance Sheet at December 31, 1993 and 1992, were:

	1993	1992
	(Thousands of Dollars)	
Nine Mile 2 Plant		
Plant in service	$304,354	$301,722
Construction work in progress	7,933	6,299
Accumulated depreciation	(41,148)	(33,272)
Roseton Plant		
Plant in service	$122,753	$124,085
Construction work in progress	1,014	373
Accumulated depreciation	(62,623)	(62,34

Allowance For Funds Used During Construction: The Company includes in plant costs an allowance for funds used during construction (AFDC) approximately equivalent to the cost of funds used to finance construction expenditures. The concurrent credit for the amount so capitalized is reported in the Consolidated Statement of Income as follows: the portion applicable to borrowed funds is reported as a reduction of interest charges while the portion applicable to other funds (the equity component, a noncash item) is reported as other income. The amount shown on the Consolidated Statement of Cash Flows for investing activities "Net cash expenditures" excludes the equity component of the AFDC.

During the construction of the Nine Mile 2 Plant, the PSC authorized the inclusion in rate base of increasing amounts of the Company's investment in that Plant. The Company did not accrue AFDC on any of the Nine Mile 2 Plant construction work in progress (CWIP) which was included in rate base and for which a cash return was being allowed; however, the PSC ordered, effective January 1, 1983, that amounts be accumulated in deferred debit and credit accounts equal to the amount of AFDC which was not being accrued on the CWIP included in rate base (Mirror CWIP). The balance in the deferred credit account is available to reduce future revenue requirements by amortizing portion

of the deferred credit to other income or by the elimination through writing off other deferred balances as directed by the PSC. Based on the history of cost escalation in the electric utility industry and the history of the Company's rate increases, the Company expects such application of the deferred credit will occur over a period substantially shorter than the life of the Nine Mile 2 Plant. When amounts of such deferred credit are applied in order to reduce revenue requirements, amortization is started for a corresponding amount of the deferred debit, which amortization continues on a level basis over the remaining life of the Nine Mile 2 Plant resulting in recovery of such corresponding amount through rates. Deferred debit and deferred credit amounts approved for amortization are identified on the Consolidated Balance Sheet as "Deferred finance charges approved for amortization." Deferred debit and deferred credit amounts not yet approved for amortization are identified on the Consolidated Balance Sheet as "Deferred finance charges - Nine Mile 2 Plant." Both the deferred debit and the deferred credit are expected to be exhausted by the end of the useful life of the Nine Mile 2 Plant either through the amortization or write-off procedures described above or through the write-off of the remaining debit and credit as directed by the PSC. The net effect of this procedure is that at the end of the amortization period for the deferred credit, the accounting and rate-making treatment will be the same as if the Nine Mile 2 Plant CWIP had not been included in rate base during the construction period.

Pursuant to the PSC Order and Opinion issued April 9, 1992 regarding the Company's electric rate case, the Company was authorized to offset $8.5 million of the deferred credit against other deferred balances and to amortize $3.0 million to other income over 12 months beginning in May 1992. Pursuant to the PSC Order Adopting Revenue Requirement and Rate Design issued on December 16, 1993 (1993 Rate Order) regarding the Company's 1993 Electric Rate Case, the Company was authorized to offset $5.5 million of the deferred credit against other deferred balances and to amortize $6.0 million to other income over 12 months beginning in December 1993. In 1993 and 1992, the Company amortized $3.3 million and $2.1 million, respectively, of this deferred credit.

Depreciation and Amortization: For financial statement purposes, the Company's depreciation provisions are computed on the straight-line method using rates based on studies of the estimated useful lives and estimated net salvage of properties, with the exception of the Nine Mile 2 Plant which is depreciated on a remaining life amortization method. Reference is made to the caption "Operating Expenses" in "Management's Discussion and Analysis of Financial Condition and Results of Operations" for the ratio of the total provision for depreciation to average depreciable property for 1993, 1992 and 1991. The Company performs depreciation studies on a continuing basis and upon approval by the PSC, periodically adjusts the rates of its various classes of depreciable property. The Company estimates the useful life of the Nine Mile 2 Plant will end in the year 2026. The provision for depreciation of transportation equipment is charged indirectly to various asset and expense accounts.

For federal income tax purposes, the Company uses an accelerated method of depreciation and generally uses the shortest life permitted for each class of assets.

Amortization of Nuclear Fuel: The cost of the Nine Mile 2 Plant nuclear fuel assemblies and components is amortized to operating expenses based on the quantity of heat produced for the generation of electric energy. Niagara Mohawk Power Corporation (Niagara Mohawk), on behalf of the Nine Mile 2 Plant cotenants, has entered into an agreement with the U.S. Department of Energy (DOE) for the ultimate disposal and storage of spent nuclear fuel. The cotenants are assessed a fee for such disposal based upon the kilowatt-hours sold which are generated by the Nine Mile 2 Plant. These costs are charged to operating expense and recovered from customers through base rates or through the electric fuel cost adjustment clause described below. The Company cannot now determine whether such arrangements with the DOE will ultimately provide for the satisfactory permanent disposal of such waste products.

Rates and Revenues: Electric and gas retail rates applicable to intrastate service (other than contractually established rates for service to municipalities and governmental bodies) are regulated by the PSC. Transmission rates, facilities charges and rates for electricity sold for resale in interstate commerce are regulated by the FERC.

Revenues are recognized on the basis of cycle billings rendered monthly or bimonthly. Estimated revenues are accrued for those customers billed bimonthly whose meters are not read in the current month. Moreover, as a result of a gas rate Order of the PSC issued in July 1991, an additional amount of unbilled revenues for gas customers is recorded in a deferred credit account. This additional amount of unbilled revenue is available to reduce future revenue requirements. In such Order, the PSC authorized $1.2 million of this additional revenue to be amortized over a 36-month period. During 1993, 1992 and the six-month period July through December 1991, the Company amortized $361,000, $394,000 and $197,000, respectively, of such revenue. Pursuant to the 1993 Rate Order, regarding the Company's 1993 Gas Rate Case, the Company discontinued such amortization as of November 30, 1993.

The Company's tariff for retail electric service includes a fuel cost adjustment clause pursuant to which electric rates are adjusted to reflect changes in the average cost of fuels used for electric generation and in certain purchased power costs, from the average of such costs included in base rates. The Company's tariff for gas service contains a comparable clause to adjust gas rates for changes in the price of purchased natural gas and in certain costs of manufactured gas.

Reference is made to the captions "Rate Proceeding - Electric" and "Rate Proceeding - Gas" in "Management's Discussion and Analysis of Financial Condition and Results of Operations" for details of the Company's 1993 Electric Rate Case and 1993 Gas Rate Case.

Deferred Electric Fuel Costs: The provisions of the electric fuel cost adjustment clause are such that changes in fuel costs incurred in the current month are not billed or credited to customers until subsequent months. Therefore, in order to match costs and revenues, the Company defers that portion of such costs incurred in the current month which will result in a cost adjustment in subsequent months.

Pursuant to a 1985 Order of the PSC, the Company's electric fuel cost adjustment clause provides for a partial sharing of variations in fuel costs from the levels of fuel costs projected in rate proceedings. The Company bears 20% of the first $10 million of variation and 10% of the second $10 million of variation. The partial sharing applies to variations in actual fuel costs either above or below the projected levels; accordingly, the Company's maximum annual exposure, or benefit, is $3 million, before taxes.

As a result of the adoption of the partial sharing electric fuel adjustment clause, the PSC adopted a symmetrical sharing arrangement for net revenues from sales to other utilities. Shortfalls below the imputed amount, as well as amounts above the imputed amount, will be shared 80% by the customers and 20% by the Company.

Reference is made to "Management's Discussion and Analysis of Financial Condition and Results of Operations" for results of both sharing arrangements mentioned above.

Deferred Gas Costs: In accordance with requirements of the PSC applicable to all New York State regulated gas utilities, the Company defers each month any difference between the amount of gas costs incurred which is recoverable through the gas cost adjustment clause (GAC) and GAC revenues. The net deferral remaining at August 31 of each year is amortized over a subsequent twelve-month period for both billing and accounting purposes. See Note 9 - Commitments and Contingencies - "Natural Gas Supply" and "Take-or-Pay Gas Costs" as to deferral of certain contract take-or-pay costs charged by pipeline suppliers.

Energy Efficiency Programs: The PSC has required utilities to adopt comprehensive long-range planning which includes demand side management and energy conservation (Energy Efficiency Program). The Company's 1993 and 1994 Energy Efficiency Program was approved by the PSC during 1993. The Energy Efficiency Program costs are deferred and amortized over either five or ten years, as directed by the PSC.

In addition to the deferral of Energy Efficiency Program costs, the Company recovers lost net revenues that result from the Program. Incentive earnings related to the achievement of energy efficiency goals are recovered through the electric fuel adjustment clause.

Accrued Vacation: The Company's employees begin accruing vacation in July of each year for use in the following year; the monthly accrual of days is based on the number of years of service for each employee. However, for rate-making purposes, vacation pay is recognized as an allowable expense only when paid. The Company accrued $3.8 million and $3.6 million as of December 31, 1993 and 1992, respectively, as a current liability for an estimate of earned vacation pay, and consistent with its rate-making treatment, recorded a deferred charge representing the future recoverability of this cost.

NOTE 2 — NINE MILE 2 PLANT

General: The Nine Mile 2 Plant is located in Oswego County, New York, and is operated by Niagara Mohawk. The Nine Mile 2 Plant is owned as tenants in common by the Company (9% interest), Niagara Mohawk (41% interest), New York State Electric & Gas Corporation (18% interest), Long Island Lighting Company (18% interest) and Rochester Gas and Electric Corporation (14% interest). The output of the Nine Mile 2 Plant, which has a rated net capability of 1,080 MW, is shared and the operating expenses of the Plant are allocated to the cotenants in the same proportions as the cotenants' respective ownership interests. The Company's share of direct operating expense for the Nine Mile 2 Plant is included in the appropriate expense classifications in the accompanying Consolidated Statement of Income.

An Operating Agreement for the operation of the Plant was entered into by the cotenants on January 1, 1993 and was submitted for approval to the PSC. Under that Agreement, Niagara Mohawk will continue as operator of the Nine Mile 2 Plant, but all five cotenant owners share certain policy, budget and managerial oversight functions. The fixed term of such Operating Agreement is two years from its effective date and, unless terminated on the expiration of such two-year period, continues subject to termination on six months' notice.

Plant Litigation and Settlements: In 1992, the Company recognized $2.328 million in other income representing the shareholders' portion of the net proceeds from various settlement agreements regarding disputes and litigations that arose in connection with the construction of the Nine Mile 2 Plant. Pursuant to the 1993 Rate Order, the ratepayers' share of the net proceeds of $3.542 million will be refunded by the Company to its customers during the twelve months beginning December 21, 1993 as discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Rate Proceeding-Electric."

Radioactive Waste: Niagara Mohawk has informed the Company that a low-level radioactive waste management program and contingency plan has been developed and provides assurance that the Nine Mile 2 Plant is properly prepared to handle interim storage of low-level radioactive waste for at least a 10-year period, if required. Niagara Mohawk has contracted with the DOE for disposal of high-level radioactive waste (spent fuel) from the Nine Mile 2 Plant (see Note 1-Summary of Significant Accounting Policies - "Amortization of Nuclear Fuel"). The DOE announced in early 1990 that the schedule for start of operations of its high-level radioactive waste repository had slipped from 2003 to no sooner than 2010. The Company has been advised by Niagara Mohawk that the Nine Mile 2 Plant Spent Fuel Storage Pool has a capacity for spent fuel that is adequate until 2014. If further DOE schedule slippage should occur, facilities that extend the on-site storage capability for spent fuel at the Nine Mile 2 Plant beyond 2014 would need to be acquired.

Refueling Outage: A scheduled refueling outage for the Nine Mile 2 Plant commenced on October 2, 1993. The refueling outage was completed and the Plant was placed back in service on November 29, 1993.

Nuclear Plant Decommissioning Costs: The Company's 9% share of costs to decommission the Nine Mile 2 Plant, which is expected to begin in the year 2027, is estimated to be approximately $118.5 million ($23.9 million in 1993 dollars; $4.4 million non-radioactive, $19.5 million radioactive), based on a 1989 cost estimate included in the decommissioning plan filed with the Nuclear Regulatory Commission (NRC) on July 18, 1990. Niagara Mohawk has informed the Company that the decommissioning study is expected to be updated in 1994. Certain estimated decommissioning costs for the Nine Mile 2 Plant are currently being recovered in rates through an annual allowance and are charged to operations through depreciation charges. The annual decommissioning allowance reflected in rate-making is based upon the 1989 estimate which includes amounts for radioactive and non-radioactive dismantlement costs. The annual allowance for recovery during the period August 1, 1988 through May 31, 1990 was $324,000. Effective June 1, 1990 the PSC authorized recovery, on an annual basis, of $212,000 for internal decommissioning funding (i.e., funds held by the Company) and $787,000 for external decommissioning funding (i.e., funds held in trust). Total recoveries authorized by the PSC for the internal decommissioning fund from August 1988 through December 31, 1993 amounted to $969,000. The external decommissioning trust fund at December 31, 1993 amounted to $3.608 million, including net earnings through December 31, 1993 of $388,000, and is reflected in the Company's Consolidated Balance Sheet in "Other Property and Investments." The amount of accumulated decommissioning costs recovered through rates and the net earnings of the external decommissioning trust fund are reflected in accumulated depreciation on the Consolidated Balance Sheet and amount to $4.6 million and $3.5 million at December 31, 1993 and 1992, respectively. NRC regulations require the direct funding of eventual decommissioning costs of nuclear facilities. The Company, effective as of March 1, 1990 established a master trust in order to comply with these NRC requirements. The trust includes a fund qualified, under the applicable provisions of the federal tax law, to take advantage of certain federal income tax benefits. Guidelines have been established by the NRC for determining minimum amounts that must be available in the trust for specified decommissioning activities at the time of decommissioning. Applying the NRC guidelines established in May 1993, the Company has estimated that its share of the minimum requirements will be approximately $38.4 million in 1993 dollars. The Company will seek an increase in its rate allowance in its next rate case to reflect the latest NRC minimum requirements or the results of the 1994 study.

The Company cannot now determine whether the decommissioning costs allowed in rates by the PSC, or the estimated costs discussed above will ultimately be adequate to decommission the Nine Mile 2 Plant in accordance with then existing law, regulation, technology and/or costs. The Company believes that decommissioning costs, if higher than currently estimated, will ultimately be recovered in the rate-making process, although no such assurance can be given.

Decontamination and Decommissioning Fund: The Energy Policy Act of 1992, signed into law in October 1992, established a Uranium Enrichment Decontamination and Decommissioning Fund (Fund) for the decommissioning of the DOE's enrichment facilities. Special annual assessments to utilities with nuclear power plants, which began in 1993 and continue until 2006, and government appropriations will be deposited into the Fund. The Energy Policy Act of 1992 also provides that such assessments shall be considered a cost of fuel and shall be recoverable in rates.

The unamortized portion of the Company's share of this assessment at December 31, 1993 of approximately $724,000 and a corresponding regulatory asset are reflected on the Consolidated Balance Sheet.

NOTE 3 — FEDERAL INCOME TAX

The Company's policy with respect to accounting for federal income taxes is to reflect in income the estimated amount of income tax currently payable and to provide for deferred taxes in accordance with generally accepted accounting principles.

Effective January 1, 1993, the Company adopted Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" (SFAS 109) prospectively. The adoption of SFAS 109 changes the Company's method of accounting for income taxes from the deferred method (in accordance with Accounting Principles Board No. 11 [APB 11]) to an asset and liability approach. Previously, the Company deferred the tax effects of certain timing differences between financial reporting and taxable income. The asset and liability approach requires the recognition of deferred tax liabilities and assets for the expected future tax consequences of temporary differences between the carrying amounts for financial reporting purposes and the tax bases of assets and liabilities. The Company's adoption of SFAS 109 was in accordance with provisions of a Statement of Interim Policy on Accounting and Rate-making Procedures to Implement SFAS 109 issued by the PSC and had no impact on the Consolidated Statement of Income. As set forth below, the adoption of SFAS 109 affected the Consolidated Balance Sheet only.

Components of Federal Income Tax: The following is a summary of the components of federal income tax as reported in the Consolidated Statement of Income:

	1993	1992	1991
	(Thousands of Dollars)		
Charged to operating expense:			
Federal income tax	$14,502	$ 5,467	$10,514
Deferred income tax	14,101	19,644	12,099
Income tax charged to operating expense	28,603	25,111	22,613
Charged (credited) to other income and deductions:			
Federal income tax	(2,937)	7,789	(2,454)
Deferred income tax	1,492	(8,537)	1,202
Income tax charged (credited) to other income and deductions	(1,445)	(748)	(1,252)
Total federal income tax	$27,158	$24,363	$21,361

Reconciliation: The following is a reconciliation between the amount of federal income tax computed on income before taxes at the statutory rate and the amount reported in the Consolidated Statement of Income:

	1993	1992	1991
	(Thousands of Dollars)		
Net income	$50,390	$47,688	$42,94[illegible]
Federal income tax	11,565	13,256	8,06[illegible]
Deferred income tax	15,593	11,107	13,301
Income before taxes	$77,548	$72,051	$64,302
Computed tax @ statutory rate (35% in 1993, 34% in 1992 and 1991)	$27,142	$24,497	$21,863
Increase (decrease) to computed tax due to:			
Tax depreciation	(10,796)	(11,833)	(12,171)
Cost of removal	(994)	(1,040)	(1,229)
Deferred electric fuel costs	135	562	1,221
Deferred gas costs	(844)	(1,315)	58
Deferred energy efficiency costs	(1,106)	(2,386)	(2,789)
Deferred OPEB expense	(1,617)	—	—
Pension expense	(893)	3,257	1,128
Alternative minimum tax	(59)	1,971	3,493
Unbilled revenues	155	752	(1,510)
Other	442	(1,209)	(2,004)
Federal income tax	11,565	13,256	8,060
Deferred income tax	15,593	11,107	13,301
Total federal income tax	$27,158	$24,363	$21,361
Effective tax rate	35%	34%	33%

Deferred Income Tax: The following is a summary of the components of deferred income tax included in the Consolidated Statement of Income (presented in accordance with APB 11, effective through 1992):

	1992	1991
	(Thousands of Dollars)	
Tax depreciation	$14,605	$15,290
Investment tax credit	(1,396)	(1,381)
Deferred electric fuel costs	(562)	(1,221)
Deferred gas costs	1,315	(58)
Deferred energy efficiency costs	2,386	2,789
Pension expense	(3,257)	(1,128)
Alternative minimum tax	(1,971)	(3,493)
Unbilled revenues	(752)	1,510
Other	739	993
Deferred income tax	$11,107	$13,301

The adoption of SFAS 109 resulted in the recording of a deferred tax liability of approximately $69.2 million representing the cumulative amount of federal income tax benefits on temporary differences which were previously flowed-through to ratepayers and in the recording of approximately $22.9 million in deferred tax assets representing the cumulative amount of federal income taxes on temporary differences which were previously flowed-through to ratepayers. The Company recorded a corresponding regulatory asset and liability on the Consolidated Balance Sheet.

In addition, the adoption of SFAS 109 resulted in the recording of a payable to ratepayers of approximately $8.6 million, representing excess deferred federal income tax resulting from the reduction of the corporate federal income tax rate from 46% to 34%. The excess deferred federal income tax amount was adjusted by approximately $2.9 million in 1993 due to the August 1993 enactment of the Omnibus Budget Reconciliation Act of 1993 which increased the corporate federal income tax rate from 34% to 35%, effective January 1, 1993. The resulting net excess deferred federal income tax will be refunded to ratepayers over the life of the related depreciable assets.

With the adoption of SFAS 109, the Company discontinued, for reporting purposes, its practice of reducing the deferred tax liabilities balance by the amount of deferred tax assets. Thus, the Consolidated Balance Sheet reflects a reclassification of prior year amounts which resulted in an increase in total assets and total liabilities at December 31, 1992 of approximately $44.2 million.

The deferred tax liabilities and assets initially recorded are adjusted quarterly to reflect the current account balances. The regulatory asset and regulatory liability related to SFAS 109 amount to $71.1 million and $28.9 million, respectively, at December 31, 1993.

The following is a summary of the components of the current and non-current deferred income taxes at December 31, 1993, as reported in the Consolidated Balance Sheet:

	Deferred Tax Assets	Deferred Tax Liabilities
	(Thousands of Dollars)	
Tax depreciation		$152,395
Accumulated deferred investment tax credit		32,250
Future revenues - recovery of plant basis differences		24,933
Future tax benefits on investment tax credit basis difference	$17,365	
Alternative minimum tax	14,533	
Tax depreciation - Nine Mile 2 Plant disallowed investment	9,232	
Unbilled revenues	5,952	
Non-deductible pension expense	3,804	
Other	13,109	22,201
Total Deferred Taxes	$63,995	$231,779

NOTE 4 — SHORT-TERM BORROWING ARRANGEMENTS

The Company has in effect a revolving credit agreement with four commercial banks which allows it to borrow up to $50 million through December 14, 1997 (Agreement). The Agreement gives the Company the option of borrowing at either the prime/federal funds rate, or three other money market rates if such rates are lower. The Agreement also provides for the payment of an annual commitment fee of 1/16 of 1% per annum on the unborrowed amount and a facility fee of 1/8 of 1% per annum on the total amount of the facility. Compensating balances are not required under the Agreement.

There were no outstanding loans under this Agreement at December 31, 1993 or 1992. In addition, the Company continues to maintain confirmed lines of credit totaling $2 million with three regional banks. There was no outstanding short-term debt at December 31, 1993. The amount of outstanding short-term debt at December 31, 1992 was $15 million, consisting of commercial paper. All commercial paper obligations are supported by the Agreement.

NOTE 5 — CAPITALIZATION CAPITAL STOCK

Common Stock, $5 par value; 30,000,000 shares authorized:
Paid-In Capital:

	Common Stock		Paid-In
	Shares Outstanding	Amount ($000)	Capital ($000)
January 1, 1991	14,950,956	$74,755	$223,957
Issued through public offering	600,000	3,000	10,788
Issued under dividend reinvestment plan	181,073	905	3,701
Issued under customer stock purchase plan	35,628	178	754
December 31, 1991	15,767,657	78,838	239,200
Issued under dividend reinvestment plan	205,950	1,030	4,847
Issued under customer stock purchase plan	54,962	275	1,302
December 31, 1992	16,028,569	80,143	245,349
Issued through public offering	700,000	3,500	19,299
Issued under dividend reinvestment plan	185,101	926	5,124
Issued under customer stock purchase plan	39,477	197	1,076
December 31, 1993	16,953,147	$84,766	$270,848

Cumulative Preferred Stock, $100 par value; 1,200,000 shares authorized:

	Series	Redemption Price 12/31/93	Shares Outstanding December 31, 1993	1992
Not Subject to Mandatory Redemption:				
	4.50%	$107.00	70,300	70,300
	4.75%	106.75	20,000	20,000
	4.35%	102.00	60,000	60,0[illegible]
	4.96%	101.00	60,000	60,0[illegible]
	7.72%	101.00	130,000	130,0[illegible]
	7.44%	101.22	120,000	120,000
	8.40%	—	—	150,000
			460,300	610,300
Subject to Mandatory Redemption:				
	A	—	—	200,000
	6.20% (Final Redemption Date 10/1/08)	(a)	200,000	—
	6.80% (Final Redemption Date 10/1/27)	(a)	150,000	—
			350,000	200,000
Total			810,300	810,300

(a) Cannot be redeemed prior to October 1, 2003.

Reference is made to the caption "Financing Program" in "Management's Discussion and Analysis of Financial Condition and Results of Operations" for details on issuances and redemptions of capital stock.

The Cumulative Preferred Stock not subject to mandatory redemption is redeemable only at the option of the Company. Upon redemption, the sum payable per share is the then current redemption price plus accrued dividends thereon. In the event of an involuntary liquidation of the Company, the redemption price is $100 per share plus accrued dividends.

Expenses incurred on issuance of capital stock are accumulated and reported as a reduction in common stock equity. Such expenses are not being amortized, with the following exceptions:

1) As directed by the PSC, the redemption costs and the unamortized expenses associated with the Adjustable Rate Cumulative Preferred Stock, Series A, and the expenses associated with the 6.20% Redeemable Cumulative Preferred Stock are being amortized over the remaining life of the redeemed Adjustable Rate Cumulative Preferred Stock Series A (i.e. 178 months).

2) As directed by the PSC, the issuance and redemption costs of the redeemed 8.40% Cumulative Preferred Stock and the expenses associated with the 6.80% Redeemable Cumulative Preferred Stock are being amortized over the life of the 6.80% Redeemable Cumulative Preferred Stock (i.e. 406 months).

NOTE 6 — CAPITALIZATION — LONG-TERM DEBT

Details of long-term debt are shown below:

Series	Maturity Date	December 31, 1993	December 31, 1992
		(Thousands of Dollars)	
First Mortgage Bonds:			
8 1/8%	September 1, 1994	$ (a)	$ 50,000
7 1/8%	January 15, 1999	—	20,000
6.10%(b)	April 28, 2000	10,000	—
7.70%(b)	June 12, 2000	25,000	25,000
8.75%	May 1, 2001	30,000	30,000
7.75%	February 1, 2002	—	20,000
7.97%(b)	June 11, 2003	8,000	8,000
7.97%(b)	June 13, 2003	8,000	8,000
6.46%(b)	August 11, 2003	10,000	—
6.25%	June 1, 2007	4,500	4,500
9.25%	May 1, 2021	70,000	70,000
8.12%(b)	August 29, 2022	10,000	10,000
8.14%(b)	August 29, 2022	10,000	10,000
8.375%	December 1, 2028	16,700	16,700
		202,200	272,200
Promissory Notes issued in connection with the sale by the New York State Energy Research and Development Authority (NYSERDA) of tax-exempt pollution control revenue bonds:			
1984 Series A (7.375%)	October 1, 2014	16,700	16,700
1984 Series B (7.375%)	October 1, 2014	16,700	16,700
1985 Series A (Var. rate)	November 1, 2020	36,250	36,250
1985 Series B (Var. rate)	November 1, 2020	36,000	36,000
1987 Series A (Var. rate)	June 1, 2027	33,700	33,700
1987 Series B (Var. rate)	June 1, 2027	9,900	9,900
		149,250	149,250
Promissory Notes (net of sinking fund requirements):			
4.85%	December 1, 1995	2,562	2,644
5.38%(b)	January 15, 1999	20,000	—
7.85%(b)	July 2, 2004	15,000	15,000
		37,562	17,644
Secured Notes Payable of Subsidiary		3,866	3,081
Unamortized Premium (Discount) on Debt - Net		(1,068)	(1,079)
Total long-term debt		$391,810	$441,096

(a) Principal amount at December 31, 1993 was reclassified to "Current Maturities of Long-term Debt."

(b) Issued under the Company's Medium Term Note Program.

In 1993, the Company redeemed two series of First Mortgage Bonds, totaling $40 million. The funds to redeem these bonds were obtained from the sale of an aggregate of $40 million of Medium Term Notes, issued in several tranches.

Under the Company's Medium Term Note Program, the Company has authorization from the PSC, by an amended order effective September 29, 1993, to issue and sell up to $125 million principal amount of Medium Term Notes through December 31, 1994, of which the Company has issued and sold $116 million of such Notes through December 31, 1993.

Reference is made to "Management's Discussion and Analysis of Financial Condition and Results of Operations" for details of the Company's Medium Term Note Program and for information regarding the amounts of long-term debt maturing within the next five years.

The NYSERDA Pollution Control Revenue Bonds, Series A and B, issued in 1985 and 1987 are variable rate obligations subject to weekly repricing and investor tender. The Company has the right, exercisable independently in respect of each series of the 1985 and 1987 NYSERDA Pollution Control Revenue Bonds, to convert the Bonds of each such series to a fixed rate for the remainder of their term.

The Company has irrevocable letters of credit which expire on various dates and which the Company anticipates being able to extend if the interest rate on the related series of NYSERDA Pollution Control Revenue Bonds is not converted to a fixed interest rate. Those letters of credit support certain payments required to be made on such Bonds. If the Company were unable to extend the letter of credit that is related to a particular series of NYSERDA Pollution Control Revenue Bonds, that series would have to be redeemed unless a fixed rate of interest becomes effective. Payments made under the letters of credit in connection with purchases of tendered NYSERDA Pollution Control Revenue Bonds are repaid with the proceeds from the remarketing of such Bonds. To the extent the proceeds are not sufficient, the Company would be required to reimburse the bank that issued the letter of credit for the amount of any resulting draw under the letter of credit by the expiration date of the letter of credit. The letter of credit expiration date for the letters of credit supporting the 1985 NYSERDA Bonds is November 16, 1996, and the letter of credit expiration date for the letters of credit supporting the 1987 NYSERDA Bonds is September 16, 1996.

In its rate orders, the PSC has provided for full recovery of the interest costs on the Company's 1985 and 1987 Series A and B Promissory Notes which were issued in connection with the sale of the NYSERDA Pollution Contr[illegible] Revenue Bonds. Such Bonds bear interest at variable rate[illegible] set weekly. Deferred accounting has been granted by the PSC for any variation (above or below) between actual interest rates and those interest rates allowed for rate-making purposes. Such deferred balances are to be disposed of in future rate cases.

Expenses incurred on debt issues and any discount or premium on debt are deferred and amortized over the lives of the related issues. Expenses incurred on debt redemptions prior to maturity have been deferred and are generally being amortized over the remaining lives of the related extinguished issues as directed by the PSC.

Certain debt agreements require the maintenance by the Company of certain financial ratios and contain other restrictive covenants.

Secured notes payable of a subsidiary of the Company consist of term loans to finance the installation of energy conservation equipment at various host facilities, located primarily in the Northeastern United States. The majority of such loans accrue interest at the prime lending rate plus 3/4 of 1% and interest and principal are amortized over the term of each respective contract. Such loans are secured principally by certain power purchase agreements and project assets.

NOTE 7 — POSTEMPLOYMENT BENEFITS

Retirement Income Plan: The Company has a non-contributory retirement income plan (Plan) covering substantially all of its employees. The Plan provides pension benefits that are based on the employee's compensation and years of service. It has been the Company's practice to provide periodic updates to the benefit formula stated in the Plan.

The Company's funding policy is to make annual contributions equal to the amount of net periodic pension cost, but not in excess of the maximum allowable tax-deductible contribution under the federal income tax law nor less than the minimum requirement under the Employee Retirement Income Security Act of 1974.

Charges to expense were 71%, 71% and 72% of the net periodic pension costs for the years 1993, 1992 and 1991, respectively. The allocation of net periodic pension costs between capital and expense follows the payroll distribution.

Net periodic pension (income) costs for 1993, 1992 and 1991 include the following components:

	1993	1992	1991
	(Thousands of Dollars)		
Service cost - benefits earned during the period	$ 4,518	$ 4,002	$ 3,780
Interest cost on projected benefit obligation	13,148	12,801	12,140
Actual return on Plan assets	(34,022)	(21,941)	(43,296)
Net amortization and deferral	13,794	6,411	29,808
Net periodic pension (income) cost	$ (2,562)	$ 1,273	$ 2,432

The following table sets forth the Plan's funded status at October 1, 1993 and 1992 and amounts recognized in the Company's Consolidated Balance Sheet at December 31, 1993 and 1992:

	1993	1992
	(Thousands of Dollars)	
Actuarial present value of benefit obligations:		
Accumulated benefit obligation, including vested benefits of $171,389 and $140,156	$173,924	$142,020
Projected benefit obligation for service rendered to date	$211,583	$169,858
Plan assets at market value	227,638	211,435
Excess of Plan assets over projected benefit obligation	16,055	41,577
Unrecognized net gain	(23,703)	(43,748)
Prior service cost not yet recognized in net periodic pension cost	1,157	1,254
Unrecognized net asset being amortized over 15 years	(5,242)	(5,877)
Contributions withdrawn from the Plan (Note 9)	—	(7,501)
Pension liability recognized in the Balance Sheet	$(11,733)	$(14,295)

Plan assets consist primarily of equities and fixed income securities. The Plan is deemed to be fully funded for federal income tax purposes, therefore, the Company did not make any contributions to the Plan during 1993 or 1992.

The actuarial present value of projected benefit obligations for October 1, 1993 and 1992 was determined using a weighted average discount rate of 6.25% and 7.75%, respectively, and an assumed rate of increase in compensation of 5.5% and 6.5%, respectively. The expected long-term rate of return on Plan assets was 9.5% for 1993 and 1992. The assumptions used in determining the funded status at October 1 are used in determining the following year's net periodic pension costs.

Prior to 1993, the cumulative unrecognized net gains or losses in excess of 10% of the greater of the market-related value of Plan assets and the projected benefit obligation were amortized over the average remaining service period of active participants. Pursuant to the PSC Statement of Policy and Order Concerning the Accounting and Rate-making Treatment for Pensions and Postretirement Benefits Other than Pensions (OPEB), issued September 7, 1993 (OPEB Order) effective January 1, 1993 the Company changed its accounting to a method of amortizing each year's experience gain or loss over 10 years. Such change had the effect of reducing 1993 net periodic pension costs by approximately $4.4 million.

The Company also has an Executive Deferred Compensation Plan (EDC Plan) and a Retirement Benefit Restoration Plan (RBR Plan) which were established for key executives, under which periodic payments will be made to such employees upon retirement. The net periodic costs of the EDC Plan, which was established in 1992, amounted to approximately $203,000 and $142,000 for 1993 and 1992, respectively. In order to recover the costs of the EDC Plan, the Company has obtained life insurance policies on the participants in such Plan, with the Company as beneficiary. The net periodic pension costs of the RBR Plan, which was established in 1993, amounted to approximately $44,000 in 1993.

Pursuant to the OPEB Order, deferred accounting has been granted by the PSC for any variation (above or below) between actual costs of the Company's pension plans and those costs allowed for rate-making purposes.

Other Postretirement Benefits: The Company provides certain health care and life insurance benefits for retired employees. Substantially all of the Company's employees may become eligible for these benefits if they reach retirement age while working for the Company. These and similar benefits for active employees are provided through insurance companies whose premiums are based on the benefits paid during the year. The cost of providing these benefits for active and retired employees was $7.9 million and $8.2 million for calendar year 1992 and 1991, respectively. Prior to 1992, the cost of providing retirees with these benefits was not separable from the cost of providing those benefits for the active employees. Beginning in 1992, such costs were separated, and for the period of April through December 1992, the cost of such benefits for retirees amounted to $1.4 million, which is included in the 1992 amount above.

Effective January 1, 1993, the Company adopted SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other than Pensions" (SFAS 106). This Statement requires that an employer's obligation for postretirement benefits expected to be provided to or for an employee be fully accrued by the date that the employee attains full

eligibility for all benefits expected to be received by that employee, any beneficiaries and covered dependents, even if the employee is expected to render additional service beyond that date. Prior to adoption of SFAS 106, the Company recorded the costs of providing such benefits when paid.

As allowed by SFAS 106, the Company intends to recognize the unfunded accumulated postretirement benefit obligation (Transition Obligation) at January 1, 1993 over a 20-year period.

Net periodic postretirement benefit cost for 1993 includes the following components:

	1993 (Thousands of Dollars)
Service cost - benefits attributed to the period	$1,754
Interest cost on accumulated postretirement benefit obligation	4,731
Actual return on postretirement benefit plan (Plan) assets	—
Amortization of Transition Obligation	3,114
Net periodic postretirement benefit cost	$9,599

The Plan's funded status reconciled with the Company's Consolidated Balance Sheet is as follows:

	December 31, 1993 (Thousands of Dollars)
Accumulated postretirement benefit obligation:	
Retirees	$(34,642)
Fully eligible employees	(6,705)
Other employees	(41,249)
	(82,596)
Plan assets at fair value	7,710
Excess of accumulated postretirement benefit obligation over Plan assets	(74,886)
Unrecognized net loss	15,776
Prior service cost not yet recognized in net periodic postretirement benefit cost	—
Unrecognized Transition Obligation	59,149
Prepaid postretirement benefit recognized in the Consolidated Balance Sheet	$ 39

The weighted average discount rate used in determining the accumulated postretirement benefit obligation under the Plan was 6.25%, and the rate of increase in future compensation levels utilized was 5.5%.

The assumed health care cost trend is 13% in the early years and trends down to an ultimate rate of 5.5% by the year 2009. A 1% increase in health care cost trend rate assumptions would produce an increase in the accumulated postretirement benefit obligation at December 31, 1993 of $10.820 million and an increase in the aggregate service and interest cost of the net periodic postretirement benefit cost of $960,000.

The Company has established tax-effective funding vehicles for such retirement benefits for collective bargaining and management employees in the form of qualified Voluntary Employee Beneficiary Association (VEBA) trusts. The Company funded the VEBA trusts in 1993 with tax-deductible contributions totaling $7.7 million.

In the OPEB Order, deferred accounting has been granted by the PSC for any variation (above or below) between actual OPEB costs and those allowed for rate-making purposes. Pursuant to the 1993 Rate Order, $4.613 million of deferred electric OPEB costs and $832,000 of deferred gas OPEB costs were offset against Mirror CWIP and other deferred gas balances, respectively. Pursuant to the 1993 Rate Order, an estimated annual level of OPEB costs is included in the Company's electric and gas rates, effective November 22, 1993.

Other Postemployment Benefits: The Company provides certain illness and disability-related benefits to former or inactive employees, beneficiaries and covered dependents. The cost of providing these benefits was $164,000, $216,000 and $245,000 in 1993, 1992 and 1991, respectively. In November 1992, the Financial Accounting Standards Board (FASB) issued SFAS No. 112, "Employers' Accounting for Postemployment Benefits" (SFAS 112), which establishes accounting and reporting requirements for employers who provide benefits to former or inactive employees after employment but before retirement. The Company will adopt SFAS 112 in the first quarter of 1994. The Company estimates that unfunded accumulated postemployment benefit obligations upon adoption will be approximately $850,000. The Company expects the PSC to allow the recording of a regulatory asset related to the adoption of SFAS 112. Accordingly, the Company believes that the adoption of SFAS 112 will not have a material impact on the Company's results of operations.

NOTE 8 — SALE OF RECEIVABLES AND RESERVE FOR UNCOLLECTIBLE ACCOUNTS

The Company has a program to sell on a daily basis, without recourse, its accounts receivable from retail customers. Such program provides the Company with the ability to receive cash immediately for such receivables and thereby reduce its working capital requirements. There were no outstanding receivables sold as of December 31, 1993 or December 31, 1992.

The average daily amount of accounts receivable sold was $700,000 in 1993, $4.3 million in 1992 and $8.3 million in 1991. The costs associated with the sale of receivables are charged to operating expense and amounted to $55,000 in 1993, $200,000 in 1992 and $600,000 in 1991.

The Company had a reserve balance for uncollectible accounts receivable of $2.0 million at December 31, 1993 and $1.5 million at December 31, 1992.

NOTE 9 — COMMITMENTS AND CONTINGENCIES

Construction Program: Reference is made to "Management's Discussion and Analysis of Financial Condition and Results of Operations" for information regarding the Company's construction program for the five-year period 1994-1998.

Roseton Plant: The Company currently has a 35% undivided interest in the ownership and output of the 1,200 MW Roseton Plant. The Company is acting as agent for the cotenant owners with respect to operation of the Roseton Plant. Generally, the owners share the costs and expenses of the operation of the Roseton Plant in accordance with their respective ownership interests. The Company's share of direct operating expense for the Roseton Plant is included in the appropriate expense classification in the accompanying Consolidated Statement of Income.

The Company, under a 1968 Agreement (Basic Agreement), has the option to purchase the interests of Niagara Mohawk (25%) and of Consolidated Edison Company of New York, Inc. (Con Edison) (40%) in the Roseton Plant in December 2004, exercise of which option is subject to the approval of the PSC. However, in 1987, in order to make provision for anticipated requirements for additional generating capacity commencing in the mid-1990s, the Company and Niagara Mohawk entered into an agreement (Amendment) revising the Basic Agreement option which the Company has to buy Niagara Mohawk's interest in the Roseton Plant. The Company's option to buy Con Edison's interest in the Roseton Plant is not affected by the Amendment. The Amendment is subject to the approval of the PSC, and in the event such approval is not obtained, the Amendment is cancelled and the parties return to their same positions under the Basic Agreement.

Pursuant to the Amendment, Niagara Mohawk will sell to the Company a 2.5% interest in the Roseton Plant on December 31, 1994 and on each succeeding December 31, through and including December 31, 2003, which will be all of Niagara Mohawk's interest in the Roseton Plant. In exchange, Niagara Mohawk will have the option to repurchase from the Company up to a 25% interest in the Roseton Plant in December 2004. The prices for the purchases will be based on the depreciated book cost of the Roseton Plant, assuming straight-line depreciation to provide for a fully depreciated facility as of December 31, 2009. Pursuant to the Amendment, the Company also was granted the option to repurchase Niagara Mohawk's interest in that Plant when that Plant reaches the end of its assumed physical life as agreed upon by the parties.

By joint petition filed with the PSC in February 1988, the Company and Niagara Mohawk requested the PSC to approve the transfers of interests in the Roseton Plant contemplated by the Amendment. In July 1988, the PSC issued an order establishing a proceeding to consider such joint petition. Among the issues identified by the PSC for consideration in such proceeding are: (1) the relationship to such transfers of the process for bidding for additional capacity, set forth in a June 1988 PSC order applicable to the major New York State electric utilities, (2) the potential for demand side management as an alternative to the transfers contemplated by the Amendment, and (3) certain technical, accounting and forecasting issues regarding the information and studies submitted by the Company and Niagara Mohawk in support of the joint petition.

In May 1989, the Company and the PSC Staff reached a Stipulation Agreement indicating that, giving consideration to expected demand side management activities, the proposed transfers of interest in the Roseton Plant were one alternative which would meet the Company's future needs for power. The Company issued a Request for Proposals (RFP) for alternative power supply arrangements approximating the capacity reflected in the proposed transfers of interest in the Roseton Plant, so as to test the reasonableness of such proposed transfers from Niagara Mohawk. In September 1992, the Company concluded that it was neither in its interest nor in its customers' interest for it to accept any of the third party bids for additional long-term generating capacity submitted under such RFP. The Company continues to evaluate its current and expected future needs for the Amendment and, if warranted by these studies, the Company intends to test the commercial reasonableness of the Amendment through a new RFP solicitation. The Company cannot predict what action the PSC may ultimately take in connection with the joint petition for the approval of such transfers under the Amendment.

Nuclear Liability and Insurance: The Price-Anderson Act is a federal law which limits the public liability which can be imposed with respect to a nuclear incident at a licensed nuclear electric generating facility. Such Act also provides for assessment of owners of all licensed nuclear units in the United States for losses in excess of certain limits due to a nuclear incident at any such licensed unit. Under the provisions of the Price-Anderson Act, the Company's potential assessment (based on its 9% ownership interest in the Nine Mile 2 Plant and assuming that the other Nine Mile 2 Plant cotenants were to contribute their proportionate shares of the potential assessments) would be $5.67 million (subject to adjustment for inflation) and the Company could be assessed $283,500 (subject to adjustment for inflation) in respect to an additional surcharge, but would be limited to

a maximum assessment of $900,000 in any year with respect to any nuclear incident. The public liability insurance coverage of $200 million required under the Price-Anderson Act for the Nine Mile 2 Plant is provided through Niagara Mohawk.

The Company also carries insurance to cover the additional costs of replacement power (under a Business Interruption and/or Extra Expense Insurance Policy) incurred by the Company in the event of a prolonged accidental outage of the Nine Mile 2 Plant. This insurance arrangement provides for payments of up to $233,000 per week if the Nine Mile 2 Plant experiences a continuous accidental outage which extends beyond 21 weeks. Such payments will continue for 52 weeks after expiration of the 21-week deductible period, and thereafter the insurer shall pay 67% of the weekly indemnity for a second 52-week period and 67% for a third 52-week period. Subject to certain limitations, the Company may request prepayment, in a lump sum amount, of the insurance payments which would otherwise be paid to it in respect of said third 52-week period, calculated on a net present value basis.

The Company is insured as to its respective interest in the Nine Mile 2 Plant under property damage insurance provided through Niagara Mohawk. The insurance coverage provides $500 million of primary property damage coverage for Units 1 and 2 of the Nine Mile Point Nuclear Station and $2.125 billion of excess property damage coverage for the Nine Mile 2 Plant. Such insurance covers decontamination costs, debris removal and repair and/or replacement of property.

The Company intends to maintain, or cause to be maintained, insurance against nuclear risks at the Nine Mile 2 Plant, provided such coverage can be obtained at an acceptable cost.

Natural Gas Supply: The Company presently has in place five firm contracts (Contracts) for the supply of an aggregate of 10,222,342 Mcf. of natural gas, all of which are with third-party gas suppliers (Suppliers). Under the Contracts, the Suppliers deliver the gas to interstate pipeline companies (Pipelines) and the Pipelines deliver the gas to the Company's gas transmission system under separate firm transportation contracts which the Company has in place with such Pipelines. In addition, the Company has interruptible transportation agreements with the Pipelines. With the exception of 19,940 Mcf. per day of gas purchased from Canadian sources under contracts which expire in January 2012, or approximately 20% of total gas purchases, all of the above gas supply contracts will terminate in 1994 after the 1993-1994 winter heating season. All such expiring gas supply contracts will be replaced before the next winter heating season with competitively bid contracts with third-party gas suppliers.

The Company has in aggregate, gas storage capability of 39,604 Mcf. per day, under long-term contracts. The Company also has a contract for the supply of liquefied natural gas which will remain in effect through September 30, 1995 and will continue from year-to-year thereafter. All pipeline transportation and storage contracts and associated tariffs are approved by FERC.

In addition to the above gas supply, transportation, storage and liquefied natural gas supply contracts, the Company has in place an interim contract for the supply of up to 100,000 Mcf. per day of gas during April through October of each year for use as boiler gas at the Roseton Plant. This interim contract expires on April 30, 1994. The Company expects to replace the interim contract with a long-term contract which will expire in October 2006.

In April 1992, FERC issued its final rule (Order 636) regarding the unbundling of natural gas supply services from transportation and storage services. These changes enable the Company to arrange for its gas supply directly with producers, gas marketers or pipelines, at its discretion, as well as arrange for transportation and gas storage services. In Order 636, FERC stated that all prudently - incurred transition costs may be recovered by the pipelines from customers. There are four elements of these transition costs: (1) unrecovered deferred purchase gas costs, (2) gas supply realignment costs, (3) stranded facilities costs, and (4) new facilities costs.

The Company has been billed $560,000 of transition costs through December 31, 1993 by the pipelines. Transition costs are being recovered through the Gas Cost Adjustment Clause at a level equal to an annual amount of $1.4 million. The aggregate amount that the Company will be billed will depend on the outcome of many FERC proceedings, the outcome of which the Company is not able to predict. Depending on the outcome of such proceedings, the aggregate amount of such transition costs could range between $3 million and $5 million over the next several years. The Company expects to recover all such costs through the Gas Cost Adjustment Clause.

Take-or-Pay Gas Costs: In prior years, many interstate gas pipeline companies had entered into contracts with gas producers which required the pipeline companies to pay for a minimum amount of gas whether or not the gas is actually taken from the producer (take-or-pay costs). Pursuant to the FERC authorization, the Company's gas suppliers have included certain amounts of their take-or-pay costs in the rates charged to the Company.

The PSC in October 1988 commenced a proceeding to determine, among other things, the recoverability and allocation in gas rates of New York State distribution companies of contract take-or-pay costs charged them by pipeline suppliers. In connection with such proceeding, the PSC has issued several orders which have directed, among other things, that 65% of take-or-pay costs being incurred by the Company may be recovered through current rates, subject to refund. Charges not subject to such conditional recovery are deferred with interest for subsequent consideration by the PSC. The amounts of the deferred charges not subject to conditional recovery at December 31, 1993 and 1992 were $2.483 million and $2.208 million, respectively.

In the PSC proceeding, the Company has contended that there is no basis on which the responsibility for its pipeline suppliers' take-or-pay liability can be attributed to it. In addition, it is the Company's position that the PSC lacks any authority to deny it recovery of costs included in the FERC approved gas rates and would intend to oppose any attempt by the PSC to require it to absorb any take-or-pay or contract reformation costs which are included in its pipeline suppliers' FERC approved rates. The Company is unable at this time to estimate the amount of take-or-pay costs which may ultimately be included in its pipeline suppliers' charges or to predict what action the PSC might take to require the Company to absorb any portion of such costs. The final amount of such costs will depend on the FERC proceedings, the PSC proceeding and certain court litigation, the outcome of which the Company is not able to predict. Depending on the outcome of such proceedings and litigation, the final amount of such take-or-pay costs could be up to $6 million, which would have a material adverse effect on the Company's future earnings if the PSC were to require the Company to absorb a substantial portion thereof.

Under similar circumstances, the PSC has recently approved certain take-or-pay cost settlements with other utilities which granted total recovery of the amounts reflected on their balance sheet. If the cost settlements achieved by other utilities were applied to the Company, this matter would not have a material adverse effect on the Company's financial position. The Company is currently discussing a settlement with the parties to the PSC proceeding.

Environmental Matters:

General: On an ongoing basis, the Company assesses environmental issues which could impact the Company and its ratepayers.

The Company is a party to several administrative proceedings (which are in their early stages) involving the effect on the environment of the operation and maintenance of facilities for the generation, transmission and distribution of electricity and the manufacture, transmission and distribution of natural gas. These proceedings include, but are not limited to, administrative proceedings before the New York State Department of Environmental Conservation related to the processing of permit application proceedings for the Company's generating stations under the State Pollution Discharge Elimination System and proceedings involving evaluation of whether properties owned by the Company, or formerly owned by the Company, may contain wastes representing a threat to the environment. At this stage of such proceedings, the Company can make no determination as to the outcome of such proceedings or the impact, if any, on the Company's financial position.

Clean Air Act Amendments: The Clean Air Act Amendments of 1990 (CAA Amendments) added several new programs which address attainment and maintenance of national ambient air quality standards. This includes control of emissions from fossil-fueled electric power plants that affect "acid rain" and ozone.

The "acid rain" emissions reduction requirements do not affect the Company's generating plants until January 1, 2000; however, the Company must comply with the monitoring provisions program as of January 1, 1995 and install continuous emission monitors. The Company's emissions of nitrogen oxides are subject to additional controls by May 31, 1995 under Title I of the CAA Amendments.

The Company estimates that the installation of continuous emissions monitors and nitrogen oxides emissions controls will cost approximately $14 million. The Company expects that it will have adequate financial resources to comply with the requirements of the CAA Amendments.

Asbestos Litigation: Since 1987, the Company, along with many other parties, has been joined as a defendant or third-party defendant in approximately 400 asbestos lawsuits commenced in New York State and federal courts. The plaintiffs in these lawsuits have each sought millions of dollars in compensatory and punitive damages from all defendants. The cases were brought by or on behalf of individuals who have allegedly suffered injury from exposure to asbestos, including exposure which allegedly occurred at Company facilities.

The Company has given notice of the cases to its insurance carriers, but such carriers have neither denied nor conceded coverage of these claims.

Approximately 150 of these cases have been dismissed with respect to the Company, and the Company has agreed to settle approximately 100 of the cases for amounts which are not material in relation to the consolidated financial statements. Consequently, on January 1, 1994, the Company was a defendant in approximately 150 asbestos cases. Although the Company is presently unable to assess the validity of the remaining asbestos lawsuits, and accordingly cannot determine the ultimate liability relating to these cases, based on information known to the Company at this

time, including its experience in settling asbestos cases and in obtaining dismissals of asbestos cases, the Company believes that the cost to be incurred in connection with the remaining lawsuits will not have a material adverse effect on the Company's financial position.

Tax Matters:

Assessments: The IRS has closed all of the Company's federal income tax returns through 1986 and has completed the field work for the examination of the Company's federal income tax returns for 1987 and 1988. The IRS has proposed adjustments which have the potential to increase the Company's tax liability for 1987 and 1988 by approximately $16 million plus interest. Included in the proposed adjustments are significant issues related to Nine Mile 2 Plant, primarily its tax in-service date. The Company will defend its position on Nine Mile 2 Plant and other significant issues raised by the IRS. To the extent the IRS is able to sustain their positions on Nine Mile 2 Plant, the Company will be required to absorb a portion of the resulting tax liability. Although the Company is unable to assess its ultimate liability in this matter, the Company believes it would be able to recover a significant portion of any additional liability through rates. Accordingly, the Company expects that the ultimate resolution of this matter will not have a material adverse effect on the Company's financial position..

Settlement with IRS under Actuarial Resolutions Program: In 1990, the IRS challenged the deductibility of an aggregate of $7.501 million of contributions made to the Company's Retirement Income Plan (Plan) during the years 1986 through and including 1989. In November 1992, the Company settled this matter under the IRS's Actuarial Resolutions Program. Such Settlement disallowed $7.501 million of the Company's claimed deductions for taxable years 1986 through 1989 and waived all related "penalties." In accordance with such Settlement, the Company withdrew the $7.501 million of contributions in question from the Plan in December 1992. The resultant increased tax due to the loss of such deductions was $1.903 million and interest on such amount was $1.160 million. The Company requested authorization from the PSC for deferral accounting on such interest. Pursuant to the 1993 Rate Order, the Company was authorized to offset the deferred interest at November 30, 1993 against Mirror CWIP and other deferred balances. In addition, the withdrawn contribution, net of tax effects, will benefit the Company's customers pursuant to such Order as follows: (1) $6.526 million will be refunded to the Company's electric customers over 36 months beginning in December 1993, and (2) $975,000 was offset against other deferred gas balances in December 1993.

Rental Expenses and Lease Commitments: The Company has lease commitments expiring at various dates, principally for real property and data processing equipment. None of these leases involves any major facilities or any material noncancelable rental commitments. Although certain items meet the criteria for recording as capital leases, such recognition would have no significant effect on the consolidated financial statements. Therefore, all items are treated as operating leases.

Other Matters: The Company is involved in various other legal and administrative proceedings incidental to its business which are in various stages. While these matters collectively involve substantial amounts, it is the opinion of management that their ultimate resolution will not have a material adverse effect on the Company's financial position.

Included in such proceedings is a PSC investigation of a November 1992 explosion in a dwelling in Catskill, New York involving personal injuries, including the death of an occupant, and property damage. The PSC, by Order issued and effective January 7, 1994, approved an Agreement which provides for a program for evaluating and replacing cast iron and unprotected steel pipeline facilities, and for an investment in four permanent employee training centers. The Company's shareholders will contribute $500,000 in 1994 toward the costs of such training centers and replacement program and $500,000 annually in 1995 and 1996 toward the costs of such replacement program. In 1997, the Company's shareholders will contribute up to $500,000 toward the cost of such replacement program depending on the Company's completion of certain tasks by specified dates.

The National Transportation Safety Board conducted an investigation of the Catskill incident and recommended that the Company amend its procedure to ensure continuity of supervisory responsibility for the timely and effective verification of the safety integrity of exposed cast iron pipe and to implement a program to identify and replace in a timely manner cast iron piping systems that may threaten public safety. By letter dated October 22, 1993, the Company indicated that it had implemented these recommendations.

Although the Company is unable to assess its ultimate liability in this matter, the Company believes it has adequate insurance coverage and, therefore, the final outcome of this matter is not expected to have a material adverse impact on the Company's financial position.

NOTE 10 — DEPARTMENTAL INFORMATION

The Company is engaged in the electric and natural gas utility businesses and serves the Mid-Hudson Valley region of New York State. Total revenues and operating income before income taxes (expressed as percentages), derived from electric and gas operations for each of the last three years, were as follows:

	Percent of Total Revenues		Percent of Operating Income Before Income Taxes	
	Electric	Gas	Electric	Gas
1993	82%	18%	89%	11%
1992	82%	18%	87%	13%
1991	86%	14%	93%	7%

For the year ended December 31, 1993, the Company served an average of 259,650 electric and 59,218 gas customers. Of the Company's total electric revenues during that period, approximately 42% was derived from residential customers, 30% from commercial customers, 22% from industrial customers and 6% from other utilities and miscellaneous sources. Of the Company's total gas revenues during that period, approximately 45% was derived from residential customers, 30% from commercial customers, 4% from industrial customers, 14% from interruptible customers and 7% from miscellaneous sources (including revenues from transportation of customer-owned gas).

The Company's largest customer is International Business Machines Corporation (IBM), which accounted for approximately 14% of the Company's total electric revenues and approximately 8% of its total gas revenues for the year ended December 31, 1993. Reference is made to "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further information regarding IBM.

Certain additional information regarding these segments is set forth in the following table. General corporate expenses, property common to both segments and depreciation of such common property have been allocated to the segments in accordance with practice established for regulatory purposes.

	Electric			Gas		
	1993	1992	1991	1993	1992	1991
	(Thousands of Dollars)					
Operating Revenues	$422,925	$427,436	$424,121	$ 94,448	$ 96,121	$70,615
Operating Expenses:						
Fuel and purchased electricity	122,250	132,805	140,488	—	—	—
Purchased natural gas	—	—	—	53,900	55,066	39,867
Depreciation and amortization	35,625	36,074	34,563	4,057	3,522	2,667
Other, excluding income tax	173,167	172,301	157,883	25,210	24,180	21,159
Total	331,042	341,180	332,934	83,167	82,768	63,693
Operating Income before Income Tax	91,883	86,256	91,187	11,281	13,353	6,922
Federal income tax, including deferred income tax-net	25,642	21,368	20,886	2,961	3,743	1,727
Operating Income	$ 66,241	$ 64,888	$ 70,301	$ 8,320	$ 9,610	$ 5,195
Construction Expenditures	$ 43,097	$ 50,159	$ 52,819	$ 10,940	$ 11,562	$18,088
Identifiable Assets at December 31*						
Net utility plant	$777,044	$779,291	$761,984	$ 95,074	$ 90,352	$71,129
Construction work in progress	35,424	30,282	36,408	7,317	4,648	15,876
Total utility plant	812,468	809,573	798,392	102,391	95,000	87,005
Materials and supplies	28,063	31,496	30,992	7,354	6,544	6,450
Total	$840,531	$841,069	$829,384	$109,745	$101,544	$93,455

* Identifiable assets not included herein are considered to be corporate assets and have not been allocated between the electric and gas segments.

NOTE 11 — FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Cash, Temporary Cash Investments and Special Deposits: The carrying amount approximates fair value because of the short maturity of those instruments.

Cumulative Preferred Stock Subject to Mandatory Redemption: The fair value is estimated based on the quoted market price of similar instruments.

Long-Term Debt: The fair value is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Company for debt of the same remaining maturities and quality.

Notes Payable: The carrying amount approximates fair value because of the short maturity of those instruments.

The estimated fair values of the Company's financial instruments are as follows:

	December 31, 1993	
	Carrying Amount	Fair Value
	(Thousands of Dollars)	
Cash, temporary cash investments and special deposits	$ 27,630	$ 27,630
Cumulative preferred stock subject to mandatory redemption (including current maturities)	(35,000)	(35,575)
Long-term debt (including current maturities)	(442,829)	(485,360)

	December 31, 1992	
	Carrying Amount	Fair Value
	(Thousands of Dollars)	
Cash, temporary cash investments and special deposits	$ 12,467	$ 12,467
Cumulative preferred stock subject to mandatory redemption (including current maturities)	(20,000)	(20,200)
Long-term debt (including current maturities)	(442,539)	(465,368)
Notes payable	(15,000)	(15,000)

In May 1993, the FASB issued SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS 115), which establishes accounting and reporting requirements for investments in equity securities that have readily determinable fair values and for all investments in debt securities. Under SFAS 115, which the Company will adopt in the first quarter of 1994, an investment that the Company maintains in an insurance company would be classified as "available-for-sale" and accordingly, an unrealized net holding gain or loss would be recorded as an adjustment to common stock equity. Under SFAS 115, common stock equity would be adjusted to reflect periodic changes in the market value of this investment. Realized gains or losses would be recorded upon sale or other disposition of this investment. At December 31, 1993, the market value of this investment exceeded its carrying amount by approximately $1.5 million. The Company believes that the adoption of SFAS 115 will not have a material impact on the Company's results of operations.

SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Selected financial data for each quarterly period within 1992 and 1993 are presented below:

	Operating Revenues	Operating Income	Income Available for Common Stock	Earnings Per Average Share of Common Stock Outstanding
	(Thousands of Dollars)			(Dollars)
Quarter Ended:				
March 31, 1992	$146,587	$23,540	$14,601	$ .92
June 30, 1992	126,171	17,058	8,699	.55
September 30, 1992	118,715	17,046	10,087	.63
December 31, 1992	132,084	16,854	8,756	.55
March 31, 1993	$153,372	$26,711	$18,715	$1.15
June 30, 1993	117,744	17,254	9,885	.59
September 30, 1993	120,076	17,068	9,264	.55
December 31, 1993	126,182	13,528	6,965	.41

Directors

Marjorie S. Brown [1]
Millbrook, NY
Homemaker, active in civic and philanthropic work, former executive in retailing and promotional organizations; member of the Retirement Committee and the Committees on Compensation and Succession and on Finance *1979

L. Wallace Cross
Poughkeepsie, NY
Former Executive Vice President and Chief Financial Officer of the Corporation; retired; member of the Committees on Audit and Finance *1990

Jack Effron
Poughkeepsie, NY
President, EFCO Products, Inc.; Chairman of the Committee on Compensation and Succession and member of the Executive Committee and the Committee on Finance *1987

Richard H. Eyman
Norwalk, CT
Former Senior Vice President, Brouillard Communications, Division of J. Walter Thompson Company; retired; Chairman of the Committee on Audit; member of the Executive Committee and the Committee on Compensation and Succession *1984

Frances D. Fergusson
Poughkeepsie, NY
President, Vassar College *1993

Heinz K. Fridrich
Fernandina Beach, FL
Former Vice President — Manufacturing, International Business Machines Corp.; retired; member of the Committee on Audit *1988

Edward F.X. Gallagher
Newburgh, NY
President and Owner, Gallagher Transportation Services; member of the Retirement Committee *1984

Paul J. Ganci
Poughkeepsie, NY
President and Chief Operating Officer; member of the Executive Committee and the Committee on Finance *1989

Charles LaForge
Rhinebeck, NY
President of Wayfarer Inns and Owner of Beekman Arms; member of the Retirement Committee *1987

John E. Mack, III
Poughkeepsie, NY
Chairman of the Board and Chief Executive Officer; Chairman of the Executive and Retirement Committees; member of the Committee on Finance *1981

Howard C. St. John
Glenford, NY
Chairman of the Board, Ulster Savings Bank; Lawyer, Howard C. St. John & Associates; Vice Chairman of the Board; Chairman of the Committee on Finance; member of the Executive Committee and the Committee on Audit *1984

Edward P. Swyer
Albany, NY
President, L.A. Swyer Realty and Management, Inc.; President, Stuyvesant Plaza, Inc.; member of the Committee on Compensation and Succession and the Retirement Committee *1990

* Year joined the board

Officers Of The Board

John E. Mack, III
Chairman of the Board and Chief Executive Officer; Chairman of the Executive and Retirement Committees

Howard C. St. John
Vice Chairman of the Board and Chairman of the Committee on Finance

Jack Effron
Chairman of the Committee on Compensation and Succession

Richard H. Eyman
Chairman of the Committee on Audit

Officers

John E. Mack, III
Chairman of the Board
and Chief Executive Officer

Paul J. Ganci
President and Chief Operating Officer

Ronald P. Brand
Vice President — Engineering
and Environmental Affairs

Benon Budziak [2]
Vice President — Production

Joseph J. DeVirgilio, Jr.
Vice President — Human Resources
and Administration

John F. Drain
Vice President — Finance and Controller

Carl E. Meyer
Vice President — Customer Services

Allan R. Page
Vice President - Corporate Services

Gladys L. Cooper
Secretary

Steven V. Lant
Treasurer and Assistant Secretary

Herbert M. Round
Assistant Vice President

Arthur R. Upright [2]
Assistant Vice President -
Cost & Rate and Financial Planning

Ellen Ahearn
Assistant Secretary

Walter A. Bossert, Jr.
Assistant Secretary and Assistant Treasurer

[1] Mrs. Brown resigned from the Board of Directors effective January 1, 1994.
[2] Promotions effective February 1, 1994

Affirmative Action Statement of Policy
It is the policy of Central Hudson Gas & Electric Corporation to provide equal employment opportunities for all persons. Central Hudson is committed to recruit, hire, train, and promote persons in all positions, without regard to race, sex, color, creed, religion, age, national origin, persons with a disability, disabled veteran or Vietnam-era veteran status, except where sex is a bona fide occupational qualification. The Company will base decisions on employment so as to further the principle of equal employment opportunity. Central Hudson will insure that promotion decisions are in accord with principles of equal employment opportunity by imposing only valid requirements for promotional opportunities. Central Hudson will insure that all personnel actions such as compensation, benefits, transfers, layoffs, return from layoff, employer sponsored training, education, tuition assistance, social and recreational programs, will be administered without regard to race, sex, color, creed, religion, age, national origin, disability, disabled veteran or Vietnam-era veteran status.

Central Hudson

Keeping The **Customer** *In Focus*

Taking Charge of the Futur

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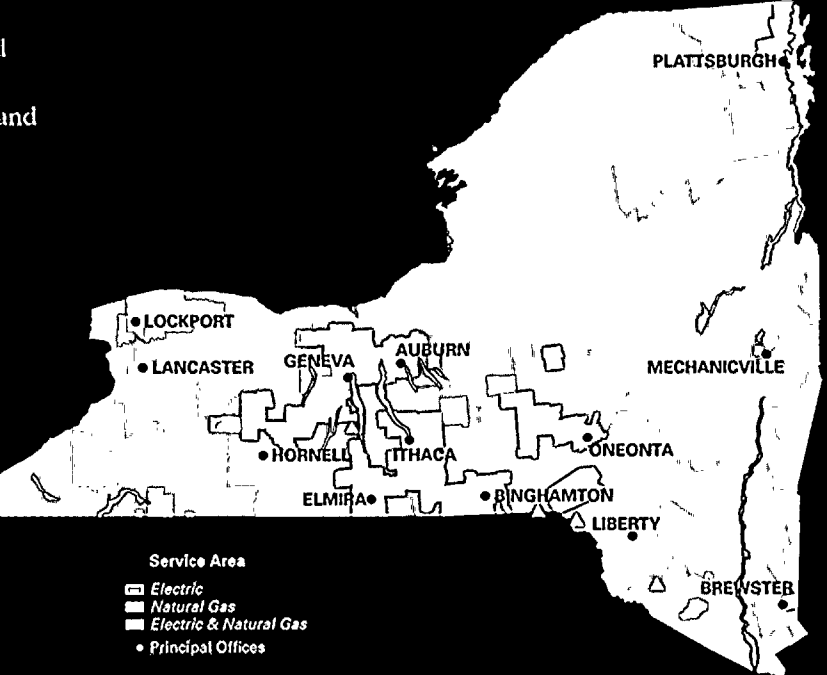
and

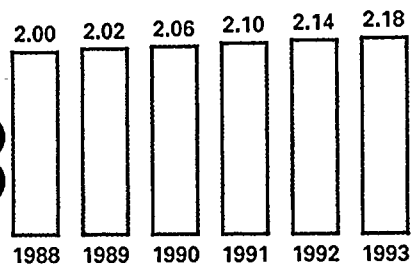

PLATTSBURGH
LOCKPORT
LANCASTER
GENEVA
AUBURN
MECHANICVILLE
HORNELL
ITHACA
ONEONTA
ELMIRA
BINGHAMTON
LIBERTY
BREWSTER
Service Area
Electric
Natural Gas
Electric & Natural Gas
Principal Offices

Financial Highlights

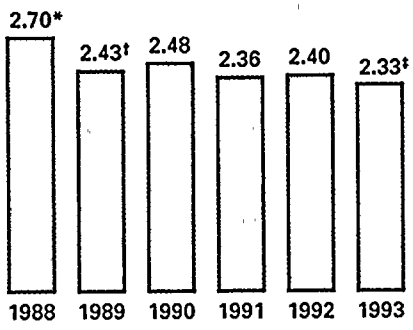
	1993	1992	% Change
At December 31			
Total Assets (000)	$5,276,016	$5,077,916	4
Capitalization (000)	$3,511,826	$3,630,901	(3)
Capital Structure (includes current maturities):			
Long-term Debt	48.6%	50.5%	(4)
Preferred Stock	9.4%	7.2%	31
Common Equity	42.0%	42.3%	(1)
Operating Results (000)			
Total Operating Revenues	$1,800,149	$1,691,689	6
Operating Expenses	$1,499,493	$1,367,926	10
Net Income	$166,028*	$183,968	(10)
Earnings for Common Stock	$145,390*	$162,973	(11)
Retail Megawatt-hour Sales	13,088	13,294	(2)
Dekatherms of Natural Gas Delivered	58,046	56,366	3
Per Common Share			
Earnings	$2.08*	$2.40	(13)
Dividends	$2.18	$2.14	2
Book Value (year end)	$22.89	$22.85	–
Market Value (year end)	$30.75	$32.50	(5)
Other Information			
Common Stock Price Range	$28¾-36½	$26⅛-32¾	
Return on Average Equity	9.1%	10.6%	(14)
Market-to-Book Ratio (year end)	134%	142%	(6)
Average Common Shares Outstanding (000)	69,990	67,972	.3
Common Shareholders (year end)	58,990	61,183	(4)

* Net income, earnings for common stock and earnings per common share for 1993 include the effects of restructuring expenses that decreased net income and earnings for common stock by $17 million and decreased earnings per share by 25 cents.

Dividends (Dollars Per Share)



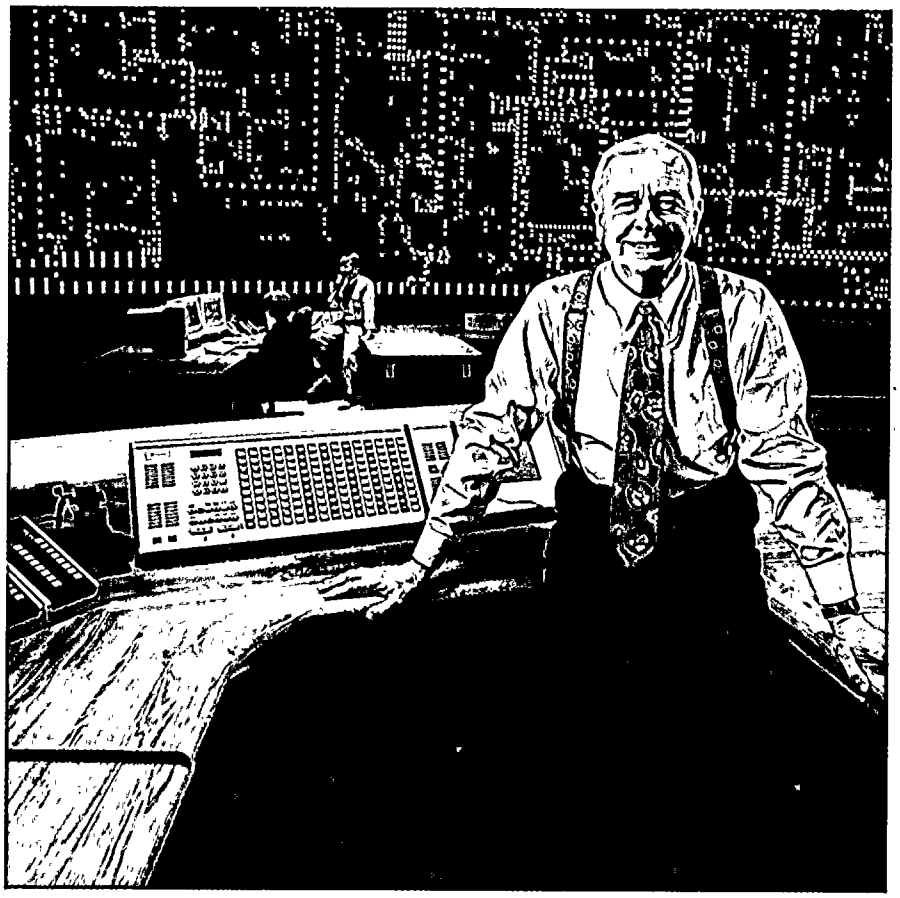
Earnings (Dollars Per Share)



* Excluding the effect of an April 1988 adjustment to the 1987 Nine Mile Point 2 write-off.

† Excluding the effect of a December 1989 adjustment to the 1987 Nine Mile Point 2 write-off.

‡ Excluding the effect of a December 1993 restructuring charge.



James A. Carrigg, chairman, president and chief executive officer, in the Company's Wells Allen Energy Control Center in Binghamton.

I write to you with a sense of urgency and pride. Urgency because NYSEG is facing competitive risks that it has never faced before. Pride because we are responding aggressively and decisively.

Competition

Where is the competition coming from?

The 1992 National Energy Policy Act opened the door for competition in the electric wholesale market. The Federal Energy Regulatory Commission's (FERC) Order 636 intensified competition within the natural gas industry on November 1, 1993.

Our large industrial customers are threatening to generate their own electricity, or move, at a time when our electric prices are increasing primarily due to mandated costs such as taxes and purchases of electricity from unregulated non-utility generators (NUGs). And the weak economy in New York State continues to depress sales, putting further pressure on electric prices.

In this rapidly changing environment, we can no longer behave as a regulator-driven monopoly. We must anticipate the demands of the marketplace and act quickly. We must take charge of our future.

Our Strategy

This past November we announced a comprehensive strategy to make the price of our electricity more competitive. Our strategy focuses on cost control, improved sales and flexible rates.

Our cost control efforts include:

- A one-third, or about $100 million, reduction in our forecasted 1994 capital expenditures with further reductions anticipated in future years.
- A 5 percent reduction in operating and maintenance expenses in each of the next two years. By 1995 this will save about $40 million annually. As part of this cutback, we have reduced our work force by about 800 people, or 16 percent, through attrition, early retirement and involuntary severance. We have also released more than 100 contractors.
- A streamlining of our field organization that will eliminate walk-in customer service at 28 locations and close up to 10 operations locations. We will also place two generating units on long-term cold standby.
- Additional efforts to reduce unregulated NUG costs. Previous NUG contract terminations and renegotiations will save customers more than $1 billion over the terms of the contracts.
- A continued emphasis on reducing capital costs. Since 1988 we have refinanced over $1.4 billion in securities, and annual interest expense has declined by $55 million.

Our electric sales effort emphasizes new, cost-effective and environmentally compatible electrotechnologies, as well as increasing wholesale power sales. One of NYSEG's greatest strengths is its abundance of low-cost generating capacity. We need to take maximum advantage of this important asset.

This brings me to our third area of focus, flexible rates. NYSEG needs the flexibility to use our excess capacity to encourage economic development and meet the competitive needs of our large customers. We were the first utility in New York State to receive approval to use a flexible rate for high-use electric customers. Thus far we have used this rate to negotiate contracts with two of our largest industrial customers. These two agreements retain about $20 million in annual electric revenues.

We also filed for a flexible incentive rate for new, incremental electric load, and we modified existing economic development incentive rates. Retaining and expanding our industrial base are critical to the health and prosperity of all of us in New York State. We need more jobs.

Achievements

In September 1993 we reached a three-year electric and natural gas rate settlement agreement with the New York State Public Service Commission (PSC). Key elements of the agreement include a revenue decoupling mechanism that allows us to adjust electric rates for variances between forecasted and actual sales; a continuation of our natural gas weather normalization clause; and the potential to enhance earnings based on our performance in customer service, demand-side management initiatives and the control of total production costs. Most importantly, this agreement provides us with an excellent opportunity to earn our allowed return on common equity, particularly in view of our cost reduction efforts. One disturbing aspect of this agreement is that our customers face price increases totaling about 20 percent over the next three years. 71 percent of this increase is due to the costs of purchasing electricity from unregulated NUGs and taxes. We must find ways to reduce those increases.

We continue to strengthen our financial condition. In June 1993 Standard & Poor's (S&P) upgraded our securities. This followed similar upgrades from Moody's and Fitch Investors Service in 1992. In October 1993 S&P concluded that more stringent financial benchmarks are appropriate for electric utilities to counter increased competition and mounting business risk. As a result, S&P lowered the outlook for about one-third of the electric utility industry, including NYSEG. However, our credit ratings were not changed. We agree with S&P's assessment. Our financial improvements must continue. A high degree of financial integrity is essential to our success in an increasingly competitive environment.

Our Gas Business Unit has made excellent progress in preparing for the challenges of FERC Order 636. We have increased the diversity of our natural gas supply by accessing Canadian natural gas at two points on our system, and we are developing our own 800 million cubic foot natural gas storage facility to provide greater flexibility to serve our customers. We have installed a state-of-the-art natural gas monitoring system and hired key personnel to

ensure expertise in all areas of natural gas management. How well is our natural gas strategy working? Our industrial rates are market-driven, and we currently offer the lowest residential natural gas rates of any combination utility in New York State. At the same time our Gas Business Unit has increased its contribution to the Company's earnings significantly.

During 1993 we took our first steps into diversification. In addition to our own natural gas storage facility, we will be developing a two billion cubic foot natural gas storage facility in cooperation with ANR Storage, Inc.

In addition, our wholly-owned subsidiary, NGE Enterprises, Inc., has formed EnerSoft Corporation, a computer software company that produces and markets software applications for natural gas utilities, marketers and pipelines in the post-FERC Order 636 environment. In October EnerSoft began a strategic alliance with the New York Mercantile Exchange to develop an information superhighway that will provide the natural gas industry with a single system for monitoring and trading natural gas and pipeline capacity in the North American market. These diversification activities demonstrate our commitment to create earnings opportunities out of the challenges of utility deregulation.

Earnings

Earnings were a disappointment in 1993. The weak New York State economy continued to depress electric sales. As a result, despite keeping our expenses below forecast, 1993 earnings fell short of both 1992 earnings and our allowed return on common equity. And this excludes the one-time charge of 25 cents per share for early retirement, employee severance and restructuring costs. These weak earnings put additional pressure on an already high dividend payout ratio at a time when growing competition dictates that we consider a more moderate dividend policy. We must significantly improve earnings if we are to continue even modest annual dividend increases.

Employees

With all the changes occurring in our industry, I am often asked how I can be so confident that NYSEG will succeed. The key to success is a talented, creative and dedicated work force that can adapt quickly to change. We have such a work force.

Never before in my years at NYSEG have I seen our organization rise to the occasion as it has during the past year. Our employees have witnessed economic distress in our communities, watched the Company rightsize, and accepted ever-increasing responsibilities. I am proud of their resourcefulness and competitive spirit. They are NYSEG's greatest asset.

Before I close, I'd like to acknowledge the retirement from our Board of Directors of Wells P. Allen, Jr., former chairman and chief executive officer of the corporation. In September 1993 we dedicated our new energy control center to Wells in honor of the significant contributions he made during his 42-year NYSEG career.

Looking Ahead

In the following pages, we focus on four primary factors we believe will define the winners in the new competitive environment: price, value, quality and speed. I strongly urge you to read on and discover what NYSEG is doing to respond to the challenges of deregulation and competition — to take charge of the future.

For the Board of Directors,

James A. Carrigg

James A. Carrigg
Chairman, President and
Chief Executive Officer
February 18, 1994

The "pit" at the New York Mercantile Exchange, the world's largest energy exchange, with whom our subsidiary has an alliance to develop an information superhighway to trade natural gas and pipeline capacity.

A struggling economy, mandated costs, FERC Order 636, the 1992 Energy Policy Act, customers with competitive options — these are the issues that confront us today.

At NYSEG we see opportunities where others see threats.

We must help our customers and our service territory remain competitive. By doing so, we provide shareholder value. NYSEG's customers are no longer competing solely with other businesses in New York State. They're competing with businesses in Canada, China, Korea, Europe, Mexico — the world. And they have increasing options for their energy supply.

We need to help them beat the competition by providing the highest possible value for their energy dollar. If our customers thrive, NYSEG thrives.

How do we compete? It's quite simple. We need to be smarter, better and quicker than our competition. We need to focus on price, value, quality and speed.

How are we meeting the competitive challenges? Both our Electric and Gas business units have a similar strategy: cut costs, implement flexible rates and increase sales.

Competition in the utility industry? Absolutely.

Our large electric customers have competitive options. They can build their own power plants or move out of state. Technological advances and the 1992 National Energy Policy Act are intensifying these competitive alternatives. With the November 1, 1993 implementation of FERC Order 636, our larger natural gas customers can bypass us as the supplier and, in some cases, the transporter of their natural gas.

How are we meeting these competitive challenges? Both our Electric and Gas business units have a similar strategy: cut costs, implement flexible rates and increase sales.

NYSEG is serious about cutting costs. In 1993 and early 1994 we reduced our work force by nearly 16 percent. Reducing operating and maintenance budgets by 5 percent in each of the next two years will save approximately $40 million annually, beginning in 1995. In 1994 we will cut capital spending by $100 million. We anticipate further reductions in future years. We are taking the actions necessary to become price competitive. We are taking charge of the future.

In January 1993 the PSC approved NYSEG service classification 13, the first electric rate in the state that allows negotiations on price with specific customers. Since then, we've negotiated contracts with two of our larger electric customers. These two agreements retain approximately $20 million in annual revenues. We beat the competition: in one case, the customer was going to generate its own electricity; in the other, the customer was going to leave the state.

In November 1993 we filed a new electric rate and three rate revisions. The new rate provides for negotiating the cost of large, new electric load. The revisions increase incentives for smaller customers, as well as those located in designated economic development zones.

Although electric sales have lagged due to the sluggish economy, our retail electric sales team has set aggressive 1994 sales goals that we'll pursue with new electrotechnologies.

These electrically-based technologies replace direct-burn fossil fuel systems, reducing emissions. Our customers can use them to improve product quality, streamline their operations and meet tighter environmental requirements. Examples of these technologies include infrared drying systems for the printing process, ultraviolet curing of paints and laser cutting for metal fabricating processes.

Our wholesale power sales team, buoyed by a generating system that boasts the lowest production costs in New York State, had several successes in 1993. Selling our excess capacity to other utilities in and out of New York State brought in $30 million in revenue.

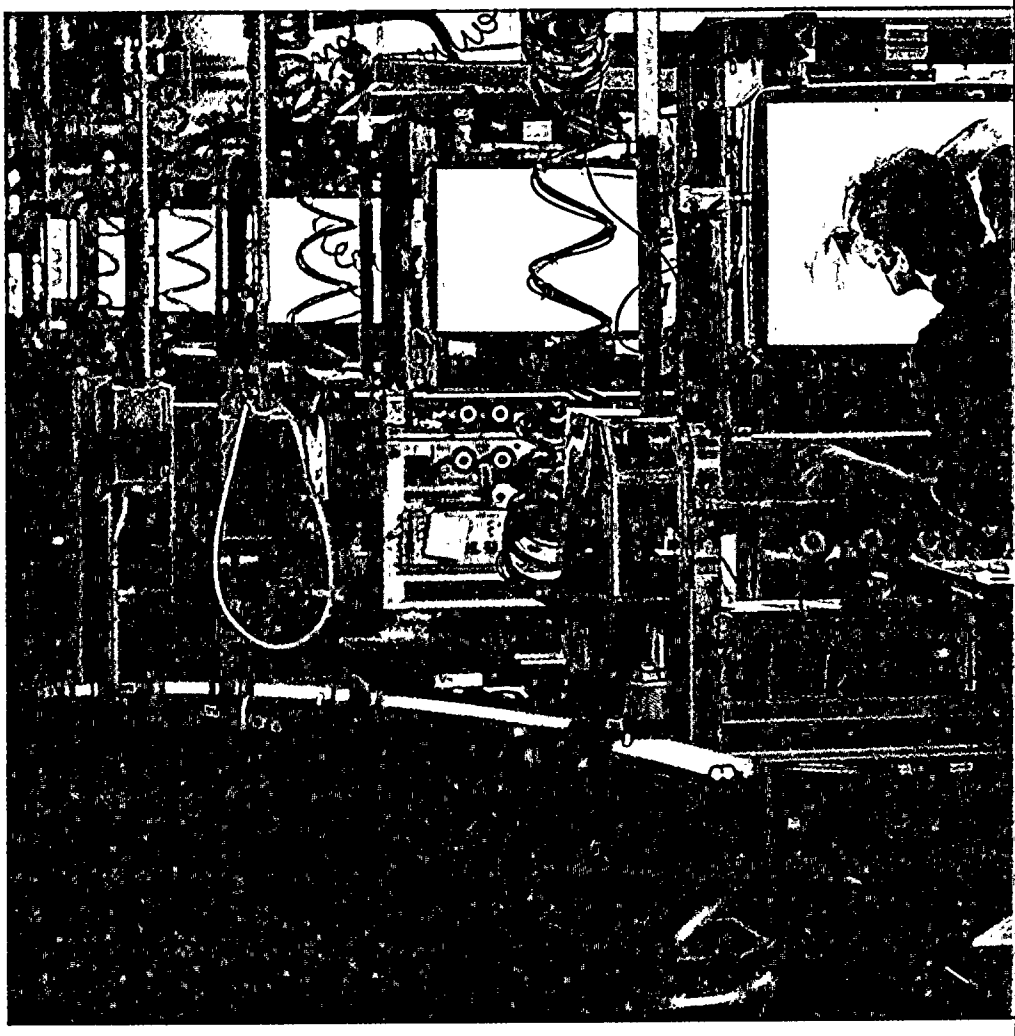
Competition is not new to the Gas Business Unit. NYSEG's natural gas customers know what they want and what they're willing to pay. We know that if we don't provide what our customers want, somebody else will.

Today's large customers can buy natural gas from us — as they have traditionally. Or they can buy their natural gas from anyone they choose while we transport that natural gas on our system — for a transportation rate. Or they can bypass our system entirely.

Our natural gas business strategy is simple. First we seek to beat the competition. On the other hand, if our customers can find cheaper supplies of natural gas, our pipelines are open and we will move the natural gas for them at our transportation rate. As long as we make the same profit on transportation as we do on a sale, we've met the market challenge. We are indifferent to the option our customer chooses. Profit margin is our bottom line.

It's a wide open game now in the natural gas industry. We are convinced our business strategies will lead to continued prosperity. With the December hook-up of a large pharmaceutical company in northern New York State, we added 350,000 dekatherms of sales and surpassed our 1993 sales goal. Our 1994 sales goal is the most aggressive ever.

This is the price story at NYSEG. But to many of our customers the price of our product is only part of the story. Many prefer value-added services — and are willing to pay for them.



Electrotechnologies provide our customers better value for their energy dollar, promote a cleaner environment and add new revenue for NYSEG. This electronics company recently installed a 1.3-megawatt electric furnace used in the production of television tubes.

price

Whether through flexible rates that meet a customer's price threshold or through value-added services, NYSEG is responding to the competitive challenge.

Very often, our customers are interested in the value-added services we provide. And it's easy to understand why. Many customers tell us they don't want to generate their own electricity. Some value our reliable energy and quality services more than the lowest competitive price.

Our goal is to be the preferred provider of energy services by increasing the efficiency, productivity and competitive position of our customers. So we're rethinking who we are. We no longer sell just electricity and natural gas — we also sell value-added services. In many cases, customers become our business partners. If our customers succeed, so will we.

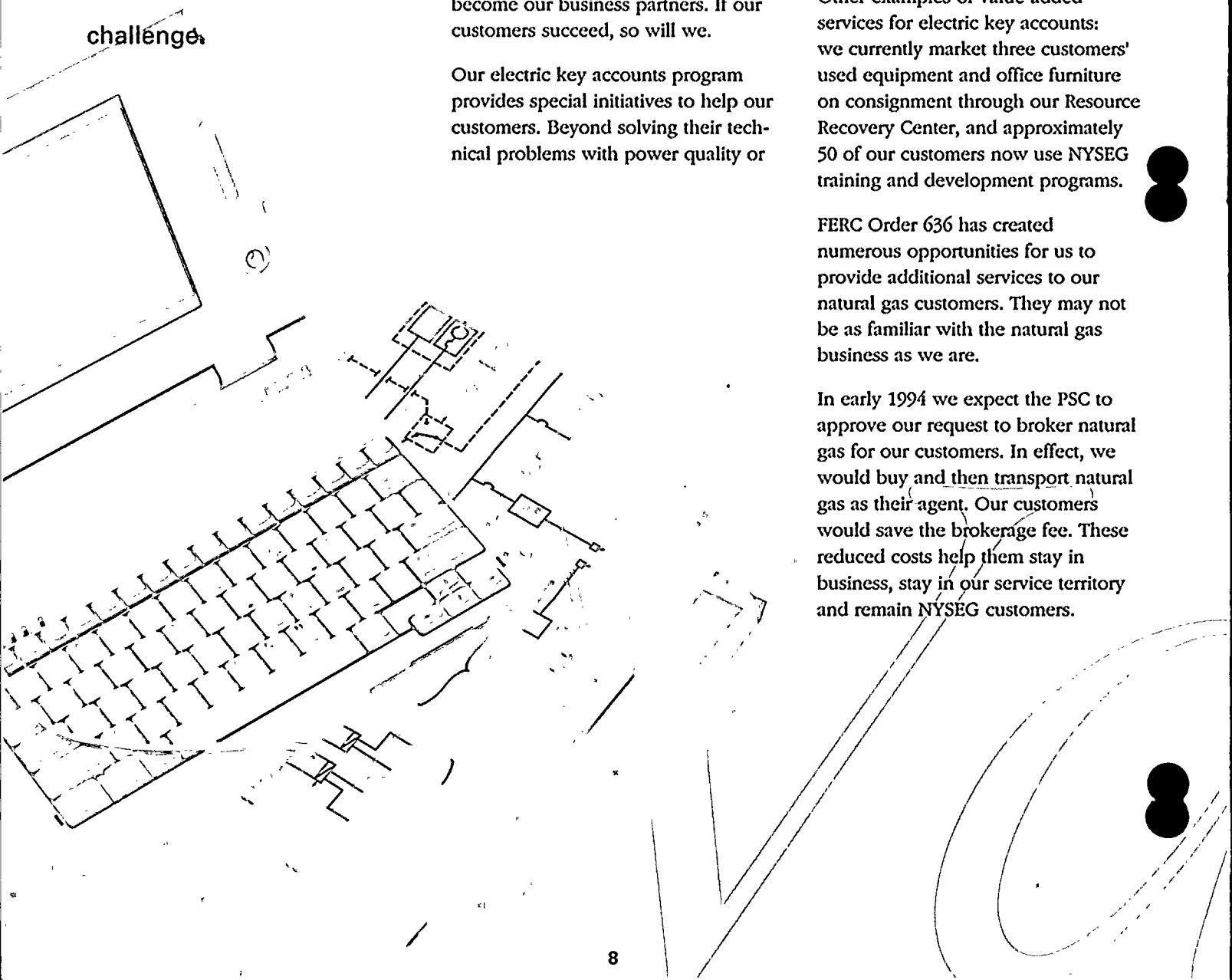
Our electric key accounts program provides special initiatives to help our customers. Beyond solving their technical problems with power quality or system efficiency, we have the expertise to maintain their substations and distribution lines. We are also talking to customers to see what expertise we can lend in plant operation, plant maintenance, fuel supply or ash disposal to improve their competitive position.

We also provide value to customers who are expanding or relocating in our service territory. We can help them find sites, profile the local labor force, identify available business and financial incentives, and structure financing alternatives.

Other examples of value-added services for electric key accounts: we currently market three customers' used equipment and office furniture on consignment through our Resource Recovery Center, and approximately 50 of our customers now use NYSEG training and development programs.

FERC Order 636 has created numerous opportunities for us to provide additional services to our natural gas customers. They may not be as familiar with the natural gas business as we are.

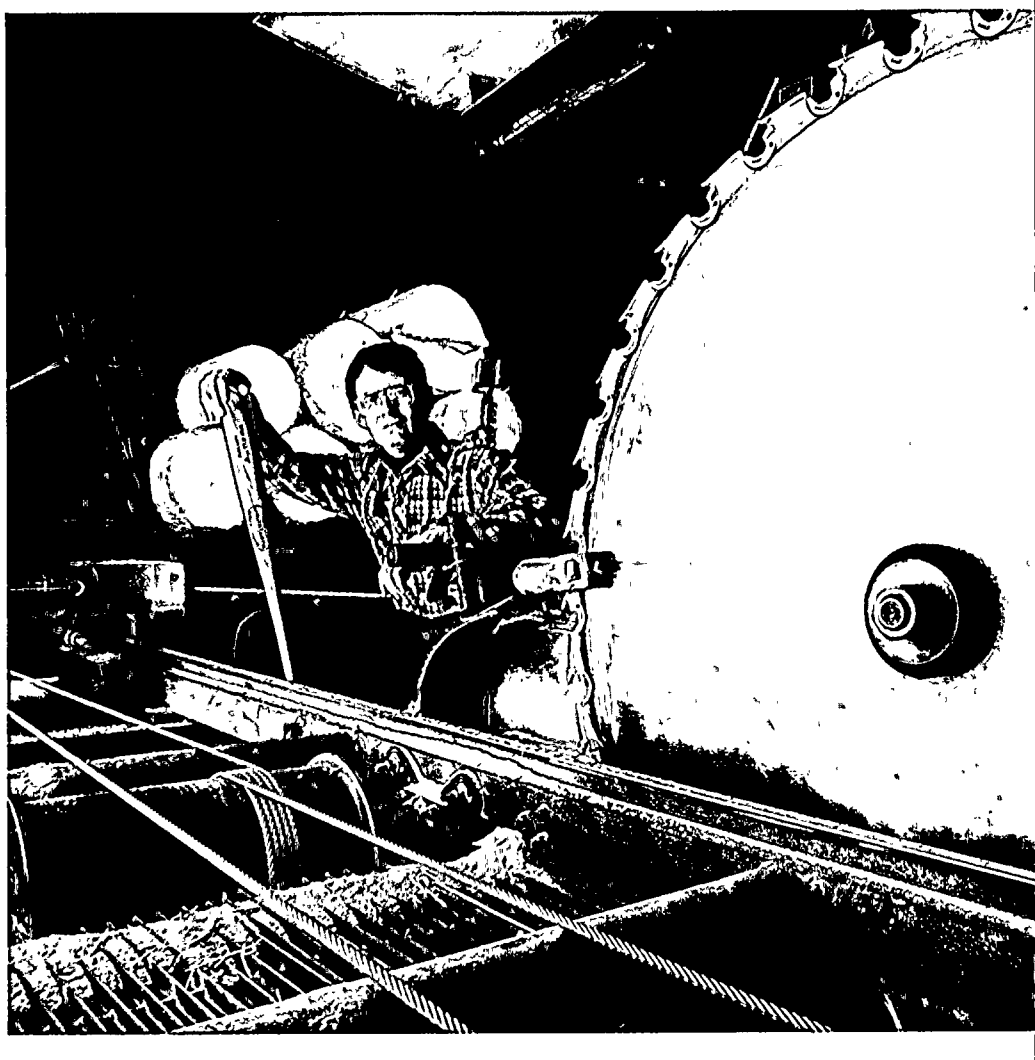
In early 1994 we expect the PSC to approve our request to broker natural gas for our customers. In effect, we would buy and then transport natural gas as their agent. Our customers would save the brokerage fee. These reduced costs help them stay in business, stay in our service territory and remain NYSEG customers.



We've given our natural gas transportation customers daily access to our electronic bulletin board. This bulletin board allows them to track their consumption so they can plan their purchases more accurately.

With FERC Order 636, our customers who fail to plan accurately for natural gas supply and pipeline capacity absorb additional costs. In early 1994 we also expect the PSC to approve a new rate that will allow our customers to use our storage for their surplus natural gas. Or we may buy their excess natural gas for our other customers. In either case, the customer can avoid these additional costs. Other natural gas suppliers don't provide this flexibility.

Whether through flexible rates that meet a customer's price threshold or through value-added services, NYSEG is responding to the competitive challenge. We know our product must have value and be competitively priced. It also must be delivered with the highest quality service and reliability.



NYSEG is helping its customers remain on the leading edge of technology in their industries. Installation of four electric dehumidification kilns increased productivity and quality for this lumber company that makes major league baseball bats — like this replica of one used by Babe Ruth.

line

Our field reorganization takes advantage of a regional approach and our state-of-the-art customer call center to provide enhanced service at reduced cost.

Ensuring high quality service and reliability after a 16 percent reduction in work force requires innovation. We knew we couldn't just shrink our existing organization. So we began with a blank slate, questioning every assumption and considering every option. The result?

Beginning in March 1994, we will have a fully redesigned field organization to serve our residential, commercial and industrial customers more efficiently. In addition, there have been significant changes in most corporate departments, and every corporate department will rightsize for the challenges that lie ahead.

Our field reorganization takes advantage of a regional approach and our state-of-the-art customer call center to provide enhanced service at reduced cost.

We will increase our efficiency and focus on the highest priority work by coordinating electric and natural gas construction crews under a common regional manager. This flexibility allows us to close up to 10 small operations locations. We will maintain more than 40 locations housing electric and natural gas crews statewide.

In this new organization, our local employees will focus on our customers' immediate electric and natural gas service needs. There will be a regional focus on major new construction, system rehabilitation and support services.

In recent surveys, our customers have told us their highest service priorities. They want reliable service and accurate, speedy response to inquiries. And they prefer to contact us by phone. Fewer than 5 percent of our customers visit our offices and of those that do more than 90 percent simply pay their bills. Our call center allows us to meet their expectations.

In fact, by the first quarter of 1994 we will increase customer accessibility to NYSEG by nearly 110 percent. How will we manage this? Our customer call center is now open from 7 a.m. to 9 p.m. Monday through Friday and will be open Saturdays 8 a.m. to 4:30 p.m. by the second quarter of 1994.

Along with these extended hours and the enhanced technology in the customer call center, we have consolidated walk-in customer service at our 13 principal offices, allowing the elimination of customer walk-in capability at 28 satellite locations. Customers may still pay their bills at more than 300 convenient pay agent locations.

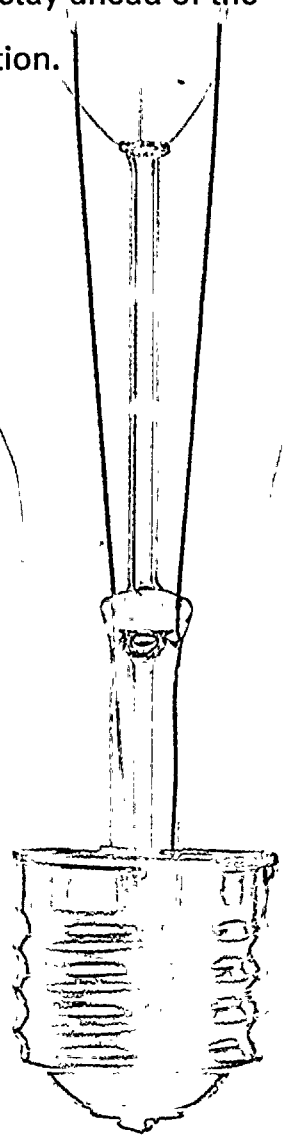
Organizational design is not the only way to achieve efficiencies and improve performance. Our continuous improvement efforts, or work simplification, continue to reap benefits for our customers. For example, our vendor contracts team shortened payment of invoices from 44 days to eight days — at a net savings of approximately $1.5 million annually. Several other work simplification teams have made process improvements that have also cut costs, increased productivity and enhanced customer service. What are the total savings for our customers? Approximately $8 million.

To thrive in the competitive utility environment of the '90s, NYSEG must ensure that our customers continue to receive the high-quality, reliable service they have grown to expect — at competitive prices. We must also be an efficient, flexible organization that adapts quickly to all future challenges.

We cannot become complacent. To beat our competition, we must move swiftly.

Meeting customers' needs in the electronic age means having state-of-the-art telecommunications facilities — like those in our customer call center in Binghamton.

At NYSEG we know we have to be innovative. We have to work at opportunities and be willing to take some risks. We also know we have the people, the technology and the strategies to stay ahead of the competition.



In a competitive world, what really counts is being first. If we want to compete, we have to be first out of the blocks. So we don't wait for problems — we anticipate them. We strive to be proactive, visionary and ready to exploit all opportunities. We constantly try to raise the bar, to look for improvement. And we're quickly adapting to change.

Some utilities that rely on coal to generate electricity saw the 1990 Clean Air Act Amendments as a threat to their competitiveness. Our generation department saw opportunities — both to reduce emissions and improve the competitive position of our generating facilities.

In August 1993 we laid the cornerstone for the Milliken Clean Coal Demonstration Project near Ithaca. Not only will this innovative flue gas desulfurization (FGD) system meet NYSEG's 1990 Clean Air Act Amendment requirements through the year 2005, but it will also lower production costs at Milliken Station where we will burn cheaper coal with a higher sulfur content. Innovative financing and $62 million in funding, primarily from the United States Department of Energy, make this the least expensive FGD system built for acid rain compliance in the United States. To date we're ahead of schedule and on budget.

In the increasingly competitive world resulting from the 1992 National Energy Policy Act, real-time information is necessary to compete in the wholesale electric marketplace. Our state-of-the-art energy control system (ECS) goes on line in the first quarter of 1994. The ECS will allow our system operators to maximize revenues and minimize our operating costs while maintaining system reliability for our customers.

With FERC Order 636, NYSEG is now responsible for the amount of natural gas we need and when we need it. That's a big shift from the way it was in the past when the pipeline was responsible for obtaining and transporting natural gas to us. So we put our gas energy management system (GEMS) on line in 63 days and under budget. GEMS gives us better control, better information and better data to operate our natural gas distribution system efficiently.

Our natural gas marketing team has introduced a variable compensation program. For the first time — and we're the only natural gas utility in the country that's doing this — we're putting the pay of our sales and marketing staffs at risk. Beginning in January 1994, nearly all natural gas marketing department employees will give up a portion of their base pay. Once they reach their goal, they will have earned that portion at risk and will then have the opportunity to earn commissions beyond their salary. In the post-FERC Order 636 world, we need to give our sales representatives the right incentives to get the right results.

Our Gas Business Unit and our wholly-owned subsidiary, NGE Enterprises, Inc., have plans to establish the first natural gas storage facilities in existing salt caverns in the Northeast — that together will hold almost three billion cubic feet of natural gas. Our strategy is to be able to move natural gas out of the fields and into storage, and respond quickly

when our customers need it. Or we can move it north, south, east or west to other utilities or large customers. We intend to be a major player in our region's supply of natural gas.

We also realized that after FERC Order 636 natural gas would be sold as a commodity and traded on an exchange where real-time information systems would be critical. We decided NGE Enterprises' subsidiary, EnerSoft, could lend some expertise — and who better to partner with than the New York Mercantile Exchange (NYMEX), the largest energy exchange in the world. We have a joint venture with NYMEX to create a cash market trading system for natural gas and pipeline capacity. While we look forward to profiting from this joint venture, we're also excited for the nation's consumers, who will benefit from its competitive efficiencies and are likely to pay less for natural gas.

At NYSEG we have to be innovative. We have to work at opportunities and be willing to take some risks. We also know we have the people, the technology and the strategies to stay ahead of the competition.

By focusing on price, value, quality and speed, we are taking charge of the future.

Our gas energy management system gives us up-to-the-moment information on natural gas pressures and flows throughout our system.

Board of Directors

First year elected in parentheses

James A. Carrigg (1983)
Chairman, President and Chief Executive Officer of the Corporation
Binghamton, NY

Alison P. Casarett (1979)
Special Assistant to the President
Cornell University
Ithaca, NY

Everett A. Gilmour (1980)
Former Chairman of the Board and Chief Executive Officer
The National Bank and Trust Company of Norwich
Norwich, NY

Paul L. Gioia (1991)
Partner
LeBoeuf, Lamb, Greene & MacRae
(Attorneys at Law)
Albany, NY

John M. Keeler (1989)
Managing Partner
Hinman, Howard & Kattell
(Attorneys at Law)
Binghamton, NY

Allen E. Kintigh (1987)
Former President and Chief Operating Officer of the Corporation
Binghamton, NY

Ben E. Lynch (1987)
President
Winchester Optical Company
Elmira, NY

Alton G. Marshall (1971)
Senior Fellow
Nelson A. Rockefeller Institute of Government
Albany, NY

David R. Newcomb (1979)
Former President and Chief Executive Officer
Buffalo Forge Company
(Manufacturer of Heating, Ventilating and Air Conditioning Equipment)
Buffalo, NY

Robert A. Plane (1982)
President
Wells College
Aurora, NY

C. William Stuart (1971)
Chairman and Chief Executive Officer
C.W. Stuart & Co., Inc.
(Interstate Trucking Concern)
Newark, NY

Committees of the Board

Chairperson listed first

Audit:
Plane, Gioia, Keeler, Lynch

Corporate Diversification:
Gioia, Carrigg, Gilmour, Lynch

Executive:
Carrigg, Gilmour, Kintigh, Marshall, Newcomb, Stuart

Executive Compensation and Succession:
Gilmour, Casarett, Lynch, Marshall, Newcomb

Nominating:
Marshall, Casarett, Gilmour, Lynch, Newcomb

Pension:
Keeler, Kintigh, Plane, Stuart

Public Affairs:
Casarett, Gioia, Keeler, Lynch

Mr. Carrigg is an ex officio member of the Pension and Public Affairs committees.


James A. Carrigg


Alison P. Casarett


Everett A. Gilmour


Paul L. Gioia


John M. Keeler


Allen E. Kintigh

Officers

Ages and years of service as of December 31, 1993, in parentheses

James A. Carrigg (60, 35)
Chairman, President and Chief Executive Officer

Patricia A. Orzell (51, 32)
Assistant Secretary

Jeffrey K. Smith (45, 23)
Executive Assistant to the Chairman, President and Chief Executive Officer

Richard P. Fagan (52, 22)
Senior Vice President-Management Services Business Unit

Russell Fleming, Jr. (55, 3)
Senior Vice President-Gas Business Unit

Jack H. Roskoz (55, 31)
Senior Vice President-Electric Business Unit

John J. Bodkin (48, 25)
Vice President-Electric Transmission and Distribution

Daniel W. Farley (38, 12)
Vice President and Secretary

Carl E. Johnson (51, 27)
Vice President-Consumer Services, Communications and Human Resources

William G. McCann (46, 24)
Vice President-East Region

Gerald E. Putman (43, 23)
Vice President-Fuel Supply and Operations Services

Sherwood J. Rafferty (46, 13)
Vice President and Treasurer (Chief Financial Officer)

Vincent W. Rider (62, 35)
Vice President-Electric Generation

Everett A. Robinson (50, 20)
Vice President and Controller (Chief Accounting Officer)

Irene M. Stillings (54, 17)
Vice President-Electric Marketing

Ralph R. Tedesco (40, 15)
Vice President-Strategic Growth Business Unit

Dennis R. Urgento (46, 22)
Vice President-West Region

Denis E. Wickham (44, 21)
Vice President-Electric Resource Planning

Roy Hogben (54, 36)
Assistant Controller

Robert T. Pochily (44, 22)
Assistant Treasurer

Gary J. Turton (46, 21)
Assistant Controller

Management Changes

Charles E. Dickson, Vice President-Regional Gas Operations, retired February 1, 1994.

John I. Fiala, Assistant Vice President-Plant Operations, retired February 1, 1994.

Paul Komar, Senior Vice President-Strategic Growth Business Unit, retired February 1, 1994.

John V. Kutz, Assistant Vice President-Transmission and Distribution Operations, retired February 1, 1994.

James M. Niefer, Assistant Secretary, retired February 1, 1994.

Richard W. Page, Vice President-Human Resources, retired February 1, 1994.

Robert A. Paglia, Vice President-Gas Marketing and Sales, retired February 1, 1994.

John D. Scott, Vice President-Economics, retired September 1, 1993.

Michael J. Turkovic, Vice President-Purchasing and Administration, retired May 1, 1993.

The Board of Directors elected Ralph R. Tedesco, Vice President-Strategic Growth Business Unit. Jeffrey K. Smith, Assistant to the Senior Vice President-Electric Business Unit, will succeed Mr. Tedesco as Executive Assistant to the Chairman, President and Chief Executive Officer.

The Board of Directors elected Dennis R. Urgento, Vice President-West Region. Mr. Urgento was previously Division Manager-Binghamton.


en E. Lynch


Alton G. Marshall


David R. Newcomb


Robert A. Plane


C. William Stuart

February
We priced $100 million of 6.05%, 40-year, tax-exempt pollution control bonds. The proceeds will be used for the redemption of $60 million of 12% and $40 million of 12.3% tax-exempt bonds in 1994. Customer savings will be $5.3 million annually. Several other bond issues and preferred stock refinancings later in the year also lowered our costs and added to customer savings.

April
We began testing one of the first of 50 Dodge Caravan electric vehicles that the Chrysler Corporation delivered to utilities nationwide.

May
The Board of Directors authorized an investment in a nonregulated company, EnerSoft — of which our subsidiary, NGE Enterprises, Inc., is the majority owner — to develop and market an integrated software package to help the energy industry share information on production, transportation and supply of natural gas.

June
Employee Allen Peterson was awarded the first U.S. patent under our Policy on Innovation program. The patent is for the Sedimat™, a device that protects streams from damage due to sediments stirred up during construction.

July
Employee Michael Eastman was awarded a U.S. patent for his invention that controls the flow of natural gas from transmission company pipelines to distribution utility pipelines and that eliminates environmentally harmful methane emissions.

The Board of Directors raised the quarterly common stock dividend one cent to 55 cents per share.

August
The Clean Coal Demonstration Project at Milliken Station officially got under way. Installation of an advanced flue gas desulfurization system at the plant is the cornerstone of our efforts to comply with the Clean Air Act Amendments of 1990.

We launched our MAXIMISER electric marketing sales program, which will increase profitability and improve our competitiveness. The program focuses on economically beneficial and environmentally sound electrotechnologies for targeted businesses.

The PSC approved our three-year rate settlement agreement.

September
We announced plans to develop two natural gas storage projects in existing salt caverns near Watkins Glen, one with our wholly-owned subsidiary, NGE Enterprises, Inc.

We received the New York State Governor's Award for Energy Excellence for our Tires-to-Energy program at Jennison Station.

The PSC approved our petitions to establish a special natural gas cooling rate — about 50 percent less than the current rate — and to develop a pooling service for qualifying transportation gas customers to help reduce their energy costs.

October
The New York Mercantile Exchange and EnerSoft began a strategic alliance to develop an information superhighway to provide the natural gas industry with a single system for monitoring and trading natural gas and pipeline capacity in the North American market.

November
To help make our electric prices more competitive, we filed with the PSC for a rate that will allow us to negotiate with large industrial customers eligible to receive power from the New York Power Authority. We also filed new and revised rates in an effort to sell more of our excess generation and boost business and employment in our service territory.

As part of our effort to reduce operating costs, we announced a 600-employee reduction in our work force through a one-time voluntary early retirement opportunity program and a subsequent involuntary severance program. Counting previous attrition, the total work force reduction is 800, or 16 percent.

December
Because of the wholesale power glut in the Northeast, we announced that one of two generating units at both Goudey and Greenidge stations would be put on long-term cold standby in the spring of 1994.

In its first nine months of operation, NYSEG's amended Dividend Reinvestment and Stock Purchase Plan enrolled more than 3,200 new participants. Optional cash payments made by participants increased by more than $6 million from the same period in the prior year. This plan, the first of its kind for a combination utility in our state, allows New York State residents to purchase shares of common stock directly from the Company.

Financial Section

Results of Operations

	1993	1992	1991	1993 over 1992 Change	1992 over 1991 Change
	(Thousands, except Per Share Amounts)				
Operating revenues	$1,800,149	$1,691,689	$1,555,815	6%	9%
Earnings available for common stock	$145,390	$162,973	$148,313	(11%)	10%
Average shares outstanding	69,990	67,972	62,906	3%	8%
Earnings per share	$2.08	$2.40	$2.36	(13%)	2%
Dividends per share	$2.18	$2.14	$2.10	2%	2%

In 1993, operating revenues increased $108 million, or 6%, compared to 1992. This increase is primarily because of increases in electric and natural gas rates that became effective in August 1992 and September 1993, which totaled $61 million, and the amounts billed to customers for higher costs of non-utility generation (NUG) power and natural gas totaling $51 million.

In 1992, operating revenues rose $136 million, or 9%, compared to 1991. The amounts billed to customers for higher costs of NUG power of $41 million, and increases in electric and natural gas rates effective in February 1991 and August 1992, which totaled $40 million, were the primary reasons for this increase. In addition, higher electric and natural gas retail sales due to an increase in retail customers, colder weather, and the April 1991 acquisition of Columbia Gas of New York, Inc. (CNY) helped boost operating revenues by $51 million in 1992.

Earnings per share decreased 32 cents, or 13%, in 1993 compared to 1992, while earnings per share increased 4 cents, or 2%, in 1992 compared to 1991. Both 1993 and 1992 had non-recurring items that lowered earnings per share. Earnings in 1993 were reduced by 25 cents per share as a result of a corporate restructuring that will reorganize the way the Company delivers services to its electric and natural gas customers beginning in March 1994. This restructuring resulted in a work force reduction throughout the organization of approximately 600, the elimination of customer walk-in services at 28 satellite locations, and the closing of up to 10 electric and natural gas operations facilities statewide. This is one of several actions the Company has taken to reduce future costs, enhance efficiencies in service to its customers, and be competitive in the rapidly changing utility industry (See Competitive Conditions). A six-month electric rate moratorium, which began in February 1992, limited 1992 earnings per share by 24 cents. Excluding the effect of these non-recurring items, earnings per share decreased 31 cents in 1993 compared to 1992, and increased 28 cents in 1992 compared to 1991.

The 31 cent 1993 decrease in earnings per share was primarily due to lower electric retail sales prior to the effective date of the Company's modified revenue decoupling mechanism (See Regulatory Matters) and lower than anticipated natural gas sales, both resulting from the sluggish economy in the Company's service territory. Also, earnings per share decreased due to changes in the Company's allowed return on equity from 11.7% effective through July 1992, to 11.2% effective through July 1993, and then to 10.8% beginning in August 1993.

In 1992, earnings per share were favorably affected by the growth in electric and natural gas retail sales primarily due to an increase in retail customers, colder weather, and the April 1991 acquisition of CNY. The Company's efforts to control costs also contributed to the increase in 1992 earnings per share.

Average shares outstanding were 70 million in 1993, 68 million in 1992, and 63 million in 1991. Average shares outstanding increased 3% in 1993 compared to 1992 due to the issuance of 1.2 million shares of common stock through the Dividend Reinvestment and Stock Purchase Plan (DRP). In 1992, average shares outstanding increased 8% because of a public offering of 5 million shares of common stock in March 1992, and the issuance of 1 million shares of common stock through the DRP.

Interest Expense

Interest expense (before the reduction for allowance for borrowed funds used during construction) decreased by $10 million, or 6%, in 1993 and $8 million, or 5%, in 1992. Interest on long-term debt decreased in 1993 and 1992 mainly due to the refinancing of certain high-coupon long-term debt at lower interest rates, and lower interest rates on the Company's variable rate debt. In 1993 and 1992 interest expense also decreased due to a reduction in the interest rate on the commercial paper borrowings (See Financing Activities).

Operating Results by Business Unit

Electric	1993	1992	1991	1993 over 1992 Change	1992 over 1991 Change
		(Thousands)			
Retail sales-kilowatt-hours (kwh)	13,088,175	13,294,466	13,107,115	(2%)	1%
Operating revenues	$1,527,362	$1,451,525	$1,367,936	5%	6%
Operating expenses	$1,250,000	$1,146,619	$1,056,969	9%	8%

Electric retail sales decreased 2% in 1993 compared to 1992 as a result of the sluggish economy in the Company's service territory and in spite of a 1% increase of customers. In 1992, electric retail sales increased 1% compared to 1991 mainly due to colder but more normal weather and an increase in customers.

The primary cause of the $76 million, or 5%, increase in electric operating revenues in 1993 was the increase in rates effective August 1992 and September 1993, which accounted for $53 million of the increase. Also contributing to this increase were higher costs of NUG power of $28 million, which were billed to customers. Electric operating revenues increased $84 million, or 6%, in 1992 compared to 1991. This increase reflects the increases in electric rates that became effective February 1991 and August 1992 and that increased revenues by $35 million. The revenue increase reflects higher NUG costs of $41 million and an increase in certain New York State gross receipts taxes of $12 million, both of which were billed to customers. Also, increased electric retail sales, due to colder weather and an increase in customers, boosted revenues by $9 million.

Electric operating expenses increased $103 million, or 9%, in 1993 compared to 1992, and $90 million, or 8%, in 1992 compared to 1991. In 1993, electricity purchased from NUGs increased $67 million. Other operating expenses increased primarily due to an increase in postretirement benefit costs other than pensions of $7 million. In addition, electric operating expenses increased $21 million due to the corporate restructuring. These increases were partially offset by a decrease of $17 million in fuel used in electric generation, the result of lower generation and a decrease in the price of coal, and a decrease of $12 million in federal income taxes, the result of lower pre-tax book income.

In 1992, electricity purchased increased primarily because of the amounts billed to customers for higher NUG costs, which totaled $41 million. Other operating expenses increased primarily because of higher demand-side management (DSM) program costs of $6 million. Federal income taxes increased $4 million resulting from higher pre-tax book income. Other taxes increased primarily because of an increase in certain New York State gross receipts taxes and property taxes of $16 million. These increases were partially offset by a decrease of $12 million in fuel used in electric generation, the result of lower generation and a decrease in the price of coal, and a decrease in maintenance expense of $7 million.

Natural Gas	1993	1992	1991	1993 over 1992 Change	1992 over 1991 Change
		(Thousands)			
Deliveries – dekatherms (dth)	58,046	56,366	42,404	3%	33%
Retail sales – dth	39,345	39,357	29,874	–	32%
Operating revenues	$272,787	$240,164	$187,879	14%	28%
Operating expenses	$249,493	$221,307	$177,751	13%	25%

Natural gas deliveries increased 3% in 1993 compared to 1992 while natural gas retail sales were flat. In 1992, natural gas deliveries and retail sales increased 33% and 32%, respectively, compared to 1991. The increase in deliveries in 1993 reflects an increase in the number of transportation customers. The 1992 increases in deliveries, as well as retail sales, are largely because of the April 1991 acquisition of CNY. Excluding CNY, natural gas retail sales increased 8% in 1992, primarily because of the colder but more normal weather.

Natural gas operating revenues rose $33 million, or 14%, in 1993 compared to 1992, and $52 million, or 28%, in 1992 compared to 1991. In 1993, the increase was primarily due to higher costs of natural gas of $23 million, which were billed to customers, and the increases in rates in August 1992 and September 1993, which totaled $8 million. The 1992 revenue increases are principally the result of the acquisition of CNY, which added $35 million, and the increases in rates effective February 1991 and August 1992 amounting to $4 million. Also, the recovery of an increase in certain New York State

gross receipts taxes, which were billed to customers, boosted 1992 revenues by $2 million.

Natural gas operating expenses increased $28 million, or 13%, in 1993 compared to 1992. The increase in natural gas purchased was primarily due to higher costs of natural gas amounting to $12 million. Federal income taxes increased $3 million due to higher pre-tax book income. Natural gas operating expenses increased $5 million due to the corporate restructuring.

Natural gas operating expenses increased $44 million, or 25%, in 1992 compared to 1991. Natural gas purchased increased $31 million due to an increase in the volume of natural gas purchased. This volume increase was primarily due to the CNY acquisition. Federal income taxes increased $4 million due to higher pre-tax book income. Other taxes increased primarily due to an increase of $3 million in certain New York State gross receipts taxes and $1 million in property taxes.

Liquidity and Capital Resources

Competitive Conditions

The utility industry is rapidly changing and facing an increasingly competitive environment. Factors contributing to this competitive environment are: the National Energy Policy Act of 1992 (Energy Policy Act), which provides open access at the wholesale level to electric transmission service, and the Federal Energy Regulatory Commission (FERC) Order 636, which significantly affects the natural gas industry. In addition, the Company's response to the economic pressures on its electric industrial and other large use customers, high purchase costs of NUGs, rising health care costs, increasing taxes, weak economic conditions, conservation programs, and compliance with environmental laws and regulations are all factors that continue to place increased pressure on electric and natural gas prices.

The Energy Policy Act, enacted in October 1992, is expected to result in major changes to the utility industry. Certain provisions of the Energy Policy Act amended the Public Utility Holding Company Act of 1935 (PUHCA). These amendments encourage greater competition in the supply market by establishing a new category of wholesale electric generators that are exempt from PUHCA regulation. The Energy Policy Act also enables the FERC to order utilities to provide open access to transmission systems for wholesale transactions, expanding opportunities for utilities and NUGs to enter new and existing wholesale markets. These developments serve to underscore the increasingly competitive environment for utilities.

The Company's five-year strategic plan is designed to address the competitive, rapidly changing utility industry. Our objective is to remain competitive in our core businesses in the face of increased competition. One of the key strategies to meet competition is to improve customer value by becoming a low-cost provider of energy services in the Northeast.

A major challenge to the Company's Electric Business Unit is to retain and grow its industrial base. The competitive energy supply options currently available to our industrial customers include self-generation, shifting production to plants in other locations, or relocation. During 1993, the Company received PSC approval for a flexible, negotiable rate tariff for some of its high-use industrial customers. Discounts negotiated in agreements under this tariff are not expected to have a material effect on the Company's 1994 earnings. Two agreements have been negotiated which eliminated threats of self-generation and relocation.

The PSC currently has a generic proceeding to study the broad subject of flexible, competitive rates, and will establish guidelines for the Company and other New York State utilities during 1994. Also in late 1993, the PSC instituted a proceeding to address issues associated with the restructuring of the emerging competitive natural gas market. The PSC intends to investigate services provided by New York State gas utilities after FERC Order 636 by the 1994-1995 heating season.

In November 1993, the Company filed with the PSC an additional flexible, negotiable rate tariff to address opportunities for new load. The proposed tariff is for large additions to load (at least 500 kilowatts) for new or existing industrial and some commercial customers. The tariff will assist the Company in attracting new customers whose location or expansion decisions are influenced by electricity costs. Smaller customers will be assisted by a concurrent proposal to increase our existing economic development incentives by one cent per kilowatt-hour. The Company has proposed and will continue to propose revisions or additional tariffs to respond to the opportunities or risks that develop in our changing industry.

A major challenge to the Company's Gas Business Unit is FERC Order 636, which became effective in November 1993, and requires interstate natural gas pipeline companies to offer customers unbundled or separate services equivalent to their former sales service. With the unbundling of services, primary responsibility for reliable natural gas supply will shift from interstate pipeline companies to local distribution companies, such as the Company. This should result in increased direct access to low cost natural gas supplies by local distribution companies and end users. One goal of FERC Order 636 is to provide equitable access to interstate pipeline capacity. FERC Order 636 will substantially restructure the interstate natural gas market and intensify competition within the natural gas industry. FERC Order 636 will

allow the Company, subject to PSC approval, to restructure rates and provide multiple service options to its customers.

In July 1993, certain interstate pipelines serving the Company began implementing restructured services in compliance with FERC Order 636. The remaining pipelines implemented restructured services by November 1993. As a result of these restructuring changes, pipelines have incurred and will continue to incur transition costs. These transition costs include those associated with restructuring existing natural gas supply contracts, the unrecovered natural gas cost that would otherwise have been billable to pipeline customers under previously existing rules, costs of assets needed to implement the order, and stranded investment costs. FERC Order 636 allows pipelines to recover all prudently incurred costs from their customers. The Company's liability for transition costs will be based on the pipelines' filings with FERC to recover transition costs. Only a few of those filings have been made. The Company recorded an estimated liability for transition costs of approximately $29 million. The Company also recorded a deferred asset for that amount since it is currently recovering transition costs from its customers through its gas adjustment clause and believes that such costs will continue to be recoverable from its customers.

The Company has developed a more aggressive and accelerated set of strategies in response to the increased challenges of competition which are necessary to achieve the objectives outlined in the Company's five-year strategic plan. The following represent strategies being implemented:

- Reduce forecasted 1994 capital expenditures by one-third, or approximately $100 million. Additional reductions will be made in 1995 and 1996.
- Reduce operating and maintenance expenses by five percent in 1994 and again in 1995. By 1995, this will save about $40 million annually. During 1993, the Company reduced its work force by 200 through attrition. In addition, as part of the O&M reduction, the Company's work force was further reduced by about 600 through an early retirement opportunity program and involuntary severance.
- Streamline our field organization to eliminate walk-in customer service at 28 locations, and to close up to 10 electric and natural gas operations facilities statewide.
- Place two generating units on long-term cold standby.
- Continue to reduce NUG costs. Our previous NUG contract terminations and renegotiations will save customers more than $1 billion over the terms of the contracts.
- Continue to reduce capital costs. Since 1988 we have refinanced over $1.4 billion in securities, and reduced annual interest expense by more than $55 million.

The cost of the corporate restructuring was $26 million and was a one-time charge against the Company's 1993 earnings. The restructuring reduced 1993 earnings available for common stock by approximately $17.2 million or 25 cents per share. Included in this amount are $13.2 million for a voluntary early retirement program, $3.2 million for an involuntary severance program, and $.8 million for the elimination and closing of operations facilities. The Company expects to recoup the one-time charge from lower O&M costs in approximately one year.

As part of our effort to meet competition and minimize future price increases associated with uneconomical power purchases from NUGs, the Company negotiated the termination of two cogeneration projects. This effort, along with the termination of NUG contracts due to developers' failures to meet contract obligations, will save our customers nearly $1 billion over the terms of the contracts. The Company has also recently negotiated amendments with two NUGs whereby the Company may direct the NUGs to reduce their output or shut down for limited periods each year. During these periods, lower-cost generation will replace the NUG energy and result in additional customer savings. The Company is negotiating with other NUGs for similar amendments.

The Company has on line and under contract 362 megawatts (mw) of NUG power. In addition, another 240 mw of NUG power is under construction. We are required to make payments under these contracts only for the power we receive. During 1993, 1992, and 1991, the Company purchased approximately $138 million, $71 million, and $30 million, respectively, of NUG power. We estimate that we will purchase approximately $255 million, $291 million, and $335 million of NUG power for the years 1994, 1995, and 1996, respectively. Increases in NUG power purchase costs are expected to be a significant contributor to price increases over the next three years.

Diversification

Diversification will play an important role in the Company's future. While the strength of the Company's core electric and natural gas businesses remains our focus, and while we will not compromise the Company's financial integrity, we are actively evaluating a number of corporate development opportunities for investment to help augment future earnings and dividend growth. In April 1992, the PSC issued an order allowing the Company to invest up to 5% of its consolidated capitalization (approximately $175 million at December 31, 1993) in one or more subsidiaries that may engage or invest in energy-related or environmental services businesses and provide related services.

In May 1993, NGE Enterprises, Inc. (NGE), a wholly-owned subsidiary of the Company, formed a computer software company, EnerSoft Corporation (EnerSoft), to produce and market software applications for natural gas utilities in the post-FERC Order 636 environment. This represents NGE's initial diversified investment.

In October 1993, EnerSoft began a strategic alliance with the New York Mercantile Exchange to develop an information superhighway that will provide the natural gas industry with a single system for monitoring and trading natural gas and pipeline capacity in the North American market. NGE invested approximately $9 million in EnerSoft through February 1994.

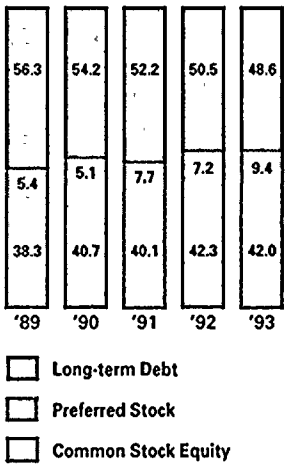
The Company and NGE plan to develop two natural gas storage projects. One of the projects, which will be regulated by the PSC, is expected to cost approximately $14 million and will be used to supplement the Company's natural gas supply. Construction of this project is scheduled to begin in 1994 and it is expected to be operating for the 1995-1996 heating season. The other project, which will be regulated by the FERC, is an equal partnership between NGE and ANR Storage, Inc., and is expected to cost approximately $44 million in total. The entire capacity of this project will be marketed to local distribution companies and NUGs, as well as marketers, producers, and end users of natural gas. Construction of this project is scheduled to begin in 1995 and it is expected to be operating for the 1996-1997 heating season.

Financing Activities

The Company believes that maintaining a high degree of financial integrity and flexibility is critical to success in an increasingly competitive environment. We intend to build on the financial improvements realized over the past several years with a goal of achieving a 50% common equity ratio. New money needs are expected to be minimal and excess cash generated from reduced construction expenditures will be used to further manage the Company's capital structure (See Investing Activities—estimated sources and uses of funds for 1994-1996).

The PSC adopted a new, innovative approach in December 1993 when it issued an order to the Company that provides for advanced approval for financings during the Company's three-year rate settlement. That order includes authorization for refundings of first mortgage bonds, preferred stock, and tax-exempt pollution control notes, issuance of common stock through the Dividend Reinvestment and Stock Purchase Plan (DRP), and issuances of other securities as required. With this order, the Company has the flexibility to achieve its financial goals of further reducing financing costs and improving its financial health as market conditions allow.

Capital Structure



The common stock equity ratio remained stable during 1993. Issuance of shares under the DRP was offset by the issuance of $100 million of preferred stock and $70 million of tax-exempt pollution control notes in December 1993. We received $38.4 million from the issuance of 1.2 million shares of common stock through the DRP.

Common stock dividends paid in 1993 increased 5% over 1992 reflecting the increase in common stock outstanding and an increase in the dividend paid from $2.14 to $2.18 per share.

The Company's dividend payout ratio has been gradually rising over the past several years, primarily as a result of declining earnings. These weak earnings put additional pressure on an already high dividend payout ratio at a time when growing competition dictates that we consider a more moderate dividend policy. We must significantly improve earnings if we are to continue even modest annual dividend increases.

The Company sold $25 million of 6.30% preferred stock, $50 million of Adjustable Rate Series B preferred stock, and $25 million of 7.40% preferred stock in December 1993. The net proceeds were used to redeem $25 million of 8.80% preferred stock and $45 million of Adjustable Rate Series A preferred stock in January 1994, and $25 million of 8.48% preferred stock in February 1994. Those refundings will save approximately $1.8 million annually. After those refundings, the capital structure will be 49.8% long-term debt, 7.1% preferred stock, and 43.1% common stock equity.

In February 1993, we redeemed, at par, through a sinking fund provision in our mortgage, the remaining $22.5 million of 10 5/8% Series first mortgage bonds due 2018.

In February 1993, the Company priced $100 million of 6.05% tax-exempt pollution control bonds, due 2034. Proceeds from the sale, which will be delivered in April 1994, will be used to redeem, at a premium, $60 million of 12% pollution control bonds, due 2014, and $40 million of 12.3% pollution control bonds, due 2014. The refunding of those bonds in 1994 will save approximately $5.3 million annually in interest costs.

In April 1993, the Company sold $50 million of 7.55% Series first mortgage bonds due 2023. Net proceeds from the sale were used in connection with the redemption of $50 million of the 9 1/4% Series due 2016. The refunding of those bonds will save approximately $300,000 annually in interest costs.

In July 1993, the Company sold $100 million of 7.45% Series first mortgage bonds due 2023. Net pro-

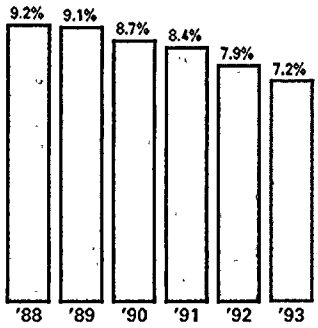
ceeds from the sale were used in connection with the redemption of $100 million of the 9% Series due 2017. The refunding of those bonds will save approximately $650,000 annually in interest costs.

In November 1993, the Company redeemed $50 million of the 8 5/8% Series first mortgage bonds due 1996, at a premium. Proceeds for the redemption were provided by a borrowing under the Company's revolving credit agreement. The refunding of those bonds will save approximately $2 million annually in interest costs.

In December 1993, $70 million of 5.70% tax-exempt pollution control notes, due 2028, were issued by a governmental authority on behalf of the Company. Proceeds from the sale will be used to finance a portion of the costs incurred in the construction of certain solid waste disposal and other related facilities at the Company's Milliken Generating Station.

The Company reduced its embedded cost of long-term debt to 7.2% at the end of 1993 from 9.2% in 1988. The Company has refinanced more than $1.2 billion in long-term debt since 1988, and reduced annual interest expense by more than $55 million. Unless interest rates fall further, however, it will be difficult to significantly improve from the 7.2% level. All opportunities continue to be pursued aggressively.

Embedded Cost of Long-term Debt



In February 1994, we redeemed, at par, through a sinking fund provision in our mortgage, $23 million of 8 5/8% Series first mortgage bonds due 2007.

In February 1994, $37.5 million of tax-exempt pollution control notes were issued by a governmental authority on behalf of the Company. The notes will have several interest rate options and have an initial rate of 2.4% through April 13, 1994. Proceeds from the sale will be used to redeem $37.5 million of annual adjustable rate pollution control notes, due 2015, in March 1994.

The Company uses interim financing in the form of short-term unsecured notes, usually commercial paper, to finance certain refundings and construction expenditures and for other corporate purposes, thereby providing flexibility in the timing and amounts of long-term financings. There was $50.2 million of commercial paper outstanding at December 31, 1993, at a weighted average interest rate of 3.5%. The weighted average interest rate during 1993 was 3.4%.

The Company also has a revolving credit agreement with certain banks that provides for borrowing up to $200 million to July 31, 1997. The Company had an outstanding $50 million loan under this agreement at December 31, 1993, at an interest rate of 4.06%.

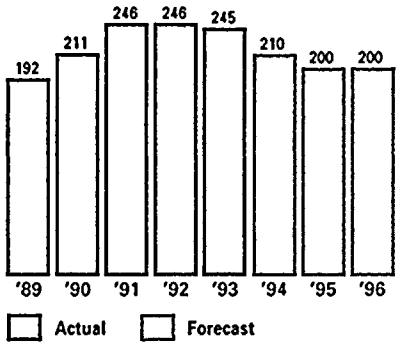
In June 1993, the Company's first mortgage bonds and unsecured pollution control notes were upgraded by Standard & Poor's (S&P). The investment rating agency stated that the higher ratings reflect expected continued improvements in the Company's financial condition as a result of the Company's three-year rate settlement, which was pending at the time of the upgrade, aggressive cost controls, and limited new money needs. S&P also noted that regulatory adjustment mechanisms, such as electric revenue decoupling and natural gas weather normalization, should add stability to earnings.

In October 1993, S&P completed its review of the U.S. investor-owned utility industry and concluded that more stringent financial benchmarks were appropriate for electric utilities to counter increased competition and mounting business risk. As a result, it revised the rating outlook downward for about one-third of the utility industry, including the Company. However, the Company's ratings were not changed.

Investing Activities

The Company's 1993 capital expenditures for its core electric and natural gas businesses totaled approximately $245 million. Most of the expenditures were for the extension of service and for improvements at existing facilities.

Capital Expenditures (Millions of Dollars)



Capital expenditures for 1994-1996 have been significantly reduced from previously forecasted levels. This represents one of many actions the Company is taking to address competition (See Competitive Conditions). Capital expenditures for 1994-1996 will be primarily for extension of service, necessary improvements at existing facilities, and compliance with the Clean Air Act Amendments of 1990 (See Environmental Matters). We forecast that our current reserve margin, coupled with more efficient use of energy (See Conservation Programs) and generation from NUGs, will eliminate the need for additional generating capacity until after the year 2005.

As part of our effort to reduce costs, one of two generating units at each of our Goudey and Greenidge Generating Stations will be placed on long-term cold standby. These actions are being taken because the abundance of power in the Northeast has driven down wholesale prices. These units will continue to be utilized to provide electrical system support.

The following table provides information on the Company's estimated sources and uses of funds for 1994-1996. This forecast is subject to periodic review and revision, and actual construction costs may vary because of revised load estimates, imposition of additional regulatory requirements, and the availability and cost of capital.

	1994	1995	1996	Total
		(Millions)		
Sources of funds				
Internal funds	$254	$265	$269	$788
Long-term financing				
Debt and stock proceeds	413	141	80	634
Debt proceeds held in trust	34	8	–	42
Net financing proceeds	447	149	80	676
Increase (decrease) in short-term debt	(50)	–	–	(50)
Decrease (increase) in temporary cash investments	89	(69)	(52)	(32)
Total	$740	$345	$297	$1,382
Uses of funds				
Construction				
Cash expenditures	$202	$193	$193	$588
AFDC	8	7	7	22
Total construction	210	200	200	610
Retirement of securities and sinking fund obligations	501	108	63	672
Working capital and deferrals	29	37	34	100
Total	$740	$345	$297	$1,382

As shown in the preceding table, internal sources of funds represent 129% of construction expenditures for 1994-1996.

Conservation Programs

The Company has implemented a number of demand-side management (DSM) programs. As a result of our three-year rate settlement agreement (See Regulatory Matters), incentives earned for conducting efficient DSM programs were reduced from 15% to 5% of the net resource savings achieved by these DSM programs. For 1994, the Company expects to earn approximately $3 million in incentives as a result of these DSM programs.

In 1993, our customers saved approximately 282 million kilowatt-hours (kwh) on an annualized basis through our DSM programs. The implementation of these programs cost $48 million in 1993 and will cost approximately $16 million in 1994 with estimated customer savings of 113 million kwh on an annualized basis. The Company has approximately $73 million and $44 million of deferred DSM program costs on the Consolidated Balance Sheets at December 31, 1993, and 1992, respectively. The two-year (1993-1994) DSM plan, which has received PSC approval, has been modified to improve cost-effectiveness and reduce rate impacts.

Environmental Matters

The Company continually assesses actions that may need to be taken to ensure compliance with changing environmental laws and regulations. Compliance programs will increase the cost of electric and natural gas service by requiring changes to our operations and facilities. Historically, rate recovery has been authorized for the cost incurred for compliance with environmental laws and regulations.

Due to existing and proposed legislation and regulations, and legal proceedings commenced by governmental bodies and others, the Company may also incur costs from the past disposal of hazardous substances produced during our operations or those of our predecessors. We have been notified by the U.S. Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation (NYSDEC) that we are among the potentially responsible parties (PRPs) who may be liable to pay for costs incurred to remediate certain hazardous substances at seven waste sites, not including our inactive gas manufacturing sites, which are discussed below. With respect to the seven sites, five sites are included in the New York State Registry of Inactive Hazardous Waste Sites (New York State Registry).

Any liability may be joint and several for certain of these sites. The ultimate cost to remediate these sites will be dependent on such factors as the remedial action plan selected, the extent of site contamination, and the portion attributed to the Company. At December 31, 1993, the Company recorded a liability in the Consolidated Balance Sheets related to four of these seven waste sites of $1.8 million. The Company has notified the NYSDEC that it believes it has no responsibility at two sites and has already incurred expenditures related to the remediation at the remaining site. A deferred asset has also been recorded in the amount of $2.6 million, of which $.8 million relates to costs that have already been incurred. The Company believes it will recover these costs, since the PSC has allowed other utilities to recover these types of remediation costs and has allowed the Company to recover similar costs in rates, such as investigation and cleanup costs relating to inactive gas manufacturing sites. This $1.8 million estimate was derived by multiplying the total estimated cost to clean up a particular site by the related Company contribution factor. Estimates of the total cleanup costs were determined by using information related to a particular site, such as investigations performed to date at a site or from the data released by a regulatory agency. In addition, this estimate was based upon currently available facts, existing technology, and presently enacted laws and regulations. The contribution factor is calculated using either the Company's percentage share of the total PRPs named, which assumes all PRPs will contribute equally, or the Company's estimated percentage share of the total hazardous wastes disposed of at a particular site, or by using a 1% contribution factor for those sites at which it believes that it has contributed a minimal amount of hazardous wastes. The Company has notified its former and current insurance carriers that it seeks to recover from them certain of these cleanup costs. However, the Company is unable to predict the amount of insurance recoveries, if any, that it may obtain.

A number of the Company's inactive gas manufacturing sites have been listed in the New York State Registry. We have filed petitions to delist the majority of the sites. Our program to investigate and initiate remediation at our 38 known inactive gas manufacturing sites has been extended through the year 2000. Expenditures over this time period are estimated to be $25 million. This estimate was determined by using the Company's experience and knowledge related to these sites as a result of the investigation and remediation that the Company has performed to date. It is based upon currently available facts, existing technology, and presently enacted laws and regulations. This liability, to investigate and initiate remediation, as necessary, at the known inactive gas manufacturing sites is reflected in the Company's Consolidated Balance Sheets at December 31, 1993 and 1992. The Company also has recorded a corresponding deferred asset, since it expects to recover such expenditures in rates, as the Company has previously been allowed by the PSC to recover such costs in rates. The Company has notified its former and current insurance carriers that it seeks to recover from them certain of these cleanup costs. However, the Company is unable to predict the amount of insurance recoveries, if any, that it may obtain.

The Clean Air Act Amendments of 1990 (1990 Amendments) will result in significant expenditures of approximately $178 million, on a present

value basis, over a 25-year period, for all capital and operating and maintenance expenses related to the reduction of sulfur dioxide and nitrogen oxides at several of our coal-fired generating stations, of which $51 million has been incurred as of December 31, 1993. The Company's current estimate is a significant reduction from its prior estimate, primarily due to the postponement of the construction of a flue gas desulfurization (FGD) system at its Homer City Generating Station. The Company plans to re-evaluate the need to construct an FGD system at the Homer City Generating Station in 1995, since its present strategy to bank Phase I emissions allowances for use during Phase II, as discussed below, will allow the Company to meet Phase II allowance requirements through the year 2005. The cost to comply with the sulfur dioxide and nitrogen oxide limitations includes the construction of an innovative FGD system and a nitrogen oxide reduction system expected to be completed in 1995 at our Milliken Generating Station. We estimate that approximately a 1% electric rate increase will be required for the cost of reducing sulfur dioxide and nitrogen oxide emissions in both Phase I (begins January 1, 1995) and Phase II (begins January 1, 2000). As a result of the 1990 Amendments, we plan to reduce our annual sulfur dioxide emissions by an amount that will allow the Company to meet the sulfur dioxide levels established for the Company, which is approximately a 49% reduction from approximately 138,000 tons in 1989 to 71,000 tons by the year 2000.

The cost of controlling toxic emissions under the 1990 Amendments, if required, cannot be estimated at this time. Regulations may be adopted at the state level which would limit toxic emissions even further, at an additional cost to the Company. We anticipate that the costs incurred to comply with the 1990 Amendments will be recoverable through rates based on previous rate recovery of required environmental costs.

The 1990 Amendments require the EPA to allocate annual emissions allowances to each of our coal-fired generating stations based on statutory emissions limits. An emissions allowance represents an authorization to emit, during or after a specified calendar year, one ton of sulfur dioxide. During Phase I, we estimate that the Company will have allowances in excess of the affected coal-fired generating stations' actual emissions. The Company's present strategy is to bank these allowances for use in later years. By using a banking strategy, it is estimated that Phase II allowance requirements will be met through the year 2005 by utilizing the allowances banked during Phase I, which includes the extension reserve allowances discussed below, together with the Company's Phase II annual emissions allowances. This strategy could be modified should market or business conditions change. In addition to the annual emissions allowances allocated to the Company by the EPA, we will receive a portion of the extension reserve allowances issued by the EPA to utilities electing to build scrubbers, as a result of the pooling agreement that we entered into with other utilities who were also eligible to receive some of these extension reserve allowances.

As a result of existing and new solid waste disposal legislation and regulations in Pennsylvania, the Company will incur approximately $24 million, on a present value basis, of additional costs over the next 30 years, beginning in 1994, at the Homer City Generating Station. These costs will be incurred to install new equipment, modify or replace existing equipment, and improve the design of a proposed expansion of disposal facilities. The Company expects to recover these expenditures in rates, since the Company has been allowed by the PSC to recover similar costs in rates, such as groundwater protection costs to meet permit conditions and regulatory requirements.

Regulatory Matters

In September 1993, the Company reached a three-year electric and natural gas rate settlement agreement (Agreement) with the PSC. The new electric and natural gas rates became effective September 4, 1993.

The allowed return on equity is 10.8% in year one, 11.4% in year two, and 11.4% (subject to an indexing mechanism) in year three. Shareholders will be allowed to keep 100% of any earnings in excess of the allowed return in year one. Shareholders and customers will share, on a 50%/50% basis, any earnings in excess of the allowed return in years two and three.

The Agreement also includes a modified revenue decoupling mechanism (RDM) for electric sales. Rates are based on sales forecasts. Since actual sales may differ significantly from forecasted sales because of conservation efforts, unusual weather, or changing economic conditions, the revenue collected may be more or less than forecast. Subject to the caps described below, the modified RDM will let the Company adjust for most of the differences between forecasted and actual sales. For example, if revenues exceed the forecast for a given year, the excess would be passed back to customers in a future year. If revenues are below the forecast, customers would receive a surcharge in a future year. The Company will share excesses or shortfalls from most large commercial and industrial sales revenues on a 70%/30% (customer/stockholder) basis.

Customer savings for production and transmission operating costs of $21 million will be imputed over three years, $7 million each year, whether or not they are realized.

Incentives for customer service, production cost, and DSM could increase the allowed return to 12.3% or decrease it to 9.95% in year one, increase it to 13.05% or decrease it to 10.4% in year two, and increase it to 13.25% or decrease it to 10.2% in year three.

The electric and natural gas rate increases discussed below represent eleven months for year one and twelve months for years two and three.

The estimated total electric price increases below include base rate increases allowed by the Agreement plus estimates of fuel and purchased power increases which will be collected through the Fuel Adjustment Clause (FAC). Actual fuel and purchased power costs could vary from estimates causing the estimated FAC and total electric price increases below to change.

	Base Rate		Estimated FAC		Total Electric	
			(Dollar Amounts in Millions)			
Year 1	$60.5	4.4%	$39.1	3.0%	$99.6	7.4%
Year 2	$70.3	4.8%	$39.2	2.8%	$109.5	7.6%
Year 3	$57.4	3.6%	$30.4	2.0%	$87.8	5.6%

The natural gas base rate increases allowed by the Agreement are $7.5 million, or 2.9%, $8.2 million, or 3.0%, and $7.2 million, or 2.5%, in years one, two, and three, respectively. They do not include changes in natural gas costs, which will be collected through the Gas Adjustment Clause. Natural gas costs can be expected to rise and fall with overall natural gas market conditions. Such fluctuations will affect the total natural gas price increases.

The Agreement also provides for the stated electric and natural gas base rate increases to be adjusted up or down in the second and third years, as well as the year after the Agreement period (year four). These adjustments will depend on several factors, such as electric sales and incentive mechanisms. The Agreement provides that no cap would apply to any downward revision to base rates for electric and natural gas service. The electric base rate increases could be increased by up to 1.5% in years two and three and 1.6% in year four (the caps). The natural gas base rate increases could also be increased by up to 1% in year two and 1.2% in year three. The Agreement does not specify a cap for natural gas base rates for year four.

Consolidated Balance Sheets

December 31	1993	1992
	(Thousands)	
Assets		
Utility Plant, at Original Cost (Note 1)		
Electric (Note 8)	$4,777,368	$4,573,444
Natural gas	381,389	352,059
Common	158,986	157,979
	5,317,743	5,083,482
Less accumulated depreciation	1,541,456	1,427,793
Net Utility Plant in Service	3,776,287	3,655,689
Construction work in progress	143,859	177,566
Total Utility Plant	3,920,146	3,833,255
Other Property and Investments, net	73,537	59,157
Current Assets		
Cash and cash equivalents (Notes 1 and 10)	4,264	3,968
Special deposits (Note 10)	145,335	96,432
Accounts receivable, net (Note 1)	181,586	171,683
Fuel, at average cost	54,791	69,077
Materials and supplies, at average cost	48,910	50,637
Prepayments	30,092	37,897
Accumulated deferred federal income tax benefits (Notes 1 and 2)	–	1,182
Total Current Assets	464,978	430,876
Deferred Charges (Note 1)		
Unfunded future federal income taxes (Notes 1 and 2)	380,056	393,720
Unamortized debt expense	112,059	96,378
Demand-side management program costs	73,113	44,049
Other	252,127	220,481
Total Deferred Charges	817,355	754,628
Total Assets	$5,276,016	$5,077,916

The notes on pages 33 through 45 are an integral part of the financial statements.

Consolidated Balance Sheets

December 31	1993	1992
	(Thousands)	
Capitalization and Liabilities		
Capitalization		
Common stock equity		
Common stock ($6.66 2/3 par value, 90,000,000 shares authorized and 70,595,985 and 69,439,397 shares issued and outstanding at December 31, 1993 and 1992, respectively)	$470,640	$462,929
Capital in excess of par value	824,943	796,505
Retained earnings	320,114	327,040
Total common stock equity	1,615,697	1,586,474
Preferred stock redeemable solely at the option of the Company (Note 4)	140,500	160,500
Preferred stock subject to mandatory redemption requirements (Notes 4 and 10)	125,000	106,900
Long-term debt (Notes 3 and 10)	1,630,629	1,777,027
Total Capitalization	3,511,826	3,630,901
Current Liabilities		
Current portion of long-term debt and preferred stock (Notes 3 and 4)	332,709	115,659
Commercial paper (Notes 5 and 10)	50,200	64,100
Accounts payable and accrued liabilities	111,481	95,996
Interest accrued (Note 10)	31,348	37,690
Accumulated deferred federal income taxes (Notes 1 and 2)	1,132	–
Other	89,443	65,073
Total Current Liabilities	616,313	378,518
Deferred Credits		
Accumulated deferred investment tax credit (Notes 1 and 2)	138,478	141,729
Excess deferred federal income taxes (Notes 1 and 2)	36,378	58,188
Other	149,620	107,160
Total Deferred Credits	324,476	307,077
Accumulated Deferred Federal Income Taxes (Notes 1 and 2)		
Unfunded future federal income taxes	380,056	393,720
Other	416,545	342,700
Total Accumulated Deferred Federal Income Taxes	796,601	736,420
Commitments and Contingencies (Note 9)	26,800	25,000
Total Capitalization and Liabilities	$5,276,016	$5,077,916

The notes on pages 33 through 45 are an integral part of the financial statements.

Consolidated Statements of Income

Year Ended December 31	1993	1992	1991
		(Thousands, except Per Share Amounts)	
Operating Revenues			
Electric	$1,527,362	$1,451,525	$1,367,936
Natural gas	272,787	240,164	187,879
Total Operating Revenues	1,800,149	1,691,689	1,555,815
Operating Expenses			
Fuel used in electric generation	245,283	262,531	274,877
Electricity purchased (Note 9)	161,967	95,026	45,808
Natural gas purchased	141,635	126,815	99,528
Other operating expenses	349,177	318,680	279,364
Restructuring expenses (Notes 6 and 7)	26,000	–	–
Maintenance	111,757	102,500	110,131
Depreciation and amortization (Note 1)	164,568	158,977	152,380
Federal income taxes (Notes 1 and 2)	94,144	102,456	94,447
Other taxes (Note 12)	204,962	200,941	178,185
Total Operating Expenses	1,499,493	1,367,926	1,234,720
Operating Income	300,656	323,763	321,095
Other Income and Deductions	6,471	12,036	6,076
Income Before Interest Charges	307,127	335,799	327,171
Interest Charges			
Interest on long-term debt	134,330	145,822	151,649
Other interest	11,120	9,566	11,877
AFDC - borrowed	(4,351)	(3,557)	(4,998)
Interest Charges-Net	141,099	151,831	158,528
Net Income	166,028	183,968	168,643
Preferred Stock Dividends	20,638	20,995	20,330
Earnings Available for Common Stock	$145,390	$162,973	$148,313
Earnings per Share	$2.08	$2.40	$2.36
Average Shares Outstanding	69,990	67,972	62,906

The notes on pages 33 through 45 are an integral part of the financial statements.

Consolidated Statements of Cash Flows

Year Ended December 31	1993	1992	1991
		(Thousands)	
Operating Activities			
Net Income	$166,028	$183,968	$168,643
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	164,568	158,977	152,380
Deferred fuel and purchased gas	(10,671)	(14,645)	2,507
Federal income taxes and investment tax credits deferred – net	50,761	52,039	59,626
Unbilled revenue recognition (Note 1)	(11,557)	(22,228)	(40,147)
Demand-side management program costs	(29,064)	(22,863)	(15,118)
Restructuring expenses	26,000	–	–
Changes in current operating assets and liabilities, net of effects from the purchase of Columbia Gas of New York, Inc. in 1991:			
Special deposits	2,438	(1,873)	(4,108)
Accounts receivable excluding accounts receivable sold	(17,483)	(11,936)	(15,541)
Accounts receivable sold (Note 1)	13,800	–	–
Prepayments	7,805	(878)	(7,882)
Inventory	16,013	(1,417)	4,590
Accounts payable and accrued liabilities	7,384	(8,287)	5,656
Interest accrued	(6,342)	(5,750)	(3,610)
Other – net	32,510	(18,840)	(1,110)
Net Cash Provided by Operating Activities	412,190	286,267	305,886
Investing Activities			
Utility plant construction expenditures, net of AFDC – other	(265,109)	(243,373)	(244,037)
Proceeds received from governmental and other sources	22,808	322	–
Expenditures for other property and investments	(16,975)	–	–
Funds set aside for construction expenditures	(42,437)	–	–
Payment for purchase of Columbia Gas of New York, Inc., net of cash acquired	–	–	(57,096)
Net Cash Used in Investing Activities	(301,713)	(243,051)	(301,133)
Financing Activities			
Issuance of first mortgage bonds and pollution control notes	217,362	247,668	147,243
Proceeds from revolving credit agreement	50,000	–	–
Sale of common stock	38,334	162,965	25,380
Sale of preferred stock	97,762	–	98,975
First mortgage bonds and preferred stock repayments, including premiums	(326,091)	(178,289)	(142,715)
Increase in funds set aside for first mortgage bond and preferred stock repayments	(8,904)	(83,096)	–
Long-term notes – net	8,393	(1,593)	(2,322)
Commercial paper – net	(13,900)	(39,800)	30,675
Dividends on common and preferred stock	(173,137)	(165,704)	(150,106)
Net Cash Provided by (Used in) Financing Activities	(110,181)	(57,849)	7,130
Net Increase (Decrease) in Cash and Cash Equivalents	296	(14,633)	11,883
Cash and Cash Equivalents, Beginning of Year	3,968	18,601	6,718
Cash and Cash Equivalents, End of Year (Notes 1 and 10)	$4,264	$3,968	$18,601

The notes on pages 33 through 45 are an integral part of the financial statements.

Consolidated Statements of Changes in Common Stock Equity

(Thousands, except Shares and Per Share Amounts)

	Common Stock $6.66 2/3 Par Value Shares	Amount	Capital in Excess of Par Value	Retained Earnings	Total
Balance, January 1, 1991	62,430,297	$416,202	$655,892	$292,250	$1,364,344
Net income				168,643	168,643
Cash dividends declared:					
Preferred stock (at serial rates)					
Redeemable - optional				(11,395)	(11,395)
- mandatory				(8,935)	(8,935)
Common stock ($2.10 per share)				(131,875)	(131,875)
Issuance of stock:					
Dividend reinvestment and stock purchase plan	969,941	6,466	17,899		24,365
Balance, December 31, 1991	63,400,238	422,668	673,791	308,688	1,405,147
Net income				183,968	183,968
Cash dividends declared:					
Preferred stock (at serial rates)					
Redeemable - optional				(11,164)	(11,164)
- mandatory				(9,831)	(9,831)
Common stock ($2.14 per share)				(144,621)	(144,621)
Issuance of stock:					
Public Offering	5,000,000	33,333	99,367		132,700
Dividend reinvestment and stock purchase plan	1,039,159	6,928	23,347		30,275
Balance, December 31, 1992	69,439,397	462,929	796,505	327,040	1,586,474
Net income				166,028	166,028
Cash dividends declared:					
Preferred stock (at serial rates)					
Redeemable – optional				(11,085)	(11,085)
– mandatory				(9,553)	(9,553)
Common stock ($2.18 per share)				(152,316)	(152,316)
Issuance of stock:					
Dividend reinvestment and stock purchase plan	1,156,588	7,711	28,438		36,149
Balance, December 31, 1993	70,595,985	$470,640	$824,943	$320,114	$1,615,697

The notes on pages 33 through 45 are an integral part of the financial statements.

1 Significant Accounting Policies

Principles of consolidation
The consolidated financial statements include the Company's wholly-owned subsidiaries, Somerset Railroad Corporation (SRC) and NGE Enterprises, Inc. (NGE). All significant intercompany balances and transactions are eliminated in consolidation.

Utility plant
The cost of repairs and minor replacements is charged to the appropriate operating expense accounts. The cost of renewals and betterments, including indirect cost, is capitalized. The original cost of utility plant retired or otherwise disposed of and the cost of removal less salvage are charged to accumulated depreciation.

Depreciation and amortization
Depreciation expense is determined using straight-line rates, based on the average service lives of groups of depreciable property in service. Depreciation accruals were equivalent to 3.4%, 3.3%, and 3.3% of average depreciable property for 1993, 1992, and 1991, respectively. Depreciation expense includes the amortization of certain deferred charges authorized by the Public Service Commission of the State of New York (PSC).

Revenue
During 1993, 1992, and 1991, the Company recognized on the income statement approximately $12 million, $22 million, and $40 million, respectively, of electric and natural gas unbilled revenues that had been accrued on its balance sheet for energy provided but not yet billed to minimize the rate increases for these years in accordance with various PSC rate decisions. The July 1992 rate decision allowed the Company to recognize on its income statement, beginning in August 1992, electric and natural gas unbilled revenues on a full accrual basis.

The Company recognizes as revenue incentives earned as the result of conducting efficient demand-side management (DSM) programs. The Company is collecting those incentives in rates within approximately one year after they are recognized. During 1993, 1992, and 1991, incentives earned were $16.4 million, $15.6 million, and $12.4 million, respectively. At December 31, 1993 and 1992, approximately $14.3 million and $9.8 million, respectively, of DSM incentives were accrued and included in accounts receivable.

Accounts receivable
The Company has an agreement that expires in November 1996 to sell, with limited recourse, undivided percentage interests in certain of its accounts receivable from customers. The agreement allows the Company to receive up to $152 million from the sale of such interests. At December 31, 1993 and 1992, accounts receivable on the Consolidated Balance Sheets is shown net of $152 million and $138 million, respectively, of interests in accounts receivable sold. All fees associated with the program are included in other income and deductions on the Consolidated Statements of Income and amounted to approximately $5.7 million, $6.5 million, and $9.3 million in 1993, 1992, and 1991, respectively. Accounts receivable on the Consolidated Balance Sheets is also shown net of an allowance for doubtful accounts of $4 million and $1.9 million at December 31, 1993 and 1992, respectively. Bad debt expense was $15.3 million, $11.5 million, and $10.7 million in 1993, 1992, and 1991, respectively.

Federal income taxes
The Company adopted Statement of Financial Accounting Standards No. 109 (SFAS 109), Accounting for Income Taxes, in January 1993. Since the Company had been accounting for income taxes under Statement of Financial Accounting Standards No. 96, Accounting for Income Taxes, there was no effect on the Consolidated Statements of Income as a result of adopting SFAS 109. However, SFAS 109 did require the Company's deferred tax balances to be reclassified on its Consolidated Balance Sheets.

The Company files a consolidated federal income tax return with SRC and NGE. Deferred income taxes are provided on all temporary differences between financial statement basis and taxable income. Investment tax credits, which reduce federal income taxes currently payable, are deferred and amortized over the estimated lives of the applicable property. The effect of the alternative minimum tax, which increases federal income taxes currently payable and generates a tax credit available for future use, is deferred and amortized at such times as the tax credit is used on the Company's federal income tax return.

Deferred charges
The Company defers certain incurred expenses when authorized by the PSC. Those expenses will be recovered from customers in the future.

Consolidated Statements of Cash Flows
The Company considers all highly liquid investments with a maturity or put date of three months or less when acquired to be cash equivalents. These investments are included in cash and cash equivalents on the Consolidated Balance Sheets.

Total income taxes paid were $27.3 million, $38.5 million, and $31.8 million for the years ended December 31, 1993, 1992, and 1991, respectively.

Interest paid, net of amounts capitalized, was $138.2 million, $149.3 million, and $159.9 million for the years ended December 31, 1993, 1992, and 1991, respectively.

The Company purchased all of the common stock of Columbia Gas of New York, Inc. in 1991. In conjunction with the acquisition, liabilities assumed were $24.9 million (fair value of assets acquired of $82 million less cash paid of $57.1 million).

Reclassification
Certain amounts have been reclassified on the consolidated financial statements to conform with the 1993 presentation.

2 Federal Income Taxes

Year ended December 31	1993	1992	1991
		(Thousands)	
Charged to operations			
Current	$34,989	$37,237	$22,991
Deferred – net			
Accelerated depreciation	49,580	41,492	37,409
Unbilled revenues	5,073	160	13,644
Alternative minimum tax (AMT) credit	(3,194)	2,123	5,557
Demand-side management	13,479	9,324	8,589
NUG termination agreement	4,760	6,800	–
Nine Mile No. 2 litigation proceeds	4,756	(2,047)	–
Restructuring expenses	(6,965)	–	–
Transmission facility agreement	(7,778)	(1,172)	(1,162)
Miscellaneous	(6,198)	(3,491)	(9,365)
Investment tax credit (ITC) deferred	5,642	12,030	16,784
	94,144	102,456	94,447
Included in other income			
Amortization of deferred ITC	(8,892)	(16,927)	(11,297)
Miscellaneous	498	3,747	(533)
Total	$85,750	$89,276	$82,617

The Company's effective tax rate differed from the statutory rate of 35% in 1993 and 34% in 1992 and 1991 due to the following:

Year ended December 31	1993	1992	1991
		(Thousands)	
Tax expense at statutory rate	$88,684	$92,903	$85,428
Depreciation not normalized	16,984	16,697	16,051
ITC amortization	(8,892)	(16,927)	(11,297)
Research & Development (R&D) credit	(5,139)	–	–
Cost of removal	(4,921)	(4,079)	(6,120)
Other – net	(966)	682	(1,445)
Total	$85,750	$89,276	$82,617

The Company's current and noncurrent deferred taxes, which net to a tax liability of approximately $936.2 million as of December 31, 1993, consisted of the following deferred tax assets and liabilities:

	Deferred Tax Assets	Deferred Tax Liabilities
	(Thousands)	
Depreciation		$698,939
Loss on reacquired debt		28,440
Regulatory Asset (SFAS 109)		149,636
Accumulated deferred ITC		91,006
Demand-side management		35,381
NUG contract settlement costs		15,163
Alternative minimum tax credit	$19,953	
Excess tax reserve	12,603	
Nine Mile No. 2 disallowed plant	19,347	
Contributions in aid of construction	20,913	
Capitalized interest	8,690	
Other	35,369	34,521
Total deferred taxes	$116,875	$1,053,086

The Revenue Reconciliation Act (RRA) of 1993 was enacted on August 10, 1993. Among other things, RRA 1993 provided for an increase of 1% in the statutory corporate income tax rate and an extension of the R&D credit until June 30, 1995.

In September 1993, the Company reached a three-year rate settlement agreement with the PSC (Agreement), which included a provision for the Company to petition to defer the effect of RRA 1993 until it is reflected in rates. The Company has deferred for collection from customers $.6 million representing additional 1993 federal income taxes resulting from RRA 1993.

The Company has recorded unfunded future federal income taxes and a corresponding receivable from customers of approximately $381 million and $393 million as of December 31, 1993 and 1992, respectively, primarily representing the cumulative amount of federal income taxes on temporary depreciation differences, which were previously flowed through to customers. Those amounts, including the tax effect of the future revenue requirements, are being amortized over the life of the related depreciable assets concurrent with their recovery in rates.

The Company has approximately $20 million of AMT credits which do not expire, and $5.1 million of R&D credits which expire beginning in 2005.

3 Long-Term Debt

At December 31, 1993 and 1992, long-term debt was (Thousands):

First mortgage bonds

Series	Due	Amount 1993	Amount 1992	Series	Due	Amount 1993	Amount 1992
8 3/8%	Aug. 15, 1994	$100,000	$100,000	9 1/4%	Apr. 1, 2016	$ –	$50,000
8 5/8%	June 1, 1996	–	50,000	9%	Mar. 1, 2017	–	100,000
5 5/8%	Jan. 1, 1997	25,000	25,000	10 5/8%	Jan. 1, 2018	–	100,000
6 1/4%	Sept. 1, 1997	25,000	25,000	9 7/8%	Feb. 1, 2020	100,000	100,000
6 1/2%	Sept. 1, 1998	30,000	30,000	9 7/8%	May 1, 2020	100,000	100,000
7 5/8%	Nov. 1, 2001	50,000	50,000	9 7/8%	Nov. 1, 2020	100,000	100,000
6 3/4%	Oct. 15, 2002	150,000	150,000	8 7/8%	Nov. 1, 2021	150,000	150,000
9 3/8%	Jan. 1, 2006	–	3,000	8.30 %	Dec. 15, 2022	100,000	100,000
7 1/4%	June 1, 2006	12,000	12,000	7.55 %	Apr. 1, 2023	50,000	–
6 7/8%	Dec. 1, 2006	25,250	25,500	7.45 %	July 15, 2023	100,000	–
8 5/8%	Nov. 1, 2007	60,000	60,000				
Total first mortgage bonds						1,177,250	1,330,500

Pollution control notes

Interest Rate	Maturity Date	Interest Rate Adjustment Date	Letter of Credit Expiration Date	Amount 1993	Amount 1992
12%	May 1, 2014*	–	–	60,000	60,000
12.30%	July 1, 2014*	–	–	40,000	40,000
2.80%	Dec. 1, 2014	Dec. 1, 1994	Dec. 15, 1995	74,000	74,000
2.75%	Mar. 1, 2015	Mar. 1, 1994	Mar. 15, 1995	37,500	37,500
2.50%	Mar. 15, 2015	Mar. 15, 1994	Mar. 31, 1995	60,000	60,000
2.60%	July 15, 2015	July 15, 1994	July 31, 1995	63,500	63,500
2.85%	Oct. 15, 2015	Oct. 15, 1994	Oct. 31, 1995	30,000	30,000
2.75%	Dec. 1, 2015	Dec. 1, 1994	Dec. 15, 1995	42,000	42,000
4.10%	July 1, 2026	July 1, 1996	July 15, 1996	65,000	65,000
5.95%	Dec. 1, 2027	–	–	34,000	34,000
5.70%	Dec. 1, 2028	–	–	70,000	–
Total pollution control notes				576,000	506,000

Revolving Credit Agreement Note due July 31, 1997	50,000	–
Long-term notes due December 31, 1996	36,100	27,707
CNG Transmission Corp. Note due November 10, 1996	8,862	–
Obligations under capital leases	30,902	38,804
Unamortized premium and discount on debt – net	(10,776)	(11,975)
	1,868,338	1,891,036
Less: debt due within one year – included in current liabilities	237,709	114,009
Total	$1,630,629	$1,777,027

*Will be refunded in 1994 with proceeds from the issuance of $100 million of 6.05% pollution control notes, due 2034

3 Long-Term Debt (Continued)

At December 31, 1993, long-term debt and capital lease payments which will become due during the next five years are:

1994	1995	1996	1997	1998
		(Thousands)		
$237,709	$12,552	$45,651	$102,196	$31,411

The Company's mortgage provides for a sinking and improvement fund. This provision requires the Company to make annual cash deposits with the Trustee equivalent to 1% of the principal amount of all bonds delivered and authenticated by the Trustee prior to January 1 of that year (excluding any bonds issued on the basis of the retirement of bonds). The Company satisfied this requirement in 1993 by depositing $22.5 million in cash which was used to redeem in February 1993, $22.5 million of 10 5/8% Series first mortgage bonds, due 2018. The Company satisfied this requirement in 1994 by depositing $23 million in cash which was used to redeem in February 1994, $23 million of 8 5/8% Series first mortgage bonds, due 2007.

Mandatory annual cash sinking fund requirements are $600,000 beginning June 1, 2001, for the 7 1/4% Series and $250,000 on December 1 in each year 1994 to 1996, for the 6 7/8% Series. The amount increases to $500,000 and $750,000 on December 1, 1997 and December 1, 2002, respectively, for the 6 7/8% Series.

The Company's first mortgage bond indenture constitutes a direct first mortgage lien on substantially all utility plant.

Adjustable rate pollution control notes were issued to secure like amounts of tax-exempt adjustable rate pollution control revenue bonds (Revenue Bonds) issued by a governmental authority. The Revenue Bonds bear interest at the rate indicated through the date preceding the interest rate adjustment date. The pollution control notes bear interest at the same rate as the Revenue Bonds. On the interest rate adjustment date and annually thereafter (every three years thereafter in the case of the Revenue Bonds due July 1, 2026), the interest rate will be adjusted, not to exceed a rate of 15%, or at the option of the Company, subject to certain conditions, a fixed rate of interest, not to exceed 18%, may become effective. In the case of the Revenue Bonds due July 1, 2026, at the option of the Company, subject to certain conditions, a fixed rate of interest may become effective prior to the interest rate adjustment date or each third year thereafter. Bond owners may elect, subject to certain conditions, to have their Revenue Bonds purchased by the Trustee.

The Company has irrevocable letters of credit which expire on the letter of credit expiration dates and which the Company anticipates being able to extend if the interest rate on the related Revenue Bonds is not converted to a fixed interest rate. Those letters of credit support certain payments required to be made on the Revenue Bonds. If the Company is unable to extend the letter of credit that is related to a particular series of Revenue Bonds, that series will have to be redeemed unless a fixed rate of interest becomes effective. Payments made under the letters of credit in connection with purchases of Revenue Bonds by the Trustee are repaid with the proceeds from the remarketing of the Revenue Bonds. To the extent the proceeds are not sufficient, the Company is required to reimburse the bank that issued the letter of credit.

Preferred Stock

At December 31, 1993 and 1992, serial cumulative preferred stock was:

Series	Par Value Per Share	Redeemable Prior to	Redeemable Per Share	Shares Authorized and Outstanding (1)	Amount 1993	Amount 1992
					(Thousands)	
Redeemable solely at the option of the Company:						
3.75%	$100		$104.00	150,000	$15,000	$15,000
4 1/2% (1949)	100		103.75	40,000	4,000	4,000
4.15%	100		101.00	40,000	4,000	4,000
4.40%	100		102.00	75,000	7,500	7,500
4.15% (1954)	100		102.00	50,000	5,000	5,000
6.48%	100		102.00	300,000	30,000	30,000
8.80% (2)	100		102.00	250,000	25,000	25,000
8.48% (3)	25		25.70	1,000,000	25,000	25,000
7.40% (4)	25	12/1/98	26.85	1,000,000	25,000	–
		Thereafter	25.00			
Adjustable Rate (5)	25		25.00	1,800,000	45,000	45,000
Adjustable Rate (6)	25	12/1/98	27.50	2,000,000	50,000	–
		Thereafter	25.00			
					235,500	160,500
Less: preferred stock redemptions within one year – included in current liabilities					95,000	–
Total					$140,500	$160,500
Subject to mandatory redemption requirements:						
[illegible].00% (7)	100			–	$ –	$8,550
[illegible]6.30% (8)	100	1/1/95	105.67	250,000	25,000	–
[illegible].95% (9)	25	1/1/95	26.79	4,000,000	100,000	100,000
					125,000	108,550
Less: sinking fund requirements at par value – included in current liabilities					–	1,650
Total					$125,000	$106,900

At December 31, 1993, preferred stock redemptions and annual redeemable preferred stock sinking fund requirements for the next five years are:

1994	1995	1996	1997	1998
		(Thousands)		
$95,000	$ –	$ –	$5,000	$5,000

(1) At December 31, 1993, and after giving effect to the redemptions referred to in (2), (3), and (5) below, there were 1,550,000 shares of $100 par value preferred stock, 3,800,000 shares of $25 par value preferred stock, and 1,000,000 shares of $100 par value preference stock authorized but unissued.

(2) Redeemed January 18, 1994.

(3) Redeemed February 1, 1994.

(4) The Company is restricted in its ability to redeem this Series prior to December 1, 1998.

(5) The Adjustable Rate Serial Preferred Stock, Series A, was redeemed January 10, 1994.

(6) The payment on the Adjustable Rate Serial Preferred Stock, Series B, for April 1, 1994, is at an annual rate of 5.12% and subsequent payments can vary from an annual rate of 4% to 10%, based on a formula included in the Company's Certificate of Incorporation. The Company is restricted in its ability to redeem this Series prior to December 1, 1998.

(7) On October 1, 1993, 33,000 shares were redeemed at par. The remaining 52,500 shares were redeemed at $100.50 per share on October 13, 1993. For the years 1991 and 1992, 16,500 shares were redeemed and cancelled annually.

(8) On January 1, in each year 2004 through 2008, the Company must redeem 12,500 shares at par, and on January 1, 2009, the Company must redeem the balance of the shares at par. This Series is redeemable at the option of the Company at $105.67 per share prior to January 1, 1995. The $105.67 price will be reduced annually by 63 cents for the years ending 1995 through 2002; thereafter, the redemption price is $100.00. The Company is restricted in its ability to redeem this Series prior to January 1, 2004.

(9) On January 1, in each year 1997 through 2016, the Company must redeem 200,000 shares at par. This Series is redeemable at the option of the Company at $26.79 per share prior to January 1, 1995. The $26.79 price will be reduced annually by 15 cents for the years ending 1995 through 1999; by 14 cents for the year ending 2000; and by 15 cents for the years ending 2001 through 2005. The Company is restricted in its ability to redeem this Series prior to January 1, 1996.

5 Bank Loans and Other Borrowings

The Company has a revolving credit agreement with certain banks which provides for borrowing up to $200 million to July 31, 1997. At the option of the Company, the interest rate on borrowings is related to the prime rate, the London Interbank Offered Rate (LIBOR) or the interest rate applicable to certain certificates of deposit. The agreement also provides for the payment of a commitment fee which can fluctuate from .15% to .375% depending upon the ratings of the Company's first mortgage bonds. The commitment fee at December 31, 1993 is .1875%.

The Company had an outstanding loan of $50 million under the revolving credit agreement at December 31, 1993, at an interest rate of 4.06% under the LIBOR option, and did not have any outstanding loans under this agreement at December 31, 1992. The revolving credit agreement does not require compensating balances.

In order to provide flexibility in the timing and amounts of long-term financings, the Company uses interim financing in the form of short-term unsecured notes, usually commercial paper, to finance certain refundings and construction expenditures, and for other corporate purposes.

Information relative to short-term borrowings is as follows:

	Commercial Paper		
	1993	1992	1991
		(Thousands)	
Ending balance	$50,200	$64,100	$103,900
Maximum amount outstanding	$95,400	$140,000	$111,000
Average amount outstanding (1)	$56,300	$31,400	$66,700
Weighted average interest rate			
On ending balance	3.5%	4.0%	5.3%
During the period (2)	3.4%	4.3%	6.2%

(1) Calculated as the average of the sum of daily outstanding borrowings.
(2) Calculated by dividing total interest expense by the average of the sum of daily outstanding borrowings.

6 Restructuring

In the fourth quarter of 1993, the Company recorded a $26 million restructuring charge. The corporate restructuring will reorganize the way the Company delivers services to its electric and natural gas customers beginning in March 1994. The restructuring reduced 1993 earnings available for common stock by approximately $17.2 million or 25 cents per share. Included in this amount are $13.2 million for a voluntary early retirement program, $3.2 million for an involuntary severance program, and $.8 million for the elimination and closing of electric and natural gas operations facilities statewide. During 1994, the restructuring resulted in a work force reduction throughout the organization of approximately 600, the elimination of customer walk-in services at 28 satellite locations, and the closing of up to 10 electric and natural gas operations facilities statewide. The work force reduction was accomplished through a voluntary early retirement program (See Note 7 - Retirement Benefits) and an involuntary severance program. 384 employees accepted the early retirement program.

Retirement Benefits

Pensions

The Company has a noncontributory retirement annuity plan that covers substantially all employees. Benefits are based principally on the employee's length of service and compensation for the five highest paid years out of the last 10 years of service. It is the Company's policy to fund pension costs accrued each year to the extent deductible for federal income tax purposes.

The net pension benefit for 1993, 1992, and 1991 totaled $5.7 million, $1.5 million, and $2.9 million, respectively.

Effective January 1, 1993, the retirement benefit plans for hourly and salaried employees were combined into one plan. Combining the two plans did not affect benefit levels.

Net pension benefit for 1993, 1992, and 1991 included the following components:

	1993	1992	1991
		(Thousands)	
Service cost: Benefits earned during the year	$17,688	$15,387	$13,252
Interest cost on projected benefit obligation	40,710	35,253	32,096
Actual return on plan assets	(77,129)	(60,020)	(111,749)
Net amortization and deferral	12,989	7,844	63,487
Net pension (benefit)	$(5,742)	$(1,536)	$(2,914)

The funded status of the plans at December 31, 1993 and 1992 were:

	1993	1992
	(Thousands)	
Actuarial present value of accumulated benefit obligation:		
Vested	$390,716	$287,504
Nonvested	55,476	42,286
Total	446,192	329,790
Fair value of plan assets	$753,292	$701,893
Actuarial present value of projected benefit obligation	(608,216)	(480,429)
Plan assets in excess of projected benefit obligation	145,076	221,464
Unrecognized net transition asset	(73,612)	(80,850)
Unrecognized net (gain) loss	(83,709)	(139,729)
Unrecognized prior service cost	4,182	5,209
Net pension (liability) asset	$ (8,063)	$6,094

Plan assets primarily consist of equity securities, corporate, U.S. agency, and Treasury bonds, and cash equivalents.

The projected benefit obligation was measured using an assumed discount rate of 7% for 1993 and 7.75% for 1992 and 1991, and a long-term rate of increase in future compensation levels of 5% for 1993 and 6% for 1992 and 1991. The net pension benefit was measured using an expected long-term rate of return on plan assets of 8% in 1993 and 7.5% in 1992 and 1991.

Early Retirement

As part of the corporate restructuring that was announced in the fourth quarter of 1993 (See Note 6 - Restructuring), the Company offered a voluntary early retirement program from December 1, 1993, through January 21, 1994, to employees who were 55 years and older and who had at least 10 years of service with the Company. The program included two provisions: an unreduced pension benefit for those eligible employees who were under 60 years old, and a monthly supplemental payment to "bridge" employees to age 62 when they can begin collecting Social Security benefits. 384 employees accepted the early retirement opportunity. In 1993, the Company recorded a $19.9 million expense for the early retirement program.

Postretirement Benefits Other Than Pensions

The Company has postretirement benefit plans, such as a comprehensive health insurance plan and a prescription drug plan, that provide certain benefits for retired employees and their dependents. Substantially all of the Company's employees who retire under the Company's pension

7 Retirement Benefits (Continued)

plan may become eligible for those benefits at retirement. At December 31, 1993, 1992, and 1991, 1,996, 1,905, and 1,866 retirees and their dependents, respectively, were covered under these plans. The postretirement benefit plans are unfunded as of December 31, 1993. However, the Company is examining the cost-effectiveness of certain funding alternatives.

In January 1993, the Company adopted Statement of Financial Accounting Standards No. 106 (SFAS 106), Employers' Accounting for Postretirement Benefits Other Than Pensions, which requires that the Company accrue a liability for estimated future postretirement benefits during an employee's working career rather than recognize an expense when benefits are paid. At the time of adoption, the actuarially determined accumulated postretirement benefit obligation (APBO) was $206.6 million. The Company elected to recognize the APBO over 20 years.

In September 1993, the PSC issued a Statement of Policy concerning the accounting and ratemaking treatment for pensions and postretirement benefits other than pensions (PSC Policy). The PSC Policy was effective January 1993, adopted SFAS 106 for accounting and ratemaking purposes, and complies with generally accepted accounting principles.

Postretirement benefits cost other than pensions that was recognized on the income statement for the twelve months ended December 31, 1993, 1992, and 1991, was $11.4 million, $5 million, and $4.4 million, respectively. The amount for 1993 represents the portion of SFAS 106 costs that the Company has been allowed to collect from its customers. The amounts for the twelve months ended December 31, 1992 and 1991, represent the postretirement benefits cost as determined prior to the adoption of SFAS 106, when the cost was not recognized as an expense until the benefits were paid. The Company has deferred $10.1 million of SFAS 106 costs as of December 31, 1993. The Company expects to recover any deferred SFAS 106 amounts in accordance with the PSC Policy.

The PSC Policy allows various rate mechanisms, including the use of excess pension fund assets, such as Internal Revenue Service Code of 1986 Section 420 transfers, to temper the effect of SFAS 106 on rates. In 1993, the Company transferred approximately $5 million of its excess pension plan assets to cover most of the cost of retirees' health care for that year. As a result of this transfer, the Company recognized a decrease in its deferred SFAS 106 asset.

The estimated net postretirement benefits cost other than pensions for the 12 months ended December 31, 1993, includes the following components:

	(Thousands)
Service cost: Benefits accumulated during the year	$6,888
Interest cost on accumulated postretirement benefit obligation	16,304
Amortization of transition obligation over 20 years	10,330
Deferral for future recovery	(22,095)
Net periodic postretirement benefits cost	**$11,427**

The status of the plans for postretirement benefits other than pensions, as reflected in the Company's Consolidated Balance Sheets at December 31, 1993, is as follows:

	(Thousands)
Accumulated postretirement benefit obligation (APBO):	
Retired employees	$69,947
Fully eligible active plan participants	36,454
Other active plan employees	107,708
Total APBO	214,109
Less unrecognized transition obligation	196,268
Less unrecognized net (gain)	(10,233)
Accrued postretirement liability	**$28,074**

A 12% annual rate of increase in the per capita costs of covered health care benefits was assumed for 1994, gradually decreasing to 5% by the year 2003. Increasing the assumed health care cost trend rates by 1% in each year would increase the APBO as of January 1, 1994 by $41.5 million and increase the aggregate of the service cost and interest cost components of the net postretirement benefits cost for 1994 by $4.6 million. A discount rate of 7% was used to determine the APBO.

Jointly-Owned Generating Stations

Nine Mile Point Unit 2

The Company has an undivided 18% interest in the output and costs of the Nine Mile Point nuclear generating unit No. 2 (NMP2), which is being operated by Niagara Mohawk Power Corporation (Niagara Mohawk). Ownership of NMP2 is shared with Niagara Mohawk 41%, Long Island Lighting Company 18%, Rochester Gas and Electric Corporation 14%, and Central Hudson Gas & Electric Corporation 9%. The Company's share of the rated capability is 189,000 kilowatts. The Company's net utility plant investment, excluding nuclear fuel, was approximately $652 million and $660 million, at December 31, 1993 and 1992, respectively. The accumulated provision for depreciation was approximately $103 million and $90 million, at December 31, 1993 and 1992, respectively. The Company's share of operating expenses is included in the Consolidated Statements of Income.

A low level radioactive waste management and contingency plan that has been developed for NMP2 provides assurance that NMP2 is properly prepared to handle interim storage of low level radioactive waste until 1998.

Niagara Mohawk has contracted with the U.S. Department of Energy (DOE) for disposal of high level radioactive waste (spent fuel) from NMP2. The Company is reimbursing Niagara Mohawk for its 18% share of the cost under the contract (currently approximately $1 per megawatt hour of net generation). The DOE's schedule for start of operations of their high level radioactive waste repository has slipped from 2003 to no sooner than 2010. The Company has been advised by Niagara Mohawk that the NMP2 Spent Fuel Storage Pool has a capacity for spent fuel that is adequate until 2014. If further DOE schedule slippage should occur, the recent development of pre-licensed dry storage facilities for use at any nuclear power plant extends the on-site storage capability for spent fuel at NMP2 beyond 2014.

Nuclear Insurance

Niagara Mohawk maintains public liability and property insurance for NMP2. The Company reimburses Niagara Mohawk for its 18% share of those costs.

The public liability limit for a nuclear incident is approximately $8.8 billion. Should losses stemming from a nuclear incident exceed the commercially available public liability insurance, each licensee of a nuclear facility would be liable for up to a maximum of $75.5 million per incident, payable at a rate not to exceed $10 million per year. The Company's maximum liability for its 18% interest in NMP2 would be approximately $13.6 million per incident. The $75.5 million assessment is subject to periodic inflation indexing and a 5% surcharge should funds prove insufficient to pay claims associated with a nuclear incident. The Price-Anderson Act also requires indemnification for precautionary evacuations whether or not a nuclear incident actually occurs.

Niagara Mohawk maintains nuclear property insurance for NMP2 and is reimbursed by the Company for its 18% interest. Niagara Mohawk has procured property insurance aggregating approximately $2.7 billion through the Nuclear Insurance Pools and the Nuclear Electric Insurance Limited (NEIL). In addition, the Company has purchased NEIL insurance coverage for the extra expense incurred in purchasing replacement power during prolonged accidental outages. Under NEIL programs, should losses resulting from an incident at a member facility exceed the accumulated reserves of NEIL, each member, including the Company, would be liable for its share of the deficiency. The Company's maximum liability under the property damage and replacement power coverages is approximately $2.3 million.

Nuclear Plant Decommissioning Costs

In May 1993, the Nuclear Regulatory Commission (NRC) updated labor, energy, and burial cost factors for determining the minimum funding requirement for nuclear decommissioning. As a result, the Company's 18% share of the cost to decommission NMP2 is currently estimated to be $234 million in 2027, when decommissioning is expected to commence ($74 million in 1993 dollars).

The Company's annual decommissioning allowance currently included in electric rates is approximately $1.6 million and is sufficient to recover the minimum funding requirement. The Company believes that any increase in decommissioning costs will ultimately be recovered in rates.

The Company has established a Qualified Fund under applicable provisions of the federal tax law. The fund also complies with the NRC regulations which require the use of an external trust fund to provide funds to decommission the contaminated portion of NMP2. The balance in this fund was approximately $5.7 million and $3.9 million at December 31, 1993 and 1992, respectively, and is included in other property and investments on the Consolidated Balance Sheets.

Homer City

The Company has an undivided 50% interest in the output and costs of the Homer City Generating Station, which is comprised of three generating units. The station is owned with Pennsylvania Electric Company, which operates the facility. The Company's share of the rated capability is 954,000 kilowatts and its net utility plant investment was approximately $258 million and $251 million at December 31, 1993 and 1992, respectively. The accumulated provision for depreciation was approximately $159 million and $148 million, at December 31, 1993 and 1992, respectively. The Company's share of operating expenses is included in the Consolidated Statements of Income.

9 Commitments and Contingencies

Capital Expenditures

The Company has substantial commitments in connection with its construction program and estimates that capital expenditures for 1994, 1995, and 1996 will approximate $210 million, $200 million, and $200 million, respectively. These forecasted levels have been significantly reduced as the Company is taking action to address competition. The program is subject to periodic review and revision, and actual construction costs may vary because of revised load estimates, imposition of additional regulatory requirements, and the availability and cost of capital.

Environmental Matters

The Company continually assesses actions that may need to be taken to ensure compliance with changing environmental laws and regulations. Compliance programs will increase the cost of electric and natural gas service by requiring changes to the Company's operations and facilities. Historically, rate recovery has been authorized for the cost incurred for compliance with environmental laws and regulations.

Due to existing and proposed legislation and regulations, and legal proceedings commenced by governmental bodies and others, the Company may also incur costs from the past disposal of hazardous substances produced during the Company's operations or those of its predecessors. The Company has been notified by the U.S. Environmental Protection Agency (EPA) and the New York State Department of Environmental Conservation (NYSDEC) that the Company is among the potentially responsible parties (PRPs) who may be liable to pay for costs incurred to remediate certain hazardous substances at seven waste sites, not including the Company's inactive gas manufacturing sites, which are discussed below. With respect to the seven sites, five sites are included in the New York State Registry of Inactive Hazardous Waste Sites (New York State Registry).

Any liability may be joint and several for certain of these sites. The ultimate cost to remediate these sites will be dependent on such factors as the remedial action plan selected, the extent of site contamination, and the portion attributed to the Company. At December 31, 1993, the Company recorded a liability in the Consolidated Balance Sheets related to four of these seven waste sites of $1.8 million. The Company has notified the NYSDEC that it believes it has no responsibility at two sites and has already incurred expenditures related to the remediation at the remaining site. A deferred asset has also been recorded in the amount of $2.6 million, of which $.8 million relates to costs that have already been incurred. The Company believes it will recover these costs, since the PSC has allowed other utilities to recover these types of remediation costs and has allowed the Company to recover similar costs in rates, such as investigation and cleanup costs relating to inactive gas manufacturing sites. This $1.8 million estimate was derived by multiplying the total estimated cost to clean up a particular site by the related Company contribution factor. Estimates of the total cleanup costs were determined by using information related to a particular site, such as investigations performed to date at a site or from the data released by a regulatory agency. In addition, this estimate was based upon currently available facts, existing technology, and presently enacted laws and regulations. The contribution factor is calculated using either the Company's percentage share of the total PRPs named, which assumes all PRPs will contribute equally, or the Company's estimated percentage share of the total hazardous wastes disposed of at a particular site, or by using a 1% contribution factor for those sites at which it believes that it has contributed a minimal amount of hazardous wastes. The Company has notified its former and current insurance carriers that it seeks to recover from them certain of these cleanup costs. However, the Company is unable to predict the amount of insurance recoveries, if any, that it may obtain.

A number of the Company's inactive gas manufacturing sites have been listed in the New York State Registry. The Company has filed petitions to delist the majority of the sites. The Company's program to investigate and initiate remediation at its 38 known inactive gas manufacturing sites has been extended through the year 2000. Expenditures over this time period are estimated to be $25 million. This estimate was determined by using the Company's experience and knowledge related to these sites as a result of the investigation and remediation that the Company has performed to date. It is based upon currently available facts, existing technology, and presently enacted laws and regulations. This liability, to investigate and initiate remediation, as necessary, at the known inactive gas manufacturing sites, is reflected in the Company's Consolidated Balance Sheets at December 31, 1993 and 1992. The Company also has recorded a corresponding deferred asset, since it expects to recover such expenditures in rates, as the Company has previously been allowed by the PSC to recover such costs in rates. The Company has notified its former and current insurance carriers that it seeks to recover from them certain of these cleanup costs. However, the Company is unable to predict the amount of insurance recoveries, if any, that it may obtain.

The Clean Air Act Amendments of 1990 (1990 Amendments) will result in significant expenditures of approximately $178 million, on a present value basis, over a 25-year period, for all capital and operating and maintenance expenses related to the reduction of sulfur dioxide and nitrogen oxides at several of the Company's coal-fired generating stations, of which $51 million has been incurred as of December 31, 1993. The Company's current estimate is a significant reduction from its prior estimate, primarily due to the postponement of the construction of a flue gas desulfurization (FGD) system at the Homer City Generating Station. The Company plans to re-evaluate the need to construct an FGD system

at the Homer City Generating Station in 1995, since its present strategy to bank Phase I emissions allowances for use during Phase II, as discussed below, will allow the Company to meet Phase II allowance requirements through the year 2005. The cost to comply with the sulfur dioxide and nitrogen oxide limitations includes the construction of an innovative FGD system and a nitrogen oxide reduction system expected to be completed in 1995 at the Company's Milliken Generating Station. The Company estimates that approximately a 1% electric rate increase will be required for the cost of reducing sulfur dioxide and nitrogen oxide emissions in both Phase I (begins January 1, 1995) and Phase II (begins January 1, 2000). As a result of the 1990 Amendments, the Company plans to reduce its annual sulfur dioxide emissions by an amount that will allow the Company to meet the sulfur dioxide levels established for the Company, which is approximately a 49% reduction from approximately 138,000 tons in 1989 to 71,000 tons by the year 2000.

The cost of controlling toxic emissions under the 1990 Amendments, if required, cannot be estimated at this time. Regulations may be adopted at the state level which would limit toxic emissions even further, at an additional cost to the Company. The Company anticipates that the costs incurred to comply with the 1990 Amendments will be recoverable through rates based on previous rate recovery of required environmental costs.

The 1990 Amendments require the EPA to allocate annual emissions allowances to each of the Company's coal-fired generating stations based on statutory emissions limits. An emissions allowance represents an authorization to emit, during or after a specified calendar year, one ton of sulfur dioxide. During Phase I, the Company estimates that it will have allowances in excess of the affected coal-fired generating stations' actual emissions. The Company's present strategy is to bank these allowances for use in later years. By using a banking strategy, it is estimated that Phase II allowance requirements will be met through the year 2005 by utilizing the allowances banked during Phase I, which includes the extension reserve allowances discussed below, together with the Company's Phase II annual emissions allowances. This strategy could be modified should market or business conditions change. In addition to the annual emissions allowances allocated to the Company by the EPA, the Company will receive a portion of the extension reserve allowances issued by the EPA to utilities electing to build scrubbers, as a result of the pooling agreement that it entered into with other utilities who were also eligible to receive some of these extension reserve allowances.

As a result of existing and new solid waste disposal legislation and regulations in Pennsylvania, the Company will incur approximately $24 million, on a present value basis, of additional costs over the next 30 years, beginning in 1994, at the Homer City Generating Station. These costs will be incurred to install new equipment, modify or replace existing equipment, and improve the design of a proposed expansion of disposal facilities. The Company expects to recover these expenditures in rates, since the Company has been allowed by the PSC to recover similar costs in rates, such as groundwater protection costs to meet permit conditions and regulatory requirements.

Long-term Power Purchase Contracts

The Company has on line and under contract 362 megawatts (mw) of nonutility generation (NUG) power. In addition, another 240 mw of NUG power is under construction. The Company is required to make payments under these contracts only for the power it receives. During 1993, 1992, and 1991 the Company purchased approximately $138 million, $71 million, and $30 million, respectively, of NUG power. The Company estimates that it will purchase approximately $255 million, $291 million, and $335 million of NUG power for the years 1994, 1995, and 1996, respectively. Increases in NUG power purchase costs are expected to be a significant contributor to price increases over the next three years.

As part of the Company's continuing effort to minimize future price increases associated with uneconomical power purchases from NUGs, the Company negotiated termination of agreements for the South Corning and Indeck-Kirkwood cogeneration projects. The PSC approved full recovery of the $11.5 million in termination costs for the Indeck-Kirkwood project in rates. The Company expects to recover the $34 million in termination costs for the South Corning project in rates because the PSC issued an order in 1993 allowing the Company to defer these costs and the Company has been allowed by the PSC to recover costs for the Indeck-Kirkwood project in rates.

Coal Purchasing Contracts

The Company has long-term contracts with nonaffiliated mining companies for the purchase of coal for the jointly-owned Homer City Generating Station. The contracts, which expire between 1994 and the end of the expected service life of the generating station, require the purchase of either fixed or minimum amounts of the station's coal requirements. The price of the coal under one of these contracts is based on recovery of production costs plus incentives. The remaining contracts are based on fixed price plus escalation provisions. The Company's share of the cost of coal purchased under these agreements is expected to aggregate $66 million, $45 million, and $31 million for the years 1994, 1995, and 1996, respectively.

In addition, the Company has a long-term contract for the purchase of coal for the Kintigh Generating Station. The contract, which expires in 1997, supplies the annual coal requirements of the station. One-third of the tonnage price is renegotiated annually to reflect market conditions. The delivered cost of coal purchased under this agreement is expected to be $56 million, $55 million, and $56 million for the years 1994, 1995, and 1996, respectively.

10 Fair Value of Financial Instruments

The estimated fair values of the Company's financial instruments at December 31, 1993 and 1992, were as follows:

	Carrying Amount		Fair Value	
	1993	1992	1993	1992
	(Thousands)			
First mortgage bonds	$1,166,779	$1,318,845	$1,274,883	$1,388,990
Pollution control notes	$575,695	$505,680	$581,928	$523,251
Preferred stock subject to mandatory redemption requirements	$125,000	$108,550	$134,000	$119,031

The carrying amount for the following items approximates estimated fair value because of the short maturity of those instruments: cash and cash equivalents, commercial paper, and interest accrued.

Special deposits include restricted funds that are set aside for preferred stock and long-term debt redemptions. Special deposits also include restricted funds that are used to finance a portion of the costs incurred in the construction of certain solid waste disposal and other related facilities. The carrying amount approximates fair value because the special deposits have been invested in securities with a short-term maturity.

The carrying amount of the revolving credit agreement note approximates fair value because its pricing is based on short-term interest rates.

The fair value of the Company's first mortgage bonds, pollution control notes, and preferred stock is estimated based on the quoted market prices for the same or similar issues of the same remaining maturities.

11 Industry Segment Information

Certain information pertaining to the electric and natural gas operations of the Company is:

	1993		1992		1991	
	Electric	Natural Gas	Electric	Natural Gas	Electric	Natural Gas
	(Thousands)					
Operating						
Revenues	$1,527,362	$272,787	$1,451,525	$240,164	$1,367,936	$187,879
Expenses	$1,250,000	$249,493	$1,146,619	$221,307	$1,056,969	$177,751
Income	$277,362	$23,294	$304,906	$18,857	$310,967	$10,128
Depreciation and amortization*	$155,231	$9,337	$150,549	$8,428	$145,700	$6,680
Construction expenditures	$208,576	$36,453	$210,185	$35,433	$210,127	$35,756
Identifiable assets**	$4,615,963	$458,596	$4,540,724	$377,424	$4,515,237	$340,090

*Included in operating expenses.

**Assets used in both electric and natural gas operations not included above were $201,457, $159,768, and $69,509 at December 31, 1993, 1992, and 1991, respectively. They consist primarily of cash and cash equivalents, special deposits, and prepayments.

12 Supplementary Income Statement Information

Charges for maintenance, repairs, and depreciation and amortization, are set forth in the Consolidated Statements of Income. Taxes, other than federal income taxes, are:

	1993	1992	1991
		(Thousands)	
Property	$84,616	$81,640	$76,589
Franchise and gross receipts	92,810	92,153	76,721
Payroll	17,985	17,096	15,467
Miscellaneous	9,551	10,052	9,408
Total Other Taxes	$204,962	$200,941	$178,185

Quarterly Financial Information (Unaudited)

Quarter ended	March 31	June 30	Sept. 30	Dec. 31
		(Thousands, except Per Share Amounts)		
1993				
Operating revenues	$522,383	$388,601	$396,410	$492,755
Operating income	$109,893	$56,649	$66,108	$68,006
Net income	$74,039	$21,500	$32,541	$37,948(1)
Earnings for common stock	$68,838	$16,299	$27,340	$32,913
Earnings per share	$.99	$.23	$.39	$.47(1)
Dividends per share	$.54	$.54	$.55	$.55
Average shares outstanding	69,561	69,836	70,119	70,431
Common stock price*				
High	$35.13	$36.50	$36.25	$35.50
Low	$31.63	$32.13	$34.63	$28.75
1992				
Operating revenues	$489,847	$401,934	$367,833	$432,075
Operating income	$111,373	$82,755	$60,109	$69,526
Net income	$76,416	$46,772	$26,581	$34,199
Earnings for common stock	$71,167	$41,488	$21,320	$28,998
Earnings per share	$1.10(2)	$.60(2)	$.31(2)	$.42(2)
Dividends per share	$.53	$.53	$.54	$.54
Average shares outstanding	64,682	68,800	69,063	69,318
Common stock price*				
High	$29.63	$29.38	$32.00	$32.75
Low	$26.13	$26.75	$29.25	$30.38

(1) Fourth quarter 1993 results reflect the effects of restructuring expenses, which decreased net income and earnings for common stock by $17.2 million and decreased earnings per share by 24 cents.

(2) Late in 1992, the Company began reflecting on its income statement the value of energy consumed but not yet billed. If the Company had been allowed by the PSC to include this unbilled revenue factor during all of 1992, quarterly earnings per share in 1992 would have been 94 cents, 39 cents, 38 cents, and 72 cents for the first, second, third, and fourth quarters, respectively.

* The Company's common stock is listed on the New York Stock Exchange. The number of stockholders of record at December 31, 1993, was 58,990.

Dividend Limitations: After dividends on all outstanding preferred stock have been paid, or declared, and funds set apart for their payment, the common stock is entitled to cash dividends as may be declared by the Board of Directors out of retained earnings accumulated since December 31, 1946. Common Stock dividends are limited if Common Stock Equity (45% at December 31, 1993) falls below 25% of total capitalization, as defined in the Company's Certificate of Incorporation. Dividends on common stock cannot be paid unless sinking fund requirements of the preferred stock are met. The Company has not been restricted in the payment of dividends on common stock by these provisions. Retained earnings accumulated since December 31, 1946, were approximately $320 million and $327 million as of December 31, 1993 and 1992, respectively.

Report of Management

The Company's management is responsible for the preparation, integrity, and objectivity of the consolidated financial statements, notes, and other information in this Annual Report. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles and include estimates which are based upon management's judgment and the best available information. Other financial information contained in this report was prepared on a basis consistent with that of the consolidated financial statements.

In recognition of its responsibility for the consolidated financial statements, management maintains a system of internal accounting controls which is designed to provide reasonable assurance as to the integrity and reliability of the financial statements, the protection of assets from unauthorized use or disposition, and the prevention and detection of fraudulent financial reporting. Management continually monitors its system of internal controls for compliance. The Company maintains an internal audit department which independently assesses the effectiveness of the internal controls. In addition, the Company's independent accountants, Coopers & Lybrand, have considered the Company's internal control structure to the extent they considered necessary in expressing an opinion on the consolidated financial statements. Management is responsive to the recommendations of its internal audit department and Coopers & Lybrand concerning internal controls and corrective measures are taken when considered appropriate. Management believes that as of December 31, 1993, the Company's system of internal controls provides reasonable assurance as to the integrity and reliability of the consolidated financial statements.

The Board of Directors oversees the Company's financial reporting through its Audit Committee. This Committee, which is comprised entirely of outside directors, meets regularly with management, the internal auditor, and Coopers & Lybrand to discuss auditing, internal control, and financial reporting matters. To ensure their independence, both the internal auditor and independent accountants have free access to the Audit Committee without management's presence.

James A. Carrigg

James A. Carrigg
Chairman, President and Chief Executive Officer

Sherwood J. Rafferty

Sherwood J. Rafferty
Vice President and Treasurer (Chief Financial Officer)

Everett A. Robinson

Everett A. Robinson
Vice President and Controller (Chief Accounting Officer)

Report of Independent Accountants

Coopers
&Lybrand

To the Stockholders and Board of Directors,
New York State Electric & Gas Corporation and
Subsidiaries
Ithaca, New York

We have audited the accompanying consolidated balance sheets of New York State Electric & Gas Corporation and Subsidiaries as of December 31, 1993 and 1992, and the related consolidated statements of income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 1993. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of New York State Electric & Gas Corporation and Subsidiaries at December 31, 1993 and 1992, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1993, in conformity with generally accepted accounting principles.

As discussed in Note 7 to the consolidated financial statements, the Company and Subsidiaries changed its method of accounting for postretirement benefits other than pensions in 1993.

Coopers & Lybrand

New York, New York
January 28, 1994

Selected Financial Data

(Thousands - except Per Share Amounts)	1993	1992	1991	1990	1989
Operating revenues	$1,800,149	$1,691,689	$1,555,815	$1,496,780	$1,427,745
Net income	$166,028*	$183,968	$168,643	$158,013	$157,779**
Earnings per share	$2.08*	$2.40	$2.36	$2.48	$2.53**
Dividends paid per share	$2.18	$2.14	$2.10	$2.06	$2.02
Average shares outstanding	69,990	67,972	62,906	58,678	57,138
Book value per share of common stock (year end)	$22.89	$22.85	$22.16	$21.85	$21.29
Interest charges	$145,450	$155,388	$163,526	$173,390	$180,068
AFDC and non-cash return	$8,003	$6,482	$7,541	$5,776	$6,387
Depreciation and amortization	$164,568	$158,977	$152,380	$147,659	$148,375
Other taxes	$204,962	$200,941	$178,185	$158,770	$146,605
Construction expenditures	$245,029	$245,618	$245,883	$210,725	$192,022
Total assets	$5,276,016	$5,077,916	$4,924,836	$4,737,431	$4,670,283
Long-term obligations, capital leases, and redeemable preferred stock	$1,755,629	$1,883,927	$1,897,465	$1,766,457	$1,799,800

*Net income and earnings per share for 1993 include the effects of restructuring expenses, which decreased net income by $17.2 million and decreased earnings per share by 25 cents.

**Net income and earnings per share for 1989 include the effects of the adjustment recorded in December 1989 to the 1987 Nine Mile Point nuclear generating unit No. 2 write-off. Excluding that adjustment, net income and earnings per share for 1989 were $151,998 and $2.43.

Glossary

Allowance for funds used during construction (AFDC): the cost of money used to finance a project which is added to construction costs and recovered over the life of the asset

Allowed return on common equity: the cost of common equity as determined by the PSC

Book value per share: common stock equity divided by the number of common shares outstanding at the end of the period

Btu (British thermal unit): the quantity of heat required to raise the temperature of one pound of water by one degree fahrenheit at sea level

Common equity: the value of common stockholders' investment in a company along with retained earnings

Competitive bidding: a mandated process by which utilities must seek bids for additional generation or demand-side management projects

Dekatherm: a measure of heating value equal to one million Btu (1,000 cubic feet of natural gas (one mcf) equals approximately one dekatherm)

Demand-side management (DSM): the planning and implementation of programs designed to help residential, commercial, and industrial electric customers conserve energy

Earnings for common stock: earnings after all expenses are recognized and preferred dividends have been paid

Earnings per share: earnings for common stock for a given period divided by the average number of shares outstanding for the period

Embedded cost of long-term debt: the average interest rate on long-term debt outstanding at the end of the year

Heat rate: a measure of generating station efficiency often expressed as the number of Btu needed to generate one kilowatt-hour of electricity

Load factor: the average load of an electric or natural gas distribution system compared to its maximum load capability for a certain period of time, expressed as a percentage

Market-to-book ratio: an indication of the market's perception of a stock's value (a ratio of over 100 indicates that the market believes the stock is worth more than its book value)

Net income: earnings after all expenses are recognized, but before preferred dividends are paid

Non-utility generator (NUG): a non-traditional power generator that is also known as an independent power producer or energy service company

Peak load: the point of highest customer demand for electricity (the Company is a winter peaking utility; its record peak is 2,618 megawatts)

Price/earnings (P/E) ratio: a measurement of the market's perception of a company's growth potential (the higher the P/E ratio, the more potential the market believes there is for growth)

Retained earnings: the portion of earnings that has been reinvested in the business and not paid out as dividends

Return on common equity: the rate of return earned on common equity calculated by dividing earnings for common stock by average common equity

Total shareholder return: the increase in the value of a shareholder's investment including dividends received and changes in the market price per common share

Transportation gas: natural gas purchased directly from a supplier by an end user and transported, for a fee, by a local distribution company, such as the Company

Unbilled revenues: the estimated revenues attributable to energy which has been delivered to the Company's customers but for which the metered amount has not yet been billed to the customers

Watt: one ampere of electric current under one volt of pressure (one kilowatt is 1,000 watts; one kilowatt-hour is one kilowatt used for one hour, and one megawatt is 1,000 kilowatts or one million watts)

Yield: the return which dividends provide a shareholder calculated by dividing the current annualized dividend per share by the current market price per share

Financial and Operating Statistics

	1993	1992	1991	1990	1989	1988	1983
			(Thousands, except Per Share Amounts)				
Operating Revenues							
Electric	$1,527,362	$1,451,525	$1,367,936	$1,334,509	$1,266,668	$ 1,191,806	$785,723
Natural gas	272,787	240,164	187,879	162,271	161,077	148,363	207,866
Total	1,800,149	1,691,689	1,555,815	1,496,780	1,427,745	1,340,169	993,589
Operating Expenses							
Fuel used in electric generation	245,283	262,531	274,877	274,245	279,075	253,326	187,148
Electricity purchased	161,967	95,026	45,808	34,613	26,019	19,432	66,575
Natural gas purchased	141,635	126,815	99,528	88,589	101,598	82,822	160,415
Other operating expenses	349,177	318,680	279,364	268,829	238,804	213,959	128,986
Restructuring expenses	26,000	–	–	–	–	–	–
Maintenance	111,757	102,500	110,131	106,665	97,420	90,097	61,234
Depreciation and amortization	164,568	158,977	152,380	147,659	148,375	134,037	56,799
Federal income taxes	94,144	102,456	94,447	89,577	64,489	81,689	67,891
Other taxes	204,962	200,941	178,185	158,770	146,605	136,706	90,604
Total	1,499,493	1,367,926	1,234,720	1,168,947	1,102,385	1,012,068	819,652
Operating Income	300,656	323,763	321,095	327,833	325,360	328,101	173,937
Other income and deductions	6,471	12,036	6,076	(1,508)	7,474	28,350	95,296
Income Before Interest Charges	307,127	335,799	327,171	326,325	332,834	356,451	269,233
Interest Charges							
Interest on long-term debt	134,330	145,822	151,649	158,209	164,573	187,304	130,488
Other interest	11,120	9,566	11,877	15,181	15,495	12,426	6,884
Allowance for borrowed funds used during construction	(4,351)	(3,557)	(4,998)	(5,078)	(5,013)	(14,746)	(24,819)
Interest charges – net	141,099	151,831	158,528	168,312	175,055	184,984	112,553
Net Income	166,028	183,968	168,643	158,013	157,779	171,467	156,680
Preferred Stock Dividends	20,638	20,995	20,330	12,662	12,975	13,492	23,466
Earnings available for Common Stock	145,390	162,973	148,313	145,351	144,804	157,975	133,214
Common Stock Dividends	152,316	144,621	131,875	121,302	115,224	112,252	98,155
Retained Earnings Increase (Decrease)	($6,926)	$18,352	$16,438	$24,049	$29,580	$45,723	$35,059
Average number of shares of common stock outstanding	69,990	67,972	62,906	58,678	57,138	56,239	43,530
Earnings per share	$2.08	$2.40	$2.36	$2.48	$2.53	$2.81	$3.06
Dividends paid per share	$2.18	$2.14	$2.10	$2.06	$2.02	$2.00	$2.26

Financial Statistics

	1993	1992	1991	1990	1989	1988	1983
Financial Statistics							
Return on average common stock equity – percent	10.1 (1)	10.6	10.7	11.4	11.5 (4)	13.2 (4)	13.5
Percentage of AFDC and non-cash return to total earnings	5.5	4.0	5.1	4.0	4.6	15.5	68.8
Mortgage bond interest – times earned	3.0	3.1	3.0	2.9	2.9	2.6	2.7
Interest charges and preferred dividends – times earned	1.9	1.9	1.8	1.8	1.8	1.7	1.8
Book value per share of common stock (year end)	$22.89	$22.85	$22.16	$21.85	$21.29	$20.71	$22.75
Market value per share of common stock (year end)	$30.75	$32.50	$29.00	$26.00	$28.88	$22.75	$20.13
Dividend payout ratio (percent)	104.8	89.2	89.0	83.1	79.8	71.2	73.9
Price earnings ratio (year end)	14.8	13.5	12.3	10.5	11.4	8.1	6.6
Property, Plant and Equipment (includes construction work in progress)				(Thousands)			
Electric	$4,887,125	$4,694,073	$4,537,356	$4,367,913	$4,217,920	$4,089,485	$3,109,469
Natural gas	393,945	361,630	336,199	222,125	201,942	189,580	142,072
Common	180,532	205,345	189,135	175,703	155,340	129,860	49,115
Total	$5,461,602	$5,261,048	$5,062,690	$4,765,741	$4,575,202	$4,408,925	$3,300,656
Accumulated Depreciation	$1,541,456	$1,427,793	$1,309,829	$1,174,651	$1,063,630	$956,415	$563,118
Capitalization (includes current maturities)				(Thousands)			
Long-term debt	$1,868,338	$1,891,036	$1,825,918	$1,815,686	$1,801,762	$1,985,276	$1,331,981
Preferred stock	360,500	269,050	270,700	172,350	174,000	178,650	278,950
Common stock equity	1,615,697	1,586,474	1,405,147	1,364,344	1,225,184	1,174,028	1,103,655
Total Capitalization	$3,844,535	$3,746,560	$3,501,765	$3,352,380	$3,200,946	$3,337,954	$2,714,586
Capitalization Ratios (percent)							
Long-term debt	48.6 (2)	50.5	52.2	54.2	56.3	59.5	49.1
Preferred stock	9.4 (2)	7.2	7.7	5.1	5.4	5.3	10.3
Common stock equity	42.0 (2)	42.3	40.1	40.7	38.3	35.2	40.6
Number of Stockholders							
Common stock	58,990	61,183	59,593	60,585	62,552	66,689	82,982
Preferred stock	3,632	3,829	3,943	4,068	4,238	4,444	6,607
Payroll (including pensions, etc.)				(Thousands)			
Charged to operations	$197,023 (3)	$181,245	$163,421	$148,007	$140,415	$132,617	$101,235
Charged to construction and other accounts	85,929	89,463	82,455	72,761	64,890	61,808	53,422
Total	$282,952	$270,708	$245,876	$220,768	$205,305	$194,425	$154,657
Number of employees (year end)	4,746	4,888	4,842	4,599	4,558	4,494	4,378

(1) The return on equity for 1993 excludes restructuring expenses.
(2) After $95 million of redemptions of preferred stock in early 1994, the capital structure will be 49.8% long-term debt, 7.1% preferred stock, and 43.1% common stock equity.
(3) Payroll charged to operations for 1993 excludes restructuring expenses.
(4) The return on equity for 1988 and 1989 excludes the Nine Mile Point nuclear generating unit No. 2 write-off adjustments.

Electric Sales Statistics

	1993	1992	1991	1990	1989	1988	1983
Kilowatt-Hour (KWH) Sales (Millions)							
Residential	5,423	5,472	5,297	5,319	5,233	5,148	4,398
Commercial	3,298	3,283	3,285	3,235	3,181	3,069	2,536
Industrial	2,950	3,082	3,068	3,175	3,210	3,159	2,691
Other	1,417	1,457	1,457	1,468	1,431	1,400	1,231
Total Retail	13,088	13,294	13,107	13,197	13,055	12,776	10,856
Other electric utilities	6,233	6,003	5,066	4,750	4,461	3,896	1,429
Total	19,321	19,297	18,173	17,947	17,516	16,672	12,285
Operating Revenues (Thousands)							
Residential	$635,155	$601,042	$553,056	$521,688	$510,941	$507,428	$335,284
Commercial	333,674	314,272	293,197	267,598	261,606	257,707	169,537
Industrial	228,215	225,832	207,933	196,016	196,701	198,344	133,007
Other	138,320	133,819	124,575	116,352	114,364	113,576	75,490
Total Retail	1,335,364	1,274,965	1,178,761	1,101,654	1,083,612	1,077,055	713,318
Other electric utilities	147,175	143,414	131,412	145,104	134,108	89,784	58,239
Unbilled revenue recognition - net	2,257	(427)	35,333	42,995	–	–	–
Other operating revenues	42,566	33,573	22,430	44,756	48,948	24,967	14,166
Total Operating Revenues	$1,527,362	$1,451,525	$1,367,936	$1,334,509	$1,266,668	$1,191,806	$785,723
Operating Revenues Per KWH (Cents)							
Residential	11.71	10.98	10.44	9.81	9.76	9.86	7.62
Commercial	10.12	9.57	8.93	8.27	8.22	8.40	6.69
Industrial	7.74	7.33	6.78	6.17	6.13	6.28	4.94
Other	9.76	9.18	8.55	7.93	7.99	8.11	6.13
Total Retail	10.20	9.59	8.99	8.35	8.30	8.43	6.57
Other electric utilities	2.36	2.39	2.59	3.05	3.01	2.30	4.08
Number of Customers (Year End)							
Residential	703,503	699,387	692,922	685,898	676,590	665,296	611,298
Commercial	73,727	72,463	71,463	70,802	69,230	67,488	60,873
Industrial	1,542	1,508	1,506	1,498	1,465	1,437	1,338
Other	11,091	11,073	10,907	10,825	10,694	10,556	10,039
TOTAL	789,863	784,431	776,798	769,023	757,979	744,777	683,548
Annual Average Use (KWH) (1)							
Residential	7,708	7,843	7,672	7,796	7,786	7,791	7,223
Commercial	44,781	45,258	45,864	45,826	46,095	45,600	41,772
Industrial (thousands)	1,935	2,047	2,047	2,142	2,200	2,226	2,019
Annual Average Bill (1)							
Residential	$903	$861	$801	$765	$760	$768	$551
Commercial	4,531	4,333	4,093	3,791	3,791	3,829	2,793
Industrial	149,747	149,955	138,714	132,265	134,819	139,777	99,780

(1) Computed using the weighted average number of customers for the year.

Electric Generation Statistics

	1993	1992	1991	1990	1989	1988	1983
System Capability (Megawatts)							
Coal	2,394	2,415	2,412	2,414	2,414	2,405	1,733
Nuclear	189	188	196	194	193	194	–
Hydro	67	70	70	68	66	67	56
Internal Combustion	7	8	8	7	7	7	10
Total Generating Capability	2,657	2,681	2,686	2,683	2,680	2,673	1,799
Purchased – Power Authority	486	489	488	487	487	510	680
– NUG	362	347	110	–	–	–	–
– Other	–	–	–	53	9	–	300
Less: Firm Sales	(311)	(8)	–	–	(115)	(125)	–
Total System Capability	3,194	3,509	3,284	3,223	3,061	3,058	2,779
System Capability (Percent)							
Coal	75	69	74	75	80	79	63
Nuclear	6	5	6	6	6	6	–
Hydro	2	2	2	2	2	2	2
Total Generating Capability	83	76	82	83	88	87	65
Purchased – Power Authority	15	14	15	15	16	17	24
– NUG	12	10	3	–	–	–	–
– Other	–	–	–	2	–	–	11
Less: Firm Sales	(10)	–	–	–	(4)	(4)	–
Total System Capability	100	100	100	100	100	100	100
Production Statistics							
Annual load factor (percent)	66.7	67.0	68.9	69.4	64.7	63.5	64.4
Coal burned (thousands of net tons)	5,918	6,478	6,310	6,395	6,472	6,106	4,666
Coal heat value (Btu per lb.)	12,674	12,668	12,610	12,510	12,477	12,572	12,033
Btu per kwh generated (net)	9,997	9,902	9,898	9,936	9,931	9,881	10,552
Kilowatt-Hour (KWH) Production-Net (Millions)							
Generated:							
Coal	15,131	16,709	16,157	16,211	16,345	15,589	10,641
Nuclear	1,295	922	1,180	743	773	639	–
Hydro	309	301	258	356	292	245	213
Total Generated	16,735	17,932	17,595	17,310	17,410	16,473	10,854
Purchased – Power Authority	1,617	1,635	1,667	1,607	1,667	1,743	2,023
– Other	2,550	1,250	343	347	102	45	714
Total	20,902	20,817	19,605	19,264	19,179	18,261	13,591
Production Expenses (Thousands)							
Generated	$371,891	$375,209	$391,393	$391,977	$381,371	$351,963	$237,309
Purchased – Power Authority	16,713	15,661	14,668	13,534	12,012	11,360	25,849
– NUG	137,791	71,260	30,028	7,700	1,905	1,393	829
– Other	7,463	8,105	1,112	13,379	12,102	6,679	39,897
Total	$533,858	$470,235	$437,201	$426,590	$407,390	$371,395	$303,884
Cost Per KWH (Mills)							
Generated	22.22	20.92	22.24	22.64	21.91	21.37	21.86
Purchased – Power Authority	10.34	9.58	8.80	8.42	7.21	6.52	12.78
– NUG	55.74	56.56	63.48	62.10	56.03	55.72	52.68
– Other	20.62	21.39	21.67	30.41	40.47	26.61	48.91
Operating expense (excluding production)	14.20	12.15	11.34	11.70	10.57	9.62	8.60
Total	39.74	34.74	33.64	33.84	31.81	29.96	30.95
Electric Operation and Maintenance Expenses (Thousands)							
Production	$533,858	$470,235	$437,201	$426,590	$407,390	$371,395	$303,884
Transmission	32,734	31,623	30,462	30,118	29,239	22,196	13,382
Distribution	69,322	64,428	62,763	58,876	54,420	49,737	39,111
Customer accounting	35,559	31,180	28,861	26,861	23,242	21,031	16,603
Customer service	34,749	31,390	24,345	27,625	23,426	20,527	5,221
Administrative and general	124,462 (1)	94,349	75,812	81,815	72,405	62,258	42,508
Total	$830,684	$723,205	$659,444	$651,885	$610,122	$547,144	$420,709

(1) Includes restructuring expenses of $21 million

Natural Gas Sales Statistics

	1993	1992	1991	1990	1989	1988	1983
Dekatherm (DTH) Sales (Thousands) (1)							
Residential	25,080	24,913	18,115	14,809	15,331	14,818	13,857
Commercial	10,640	10,796	8,054	6,532	6,926	7,055	7,514
Industrial	1,820	1,689	1,788	2,023	2,167	3,121	9,296
Other	1,805	1,959	1,917	2,151	2,071	2,242	3,718
Total Retail	39,345	39,357	29,874	25,515	26,495	27,236	34,385
Transportation of customer-owned natural gas	18,701	17,009	12,530	8,157	8,853	7,825	–
Total	58,046	56,366	42,404	33,672	35,348	35,061	34,385
Operating Revenues (Thousands) (1)							
Residential	$170,734	$152,325	$111,106	$94,531	$93,873	$83,115	$92,974
Commercial	66,648	59,939	43,969	37,852	38,726	35,680	44,980
Industrial	9,602	8,092	8,640	10,267	10,437	12,821	49,217
Other	10,943	10,762	10,243	11,574	10,776	10,738	20,695
Total Retail	257,927	231,118	173,958	154,224	153,812	142,354	207,866
Transportation of customer-owned natural gas	12,091	11,639	9,571	7,169	6,721	5,523	–
Unbilled revenue recognition - net	2,686	(3,626)	3,770	853	–	–	–
Other natural gas revenue	83	1,033	580	25	544	486	–
Subtotal	14,860	9,046	13,921	8,047	7,265	6,009	–
Total Operating Revenues	$272,787	$240,164	$187,879	$162,271	$161,077	$148,363	$207,866
Operating Revenues per DTH							
Residential	$6.81	$6.11	$6.13	$6.38	$6.12	$5.61	$6.71
Commercial	6.26	5.55	5.46	5.79	5.59	5.06	5.99
Industrial	5.28	4.79	4.83	5.08	4.82	4.11	5.29
Other	6.06	5.49	5.34	5.38	5.20	4.79	5.57
Total Retail	6.56	5.87	5.82	6.04	5.83	5.24	6.05
Transportation	0.65	0.68	0.76	0.88	0.76	0.71	–
Number of Customers (Year End) (1)							
Residential with house heating	185,117	182,795	178,625	117,429	114,497	111,543	103,040
Residential without house heating	12,943	13,181	12,906	8,360	8,079	8,340	8,740
Commercial with space heating	23,327	23,165	23,023	16,843	16,626	16,419	15,602
Commercial without space heating	2,281	2,282	2,241	1,548	1,476	1,444	1,455
Industrial	394	390	386	334	343	343	387
Transportation of customer-owned natural gas	444	389	342	277	228	214	–
Other	1,693	1,657	1,557	1,246	1,154	1,133	1,130
Total	226,199	223,859	219,080	146,037	142,403	139,436	130,354
Annual Average Use (DTH) (2)							
Residential	127	129	105	119	126	125	124
Commercial	416	428	345	358	386	398	449
Industrial	4,515	4,387	4,781	6,003	6,246	8,694	24,272
Annual Average Bill (2)							
Residential	$864	$786	$641	$763	$774	$703	$833
Commercial	2,605	2,377	1,882	2,076	2,158	2,012	2,689
Industrial	23,827	21,018	23,102	30,466	30,079	35,713	128,504
Cost of Natural Gas Purchased							
Amount (thousands)	$141,635	$126,815	$99,528	$88,589	$101,598	$82,822	$160,415
Per dth	$3.56	$3.22	$3.30	$3.64	$3.57	$3.02	$4.52
Natural Gas Operation and Maintenance Expenses (Thousands)							
Production	$142,229	$126,984	$101,458	$88,901	$102,014	$83,155	$160,928
Transmission and distribution	20,712	19,938	18,491	13,982	13,247	11,712	8,908
Customer accounting	10,959	9,233	8,046	5,765	4,990	4,516	3,783
Customer service	6,972	8,152	6,533	5,942	3,972	3,352	1,328
Administrative and general	24,263 (3)	18,040	15,735	6,464	8,571	9,758	8,701
Total	$205,135	$182,347	$150,263	$121,054	$132,794	$112,493	$183,650

(1) The increase in 1991 is primarily due to the acquisition of Columbia Gas of New York, Inc.
(2) Computed using the weighted average number of customers for the year.
(3) Includes restructuring expenses of $5 million.

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