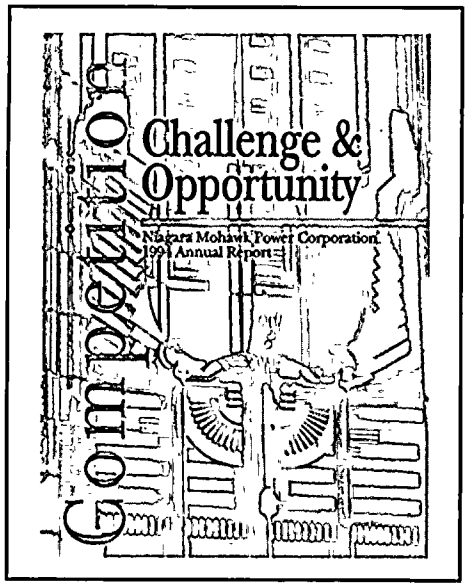
Challenge & Opportunity

Niagara Mohawk Power Corporation
1994 Annual Report



ON THE COVER: In this era of change, there remain some constants at Niagara Mohawk. One of these is the tremendous pride we all take in the heritage of the company. That pride is perhaps best embodied by The Spirit of Light, which graces both our corporate headquarters in Syracuse and the cover of this year's Annual Report.

This report was produced by Niagara Mohawk employees.

Contents

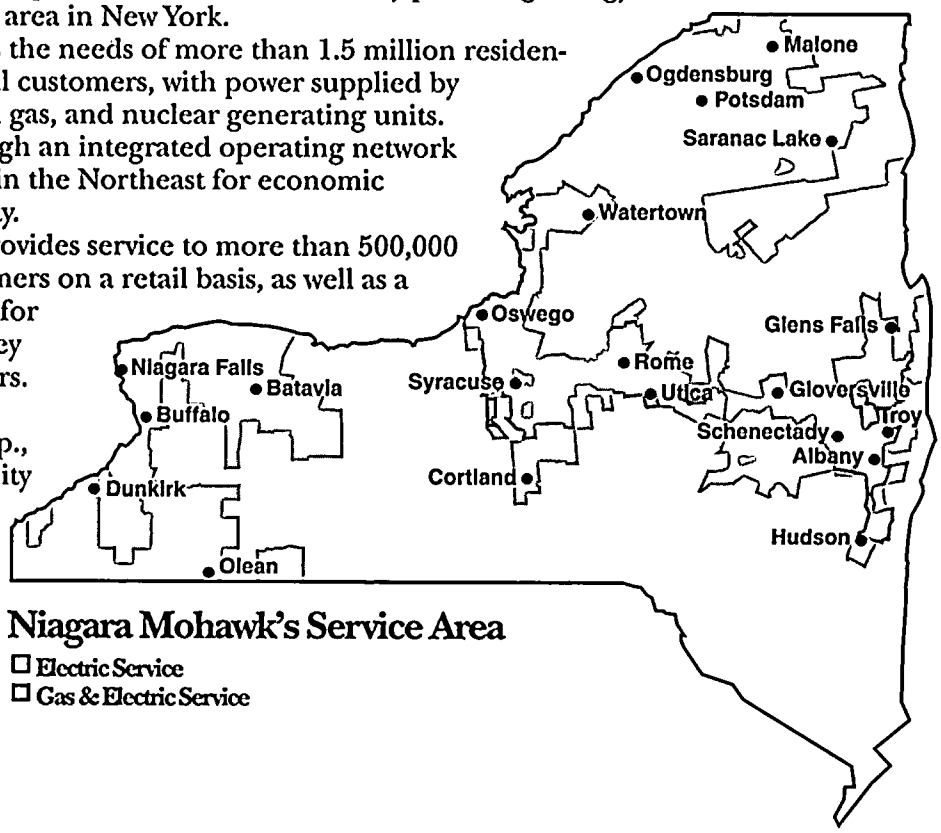
Serving Our Customers in Upstate New York

Niagara Mohawk Power Corp. is an investor-owned utility providing energy to the largest customer service area in New York.

Our electric system meets the needs of more than 1.5 million residential, commercial, and industrial customers, with power supplied by hydroelectric, coal, oil, natural gas, and nuclear generating units. Electricity is transmitted through an integrated operating network that is linked to other systems in the Northeast for economic exchange and mutual reliability.

Our natural gas system provides service to more than 500,000 residential and business customers on a retail basis, as well as a growing number of customers for whom we transport gas that they purchase directly from suppliers.

We also own a Canadian subsidiary, Opinac Energy Corp., which operates the electric utility Canadian Niagara Power.



Niagara Mohawk's Service Area

☐ Electric Service
☐ Gas & Electric Service

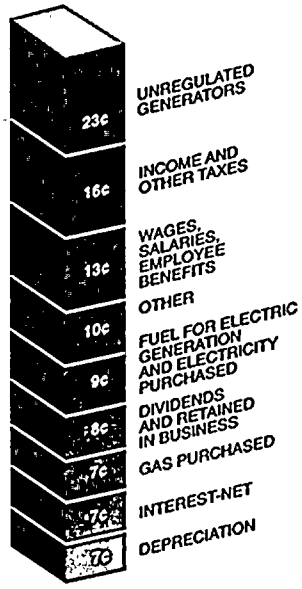
Printed on recycled paper

Highlights

	1994	1993	%Change
Total operating revenues	$ 4,152,178,000	$ 3,933,431,000	5.6
Income available for common stockholders	$ 143,311,000	$ 239,974,000	(40.3)
Earnings per common share	$ 1.00	$ 1.71	(41.5)
Dividends per common share	$ 1.09	$ 0.95	14.7
Common shares outstanding (*average*)	143,261,000	140,417,000	2.0
Utility plant (*gross*)	$10,485,339,000	$10,108,529,000	3.7
Construction work in progress	$ 481,335,000	$ 569,404,000	(15.5)
Gross additions to utility plant	$ 490,124,000	$ 519,612,000	(5.7)
Public kilowatt-hour sales	34,006,000,000	33,750,000,000	0.8
Total kilowatt-hour sales	41,599,000,000	37,724,000,000	10.3
Electric customers at end of year	1,559,000	1,552,000	0.5
Electric peak load (*kilowatts*)	6,458,000	6,191,000	4.3
Natural gas sales (*dekatherms*)	85,615,000	83,201,000	2.9
Natural gas transported (*dekatherms*)	85,910,000	67,741,000	26.8
Gas customers at end of year	512,000	501,000	2.2
Maximum day gas deliveries (*dekatherms*)	995,801	929,285	7.2

THE 1994 REVENUE DOLLAR

*AND WHERE IT WENT**



* Excluding the effect of the write-off of costs associated with the Voluntary Employee Reduction Program.

A Letter to Our Shareholders

From Chairman and CEO William E. Davis

"We are incorporating the lessons of the past few years into an aggressive agenda designed to protect the interests of our shareholders and customers, and guide Niagara Mohawk into the new competitive era."

For the past several years, this letter has chronicled the approach of competition in the electric utility industry, and the preparations your company has been making to meet the challenges and take advantage of the opportunities that lie ahead.

The events of 1994 provided vivid examples of both the challenges and opportunities facing us. We saw how well-intended government action, as well as government inaction, can have dramatic and harmful consequences. We are incorporating the lessons of the past few years into an aggressive agenda designed to protect the interests of our shareholders and customers, and guide Niagara Mohawk into the new competitive era.

November's election results are still reverberating in Washington as well as Albany, where a new party has taken over leadership after 20 years. Governor Pataki's administration has already appointed a new chairman, commissioner, and general counsel of the New York State Public Service Commission, has moved to abolish the state Energy Office, and other personnel and policy changes are likely. Niagara Mohawk is eager to work with these new government officials to reform regulatory policies that have cost our customers and shareholders dearly.

To that end, I have designated a team to help put in place a legislative and regulatory regime based on sound economic principles, and to spearhead efforts to reduce the unreasonable payments we must make to unregulated generators, from whom we are required to buy power.

Headed by Gary Lavine, our senior vice president for Legal and Corporate Relations, the team includes experienced talent in the governmental, legal, communications, and financial areas, as well as planning, power supply, gas, and marketing. Their mission is to persuade government leaders to allow Niagara Mohawk to compete on an equal footing with unregulated generators and to ensure that risk is properly compensated, good service is rewarded, and consumers have the benefit of energy costs that will facilitate, rather than stifle, economic growth.

California Proposal Becomes A Catalyst for Competition

Several key government actions during 1994 had major impacts on the industry, hastening the approach of competition. Perhaps the most important move took place in April when the California Public Utilities Commission announced a proposal to allow large industrial and commercial electricity users in that state to choose their suppliers by 1996. All customers, including residential, would be able to choose their suppliers by 2002.

Open competition, or retail wheeling, had long been discussed as an abstract concept, but the California proposal brought it into the here and now. The proposal triggered intense debate nationwide, with more than a dozen other states around the country entertaining some sort of retail wheeling plan.

Financial markets reacted strongly. California utility stocks lost the most value, but the shares of virtually every electric utility in the country dropped, not just in reaction to the California proposal but also to other industry events throughout the year.

Niagara Mohawk's stock price fell in September as a direct result of two adverse regulatory actions. First, the Public Service Commission's trial staff unveiled a proposal to cut our rates by $146 million. At the same time, the trial staff proposed a plan that would phase in market-based pricing for electricity generation over a 10-year period.

Then, the PSC leap-frogged the California proposal by approving the sale of electricity at the retail level by an unregulated generator, Sithe Energies, to Alcan Rolled Products, one of our largest customers.

As a condition of the sale, the PSC required Sithe to partially compensate Niagara Mohawk for the loss of Alcan's revenue. Nevertheless, we believe that the Sithe/Alcan sale is illegal, and are challenging it in court. Without question, this PSC decision highlights the challenges of emerging competition.

Internal Efforts Help Improve Bottom Line

We are working to meet that competition by streamlining our organization dramatically. Since the beginning of 1993, we have consolidated operations and reduced our work force by more than 3,100 positions, or roughly 27 percent.

Despite a smaller work force, we are aggressively pursuing continued improvement in our performance. We're redesigning processes to gain operating efficiencies, eliminating low-value activities, and working together with our labor union to implement important work-practice improvements that will help us compete.

During 1994 we announced the sale of HYDRA-CO, our independent power production subsidiary, for more than $200 million. We took that action after a careful review of the regulatory environment for utility subsidiaries in New York state and the advantages of selling the operation at this time.

We have strengthened our focus on internal cost control by pursuing an activity-based budgeting process. Every program must be justified each year to ensure that resources are being used efficiently.

For 1994, departmental expenses finished below the toughest targets we've ever imposed. Moreover, our 1995-1997 capital budget has been cut by nearly $130 million from the forecast developed at the beginning of 1994.

The company earned $1.00 per share in 1994, including a one-time charge against earnings of 89 cents-per-share in the fourth quarter to reflect the costs associated with our Voluntary Employee Reduction Program. That program resulted in a 1,400-person reduction in staffing and will produce long-term operational savings, including expected savings of nearly $100 million in 1995.

Also, shortfalls in all classes of sales, equivalent to 46 cents-per-share, were deferred for future recovery in rates under the Electric Revenue Adjustment Mechanism. With the continuing trend toward competition, this adjustment mechanism may soon be eliminated, making the company's sales and earnings more sensitive to market conditions.

In April, your Board of Directors increased the quarterly dividend to 28 cents-per-share, the third increase since the dividend was restored in 1991. At the same time, however, the Board is keenly aware that market and regulatory pressures will challenge the company's dividend policy in the future.

Unregulated Generation and Taxes Remain Major Concerns

We're building strength and competitiveness in our electric operations, but it is clear that internal changes alone aren't enough. We have significant external costs, and chief among them is the cost of electricity we are required to buy from unregulated generators.

Payments made to unregulated generators amounted to nearly $1 billion in 1994, more than 27 cents of every dollar we collected from our electricity customers. More than $350 million of that total is excess cost – above what customers would have paid had we not been required to purchase unneeded electricity from unregulated generators. Through a variety of actions, we have cut the size of our potential obligations to unregulated generators by nearly $2 billion since 1991. Notwithstanding the success of these efforts, we expect our customers will still pay more than $400 million in excess costs during 1995.

> *"Despite our progress, it is clear that a comprehensive solution to the unregulated generator problem is needed to resolve competitive inequities. We will continue to aggressively pursue changes in state policy that will reduce our obligation to purchase unneeded electricity at above-market prices from unregulated generators."*

Despite our progress, it is clear that a comprehensive solution to the unregulated generator problem is needed to resolve competitive inequities. We will continue to aggressively pursue changes in state policy that will reduce our obligation to purchase unneeded electricity at above-market prices from unregulated generators. We also have joined other utilities across the nation to pursue actions at the federal level to reduce unregulated generator payments and obligations.

Taxes also are a major cause of escalating electric bills. On average,

continued...

New York's utilities pay more than twice as much in taxes as utilities elsewhere. Our second major effort to control external cost factors is directed toward lessening our tax burden, challenging property tax assessments in localities across our service territory, and working to cut or eliminate New York's regressive Gross Receipts Tax.

Setting the Stage for An Orderly Transition

We undertook two major initiatives in 1994 to help promote an orderly transition to a competitive energy marketplace. First, we proposed a five-year rate plan that would give us more flexibility to compete and save both the company and its regulators the time and expense of annual rate case litigation. We proposed a modest rate increase for 1995, followed by four years during which any rate increases would be capped by a formula based on the inflation rate.

The PSC trial staff responded with a plan intended to cut our electricity rates dramatically over the next 10 years, and force Niagara Mohawk shareholders to bear the brunt of the price cuts. We have strongly opposed the trial staff's plan because it would unfairly penalize shareholders for unregulated generator payments, taxes, and other utility obligations that result directly from state policy.

In late January 1995, the PSC Administrative Law Judges issued a recommended decision on our 1995 rate proposal. The effect would be a decrease in 1995 electricity revenues of $28 million, or 0.9 percent, while gas rates would increase $10.3 million, or 1.7 percent. If the PSC approves 1995 rates at levels similar to those proposed in the ALJ recommended decision, and sales remain weak because of the lag in the economic recovery in upstate New York, our 1995 earnings will be considerably lower than adjusted 1994 results of $1.89 per share.

The second major initiative was a proposal to the PSC of our own transition plan entitled "The Impacts of Emerging Competition in the Electric Utility Industry." Our proposal would reduce some utility costs, redistribute others, and slow down the transition enough for all parties to adjust to a world of greater choice. It would share the costs and benefits of competition among all energy suppliers and their customers. We are eager to compete but we will oppose any transition plan – or any outcome based on a lack of planning – that treats our shareholders and our customers unfairly.

Although the past year was a difficult one, we made progress in several areas. We are buoyed, for instance, by the strong performance and growth of our natural gas operations and by our nuclear performance. We also are encouraged by our economic development activities, which have helped maintain and attract business.

We remain committed to our Vision of becoming the most responsive and efficient energy services company in the Northeast, and to being the energy provider of choice for our customers. Achievement of that Vision requires that we continue to change, and that we influence both the pace and the direction of the transition to competition in our industry.

The leadership of your company remains certain that every employee is up to the task, and we are grateful for your confidence in our efforts.

William E. Davis

Chairman of the Board and
Chief Executive Officer
Niagara Mohawk Power Corp.

In Appreciation

John M. Endries

Michael P. Ranalli

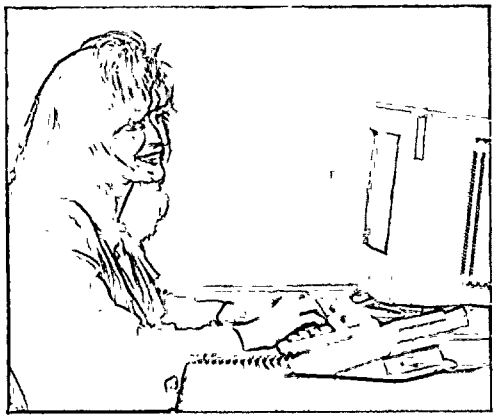
Niagara Mohawk recognizes with deep gratitude the many contributions of company President John M. Endries and Electric Supply & Delivery Senior Vice President Michael P. Ranalli, both of whom will retire this year.

Endries joined the company in 1973 as the assistant to the executive vice president of Finance and Corporate Planning. Advancing through positions of increasing responsibility, he was named president in 1988. Endries leaves Niagara Mohawk with a reputation as an astute strategist in a rapidly changing industry.

"I've had the privilege of working alongside Jack since the day I joined the company," said Chairman William E. Davis. "I have been greatly impressed with his intelligence and character. Jack has been the steady hand that guided our operations through a period of major change and challenge."

Ranalli, a 37-year employee, has played many critical roles in the company – from overseeing completion of the Nine Mile Unit Two nuclear plant, to running a successful, corporatewide self-assessment program, to streamlining and reshaping the Electric Supply & Delivery business unit.

"Everyone who has worked with Mike appreciates his tenacity and forthrightness," said Davis. "We wish them both well."



A Commitment to Customer Service

We are striving for better service to all customers, even as we cut the cost of providing that service.

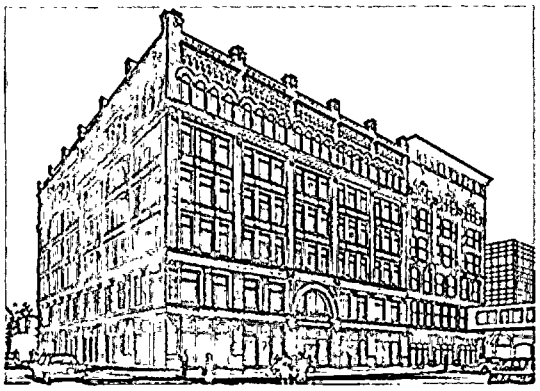
In the world of customer service, Niagara Mohawk competes with more than just energy providers. We measure our performance against companies of all types with the best service levels.

To meet this formidable challenge, we've revamped our customer service organization from top to bottom. Two newly renovated facilities – the Center for Customer Service Excellence in downtown Syracuse, and Collection Services in the Buffalo Electric Building – embody our customer service commitment. Replacing regional customer service and collection centers, these centralized operations offer both improved efficiency and one-stop shopping for all customers.

But our commitment goes far beyond these physical changes. We have been busy identifying best practices – within Niagara Mohawk and among peer utilities and other service-oriented industries – and incorporating them into our standard customer service procedures. The result is consistent, high-quality service.

The Best Systems and Employees

The telecommunication system to be used at these facilities will be second to none. We also will employ various state-of-the art employee monitoring and assessment methods to ensure continual improvement of the level of customer service.

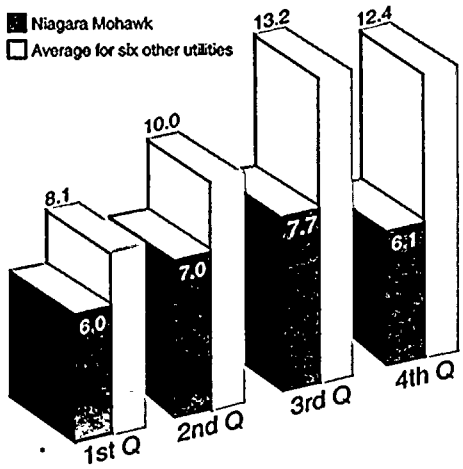


Artist's rendering of the completed Center for Customer Service Excellence in downtown Syracuse.

Operating these new facilities are a group of highly trained employees dedicated to helping customers in any way they can. The goal of both the Center for Customer Service Excellence and Collection Services is to provide convenient, efficient, around-the-clock telephone service for customers who deserve prompt answers to their questions and concerns, and quick responses to their service needs.

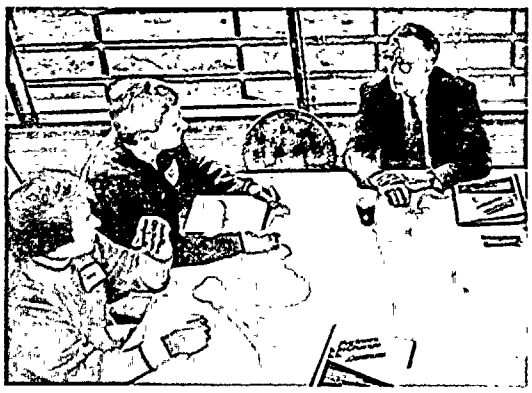
Despite the obstacles inherent in broad organizational change, we are making progress in the customer service area. In 1994, for example – even with the retirement of experienced employees and the coldest winter on record – we achieved the second-lowest combined gas and electric PSC complaint rate among New York state utilities. Also, a recent survey showed a significant increase in the number of customers who gave us a positive rating for their telephone contacts with the company.

1994 PSC Complaint Rates for New York State Investor-Owned Gas and Electric Utilities
(per 100,000 customers)



During 1995, we will aggressively implement and evaluate a new service commitment: service guarantees. We will promise to deliver accurate bills and install service within a specific time frame. And we will back that promise with customer rebates.

Superior customer service is vital to our success. We are striving for better service to all customers, even as we cut the cost of providing that service.



Working to Improve Our Performance and Financial Strength

The company confronted each issue head-on, challenging ill-advised policy, cutting internal and external costs, and improving efficiency.

Niagara Mohawk was tested at every turn in 1994. Several regulatory developments and escalating payments to unregulated generators took their toll on the company's stock price and credit ratings.

Yet the company confronted each issue head-on, challenging ill-advised policy, cutting internal and external costs, and improving efficiency.

Stock Price

Niagara Mohawk's common stock price declined along with other utility stocks in response to investor perceptions of increasing risk due to growing competition. Our stock declined further following two negative actions taken by the New York State Public Service Commission. The price held steady, however, through the latter part of 1994, closing the year at $14.25.

Financial Developments

In 1994, the company completed public offerings of $150 million of preferred stock and $325 million in first mortgage bonds. In early 1995, we finalized the sale of HYDRA-CO Enterprises, an unregulated generating subsidiary, to CMS Generation, for $206.6 million. Also, through various refinancing activities during 1994, Niagara Mohawk achieved savings of $5.5 million on long-term debt.

One-time Charge for Employee Reduction

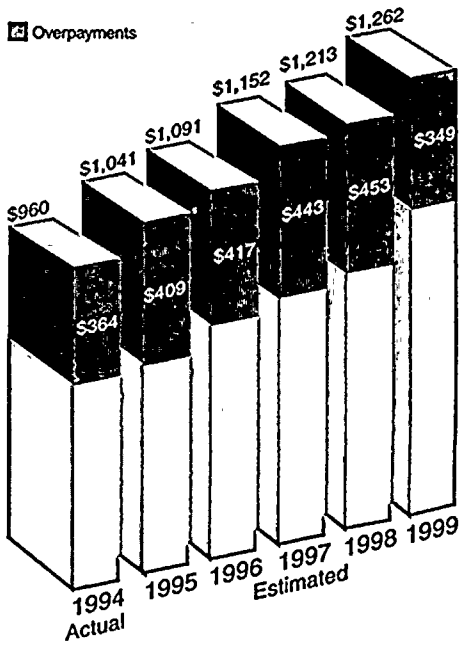
In December, the company took a $197 million charge against earnings to cover the cost of the Voluntary Employee Reduction Program offered to all employees. In 1995 alone, this program is expected to produce capital and operational savings of nearly $100 million.

Reducing Payments to Unregulated Generators

Mandated payments to unregulated generators are the leading cause of rising electricity bills. We have taken a number of aggressive actions to reduce these payments, including strictly enforcing, and in some cases, renegotiating or canceling contracts. These actions are expected to save customers an estimated $2 billion in future payments.

However, the problem continues to grow. About 2,400 megawatts of unregulated generator capacity are expected to be on-line by the end of 1995. The company is continuing its efforts to mitigate price impacts on customers. During 1994, for example, Niagara Mohawk sought to require several unregulated generators to provide assurance they will repay front-end subsidies. We estimate that unregulated generators will owe our customers approximately $2.5 billion in such subsidies by 2008. The matter is now in court.

1994 Total Payments and Overpayments to Unregulated Generators
(in millions of dollars)



NMGas Continues Strong Performance

Competition is nothing new to NMGas, our natural gas business unit. In 1994, NMGas operated under the effects of the Federal Energy Regulatory Commission Order 636, the first full year the order was in place. By unbundling gas services, Order 636 allowed NMGas to compete more effectively for large industrial customers and gave the business unit the ability to buy natural gas directly from producers through interstate pipelines.

During the year, several natural gas refueling stations also were added to serve the growing number of natural gas vehicles operating in our service territory. NMGas excelled at obtaining, storing and delivering natural gas economically, offering the lowest prices of any gas utility in New York state during the harsh 1993-1994 winter. And NMGas performed admirably when it set a one-day record for natural gas deliveries by supplying nearly 1 billion cubic feet over a 24-hour period in January 1994.

Seizing these and other opportunities to expand its business, NMGas transported approximately 86 million dekatherms of gas for the year, an increase of nearly 27 percent over the 1993 level. At year-end 1994, NMGas had 512,000 customers, a jump of 11,000 over the year-end 1993 number.

Improving Other Areas

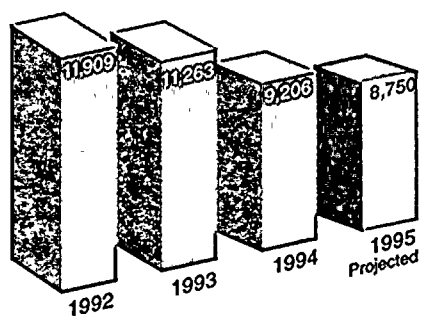
Nuclear Performance: The Nine Mile Units One and Two nuclear plants enjoyed an exceptional year, operating at 92.1 percent and 90.4 percent of capacity, respectively, compared to an industry average of approximately 75 percent. This performance marks the best production year ever as a two-unit site, and their capacity factors are expected to rank Units One and Two on the list of the Top 20 performing nuclear plants in the United States.

In addition, an economic study completed in November supported the continued operation of Nine Mile One, which marked its 25th year of commercial operation during 1994.

Cutting Other Generation Costs: Responding to a continuing generating capacity surplus, we have placed Oswego Five, an oil-fired 850-megawatt unit, in long-term cold standby and moved aggressively to lower the cost of our remaining generation. Our fossil and hydro generation expense budget has declined 45 percent since 1991, improving our ability to compete in the wholesale market and helping drive 1994 wholesale sales volume to an all-time high. Capital budgets have declined almost 60 percent since 1991, and will decrease further when federal Clean Air Act modifications to our generating facilities are completed in 1995.

Employment Levels: The Voluntary Employee Reduction Program was the biggest cost-reduction step in 1994. Nearly 1,400 employees took advantage of this program. By year-end 1995, the company will have 8,750 full-time employees, representing a reduction of 3,100 employees, or nearly 27 percent of the work force, since early 1993.

Employment Levels (year-end)



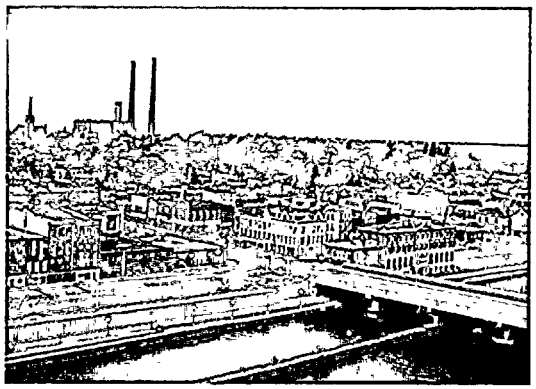
Committed to the Environment

The company continues to build its standing as an environmental leader. In November, Niagara Mohawk and Arizona Public Service signed a precedent-setting agreement to reduce carbon dioxide and sulfur dioxide emissions.

Niagara Mohawk will exchange carbon dioxide reductions achieved through its Greenhouse Warming Action Plan for sulfur dioxide allowances earned by APS under the federal Clean Air Act's acid rain regulations. Niagara Mohawk will permanently remove the sulfur dioxide allowances from the marketplace by donating them to an environmental group. The agreement will reduce national sulfur dioxide emissions, the principal cause of acid rain, by 25,000 tons. Pending IRS approval, Niagara Mohawk will use about $1 million in expected tax benefits from the agreement to fund additional projects that benefit our customers and the environment.

The company also completed plans for the protection of environmentally sensitive lands on three major river corridors. Niagara Mohawk conveyed 1,768 acres along the Salmon River to the state as part of a comprehensive plan for the use and care of the corridor, and sold a 4,000-acre gorge along the Hudson River to the Nature Conservancy, which will open the area to the public. The company also plans improvements on the Beaver River as part of a hydro relicensing agreement with the state.

The land-use projects earned the company several environmental awards, including the American Greenways DuPont Award, presented by the Conservation Fund, DuPont and the National Geographic Society. Chairman William E. Davis also was selected to serve on the Energy and Transportation Task Force of the President's Council on Sustainable Development.



Building Our Business

Cost cutting and improved performance are just two aspects of Niagara Mohawk's strategy to enhance its financial standing. To attract new business and to help existing business customers grow, we have enhanced our marketing and pricing programs.

The company's newest service classification rates, SC-10 and SC-11, provide discounted flexible pricing options for customers who have alternatives to Niagara Mohawk's electric service. These alternatives include self-generation, moving, or transferring work to facilities outside of our franchise area.

For the year, a total of 17 commercial and industrial customers took advantage of SC-10, resulting in discounts of approximately $12 million. Our SC-11 rate, available since August, has already attracted interest from more than 50 customers.

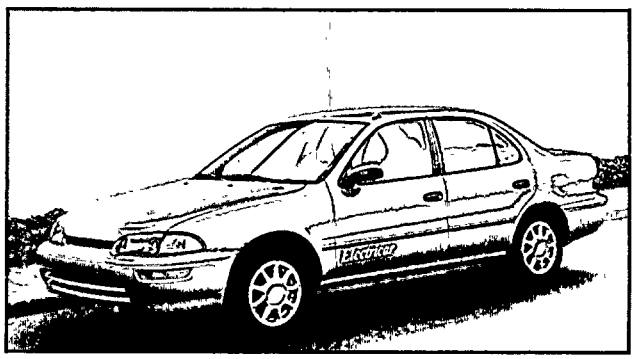
To attract new business and to help existing business customers grow, we have enhanced our marketing and pricing programs.

Giving Customers the Flexibility to Compete

Our Economic Development department also has been heavily involved in helping customers compete through discounted rate offerings. The most widely used during 1994 was the Economic Revitalization Incentive Rider, available for business customers experiencing financial distress. In 1994, 25 customers took advantage of ERIR discounts, helping to preserve $13.2 million in net electricity sales and 7,500 jobs. Another 375 customers participated in two other economic development programs that offer discounts for customers who increase electricity usage, resulting in discounts of approximately $8.5 million during 1994.

Niagara Mohawk's Economic Development department also played a vital role in attracting new business and industry. Among the success stories:

- Wal-Mart Distribution centers in Marcy and Sharon Springs will create more than 1,200 new jobs.
- The United States Post Office selected Syracuse and Latham as locations for two major new facilities; 1,250 jobs will result.
- Deluxe Corp. will bring 250 jobs to downtown Syracuse when the banking supply company opens a 30,000-square-foot processing center in 1995.
- Transcedar Industries selected Wheatfield in western New York as the location for a 20,000-square-foot warehouse that will eventually employ 40 people.
- U.S. Electricar chose central New York as the site of a new facility for the production, maintenance, and marketing of electric vehicles, bringing at least 100 jobs to the area. Niagara Mohawk will work with U.S. Electricar to market electric vehicles in New York state.



California-based U.S. Electricar made major economic news when it selected upstate New York as the site of a new production facility. Pictured is the mid-size Electricar Sedan.

All told, Niagara Mohawk's Economic Development department, working with other agencies, chambers of commerce, and local governments, helped bring at least 3,300 new jobs to upstate New York. Niagara Mohawk also assisted in the expansion of existing companies that resulted in over 2,200 additional jobs.

Financial Results

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Market Price of Common Stock and Related Stockholder Matters

The Company's common stock and certain of its preferred series are listed on the New York Stock Exchange. The common stock is also traded on the Boston, Cincinnati, Midwest, Pacific and Philadelphia stock exchanges. Common stock options are traded on the American Stock Exchange. The ticker symbol is "NMK".

Preferred dividends were paid on March 31, June 30, September 30 and December 31. Common stock dividends were paid on February 28, May 31, August 31 and November 30. The Company presently estimates that none of the 1994 common or preferred stock dividends will constitute a return of capital and therefore all of such dividends are subject to Federal tax as ordinary income.

The table below shows quoted market prices and dividends per share for the Company's common stock:

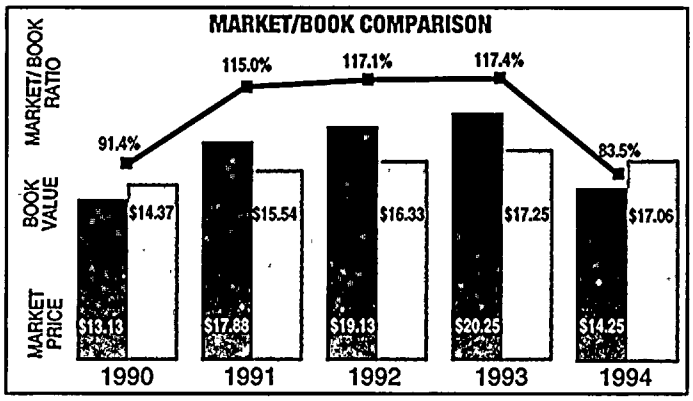
1994	Dividends Paid Per Share	Price Range High	Low
1st Quarter	$.25	$20¾	$17¾
2nd Quarter	.28	19	14⅝
3rd Quarter	.28	17½	12
4th Quarter	.28	14¾	12⅞
1993			
1st Quarter	$.20	$22⅞	$18⅞
2nd Quarter	.25	24¼	21⅝
3rd Quarter	.25	25¼	23¾
4th Quarter	.25	23⅞	19¼

Other Stockholder Matters: The holders of Common Stock are entitled to one vote per share and may not cumulate their votes for the election of Directors. Whenever dividends on Preferred Stock are in default in an amount equivalent to four full quarterly dividends and thereafter until all dividends thereon are paid or declared and set aside for payment, the holders of such stock can elect a majority of the Board of Directors. Whenever dividends on any Preference Stock are in default in an amount equivalent to six full quarterly dividends and thereafter until all dividends thereon are paid or declared and set aside for payment, the holders of such stock can elect two members to the Board of Directors. No dividends on Preferred Stock are now in arrears and no Preference Stock is now outstanding. Upon any dissolution, liquidation or winding up of the Company's business, the holders of Common Stock are entitled to receive a pro rata share of all of the Company's assets remaining and available for distribution after the full amounts to which holders of Preferred and Preference Stock are entitled have been satisfied.

The indenture securing the Company's mortgage debt provides that retained earnings shall be reserved and held unavailable for the payment of dividends on Common Stock to the extent that expenditures for maintenance and repairs plus provisions for depreciation do not exceed 2.25% of depreciable property as defined therein. Such provisions have never resulted in a restriction of the Company's retained earnings.

At year end, about 92,000 stockholders owned common shares of the Company and about 6,000 held preferred stock. The chart below summarizes common stockholder ownership by size of holding:

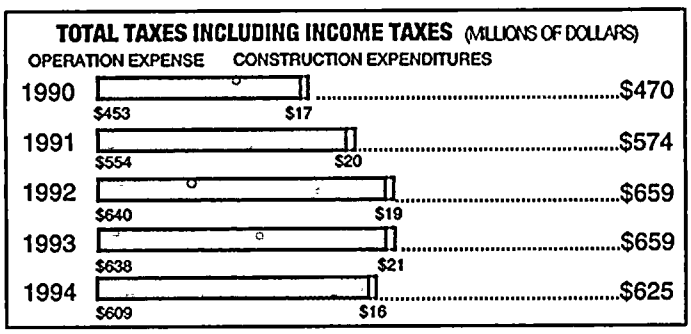
Size of Holding (Shares)	Total Stockholders	Total Shares Held
1 to 99	35,919	1,045,670
100 to 999	50,539	12,596,578
1,000 or more	5,247	130,669,218
	91,705	144,311,466

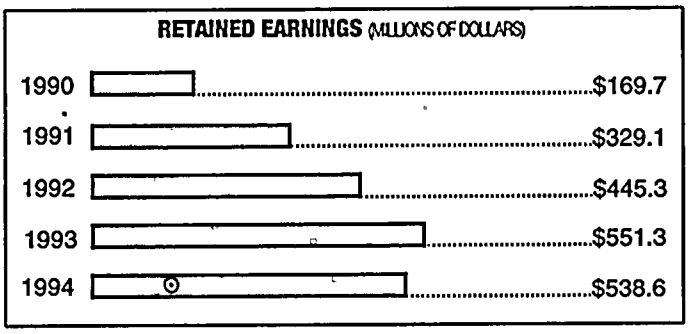


Selected Financial Data

As discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations and Notes to Consolidated Financial Statements, certain of the following selected financial data may not be indicative of the Company's future financial condition or results of operations.

	1994	1993	1992	1991	1990
Operations: (000's)					
Operating revenues	$ 4,152,178	$3,933,431	$3,701,527	$3,382,518	$3,154,719
Net income	176,984	271,831	256,432	243,369	82,878
Common stock data:					
Book value per share at year end	$17.06	$17.25	$16.33	$15.54	$14.37
Market price at year end	14 1/4	20 1/4	19 1/8	17 7/8	13 1/8
Ratio of market price to book value at year end	83.5%	117.4%	117.1%	115.0%	91.4%
Dividend yield at year end	7.9%	4.9%	4.2%	3.6%	0.0%
Earnings per average common share	$ 1.00	$ 1.71	$ 1.61	$ 1.49	$ .30
Rate of return on common equity	5.8%	10.2%	10.1%	10.0%	2.1%
Dividends paid per common share	$ 1.09	$ .95	$ .76	$ .32	$ .00
Dividend payout ratio	109.0%	55.6%	47.2%	21.5%	0.0%
Capitalization: (000's)					
Common equity	$ 2,462,398	$2,456,465	$2,240,441	$2,115,542	$1,955,118
Non-redeemable preferred stock	290,000	290,000	290,000	290,000	290,000
Redeemable preferred stock	256,000	123,200	170,400	212,600	241,550
Long-term debt	3,297,874	3,258,612	3,491,059	3,325,028	3,313,286
Total	6,306,272	6,128,277	6,191,900	5,943,170	5,799,954
First mortgage bonds maturing within one year	—	190,000	—	100,000	40,000
Total	$ 6,306,272	$6,318,277	$6,191,900	$6,043,170	$5,839,954
Capitalization ratios: *(including first mortgage bonds maturing within one year)*					
Common stock equity	39.0%	38.9%	36.2%	35.0%	33.5%
Preferred stock	8.7	6.5	7.4	8.3	9.1
Long-term debt	52.3	54.6	56.4	56.7	57.4
Financial ratios:					
Ratio of earnings to fixed charges	1.91	2.31	2.24	2.09	1.41
Ratio of earnings to fixed charges without AFC	1.89	2.26	2.17	2.03	1.35
Ratio of AFC to balance available for common stock	6.3%	6.7%	9.7%	9.3%	52.8%
Ratio of earnings to fixed charges and preferred stock dividends	1.63	2.00	1.90	1.77	1.17
Other ratios – % of operating revenues:					
Fuel, purchased power and purchased gas	39.6%	36.1%	34.1%	32.1%	36.9%
Other operation expenses	18.2	20.9	19.7	20.0	19.9
Maintenance, depreciation and amortization	12.3	13.0	13.5	14.4	14.4
Total taxes	14.7	16.2	17.3	16.4	14.4
Operating income	10.4	13.3	14.2	15.5	14.3
Balance available for common stock	3.5	6.1	5.9	6.0	1.3
Miscellaneous: (000's)					
Gross additions to utility plant	$ 490,124	$ 519,612	$ 502,244	$ 522,474	$ 431,579
Total utility plant	10,485,339	10,108,529	9,642,262	9,180,212	8,702,741
Accumulated depreciation and amortization	3,449,696	3,231,237	2,975,977	2,741,004	2,484,124
Total assets	9,649,439	9,471,327	8,590,535	8,241,476	7,765,406





Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview of 1994 Results

Earnings declined to $143.3 million or $1.00 per share as compared to $240.0 million or $1.71 per share in 1993, reflecting management's decision to charge earnings for nearly all of the cost of the Voluntary Employee Reduction Program (VERP), described below, rather than seek rate recovery, based on the impact on future rates of deferring and recovering these costs. The VERP had been initiated to bring the Company's staffing levels and work practices more into line with peer utilities and to enable the Company to become more competitive in its cost structure. Without the VERP charge of approximately $197 million ($.89 per share), earnings would have improved, reflecting continued cost control efforts and improved gas sales. Also, because of the Company's NERAM (described below), shortfalls in all classes of sales, equivalent to $.46 per share in 1994, were deferred for future recovery in rates. The Company's 1995 and multi-year rate proceedings do not seek to extend the NERAM in view of the pricing flexibility sought, although the separation of the 1995 phase of the case may present some opportunity to extend this mechanism. The Company's earned return on equity was 5.8%, but without the VERP charge would have been 10.7%, somewhat below the PSC authorized return on equity on electric utility operations of 11.4%. Earnings for 1995 depend substantially on the outcome of the 1995 rate case discussed below and the level of rate discounts necessary to minimize loss of industrial customers. An Administrative Law Judge's Recommended Decision, discussed below, if adopted by the PSC, could result in 1995 earnings being considerably lower than 1994 earnings exclusive of VERP costs. Beyond 1995, earnings will depend on the outcome of the multi-year rate case, also discussed below, and the extent to which competition may erode the Company's revenues without relief from the burden of regulatory and legislatively mandated costs.

The Company increased the common stock dividend 12% in 1994 to an annual rate of $1.12. Exclusive of the VERP charge, the common dividend payout ratio was relatively low, 57.7%, as compared to the rest of the electric and gas industry in 1994. However, several utilities reduced common dividend levels and resulting payout ratios in 1994, stating publicly that such actions were to better position these companies for a more competitive future. In making future dividend decisions, the Company must likewise evaluate the results of the 1995 and multi-year phases of its pending rate case and the degree of competitive pressure on its prices and, therefore, on its future earnings.

The outcome of these rate proceedings will have a significant effect on the Company's liquidity and financing requirements and its ability to obtain financing on customary terms. Short-term debt exceeded $400 million at December 31, 1994. A substantial portion of this short-term debt was repaid in January 1995 with the proceeds from the sale of HYDRA-CO (discussed later). The Company must renew a significant portion of its bank credit arrangements in 1995, and while it expects to be able to secure new arrangements, the cost may be significantly higher. The Company also faces a possible downgrade in the ratings of its senior securities to below investment grade. While management believes long-term debt financing can still be secured by issuing First Mortgage Bonds, the cost of such securities will likely be higher. The Company is precluded from issuing preferred stock in 1995 due to insufficient dividend coverage, as a result of the VERP writeoff.

The Company is increasingly challenged to maintain its financial condition in the face of expanding competition and probable erosion of traditional regulation. While utilities across the nation must address these concerns to varying degrees, the Company believes that it is more vulnerable than others to competitive threats. The factors contributing to this vulnerability include a large industrial customer base, an oversupply of high cost mandated power purchases from unregulated generators, an excess supply of wholesale power at relatively low prices and a high tax burden. Recent changes in state leadership may change the energy policies of New York State. The Company will be pursuing actions to redress inequities and reform regulatory policies that have contributed to the Company's increasing prices.

The following sections present an assessment of competitive conditions and steps being taken to improve the Company's strategic and financial position.

Changing Competitive Environment

The potential intensity and accelerating pace of competition may be the most significant factor driving fundamental changes in the way utilities, including the Company, are being managed. The Company believes that the price of electricity may be the most important element of future success in the industry and has intensified its efforts to reduce various costs that significantly influence the price of electricity. The ability to control or reduce costs may be significantly limited in a number of ways, particularly in the areas of state mandated unregulated generator contracts and excessive taxes such as the gross receipts tax and property taxes. These costs are among the most prominent causes of the Company's recent increases in prices, but may be the most controversial problems to solve as judicial, regulatory and/or legislative action will almost certainly be needed to achieve desired results. The dismissal of the Inter-Power lawsuit and certain developments in the Sithe/Alcan proceeding described below demonstrate some progress, but much more needs to be accomplished. The failure to secure favorable

judicial, regulatory and/or legislative actions in the near future could have, depending on the pace of competition, severe financial consequences to the Company and would require dramatic steps to protect stockholder interests.

The Company has made significant progress in managing the costs under its direct control. As described below, the Company, as part of its downsizing efforts, completed the VERP program, in which approximately 1,400 active employees elected to participate. Since December 1992, the employee level will have been reduced by over 3,100, or 27%. Capital spending has also been reduced sharply in recent years, with electric construction spending in future years expected to be limited to the level of depreciation expense, thereby resulting in little growth in traditional rate base. The Company remains focused on materially reducing its total costs.

The increasing movement towards a competitive environment has required regulators on both the state and federal levels to begin to address the many substantial issues confronting electric utilities. During 1994, the Federal Energy Regulatory Commission (FERC) and the New York State Public Service Commission (PSC) each provided or proposed guidelines to address different aspects of competition. The FERC issued guidelines for pricing electric transmission service and proposed guidelines for the recovery of stranded (unrecoverable due to a change in the regulatory environment) costs. Meanwhile, the PSC, in Phase I of its generic competitive proceeding, adopted guidelines to govern flexible rates which could be offered by utilities to retain qualified customers. Phase II of this proceeding will examine issues relating to the establishment of a wholesale and retail competitive markets (see "Defining Competitive Challenges" below).

Defining Competitive Challenges

Company Competitiveness Study. Under the terms of its 1994 Rate Agreement with the PSC, the Company filed a "competitiveness" study on April 7, 1994, entitled "The Impacts of Emerging Competition in the Electric Utility Industry." The assessment of competition contained in the report describes the initial results of the Company's CIRCA 2000 (Comprehensive Industry Restructuring and Competitive Assessment for the 2000s) studies. Although there is considerable debate about what changes should occur in the electric industry and even more uncertainty about what will actually happen, the study explores the Company's best estimate of how impacts would vary depending on the extent of changes in the industry and the pace at which those changes are allowed to unfold.

The Company generates electricity from diverse sources to reduce sensitivity to changes in the economics of any single fuel source. However, the average cost of these diverse fuel sources may be greater than any single fuel source. While the Company's average generation costs are competitive with costs of new suppliers of electricity, the current excess supply of capacity in the Northeast and Canada has significantly depressed wholesale prices, which may be indicative of retail prices in the near term if retail customers are allowed direct access to the wholesale generation market. Under these circumstances, by-pass (i.e., sale directly to existing customers by others) of the Company's generation system is a growing threat, although no regulatory structure for by-pass currently exists in New York State. A growing number of municipalities within the Company's service territory are investigating the possibility of achieving by-pass through formation of their own utility operations. As wholesale entities these new utilities would have open access to transmission and thus would be able to acquire alternative sources of supply. While the municipalities exploring this possibility are mostly in the earliest stages of inquiry and currently represent an extremely small percentage of Company sales, municipalization has the potential to adversely affect the Company's customer base and profitability.

From a broader industry perspective, the Company's assessment concludes that selective discounting to avoid uneconomic by-pass is likely to be effective in the current regulatory and competitive regime. Full retail competition, if not managed appropriately and consistently, could create significantly higher prices for core customers, jeopardize the financial viability of the Company and devastate the social programs delivered by the Company. While aggressive cost management must be part of any response to competition, it alone cannot address the financial consequences that may arise from any sudden and dramatic policy change. As mentioned above, a significant portion of the Company's costs are outside its direct control. The Company believes that regulators, legislators, and utilities must collaborate to deal with overpaid unregulated generation and other issues to create a fair and equitable transition to increased competition that addresses the obligation to serve, including addressing regulatory obligations for social programs, (i.e., low-income programs), and provide for proper recovery of shareholder's investment.

Certain adversaries of the Company in New York State and certain governmental officials have stated that the best way for the Company to address competitive issues would be to take substantial, but unspecified in amount, writedowns of its assets, particularly its nuclear and fossil generating plants. The Company's position is that any proper solution to the problems posed by increasing competition and deregulation must be substantially more evenhanded, and will necessarily be more complicated, than any such proposal. The Company will vigorously contest inequitable solutions to competitive conditions.

FERC NOPR on Stranded Investment. The FERC issued a Notice of Proposed Rulemaking (NOPR) on June 29, 1994 proposing rules governing the ability of utilities to recover wholesale and retail stranded investments (or costs). The NOPR defines wholesale stranded costs as "any legitimate, prudent and verifiable costs incurred by a public utility or a transmitting utility to provide service to a wholesale customer that subsequently becomes, in whole or in part, an unbundled transmission service customer of that public utility or transmitting utility." The same definition applies to "retail stranded investment" for "retail franchise customers."

For existing contracts, the NOPR proposes that a three-year period be set during which the contracts can be negotiated to permit recovery of stranded costs. FERC would bar recovery where contracts already have exit fees or address stranded costs in some other way. If the parties fail to reach agreement, the utility may unilaterally file a stranded cost provision.

The FERC believes it to be generally inappropriate to permit recovery of stranded costs via transmission rates and instead prefers renegotiation of bulk (generally wholesale) power contracts. Further, FERC has indicated a strong preference for the costs of the transition to competition at the retail level to be addressed by the states. The NOPR seeks comments as to whether the FERC should allow recovery of retail stranded costs in transmission rates under certain circumstances. The Company has responded, with other New York State utilities, that it is generally supportive of the FERC's findings, but believes that the FERC must play a more active role in addressing retail stranded cost recovery, particularly in the context of increased municipalization activity discussed above.

PSC Competitive Opportunities Proceeding – Electric. In June 1994, the PSC instituted Phase II of its competitiveness opportunities proceeding, the overall objective of which is "to identify regulatory and ratemaking practices that will assist in the transition to a more competitive electric industry designed to increase efficiency in the provision of electricity while maintaining safety, environmental affordability, and service quality goals." In an order issued December 22, 1994, the PSC released for comment a series of principles to guide the transition to competition. The principles emphasize the importance of the economic and environmental well-being of New York State, which "cannot be compromised to accommodate other principles." Other proposed principles recognize that competition, at least at the wholesale level, will further the economic and environmental well-being of New York State, that "bill shock" for any class of customers should be minimized, that the integrity, safety and reliability of the bulk (transmission and distribution) electric system should not be jeopardized, that the current industry structure of a vertically integrated utility (ownership of generation, transmission and distribution activities) is incompatible with effective wholesale or retail competition and that utilities should have a reasonable opportunity to recover "prudent and verifiable expenditures and commitments made pursuant to their legal obligations, as long as the utilities are cooperating in furthering all of the principles." According to the order, similar cooperation by independent power producers (IPP) should result in "respect for the reasonable expectations of IPP investors." The PSC has said it believes the transition to competition should balance order, deliberation and speed. Although the focus of the original order was on the wholesale market, the PSC concluded that the proceeding should examine issues related to retail competition as well. The PSC notes, in its order, that it can only implement these principles within the context of its own authority and that coordination across government is necessary to avoid major dislocation among suppliers of electricity. The Company cannot predict the timing of results of the proceeding.

FERC Order 636 and PSC Competitive Opportunities Proceeding – Gas. Portions of the natural gas industry have undergone significant structural changes. A major milestone in this process occurred in November 1993 with the implementation of FERC Order 636. FERC Order 636 requires interstate pipelines to unbundle pipeline sales services from pipeline transportation service. These changes enable the Company to arrange for its gas supply directly with producers, gas marketers or pipelines, at its discretion, as well as to arrange for transportation and gas storage services. The flexibility provided to the Company by these changes should enable it to protect its existing market and still expand its core and non-core market offerings. With these expanded opportunities come increased competition from gas marketers and other utilities.

Similar rate initiatives on competitively priced natural gas were addressed in a generic investigation completed by the PSC in December 1994. The PSC order in the proceeding significantly expands customer access to competitive gas suppliers using a framework designed to "assure that (1) local distribution companies (LDCs) and new entrants can compete; (2) customers benefit from increased choices and improved performance resulting from a more competitive industry; and (3) core customers continue to receive quality services at affordable rates." The Company intends to respond by proposing a comprehensive restructuring of rates and services designed to take advantage of the opportunities presented by this new "open" environment.

State Energy Planning Board Initiatives. In October 1994, the State Energy Planning Board issued an updated New York State Energy Plan, which called for significant reductions in state energy taxes, called upon the New York Power Authority (NYPA) and the state's investor-owned utilities to study the feasibility of creating a joint entity to operate and maintain the nuclear generating stations in the state and endorsed greater competition in utility purchases of electricity. The report also called for the development of a fully competitive wholesale generation market in the state within five years and observed that if utility generation is separated from transmission, the PSC "should consider carefully the valuation and allocation of utility assets in the regulated and competitive sectors." It recommended that retail competition should occur when fair treatment of all customer classes, competitors, energy efficiency and renewables and capital committed in prudent response to past government mandates is reasonably assured. The Company is unable to predict whether or how this plan will influence regulatory policy.

NYPA Restructuring Study. Also during 1994, the NYPA issued a report to its trustees concerning a proposed restructuring effort for the 21st century. This report stated that a major step toward a competitive electric industry would be to separate transmission from generation. It also stated that another significant advance toward cutting the price of electricity would be the creation of a single

operating company for all six of New York State's nuclear power plants. In addition, the report recommends creation of a "New York State Electrical Thruway" that would combine all of the State's transmission lines into one independent entity.

The effect on the Company's financial position or results of operations based on any or all of the above events cannot be determined at this time.

In summary, the electric and gas utility industry is undergoing large changes and faces an uncertain future. To succeed, utilities must be prepared to respond quickly to change. The Company must be successful in, among other things, helping to bring about favorable regulatory reform to deal with such change, managing the economic operation of its nuclear units and addressing growing electric competition, expanded gas supply competition, and various cost impacts, especially excess high-cost unregulated generator power contracts and taxes. While the Company will seek full recovery of its investment through the rate setting process with respect to the issues described herein, a review of political and regulatory actions during the past 15 years with respect to industry issues and the experiences of virtually every other industry that has gone through deregulation, indicate that utility shareholders may ultimately bear a significant portion of the burden of solving these problems.

Company Efforts to Address Competitive Challenges

In response to these issues being faced by the Company, the Company has considered, and is continuing to consider, various strategies designed to enhance its competitive position and to increase its ability to adapt to and anticipate changes in its utility business. These strategies may include business combinations with other companies, acquisitions of related or unrelated businesses, and additions to or disposition of portions of its franchised service territories. Additionally, a number of electric utilities have recently announced consideration of plans to organize their operations so that generation and power supply activities are conducted by an entity within the corporate group separate from the entity which provides transmission and distribution services to the utility's customers. The Company is also studying such a division of its operations, in part because of suggestions by New York governmental officials that power supply should be separated from transmission and distribution functions and in part as a means of dealing with issues related to unregulated generator contracts.

Voluntary Employee Reduction Program (VERP). In July 1994, the Company announced a voluntary early retirement program and a voluntary separation program (together the VERP) to achieve substantial reductions in its staffing levels in an effort to bring the Company's staffing levels and work practices more into line with other peer group utilities and become more competitive in its cost structure. Later, union employees approved amendments to the current labor agreement which offered union employees the VERP, in exchange for a negotiated package of work rule changes.

Approximately 1,400 active employees elected to participate in the VERP and most terminated their employment as of October 31, 1994. The number of employees electing the VERP did not meet management's expectations, and some layoffs have and will continue to occur in an effort to reach a level of approximately 8,750 regular employees during 1995. At December 31, 1994, the Company had approximately 9,200 employees. The accrued cost of the VERP is estimated at approximately $212 million. The Company decided to reduce 1994 earnings by the cost of the VERP that is allocable to electric customers, net of allocation to cotenant and other ventures, or approximately $197 million ($.89 per share). The Company deferred, for proposed recovery over a five year period beginning in 1995, the $11 million of VERP costs allocable to gas customers. In reaching these decisions, the Company considered, among other things, the impact on future rates of deferring and recovering these costs.

Most of the VERP cash cost will be provided by pension fund assets over time, thereby limiting the immediate cash impact to the Company. The 1995 cash impact will be approximately $20 million, primarily in the first quarter.

In a filing with the PSC on December 23, 1994, the Company updated its rate request for 1995 to reflect the labor and labor-related savings in operating costs as a result of the VERP. The savings are expected to amount to nearly $100 million annually, of which $60 million in 1995 is the labor and related savings allocable to electric and gas expense (the remaining savings, generally allocable to construction, should enable the Company to achieve its construction spending plans for 1995, which have been reduced from prior forecasts).

Unregulated Generator Initiatives are discussed in a separate section below.

Tax Initiatives. The Company has launched a media initiative to inform customers of how much (approximately 16%) of their utility bill directly pays various forms of taxes. The Company is also working with utility and state representatives to explain the negative impact that all taxes, including the gross receipts tax, are having on rates and the state of the economy. At the same time, the Company is contesting with many taxing authorities the high real estate taxes it is assessed, particularly compared to the taxes assessed unregulated generators.

Customer Discounts. The Company is experiencing a loss of industrial load across its system for a variety of reasons. In some cases, customers have found alternative suppliers or are generating their own power. In other cases a weakened economy has forced customers to relocate or shut down.

As a first step in addressing the threat of further loss of industrial load, the PSC approved a rate (referred to as SC-10) under which the Company was allowed to negotiate

individual contracts with some of its largest industrial and commercial customers to provide them with electricity at lower prices. Under this rate, customers had to demonstrate that they could generate power more economically than the Company's service. While the SC-10 tariff has now been superseded by the SC-11 tariff described below, seventeen contracts are still in effect and expire by early 1997. The total SC-10 discounts amounted to $12.4 million in 1994.

In June 1994, the PSC announced the adoption of guidelines to govern flexible electric rates offered by utilities to retain qualified industrial customers in the face of growing competition from unregulated generators, and requiring the Company (and other New York utilities with flexible tariffs) to file amendments to SC-10. On August 10, 1994, the Company filed for a new service tariff, SC-11, for "Individually Negotiated Contract Rates." All new contract rates will be administered under the new SC-11 service classification based on demonstrated industrial and commercial competitive pricing situations including, but not limited to, on-site generation, fuel switching, facility relocation and partial plant production shifting. Contracts will be for a term not to exceed seven years without PSC approval.

The Company expects a significant number of industrial customers to negotiate contracts. Many of these contracts may result in increased load which may be revenue enhancing. As of December 31, 1994, approximately 20 customers, representing approximately 80 MW of load, had made requests to the Company for an SC-11 contract. The Company also offers economic development rates, which can result in discounts for existing, as well as new, load. In total, the Company granted $39 million in discounts against 1994 revenues, of which it absorbed 20% pursuant to the 1994 Settlement. Under its 1995 and multi-year rate proposal, the Company anticipates offering approximately $30 million of discounts in excess of the approximately $42 million expected to be reflected in rates in 1995, although no assurance can be given as to the actual amount of discounts. The amount of discounts given will also depend on the level of rates authorized in the 1995 rate proceeding and the allocation between customer classes. The level of discounts beyond 1995 and the attendant financial consequences will depend on a variety of factors.

The increase in the Company's rates over the past four years, due in large part to required purchases from unregulated generators, has made cogeneration and self-generation by many industrial and large commercial customers more economically feasible. The Company believes its SC-11 tariff pricing flexibility will help prevent erosion of its customer base. Price pressure, however, may limit the recovery of such costs from the remainder of its customer base.

Sithe/Alcan. In April 1994, the PSC ruled that, in the event Sithe Independence Power Partners Inc. (Sithe) ultimately obtained authority to sell electric power at retail, those retail sales would be subject to a lower level of regulation than the PSC presently imposes on the Company. Sithe, which sells electricity to Consolidated Edison Company of New York, Inc. and the Company on a wholesale basis from its 1,040 megawatt natural gas cogeneration plant, also provides steam to Alcan Rolled Products (Alcan). As authorized by the PSC in September 1994, Sithe also sells a portion of its electricity output on a retail basis to Alcan, previously a customer of the Company, and is authorized to sell to Liberty Paperboard (Liberty), a potential new industrial customer. The PSC ordered that Sithe pay the Company a fee over a period of ten years, based upon the prices at which Sithe would sell to Alcan, structured to produce a net present value of approximately $19.6 million. For 1995, the fee would be approximately $3.05 million. The Company had argued for compensation, which assures discounted rates to Alcan, with a net present value of $39 million. The PSC did not authorize a fee in connection with Sithe's sale to Liberty.

On October 12, 1994, the Company filed an appeal in State Supreme Court, Albany County, which states that the April 1994 PSC Order is a violation of legal procedure and precedent and should be reversed. The Company cannot predict the outcome of this proceeding, but will continue to press its position vigorously. Notwithstanding the Company's strong opposition to Sithe's ability to sell to a retail customer, and the level of compensation involved, the decision to require compensation to utilities for costs that would otherwise be stranded has established a precedent in by-pass situations for some level of recovery of the Company's investment.

Asset Management Studies – Fossil. The Company continually examines its competitive situation and future strategic direction. Among other things, it has, and continues to, study the economics of continued operation of its fossil-fueled generating plants, given current forecasts of excess capacity. Growth in unregulated generator supply sources, compliance requirements of the Clean Air Act and low wholesale market prices are key considerations in evaluating the Company's internal generation needs. While the Company's coal-burning plants continue to be cost advantageous, certain older units and certain gas/oil-burning units are continually assessed to evaluate their economic value and estimated remaining useful lives. Due to projected excess capacity, the Company plans to retire or put certain units in long-term cold standby. A total of 340 MW's of aging coal fired capacity is to be retired by the end of 1999 and 850 MW's of oil fired capacity was placed in long-term cold standby in 1994. The Company is also continuing to evaluate under what circumstances the standby plant would be returned to service, but barring unforeseen circumstances it is not likely that a return would occur before the end of 1999. This action will permit the reduction of operating costs and capital expenditures for retired and standby plants. The remaining investment in these plants of approximately $250 million at December 31, 1994 (of which approximately $180 million relates to the facility in cold standby) is currently being recovered in rates through depreciation. See Note 1 of Notes to Consolidated Financial Statements – "Exposure Draft on Impairment of Assets."

Asset Management Studies – Nine Mile Point Nuclear Station Unit No. 1 (Unit 1). Under the terms of a previous regulatory agreement, the Company agreed to prepare and update studies of the advantages and disadvantages of continued operation of Unit 1 prior to the start of the then next two refueling outages. The first report, which recommended continued operation of Unit 1 over the then next fuel cycle, was filed with the PSC in March 1990 and a second study in November 1992 indicated that the Unit could continue to provide benefits for the term of its license if operating costs could be reduced and generating output improved above its then historical average.

Operating experience at Unit 1 has improved substantially since the 1992 study. Unit 1's capacity factor has been about 94% since its last refueling outage.

The third study was filed with the PSC on November 1, 1994. This study agreed with the November 1992 study, confirming continued operation over the remaining term of its license. No further economic studies are currently required for this Unit, although the Company continues as a matter of course to examine the economic and strategic issues related to operation of all its generating units.

In connection with these asset management studies, the Company also updated its estimated costs to decommission Unit 1. The estimate includes amounts for both radioactive and non-radioactive dismantlement costs, as well as spent fuel storage cost estimates until the fuel can be transferred to a permanent federal repository. The current estimate of radioactive ($344 million) and non-radioactive ($51 million) dismantlement in 1994 dollars is approximately $395 million. Fuel storage and plant maintenance estimates will increase the total estimated costs to approximately $527 million (in 1994 dollars), and this amount escalates to $1.4 billion by the time decommissioning is completed. While these estimates have increased from previous estimates, the delayed dismantlement approach is believed to be the most economic. The new estimates along with increased estimates for the decommissioning of Nine Mile Point Nuclear Station Unit No. 2 (Unit 2), will be required to be reflected in rates in the future. See also Notes 1 and 3 of Notes to the Consolidated Financial Statements.

Regulatory Agreements/Proposals

1995 Five-Year Rate Plan. In February 1994, the Company made an electric and gas rate filing, for rates to be effective January 4, 1995, seeking a $133.7 million (4.3%) increase in electric revenues and a $24.8 million (4.1%) increase in gas revenues. The electric filing included a proposal to institute a methodology to establish rates beginning in 1996 and running through 1999. The proposal would provide for rate indexing to an applicable quarterly forecast of the consumer price index as adjusted for a productivity factor. The methodology sets a price cap, but the Company could elect not to raise its rates up to the cap. Such a decision would be based on the Company's assessment of the market. NERAM (see "Prior Regulatory Agreements" below) and certain other expense deferrals would be eliminated, while the fuel adjustment clause would be modified to cap the Company's exposure to fuel and purchased power cost variances from forecast at $20 million annually. However, certain items which are not within the Company's control would be included in billing adjustment factors outside of the indexing; such items would include legislative, accounting, regulatory and tax law changes as well as environmental and nuclear decommissioning costs. These items and the existing balances of certain other deferral items, such as MERIT (see "Prior Regulatory Agreements" below), NERAM and demand-side management (DSM), would be recovered or returned using a temporary rate surcharge. The proposal would also establish a minimum return on equity which, if not achieved, would permit the Company to refile and reset base rates subject to indexing or to seek some other form of rate relief. Conversely, in the event earnings exceeded an established maximum allowed return on equity, such excess earnings would be used to accelerate recovery of regulatory or other assets. The proposal would provide the Company with greater flexibility to adjust prices within customer classes to meet competitive pressures from alternative electric suppliers, but would also substantially increase the risk that the Company will not earn its allowed rate of return and that earnings would be much more volatile than in the past. The Company believes that its proposed rate plan meets the criteria for continued application of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). Gas rate adjustments beyond 1995 would follow traditional regulatory methodology.

In 1994, the Company agreed to extend the date by which the PSC must rule on the Company's rate request by twelve weeks, to March 29, 1995. The Company will absorb one-half of the costs (the lost margin) arising because of the extension from January 4, 1995. The remainder of the costs will be recovered through a noncash credit to income, and is dependent upon the amount of rate relief ultimately granted by the PSC for 1995. Based on its recent updated filing described below, the Company would absorb approximately $41 million.

On August 31, 1994, the PSC Staff, in response to the Company's proposal, proposed an overall decrease in electric revenues from 1994 levels of approximately $146 million, excluding anticipated sales growth. This contrasts with the Company's original proposed total revenue increase, excluding sales growth, of $146 million for 1995. Because the Company's proposed total revenue increase reflects an effective date of March 29, 1995, while the PSC Staff's proposal is an annualized amount, the difference between the two positions is approximately $366 million. The more significant adjustments proposed by the PSC Staff include disallowance of approximately $90 million in purchased power payments made principally to unregulated generators; additional adjustments to the 1995 unregulated generator forecast for prices, capacity levels and in-service dates of certain projects; reductions in operating and maintenance expenses stemming largely from the PSC Staff's contention that the Company's forecast was unsupported; and assumed increases in

revenues from sales to other utilities and transmission revenues. The PSC Staff also proposes to disallow certain unregulated generator buyout costs equal to approximately $12 million in 1995 and to set the electric return on equity at 10.5%, as compared to the Company's request of 11%. The PSC Staff recommends that gas revenues be reduced by $5 million in 1995, while also recommending a return on equity of 10.5% (as opposed to the Company's request of 11.59%). The reduction from the Company's gas proposal relates principally to lower departmental expenses and higher expected sales in 1995.

In response to the Company's electric indexing proposal for 1996 through 1999, the PSC Staff proposed the use of a different index based on the annual change in a national average electricity price, elimination of all of the Company-proposed adjustment factors outside of indexing, including those for fuel and purchased power costs, environmental costs, nuclear decommissioning and accounting and tax law changes, and elimination of the minimum and maximum return on equity limit. The PSC Staff went well beyond the Company's proposal by recommending a "regulatory regime that accepts market based prices for utility generation." The PSC Staff's plan would limit, in increasing amounts, the amount of embedded generation costs (including certain plant and unregulated generator costs) that could be charged to customers. The reference price each year would be based initially upon the Company's marginal cost of generation (which is significantly below its embedded cost) until a reliable market price becomes available. After a 10 year phase-down, the Company would only be able to charge a market-related price for generation. The Company would be forced to absorb the difference between its embedded costs and what it could charge customers, regardless of whether its past practices were prudent or even mandated by government action. Rates with respect to the Company's costs of transmission, distribution and customer service would continue to be based on cost of service for 1995, but would be indexed in 1996-1999 by the national average electricity index.

While the PSC Staff's case contains no financial modeling of the potential consequences of its proposal on the Company, such consequences, if the plan is adopted as proposed could be substantial. While the PSC Staff identified a number of general cost reduction measures intended to mitigate the financial consequences of its proposal, the Company believes the value of the measures is greatly overstated. The PSC Staff's plan is based on a price ceiling rather than a cost of service theory of ratemaking — a departure from the Company's case and all prior New York State ratemaking principles. It in effect also proposes a substantial but unquantified disallowance with respect to the Company's generating plants and a similar but undifferentiated disallowance with respect to the difference between estimated market costs of power and the amount the Company is required, by law and PSC mandate, to pay for unregulated generator power.

If those elements of the PSC Staff's case were to be implemented as proposed, the Company would also be required to discontinue the application of SFAS No. 71 and incur substantial additional writeoffs. Such writeoffs, which would include a substantial portion of the $1.4 billion of regulatory assets on the Company's balance sheet as well as the disallowed plant costs and purchased power costs described above, would arise because of the departure from cost-based ratemaking and because they would no longer meet the accounting criteria regarding probability of recovery. The Company believes the financial consequences to be of an order of magnitude that would adversely affect the Company's financial position and results of operations, its ability to access the capital markets on reasonable and customary terms, its dividend paying capacity, its ability to continue to make payments to unregulated generators and its ability to maintain current levels of service to its customers.

Senior members of the PSC Staff and other senior public officials in Albany have stated that the PSC trial staff's proposal was developed independent of consultation with Commissioners, that the trial staff functions independently of those individuals and that the process in this proceeding is far from complete. In the meantime, the Company is continuing to aggressively advocate its own position.

With the December 1994 filing in which the Company proposed to absorb certain VERP costs and reflect labor and related savings, the Company updated its rate request and resultant total bill impact for 1995. The Company is now requesting an increase in 1995 electric revenues of approximately $89 million (2.8%), which reflects the delay in implementing new rates, and an increase in 1995 gas revenues of $20.6 million (3.4%). This compares with the electric bill impact of approximately 4.3% and gas revenue increase of 4.1% requested in its original filing. The difference between the Company's most recent filing and the PSC Staff's proposal still exceeds $300 million on an annualized basis.

The current rate proceeding has been separated into two distinct phases. A final PSC decision on 1995 rates is not expected until the end of April 1995 and new electric rates would be implemented about that time along with any final adjustments to gas rates. A schedule for the multi-year phase of the proceeding has not been established, but is expected to extend at least into the summer of 1995.

On January 27, 1995, the Administrative Law Judges (ALJ) issued a Recommended Decision with respect to the 1995 phase of the rate proceeding. The Recommended Decision would allow the Company to increase its electric base rates $253.8 million (7.3%) for the 1995 rate year and $10.3 million (1.7%) for gas base rates. The ALJ disallowed from recovery approximately $18 million of unregulated generator costs, but rejected $68 million of disallowances associated with contracts the PSC Staff believed should have been bought out. The existing fuel adjustment clause mechanism would be retained, including full recovery of prudent unregulated generator payments, until addressed in the multi-year phase of the proceeding. A number of other adjustments to unregulated generator purchases relate to timing of in-service dates, generation levels and pricing, which the Company expects will be fully considered in the fuel adjustment clause. Finally, the ALJ stated that sufficient evidence had been produced by the

PSC Staff to warrant a prudence investigation of the Company's unregulated generator contract practices absent a multi-year rate plan.

The Recommended Decision reduced the level of departmental expenses by over $50 million based on the ALJ's assessment of lack of adequate support for the Company's rate request. The ALJ also recommended a 1% gross margin penalty to ensure that all of the benefits that might otherwise inure to the shareholders due to the ALJ's perceived lack of support are captured for ratepayers. In addition, the Recommended Decision does not reflect any of the VERP cost savings, which could be used to further reduce the annualized electric base rate increase by as much as $55 million, and the gas base rate increase by $5 million, depending on whether the Company could demonstrate that several of the ALJs' recommendations would be duplicated by the VERP cost savings. An 11% return on equity was recommended.

If the Recommended Decision were to be adopted in its entirety by the PSC, excluding the further reduction in base rate relief granted for VERP cost savings, the Company expects that 1995 electric revenues would decrease by at least 1% or approximately $28 million as compared to 1994, although on a twelve month basis, electric revenues would increase approximately $57 million or 1.9%. The impact on the Company's earnings, if the Recommended Decision were to be fully adopted by the PSC, will depend substantially on the Company's ability to further reduce costs since little growth in sales is forecast. Without further cost reductions, which must be judged relative to costs under the Company's direct control, earnings for 1995 will be considerably lower than 1994 earnings adjusted for VERP. If the unregulated generator disallowances were adopted by the PSC, the Company would be required to assess whether a loss associated with these contracts, measured by the net present value of unrecoverable costs over the remaining term of the contracts, would be recorded in 1995. Using projections of long-run avoided costs, the recordable loss could exceed $100 million.

While the adoption of the PSC Staff's proposals or the Recommended Decision by the PSC would have a material adverse impact on the Company's 1995 results of operations, the Company is unable to predict the outcome of these proceedings, or the possible attendant financial consequences. However, the Company strongly believes that its unregulated generator administrative practices were prudent and should not be disallowed, that the Company's unregulated generator purchases are in large part the result of government policy and should be recovered at no penalty to the shareholders and that any transition plan to a more competitive environment must provide for an equitable allocation of transition costs across customer classes. In addition, the Company believes that any transition to a more competitive rate structure should be addressed in a generic proceeding rather than the Company's current multi-year rate filing. The ultimate impact on the Company's financial condition will depend on the pace of change in the marketplace, the actions of regulators and government in response to that change and the actions of the Company in controlling costs and competing effectively while remaining, in substantial part, a regulated enterprise. The Company is unable to predict the effects of the interaction of these factors.

Prior Regulatory Agreements. The Company's results during the past several years have been strongly influenced by several agreements with the PSC. A brief discussion of the key terms of certain of these agreements is provided below.

The 1991 Financial Recovery Agreement implemented the Niagara Mohawk Electric Revenue Adjustment Mechanism (NERAM) and the Measured Equity Return Incentive Term (MERIT).

The NERAM requires the Company to reconcile actual results to forecast electric public sales gross margin used in establishing rates. The NERAM produces certainty in the amount of electric gross margin the Company will receive in a given period to fund its operations. While reducing risk during periods of economic uncertainty and mitigating the variable effects of weather, the NERAM does not allow the Company to benefit from unforeseen growth in sales. The Company's 1995 and multi-year rate proceedings do not seek to extend the NERAM in view of the pricing flexibility sought, although, the separation of the 1995 phase of the case may present some opportunity to extend this mechanism. The lack of a NERAM will inevitably increase earnings volatility due to variations in weather and economic conditions. In 1994, the Company deferred for recovery $101.2 million of revenue under the NERAM mechanism for collection in 1995 and 1996.

The MERIT program is the incentive mechanism which originally allowed the Company to earn up to $180 million of additional return on equity through May 31, 1994. The program was later amended to extend the performance period through 1995 and add $10 million to the total available award. Overall goal targets and criteria for the 1993-1995 MERIT periods are results-oriented and are intended to measure change in key overall performance areas. The total available award for 1994 is $34 million and $41 million in 1995. Through the 1993 MERIT period, the Company has earned approximately $85.5 million of the $115 million of MERIT available and presently assesses that it earned approximately $28 million of the $34 million available for 1994.

On January 27, 1993, the PSC approved a 1993 Rate Agreement authorizing a 3.1% increase in the Company's electric and gas rates providing for additional annual revenues of $108.5 million (electric $98.4 million or 3.4%; gas $10.1 million or 1.8%). Retroactive application of the new rates to January 1, 1993 was authorized by the PSC.

The increase reflected an allowed return on equity of 11.4%, as compared to the 12.3% authorized for 1992. The agreement also included extension of the NERAM through December 1993 and provisions to defer expenses related to mitigation of unregulated generator costs, (aggregating $50.7 million at December 31, 1993) including contract buyout costs and certain other items.

The Company and the local unions of the International Brotherhood of Electrical Workers, agreed on a two-year

nine-month labor contract effective June 1, 1993. The new labor contract includes general wage increases of 4% on each June 1st through 1995 and changes to employee benefit plans including certain contributions by employees. Agreement was also reached concerning several work practices which should result in improved productivity and enhanced customer service. The PSC approved a filing resulting from the union settlement and authorized $8.1 million in additional revenues ($6.8 million electric and $1.3 million gas) for 1993.

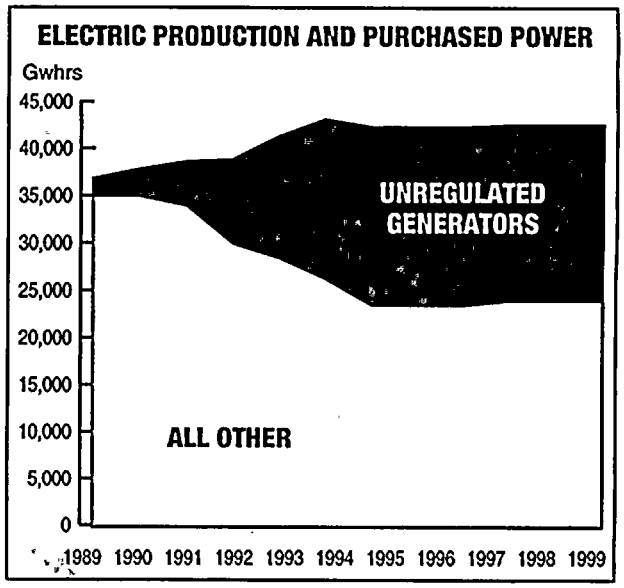
On February 2, 1994, the PSC approved an increase in gas rates of $10.4 million or 1.7%. The gas rates became effective as of January 1, 1994 and include for the first time a weather normalization clause.

The PSC also approved the Company's electric supplement agreement with the PSC Staff and other parties to extend certain cost recovery mechanisms in the 1993 Rate Agreement without increasing electric base rates for calendar year 1994. The goal of the supplement was to keep total electric bill impacts for 1994 at or below the rate of inflation. Modifications were made to the NERAM and MERIT provisions which determine how these amounts are to be distributed to various customer classes and also provided for the Company to absorb 20% of margin variances (within certain limits) originating from SC-10 rate discounts (as described above) and certain other discount programs for industrial customers as well as 20% of the gross margin variance from NERAM targets for industrial customers not subject to discounts. The supplement also allows the Company to begin recovery over three years of approximately $15 million of unregulated generator buyout costs, subject to final PSC determination with respect to the reasonableness of such costs.

Unregulated Generators

In recent years, a leading factor in the increases in customer bills and the deterioration of the Company's competitive position has been the requirement to purchase power from unregulated generators at prices in excess of the Company's internal cost of production and in volumes greater than the Company's needs.

The Company is being forced to make excess payments to unregulated generators, in comparison with its own costs of production, for energy and capacity it does not currently need. The Company estimates that it made excess payments of approximately $205 million in 1993 and approximately $364 million in 1994 and expects to make excess payments of approximately $409 million in 1995. The Company has initiated a series of actions to address

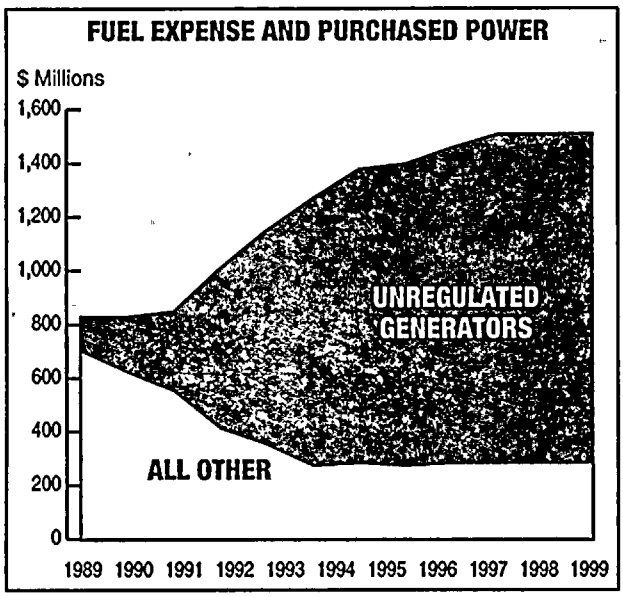


this situation, but cannot predict the outcome. Recent changes in state leadership may change the energy policies of New York State. The Company will be pursuing actions to redress inequities and reform regulatory policies that have contributed to the Company's increasing prices.

As of December 31, 1994, 148 of these unregulated generators with a combined capacity of 2,592 MW were on line and selling power to the Company. Of these, 2,273 MW are considered firm capacity (including 207 MW of unregulated generator projects on standby). The table at the bottom of the page illustrates the actual and estimated growth in capacity, payments and relative magnitude of unregulated generator purchases compared to Company requirements. By the end of 1994, the Company had virtually all unregulated generator capacity scheduled to come into service on line.

In order to deal with the growth of excess supply, the Company has taken numerous actions to attempt to realign its supply with demand. These actions include mothballing and retirement of Company owned generating facilities (see "Asset Management Studies – Fossil") and buyouts of unregulated generator projects, as well as the implementation of an aggressive wholesale marketing effort. Such actions have been successful in bringing installed capacity reserve margins down to levels in line with normal planning criteria. The Company is actively pursuing other initiatives to reduce its unregulated generator costs.

	Actual				Estimated				
	1991	1992	1993	1994	1995	1996	1997	1998	1999
Capacity MW's	1,027	1,549	2,253	2,273	2,403	2,403	2,403	2,413	2,413
Payments (millions)	$268	$543	$736	$960	$1,041	$1,091	$1,152	$1,213	$1,262
Percent of Total Fuel and Purchased Power Costs	32%	56%	67%	73%	76%	77%	77%	78%	78%



FERC Proceeding. On January 11, 1995, the FERC issued an order in a case involving Connecticut Light & Power (CL&P) that the Public Utility Regulatory Policy Act (PURPA) forbids the states from requiring utilities to pay more than avoided cost to qualifying facilities (QFs) for electric power. FERC, however, also ruled that it would not invalidate any pre-existing contracts, but only would apply its ruling prospectively or to contracts that are subject to a pending challenge (instituted at the time of signing) by a utility. On the same day, FERC issued an order that an ongoing challenge by the Company to the New York Law requiring utilities to pay QFs a minimum of six cents for electric power (the "Six Cent Law") was moot in light of amendment of that law in 1992 to prohibit future power purchase contracts requiring the utility to pay more than its avoided cost. This latter proceeding had been filed in 1987. In April 1988, FERC had ruled in the Company's favor, finding that the states could not impose rates exceeding avoided cost for purchases from QFs, but then stayed that decision in light of a rulemaking it was instituting to address the issue. That rulemaking was never completed.

On February 10, 1995, the Company filed a petition for rehearing of both orders. The Company argues, among other things, that Federal law requires that FERC apply the ruling in CL&P in all pending cases, including its case involving the Six Cent Law, and that it is entitled to the opportunity, either at FERC or in the courts, to demonstrate that pre-existing power purchase contracts resulting from the Six Cent Law should be invalidated. The Company argues further that amendment of the Six Cent Law did not render the proceeding addressing that law moot because the amendment has perpetuated and, in some instances, expanded the Company's obligation to purchase power from QFs at rates above avoided cost. The Company intends to press its rights vigorously, but cannot predict the outcome of these proceedings.

Curtailment Procedures. On August 18, 1992, the Company filed a petition with the PSC which calls for the implementation of "curtailment procedures." Under existing FERC and PSC policy, this petition would allow the Company to limit its purchases from unregulated generators when demand is low. Also, the Company has commenced settlement discussions with certain unregulated generators regarding curtailments. On April 5, 1994, after informing the PSC of its progress in settlement, the Company requested the PSC to expedite the consideration of its petition. The Company cannot predict the outcome of this action.

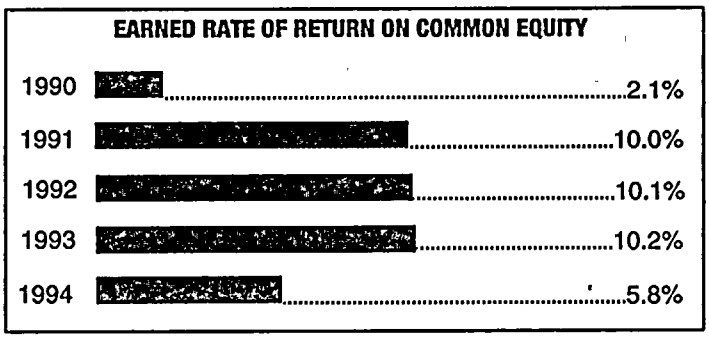
Demand for Adequate Assurance. On February 4, 1994, the Company notified the owners of nine projects with contracts that provide for front-end loaded payments of the Company's demand for adequate assurance that the owners will perform all of their future repayment obligations, including the obligation to deliver electricity in the future at prices below the Company's avoided cost and the repayment of any advance payment balance which remains outstanding at the end of the contract.

The projects at issue total 426 MW. The Company's demand is based on its assessment of the amount of advance payment to be accumulated under the terms of the contracts, future avoided costs, and future operating costs of the projects. The Company has been sued by the owners of three unregulated generator projects who challenge the Company's right to demand adequate assurance.

The Company cannot predict the outcome of these federal and state court actions or the response otherwise to its February 4, 1994 notifications, but will continue to press for adequate assurance that the owners of these projects will honor their repayment obligations.

Results of Operations

Earnings for 1994 were $143.3 million or $1.00 per share compared with $240.0 million or $1.71 per share in 1993 and $219.9 million or $1.61 per share in 1992. The decline in 1994 earnings was principally due to the charge to earnings of the cost of the VERP of $197 million ($.89 per share). NERAM equivalent to $101.2 million ($.46 per share) was recorded in 1994 and deferred for future recovery in rates as compared to NERAM of $65.7 million ($.31 per share) recorded in 1993. The primary factor contributing to the increase in earnings in 1993 as compared to 1992 was the impact of electric and gas rate increases effective January 1, 1993 and July 1, 1992.



In 1994, the Company's earned return on common equity was 5.8%, but without the VERP charge would have been 10.7%, compared to 10.2% in 1993 and 10.1% in 1992. The Company's return on common equity authorized in the rate setting process for the year ended December 31, 1994, provided an electric return on equity cap of 11.4% and a return on equity cap for gas of 10.4%. Factors contributing to the earnings being below authorized levels in 1993 included lower than anticipated results from the Company's subsidiaries, certain operating expenses which were not included in rates and exclusion of approximately $23 million from the Company's rate base (upon which the Company would otherwise earn a return) as a consequence of prior year writeoffs of disallowed Unit 2 costs.

The following discussion and analysis highlights items having a significant effect on operations during the three-year period ended December 31, 1994. It may not be indicative of future operations or earnings. It also should be read in conjunction with the Notes to Consolidated Financial Statements and other financial and statistical information appearing elsewhere in this report.

Electric revenues increased $621.7 million or 21.4% over the three-year period. This increase results primarily from rate increases, NERAM revenues, higher recoveries through the operation of the fuel adjustment clause mechanism, increased sales to other electric systems and other factors as indicated in the table below. An increase in the base cost of fuel, (which is included in base rates), would typically result in a corresponding decrease in fuel and purchased power cost revenues, thus having a revenue neutral impact. Purchased power costs, largely from unregulated generators, have increased significantly during this period, offsetting much of the decrease in Fuel Adjustment Clause (FAC) revenues which would have occurred otherwise.

	Increase (decrease) from prior year (In millions of dollars)			
Electric revenues	1994	1993	1992	Total
Increase in base rates	$ 36.0	$193.1	$250.6	$479.7
Fuel and purchased power cost revenues	108.3	(42.6)	(6.4)	59.3
Sales to ultimate consumers	(13.6)	11.0	39.7	37.1
Sales to other electric systems	62.1	11.7	(12.8)	61.0
DSM revenue	(27.7)	(30.3)	(24.3)	(82.3)
Miscellaneous operating revenues	(4.6)	23.9	(11.3)	8.0
NERAM revenues	35.5	24.0	7.8	67.3
MERIT revenues	0.5	(6.0)	(2.9)	(8.4)
	$196.5	$184.8	$240.4	$621.7

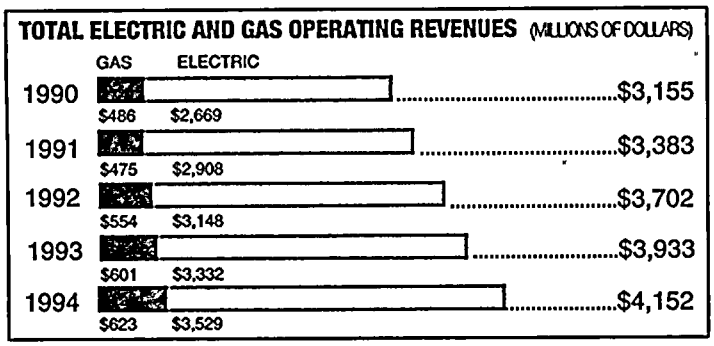
Although sales to ultimate customers increased slightly in 1994, this level of sales was substantially below the forecast used in establishing rates for the year. As a result, the Company accrued NERAM revenues of $101.2 million ($.46 per share) during 1994 as compared to $65.7 million ($.31 per share) of NERAM revenues in 1993. NERAM would no longer be available under the new rate plan as originally proposed by the Company, thus creating exposure for lost margin if sales forecasts are not met. The sales forecast underlying the Company's 1995 rate request reflects an increase in kwh sales of .5% over 1994 actual results. The Company recorded $12.3 million of the 1994 MERIT available based on management's assessment of the achievement of objectively measured criteria.

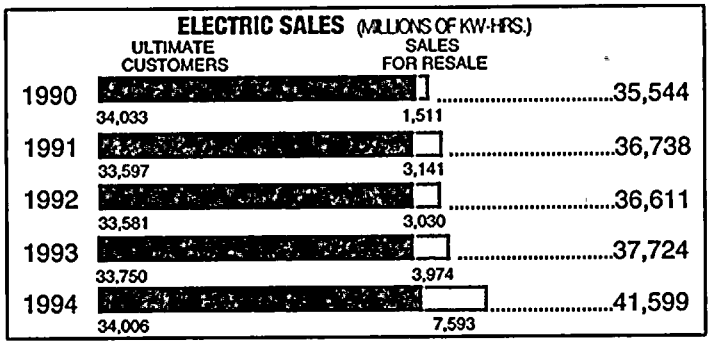
Changes in fuel and purchased power cost revenues are generally margin-neutral (subject to an incentive mechanism discussed in Note 1 of Notes to Consolidated Financial Statements), while sales to other utilities, because of regulatory sharing mechanisms and relatively low prices due to excess supply, generally result in low margin contribution to the Company. Thus, fluctuations in these revenue components do not generally have a significant impact on net operating income. The Company has proposed certain changes in the fuel adjustment clause in its 1995 and multi-year rate proposal (discussed above under "1995 Five-Year Rate Plan"). Electric revenues reflect the billing of a separate factor for DSM programs, which provide for the recovery of program related rebate costs and a Company incentive based on 10% of total net resource savings.

Electric kilowatt-hour sales were 41.6 billion in 1994, an increase of 10.3% from 1993 and an increase of 13.6% over 1992. The 1994 increase reflects increased sales to other electric systems, while sales to ultimate consumers were generally flat. The increase in wholesale sales reflects the increase in purchases from unregulated generators and the increase in nuclear production, both of which enabled the Company to make its fossil generation available for sale. The 1993 increase reflected increased sales to other electric systems, while sales to ultimate customers increased slightly (See Electric and Gas Statistics – Electric Sales). The electric margin effect of sales in 1994 was adjusted by the NERAM except for the large industrial customer class, within which the Company absorbed 20% of the variance from the NERAM sales forecast. Industrial-Special sales are New York State Power Authority allocations of low-cost power to specified customers, from which the Company earns a transportation charge.

Details of the changes in electric revenues and kilowatt-hour sales by customer group are highlighted in the table below:

Class of service	1994 % of Electric Revenues	% Increase (decrease) from prior years					
		1994		1993		1992	
		Revenues	Sales	Revenues	Sales	Revenues	Sales
Residential	34.9%	5.2%	(0.6)%	6.9%	0.8%	11.3%	0.7%
Commercial	36.1	2.5	(2.2)	7.0	3.9	11.1	(0.5)
Industrial	16.4	4.3	5.0	(6.0)	(5.2)	13.0	(1.3)
Industrial - Special	1.4	14.5	5.9	9.1	0.8	11.8	1.9
Municipal service	1.4	(1.3)	(2.3)	0.6	(3.1)	5.8	(0.4)
Total to ultimate consumers	90.2	3.9	0.8	4.3	0.5	11.4	0.0
Other electric systems	4.7	59.1	91.1	12.6	31.2	(12.1)	(3.5)
Miscellaneous	5.1	8.2	—	40.6	—	(29.0)	—
Total	100.0%	5.9%	10.3%	5.9%	3.0%	8.3%	(0.3)%





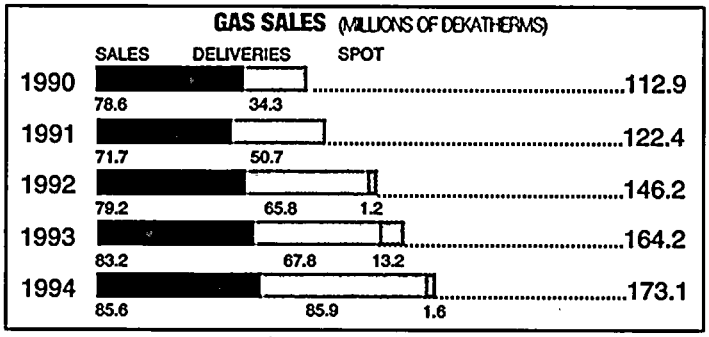
As indicated in the table below, internal generation from fossil fuel sources continued to decline in 1994, principally at the Oswego oil-fired facility and Albany gas-fired station, corresponding to the increase in required unregulated generator purchases. There were no nuclear refueling outages in 1994, while both Units were refueled in 1993. Unit 1 operated at a capacity factor of approximately 92% for 1994, while Unit 2 operated at approximately 90%. The next nuclear refueling outages at each unit are scheduled for 1995. See Note 3 of Notes to the Consolidated Financial Statements.

(In millions of dollars)	1994		1993		1992		% Change from prior year			
							1994 to 1993		1993 to 1992	
	GwHrs.	Cost	GwHrs.	Cost	GwHrs.	Cost	GwHrs.	Cost	GwHrs.	Cost
Fuel for electric generation:										
Coal	6,783	$ 107.3	7,088	$ 113.0	8,340	$128.8	(4.3)%	(5.0)%	(15.0)%	(12.3)%
Oil	1,245	40.9	2,177	74.2	3,372	106.6	(42.8)	(44.9)	(35.4)	(30.4)
Natural gas	700	16.1	548	12.5	1,769	44.6	27.7	28.8	(69.0)	(72.0)
Nuclear	8,327	49.5	7,303	43.3	5,031	28.9	14.0	14.3	45.2	49.8
Hydro	3,485	—	3,530	—	3,818	—	(1.3)	—	(7.5)	—
	20,540	213.8	20,646	243.0	22,330	308.9	(0.5)	(12.0)	(7.5)	(21.3)
Electricity purchased:										
Unregulated generators	14,794	960.1	11,720	735.7	8,632	543.0	26.2	30.5	35.8	35.5
Other	10,382	140.3	9,046	118.1	8,917	115.7	14.8	18.8	1.5	2.1
	25,176	1,100.4	20,766	853.8	17,549	658.7	21.2	28.9	18.3	29.6
Total generated and purchased	45,716	1,314.2	41,412	1,096.8	39,879	967.6	10.4	19.8	3.8	13.4
Fuel adjustment clause	—	12.7	—	(2.2)	—	6.0	—	(677.3)	—	(136.7)
Losses/Company use	4,117	—	3,688	—	3,268	—	11.6	—	12.9	—
	41,599	$1,326.9	37,724	$1,094.6	36,611	$973.6	10.3%	21.2%	3.0%	12.4%

Gas revenues increased $148.0 million, or 31.1%, over the three-year period. As shown by the table below, this increase is primarily attributable to increased sales to ultimate customers and increased base rates and gas adjustment clause recoveries. In 1994, spot market sales declined because the abundance and price of spot gas made it more difficult to earn sufficient margin on these sales. Spot market sales are generally the higher priced gas available and sold in the wholesale market and yield margins substantially lower than traditional sales to ultimate customers. Rates for transported gas also yield lower margins than gas sold directly by the Company and, therefore, increases in the volume of gas transportation services have not had a proportionate impact on earnings. Changes in purchased gas adjustment clause revenues are generally margin-neutral.

	Increase (decrease) from prior year (In millions of dollars)			
Gas revenues	1994	1993	1992	Total
Increase in base rates	$ 7.1	$ 7.3	$ 4.7	$ 19.1
Transportation of customer-owned gas	3.5	(9.7)	6.3	0.1
Purchased gas adjustment clause revenues	7.7	12.2	12.5	32.4
Spot market sales	(25.4)	27.2	2.6	4.4
MERIT revenues	(1.3)	(0.4)	(0.3)	(2.0)
Miscellaneous operating revenues	7.6	(4.6)	—	3.0
Sales to ultimate consumers and other sales	23.0	15.1	52.9	91.0
	$22.2	$47.1	$78.7	$148.0

Gas sales, excluding transportation of customer-owned gas and spot market sales, were 85.6 million dekatherms in 1994, a 2.9% increase from 1993 and an 8.1% increase from 1992 (See Electric and Gas Statistics – Gas Sales). The increase in 1994 includes a 2.9% increase in residential sales, a 8.6% increase in commercial sales, both of which were strongly influenced by weather, and a 28.2% decrease in industrial sales. The gas weather normalization clause had an effective date of February 12, 1994, was not ordered to be implemented on a retroactive basis and, therefore, did not have a significant impact on gas revenues. The Company has added approximately 30,000 new customers since 1991, primarily in the residential class, an increase of 6.2%, and expects a continued increase in new customers in 1995. During 1993, there also was a shift from the transportation sales class to the industrial sales class, corresponding with the implementation of a stand-by industrial rate.



In 1994, the Company transported 85.9 million dekatherms (a significant increase from 1993) for customers purchasing gas directly from producers, and expects a continued increase in such transportation volumes in 1995, leading to a forecast increase in total gas deliveries in 1995 of approximately 18% above 1994. Public sales are expected to increase approximately 2%. Factors affecting these forecasts include the economy, the relative price differences between oil and gas in combination with the relative availability of each fuel, the expanded number of cogeneration projects served by the Company and increased marketing efforts. Changes in gas revenues and dekatherm sales by customer group are detailed in the table below:

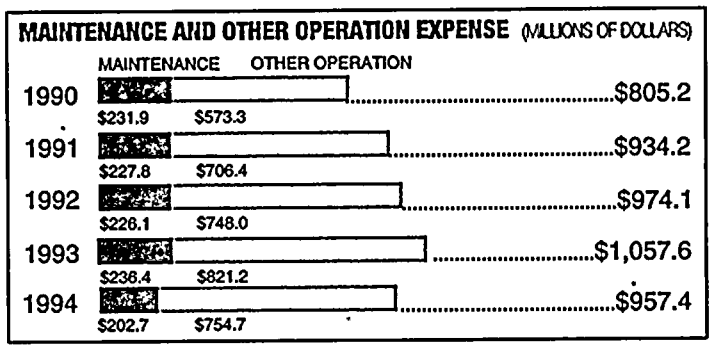
		% Increase (decrease) from prior years					
		1994		1993		1992	
Class of service	1994 % of Gas Revenues	Revenues	Sales	Revenues	Sales	Revenues	Sales
Residential	63.9%	7.5%	2.9%	4.6%	1.8%	17.0%	12.0%
Commercial	25.5	9.9	8.6	9.2	6.5	16.6	10.2
Industrial	2.4	(21.0)	(28.2)	84.8	143.6	18.6	(2.2)
Total to ultimate consumers.	91.8	7.1	2.9	7.4	6.4	16.9	11.1
Other gas systems	0.2	8.7	4.3	(77.5)	(80.3)	(32.0)	(21.7)
Transportation of customer-owned gas	6.1	10.1	26.8	(18.5)	2.9	17.2	30.0
Spot market sales	0.7	(85.3)	(88.1)	1,056.1	1,053.8	—	—
Miscellaneous	1.2	423.3	—	(79.4)	—	0.4	—
Total	100.0%	3.7%	5.4%	8.5%	12.3%	16.5%	19.5%

The total cost of gas purchased decreased 3.2% in 1994, while increasing 13.6% in 1993 and 16.1% in 1992. The cost fluctuations generally correspond to sales volume changes, particularly in 1993, as spot market sales activity increased. The Company sold 1.6 and 13.2 million dekatherms on the spot market in 1994 and 1993, respectively. In 1993, this activity accounted for two-thirds of the 1993 purchased gas expense increase. The purchased gas cost increase associated with purchases for ultimate consumers in 1994 resulted from a 1.5% increase in dekatherms purchased, coupled with a .9% increase in rates charged by suppliers and an increase of $6.4 million in purchased gas costs and certain other items recognized and recovered through the purchased gas adjustment clause. Gas purchased for spot market sales decreased $24.4 million in 1994 and increased $25.8 million in 1993. The purchased gas cost increase associated with purchases for ultimate consumers in 1993 resulted from a 8.7% increase in dekatherms purchased, combined with a 2.1% increase in rates charged by suppliers, offset by a $17.8 million decrease in purchased gas costs and certain other items recognized and recovered through the purchased gas adjustment clause. The Company's net cost per dekatherm purchased for sales to ultimate consumers increased to $3.44 in 1994 from $3.34 in 1993 and was $3.47 in 1992.

Through the electric and purchased gas adjustment clauses, costs of fuel, purchased power and gas purchased, above or below the levels allowed in approved rate schedules, are billed or credited to customers. The Company's electric fuel adjustment clause provides for partial pass-through of fuel and purchased power cost fluctuations from those forecast in rate proceedings, with the Company absorbing a portion of increases or retaining a portion of decreases to a maximum of $15 million per rate year. While the amounts absorbed in 1992 and 1993 were not material, the Company retained the maximum benefit of $15 million in 1994.

Other operation expense decreased in 1994 by 8.1%, as compared to increases of 9.8% in 1993 and 5.9% in 1992. The 1994 decrease relates primarily to decreases in nuclear costs associated with the Unit 1 and Unit 2 refueling outages in 1993 ($27 million) and the decrease in amortization of regulatory deferrals ($49 million) which expired in 1993. The 1993 increase is due to an increase in DSM program expenses, nuclear expenses related to increased production along with refueling outages at Unit 1 and Unit 2, amortization of regulatory assets deferred in prior years, increased recognition of other post-retirement benefit costs and inflation.

Maintenance expense decreased 14.2% in 1994 as compared to an increase of 4.5% in 1993, principally due to nuclear expenses incurred during the 1993 refueling outages at Unit 1 and Unit 2 ($19 million).



Depreciation and amortization expense for 1994 and 1993 increased 11.5% and 0.9%, respectively. The increase is attributable to the completion of required improvements to plant into service during late 1993 and early 1994.

Net Federal and foreign income taxes for 1994 decreased due to lower pre-tax income. In 1993 the decrease was due to the tax benefit derived from the Company's Canadian subsidiary upon the sale of its oil and gas investments. The increase in **Other taxes** in the three-year period is due principally to higher revenue-based taxes ($36 million), combined with higher property taxes ($28 million).

Other items, net, excluding Federal income taxes and allowance for funds used during construction (AFC), increased $8.0 million in 1994 and increased $23.4 million in 1993. The 1994 increase primarily related to increased earnings of subsidiaries which included a nonrecurring gain on the sale of an investment for $9 million. The 1993 increase was the effect of the recording in 1992 of a $45 million reserve against the carrying value of Canadian subsidiary oil and gas reserves. The sale of the Company's subsidiary, HYDRA-CO Enterprises, Inc. (HYDRA-CO), will be recorded in the first quarter of 1995 as the sale was completed in January 1995 and did not affect 1994 earnings. HYDRA-CO's earnings for the three years ended December 31, 1994 were not material.

Net interest charges decreased $5.5 million in 1994 and $9.3 million in 1993, as the result of the First Mortgage Bond refinancing program that began in 1992 and based on existing market conditions is now complete. Dividends on preferred stock increased $1.8 million in 1994 due to the issuance of $150 million of preferred stock in August 1994, while decreasing $4.7 million and $3.9 million in 1993 and 1992, respectively, because of reductions in the average amounts of stock outstanding. The weighted average long-term debt interest rate and preferred dividend rate paid, reflecting the actual cost of variable rate issues, changed to 7.79% and 6.84%, respectively, in 1994, from 7.97% and 6.70%, respectively, in 1993, and from 8.29% and 7.04%, respectively, in 1992.

Effects of Changing Prices

The Company is especially sensitive to inflation because of the amount of capital it typically needs and because its prices are regulated using a rate base methodology that reflects the historical cost of utility plant.

The Company's consolidated financial statements are based on historical events and transactions when the purchasing power of the dollar was substantially different from the present. The effects of inflation on most utilities, including the Company, are most significant in the areas of depreciation and utility plant. The Company could not replace its utility plant and equipment for the historical cost value at which they are recorded on the Company's books. In addition, the Company would not replace these assets with identical ones due to technological advances and competitive and regulatory changes that have occurred. In light of these considerations, the depreciation charges in operating expenses do not reflect the current cost of providing service. The Company will seek additional revenue or reallocate resources, if possible, to cover the costs of maintaining service as assets are replaced or retired.

Financial Position, Liquidity and Capital Resources

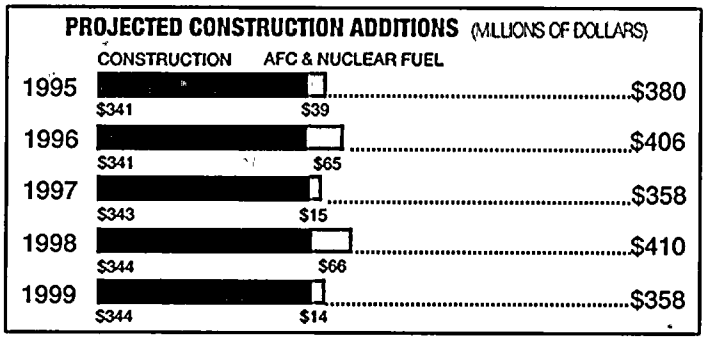
Financial Position. The Company's capital structure at December 31, 1994 was 52.3% long-term debt, 8.7% preferred stock and 39.0% common equity, as compared to 54.6%, 6.5% and 38.9%, respectively, at December 31, 1993. Book value of the common stock was $17.06 per share at December 31, 1994, as compared to $17.25 per share at December 31, 1993, reflecting the charge to earnings of the VERP and the payment of dividends in 1994. Market analysts have observed that the Company's low market to book ratio, 83.5% at December 31, 1994, stems from the adverse effects of New York State's economy and regulatory attitudes, as well as uncertainties about the pace of regulatory change, which could result in increased competition and reduced prices. These adverse effects and uncertainties, coupled with high embedded costs of the Company due principally to unregulated generators and taxes, may make the Company more vulnerable than some other traditional utilities.

The 1994 ratio of earnings to fixed charges was 1.91. Without the VERP charge, the ratio would have been 2.54. The ratios of earnings to fixed charges for 1993 and 1992 were 2.31 and 2.24, respectively.

Firms which publish securities ratings have begun to impute certain items into the Company's interest coverage calculations and capital structure, the most significant of which is the inclusion of a "leverage" factor for unregulated generator contracts. These firms believe that the financial structure of the unregulated generators (which typically have very high debt-to-equity ratios) and the character of their power purchase agreements increase the financial risk of utilities. The Company's reported interest coverage and debt-to-equity ratios have recently been discounted by varying amounts for purposes of establishing credit ratings. Because of existing commitments for unregulated generator purchases, the imputation has had and will continue to have a materially negative impact on the Company's financial ratings.

At present, sales of preferred stock are not possible and sales of common stock, which would cause substantial dilution to current shareholders, are financially inadvisable.

Construction and Other Capital Requirements. The Company's total capital requirements consist of amounts for the Company's construction program, working capital needs, maturing debt issues and sinking fund provisions on preferred stock. Annual expenditures for the years 1992 to 1994 for construction and nuclear fuel, including related AFC and overheads capitalized, were $502.2 million, $519.6 million and $490.1 million, respectively.



The 1995 estimate for construction additions, including overheads capitalized, nuclear fuel and AFC, is approximately $380 million, and is expected to be funded by cash provided from operations. Mandatory debt and preferred stock retirements and other requirements are expected to add approximately another $77 million (expected to be refinanced from external sources) to the Company's capital requirements, for a total of $457 million. Current estimates of total capital requirements for the years 1996 to 1999 are $475, $408, $480 and $566 million, respectively, of which $406, $358, $410 and $358 million relates to expected construction additions. The estimate of construction additions included in capital requirements for the period 1996 to 1999 will be reviewed by management during 1995 with the objective of further reducing these amounts where possible.

The provisions of the Clean Air Act Amendments of 1990 (Clean Air Act) are expected to have an impact on the Company's fossil generation plants during the period through 2000 and beyond. The Company has evaluated options for compliance with Phase I of the Clean Air Act, which becomes effective on May 31, 1995 and continues through 1999. The Company spent approximately $32 and $19 million in 1994 and 1993, respectively, and has included $6 million for Phase I in its construction forecast for 1995 through 1999 to make combustion modifications at its fossil fired plants, including the installation of low NOx burners at the Dunkirk and Huntley plants. With respect to Phase II, preliminary estimates for compliance anticipate approximately $17 million in capital costs. The Company anticipates that

additional expenditures of approximately $70 million may be necessary for Phase III to be incurred beyond 2000. The asset management studies, described above, include Phase I, II and III estimates for Clean Air Act compliance.

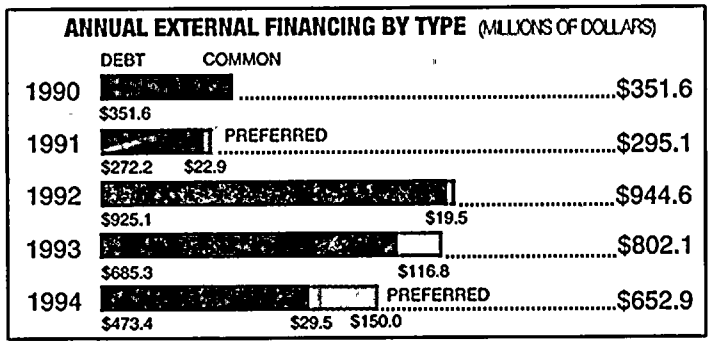
Liquidity and Capital Resources. Cash flows to meet the Company's requirements for operating, investing and financing activities during the past three years are reported in the Consolidated Statements of Cash Flows.

During 1994, the Company raised approximately $652.9 million from external sources, consisting of $325.7 million of First Mortgage Bonds, $150 million of Preferred Stock, $29.5 million of common stock and a net increase of $147.7 million of short and intermediate term debt. The proceeds of the $325.7 million of First Mortgage Bonds were used to provide for the early redemption of approximately $315.7 million of higher coupon First Mortgage Bonds. The Company also retired $190 million of First Mortgage Bonds that matured during 1994.

During January 1995, the Company completed the sale of its wholly-owned subsidiary, HYDRA-CO. Enterprises, Inc. Net cash proceeds of approximately $200 million were used to reduce short-term debt which aggregated over $400 million at December 31, 1994.

External financing for 1995 is projected to consist of $400 to $600 million of First Mortgage Bonds depending upon the final outcome of the current rate proceeding discussed above. The Company's ability to issue more common stock to improve its capital structure is limited by the uncertainties that have depressed the stock's price. The Company would not likely pursue a new issue offering unless the common stock price was closer to book value.

Depending on the outcome of the multi-year rate case discussed above, cash provided by operations is generally expected to provide sufficient funds for the Company's anticipated construction program for 1996 to 1999. External financing plans are subject to periodic revision as underlying assumptions are changed to reflect developments, most importantly in its rate proceedings. The ultimate level of financing during this four year period will reflect, among other things, the extent and timing of rate relief, the Company's competitive positioning and the extent to which competition penetrates the Company's markets, uncertain energy demand due to economic conditions and capital expenditures relating to distribution and transmission load reliability projects, as well as continued expansion of the gas business. Environmental standards compliance costs, the effects of rate regulation and various regulatory initiatives, the level of internally generated funds and dividend payments, the availability and cost of capital and the ability of the Company to meet its interest and preferred stock dividend coverage requirements, to satisfy legal requirements and restrictions in governing instruments and to maintain an adequate credit rating, also will impact the amount and type of future external financing.



The Company has initiated a ten to fifteen year site investigation and remediation program that seeks a) to identify and remedy environmental contamination hazards in a proactive and cost-effective manner and b) to ensure financial participation by other responsible parties. The Company is currently aware of 89 sites with which it has been or may be associated, including 47 which are Company-owned. With respect to non-owned sites, the Company may be required to contribute some proportionate share of remedial costs.

The Company has accrued a minimum liability of $240 million at December 31, 1994 for its estimated liability for investigation and remediation of certain Company-owned and Company-associated hazardous waste sites, which represents the low end of a range of estimates developed from the Company's ongoing site investigation and remediation program. The potential high end of the range is presently estimated at approximately $1 billion, including approximately $500 million in the unlikely event the Company were required to assume 100% responsibility at non-owned sites.

The Company believes that costs incurred in the investigation and remediation process are recoverable in the ratesetting process as currently in effect. See Note 9 of Notes to Consolidated Financial Statements–"Environmental Contingencies." Rate agreements since 1991 have included a recovery mechanism and an annual allowance for costs expected to be incurred for waste site investigation and remediation. The recovery mechanism provides that expenditures over or under the allowance be deferred for future rate consideration. The Company does not expect these costs to impact external financing, although any such impact is dependent upon the timing of expenditures and associated recovery.

The Nuclear Regulatory Commission (NRC) requires owners of nuclear power plants to place funds associated with decommissioning activities for contaminated portions of nuclear facilities into an external trust. Further, the NRC established guidelines for determining minimum amounts that must be available in the trust for these specified decommissioning activities at the time of decommissioning. Applying the NRC guidelines, the

Company has estimated that the minimum requirements for Unit 1 and its share of Unit 2, respectively, will be $381 million and $173 million in 1994 dollars. The Company is seeking an increase in its rate allowance for Unit 1 and Unit 2 decommissioning in its rate case for 1995 to reflect new NRC minimum requirements. Amounts collected for the NRC minimum are being placed in an external trust. See Note 3 of Notes to Consolidated Financial Statements – "Nuclear Plant Decommissioning."

The Company believes that traditionally available sources of financing should be sufficient to satisfy the Company's external financing needs during the period 1995 through 1999. As of December 31, 1994, the Company could issue an additional $2,351 million aggregate principal amount of First Mortgage Bonds. This includes approximately $1,311 million from retired bonds without regard to an interest coverage test and approximately $1,040 million supported by additional property currently certified and available, assuming a 10% interest rate, under the applicable tests set forth in the Company's mortgage trust indenture. The Company also has $200 million of Preference Stock authorized for sale. The Company will continue to explore and use, as appropriate, other methods of raising funds.

Ordinarily, construction related short-term borrowings are refunded with long-term securities on a regular basis. This approach generally results in the Company showing a working capital deficit. Working capital deficits also may be temporarily created because of the seasonal nature of the Company's operations as well as timing differences between the collection of customer receivables and the payment of fuel and purchased power costs.

The Company's accounts receivable increased 23% over 1993, due primarily to the effects of economic conditions in the Company's service territory. A focus on the Company's new centralized collections function will be to improve receivable collections in 1995.

The Company has had sufficient borrowing capacity to fund such a working capital deficit as necessary. Bank credit arrangements which, at December 31, 1994, totaled $580 million are used by the Company to enhance flexibility as to the type and timing of its long-term security sales. Of the $580 million total available, $200 million is represented by a Revolving Credit Agreement which expires in 1997. The remainder of the arrangements are subject to review by the lenders on an ongoing basis with interest rates negotiated at the time of use. In 1994, the Company also obtained $161 million in bank loans, which will expire in 1995 and which the Company expects to renew.

The Company's charter restricts the amount of unsecured indebtedness that may be incurred by the Company to 10% of consolidated capitalization plus $50 million. The Company has not reached this restrictive limit.

The Company's securities ratings at December 31, 1994, were:

	Secured Debt	Preferred Stock	Commercial Paper
Standard & Poors Corporation	*BBB-	BB+	A-3
Moody's Investors Service.....	Baa2	*baa3	P-2
Duff & Phelps	BBB	*BBB-	Not applicable
Fitch Investors Service.....	BBB	*BBB-	Not applicable

*Lowest investment grade rating.

As described further below, the security ratings set forth above are subject to revision and/or withdrawal at any time by the respective rating organizations and should not be considered a recommendation to buy, sell or hold securities of the Company.

The Company's costs of financing and access to markets have been and could be further negatively affected by events outside its control. The Company's securities ratings could be negatively affected by, among other things, the Company's obligations to purchase power from unregulated generators. Rating agencies have expressed concern about the impact on Company financial indicators and risk that unregulated generator financial leveraging may have. The Company's securities ratings and the terms of its access to capital markets could also be negatively impacted by adverse outcomes in the 1995 and multi-year rate proceedings or rapid penetration of competition in the Company's service territory.

In September 1994, Moody's Investors Service placed the credit ratings of the Company under review for possible downgrade. The review was prompted by both the PSC's September 1994 decision on Sithe/Alcan and the August 1994 proposal from the PSC Staff to reduce the Company's electric and gas rates over the next five years.

Also in September 1994, Standard and Poors (S&P) placed its ratings on the Company, Con Edison and Long Island Lighting Company on credit watch with negative implications. This action by S&P reflected continued concern about a shift in the regulatory environment in New York State that would be even more hostile to the financial health of the state's utilities. If any rating agency lowers the Company's securities rating, particularly to below investment grade, such action could increase the cost to issue new securities, and/or limit the Company's flexibility.

Report of Management

The consolidated financial statements of Niagara Mohawk Power Corporation and its subsidiaries were prepared by and are the responsibility of management. Financial information contained elsewhere in this Annual Report is consistent with that in the financial statements.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls, which is designed to provide reasonable assurance, on a cost effective basis, as to the integrity, objectivity and reliability of the financial records and protection of assets. This system includes communication through written policies and procedures, an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program. In addition, the Company has a Corporate Policy Register and a Code of Business Conduct which supply employees with a framework describing and defining the Company's overall approach to business and requires all employees to maintain the highest level of ethical standards as well as requiring all management employees to formally affirm their compliance with the Code.

The financial statements have been audited by Price Waterhouse LLP, the Company's independent accountants, in accordance with generally accepted auditing standards. In planning and performing their audit, Price Waterhouse considered the Company's internal control structure in order to determine auditing procedures for the purpose of expressing an opinion on the financial statements, and not to provide assurance on the internal control structure. The independent accountants' audit does not limit in any way management's responsibility for the fair presentation of the financial statements and all other information, whether audited or unaudited, in this Annual Report. The Audit Committee of the Board of Directors, consisting of five outside directors who are not employees, meets regularly with management, internal auditors and Price Waterhouse to review and discuss internal accounting controls, audit examinations and financial reporting matters. Price Waterhouse and the Company's internal auditors have free access to meet individually with the Audit Committee at any time, without management being present.

Report of Independent Accountants

To the Stockholders and Board of Directors of
Niagara Mohawk Power Corporation

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and retained earnings and of cash flows present fairly, in all material respects, the financial position of Niagara Mohawk Power Corporation and its subsidiaries at December 31, 1994 and 1993, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1994, in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

As discussed in Note 9, the Company is a defendant in lawsuits relating to its actions with respect to certain purchased power contracts. Management is unable to predict whether the resolution of these matters will have a material effect on its financial position or results of operations. Accordingly, no provision for any liability that may result upon resolution of this uncertainty has been made in the accompanying 1994 and 1993 financial statements.

As discussed in Note 2, certain representatives of the New York Public Service Commission have proposed: i) a plan to establish the Company's rates for its electric business based on a transition plan to market-based prices rather than based on the Company's costs and ii) disallowance of certain costs with respect to unregulated generator contracts. If these proposals or certain provisions thereof are implemented as proposed, the Company would be required to writedown certain assets, recognize a loss on uneconomic unregulated generator contracts and/or discontinue the application of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), with respect to portions of the Company's business. Such writedowns or losses could have a material adverse effect on the Company's financial position and results of operations. Because the outcome of these matters cannot be predicted, the accompanying financial statements do not include any adjustments that might result from the resolution of these proceedings.

Price Waterhouse LLP

Syracuse, New York February 1, 1995

Consolidated Statements of Income and Retained Earnings

For the year ended December 31,	In thousands of dollars 1994	1993	1992
Operating revenues:			
Electric	$3,528,987	$3,332,464	$3,147,676
Gas	623,191	600,967	553,851
	4,152,178	3,933,431	3,701,527
Operating expenses:			
Operation:			
Fuel for electric generation	219,849	231,064	323,200
Electricity purchased	1,107,133	863,513	650,379
Gas purchased	315,714	326,273	287,316
Other operation expenses	754,695	821,247	748,023
Employee reduction program	196,625	—	—
Maintenance	202,682	236,333	226,127
Depreciation and amortization (*Note 1*)	308,351	276,623	274,090
Federal and foreign income taxes (*Note 7*)	117,834	162,515	183,233
Other taxes	496,922	491,363	484,833
	3,719,805	3,408,931	3,177,201
Operating income	432,373	524,500	524,326
Other income and deductions:			
Allowance for other funds used during construction (*Note 1*)	2,159	7,119	9,648
Federal and foreign income taxes (*Note 7*)	6,365	15,440	27,729
Other items (net)	15,045	7,035	(16,338)
	23,569	29,594	21,039
Income before interest charges	455,942	554,094	545,365
Interest charges:			
Interest on long-term debt	264,891	279,902	290,734
Other interest	20,987	11,474	9,982
Allowance for borrowed funds used during construction	(6,920)	(9,113)	(11,783)
	278,958	282,263	288,933
Net income	176,984	271,831	256,432
Dividends on preferred stock	33,673	31,857	36,512
Balance available for common stock	143,311	239,974	219,920
Dividends on common stock	156,060	133,908	103,784
	(12,749)	106,066	116,136
Retained earnings at beginning of year	551,332	445,266	329,130
Retained earnings at end of year	$ 538,583	$ 551,332	$ 445,266
Average number of shares of common stock outstanding (*in thousands*)	143,261	140,417	136,570
Balance available per average share of common stock	$ 1.00	$ 1.71	$ 1.61
Dividends paid per share	$ 1.09	$ .95	$ .76

( ) Denotes deduction

Consolidated Balance Sheets

At December 31,	In thousands of dollars 1994	1993
ASSETS		
Utility plant (*Note 1*):		
Electric plant	$8,285,263	$7,991,346
Nuclear fuel	504,320	458,186
Gas plant	922,459	845,299
Common plant	291,962	244,294
Construction work in progress	481,335	569,404
Total utility plant	10,485,339	10,108,529
Less: Accumulated depreciation and amortization	3,449,696	3,231,237
Net utility plant	7,035,643	6,877,292
Other property and investments	224,039	209,051
Current assets:		
Cash, including temporary cash investments of $50,052 and $100,182 respectively	94,330	124,351
Accounts receivable (less allowance for doubtful accounts of $3,600) (*Note 9*)	317,282	258,137
Unbilled revenues (*Note 1*)	196,700	197,200
Electric margin recoverable	66,796	21,368
Materials and supplies, at average cost:		
Coal and oil for production of electricity	31,652	29,469
Gas storage	30,931	31,689
Other	150,186	163,044
Prepayments:		
Taxes	43,249	23,879
Pension expense (*Note 8*)	—	37,238
Other	45,189	34,382
	976,315	920,757
Regulatory and other assets (*Note 2*):		
Unamortized debt expense	153,047	154,210
Deferred recoverable energy costs	62,884	67,632
Deferred finance charges	239,880	239,880
Income taxes recoverable	465,109	558,771
Recoverable environmental restoration costs (*Note 9*)	240,000	240,000
Other	252,522	203,734
	1,413,442	1,464,227
	$9,649,439	$9,471,327
CAPITALIZATION AND LIABILITIES		
Capitalization (*Note 6*):		
Common stockholders' equity:		
Common stock, issued 144,311,466 and 142,427,057 shares, respectively	$ 144,311	$ 142,427
Capital stock premium and expense	1,779,504	1,762,706
Retained earnings	538,583	551,332
	2,462,398	2,456,465
Non-redeemable preferred stock	290,000	290,000
Mandatorily redeemable preferred stock	256,000	123,200
Long-term debt	3,297,874	3,258,612
Total capitalization	6,306,272	6,128,277
Current liabilities:		
Short-term debt (*Note 5*)	416,750	368,016
Long-term debt due within one year (*Note 6*)	77,971	216,185
Sinking fund requirements on redeemable preferred stock (*Note 6*)	10,950	27,200
Accounts payable	277,782	299,209
Payable on outstanding bank checks	64,133	35,284
Customers' deposits	14,562	14,072
Accrued taxes	43,358	56,382
Accrued interest	63,639	70,529
Accrued vacation pay	36,550	40,178
Other	77,818	39,565
	1,083,513	1,166,620
Regulatory and other liabilities:		
Accumulated deferred income taxes (*Notes 1 and 7*)	1,258,463	1,344,259
Deferred finance charges (*Note 2*)	239,880	239,880
Employee pension and other benefits (*Note 8*)	235,741	35,507
Unbilled revenues (*Note 1*)	93,668	94,968
Deferred pension settlement gain	50,261	62,282
Other	141,641	159,534
	2,019,654	1,936,430
Commitments and contingencies (*Notes 2 and 9*):		
Liability for environmental restoration	240,000	240,000
	$9,649,439	$9,471,327

Consolidated Statements of Cash Flows
Increase (Decrease) in Cash

For the year ended December 31,	In thousands of dollars 1994	1993	1992
Cash flows from operating activities:			
Net income	$176,984	$271,831	$256,432
Adjustments to reconcile net income to net cash provided by operating activities:			
Amortization of nuclear replacement power cost disallowance	(23,081)	(23,720)	(39,547)
Depreciation and amortization	308,351	276,623	274,090
Amortization of nuclear fuel	37,887	35,971	26,159
Provision for deferred income taxes	7,866	30,067	55,929
Electric margin recoverable	(45,428)	(9,773)	3,670
Employee reduction program	196,625	—	—
Allowance for other funds used during construction	(2,159)	(7,119)	(9,648)
Deferred recoverable energy costs	4,748	(5,688)	(14,329)
(Gain)loss on investments — net	—	(5,490)	44,296
Deferred operating expenses	—	15,746	20,257
Increase in net accounts receivable	(59,145)	(36,972)	(44,969)
(Increase) decrease in materials and supplies	6,290	43,581	(28,293)
Increase (decrease) in accounts payable and accrued expenses	(5,991)	15,716	31,025
Increase (decrease) in accrued interest and taxes	(19,914)	3,996	10,133
Changes in other assets and liabilities	14,188	10,624	39,565
Net cash provided by operating activities	597,221	615,393	624,770
Cash flows from investing activities:			
Construction additions	(439,289)	(506,267)	(452,497)
Nuclear fuel	(46,134)	(12,296)	(37,247)
Less: Allowance for other funds used during construction	2,159	7,119	9,648
Acquisition of utility plant	(483,264)	(511,444)	(480,096)
(Increase) decrease in materials and supplies related to construction	5,143	3,837	(7,359)
Increase (decrease) in accounts payable and accrued expenses related to construction	(1,498)	3,929	7,756
Increase in other investments	(23,375)	(26,774)	(11,615)
Proceeds from sale of subsidiary	—	95,408	—
Other	(17,979)	(15,260)	(31,588)
Net cash used in investing activities	(520,973)	(450,304)	(522,902)
Cash flows from financing activities:			
Proceeds from sale of common stock	29,514	116,764	13,340
Proceeds from long-term debt	424,705	635,000	835,000
Issuance of preferred stock	150,000	—	—
Redemption of preferred stock	(33,450)	(47,200)	(41,950)
Reductions of long-term debt	(526,584)	(641,990)	(796,795)
Net change in short-term debt	48,734	50,318	90,130
Dividends paid	(189,733)	(165,765)	(140,296)
Other	(9,455)	(31,759)	(44,781)
Net cash used in financing activities	(106,269)	(84,632)	(85,352)
Net increase (decrease) in cash	(30,021)	80,457	16,516
Cash at beginning of year	124,351	43,894	27,378
Cash at end of year	$ 94,330	$124,351	$ 43,894
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest	$300,242	$300,791	$323,972
Income taxes	136,876	106,202	76,519
Supplemental schedule of noncash investing and financing activities:			
Liability for environmental restoration	—	25,000	15,000

1 Summary of Significant Accounting Policies

The Company is subject to regulation by the PSC and FERC with respect to its rates for service under a methodology which establishes prices based on the Company's cost. 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 ratemaking practices of the regulatory authorities. See "Exposure Draft on Impairment of Assets" below and Note 2 – Rate and Regulatory Issues and Contingencies.

Principles of Consolidation: The consolidated financial statements include the Company and its wholly-owned subsidiaries. Intercompany balances and transactions have been eliminated.

Utility Plant: The cost of additions to utility plant and of replacements of retirement units of property is capitalized. Cost includes direct material, labor, overhead and allowance for funds used during construction (AFC). Replacement of minor items of utility plant and the cost of current repairs and maintenance is charged to expense. Whenever utility plant is retired, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation.

Allowance for Funds Used During Construction: The Company capitalizes AFC in amounts equivalent to the cost of funds devoted to plant under construction. AFC rates are determined in accordance with FERC and PSC regulations. The AFC rate in effect at December 31, 1994 was 5.75%. AFC is segregated into its two components, borrowed funds and other funds, and is reflected in the Interest charges and the Other income and deductions sections, respectively, of the Consolidated Statements of Income.

Depreciation, Amortization and Nuclear Generating Plant Decommissioning Costs: For accounting and regulatory purposes, depreciation is computed on the straight-line basis using the remaining service lives for nuclear and hydro classes of depreciable property and the average service lives for all other classes. The percentage relationship between the total provision for depreciation and average depreciable property was 3.3% for 1994, 3.2% for 1993 and 3.3% for 1992. The Company performs depreciation studies to determine service lives of classes of property and adjusts the depreciation rates periodically.

Estimated decommissioning costs (costs to remove a nuclear plant from service in the future) for the Company's Unit 1 and its share of Unit 2 are being accrued over the service lives of the units, recovered in rates through an annual allowance and currently charged to operations through depreciation. The Company expects to commence decommissioning of both units shortly after cessation of operations at Unit 2 (currently planned for 2026), using a method which removes or decontaminates Unit components promptly at that time. See Note 3 – "Nuclear Plant Decommissioning."

The Financial Accounting Standards Board (FASB) has added to its agenda a project on accounting for obligations for decommissioning of nuclear power plants. The objective of the FASB's project is to determine when a liability for nuclear decommissioning should be recognized, how any such liability should be measured, and whether a corresponding asset is created. If current electric utility industry accounting practices for such decommissioning are changed, the Company may be required to record the estimated cost for decommissioning as a liability rather than as accumulated depreciation, establish a regulatory asset for the difference between the amount accrued to date and the total estimated decommissioning liability and report income from the external decommissioning trusts as investment income rather than as a reduction to decommissioning expense. The annual provisions for decommissioning could increase. The Company does not believe that such changes, if required, would have an adverse effect on results of operations due to the Company's belief that decommissioning costs will continue to be recovered in rates (See "Exposure Draft on Impairment of Assets", below).

Amortization of the cost of nuclear fuel is determined on the basis of the quantity of heat produced for the generation of electric energy. The cost of disposal of nuclear fuel, which presently is $.001 per kilowatt-hour of net generation available for sale, is based upon a contract with the U.S. Department of Energy. These costs are charged to operating expense and recovered from customers through base rates or through the fuel adjustment clause.

Revenues: Revenues are based on cycle billings rendered to certain customers monthly and others bi-monthly. Although the Company commenced the practice in 1988 of accruing electric revenues for energy consumed and not billed at the end of the fiscal year, the impact of such accruals has not yet been fully recognized in the Company's results of operations because of regulatory requirements. At December 31, 1994 and 1993, approximately $71.8 million and $74.1 million, respectively, of unbilled electric revenues remained unrecognized in results of operations, are included in Deferred Credits and may be used to reduce future revenue requirements. At December 31, 1994 and 1993, the Company accrued $21.9 and $20.9 million, respectively, of unbilled gas revenues which remained unrecognized in results of operations and will similarly be used to reduce future gas revenue requirements.

The Company's tariffs include electric and gas adjustment clauses under which energy and purchased gas costs, respectively, above or below the levels allowed in approved rate schedules, are billed or credited to customers. The Company, as authorized by the PSC, charges operations for energy and purchased gas cost

increases in the period of recovery. The PSC has periodically authorized the Company to make changes in the level of allowed energy and purchased gas costs included in approved rate schedules. As a result of such periodic changes, a portion of energy costs deferred at the time of change would not be recovered or may be overrecovered under the normal operation of the electric and gas adjustment clauses. However, the Company has to date been permitted to defer and bill or credit such portions to customers, through the electric and gas adjustment clauses, over a specified period of time from the effective date of each change.

The Company's electric fuel adjustment clause (FAC) provides for partial pass-through of fuel and purchased power cost fluctuations from amounts forecast, with the Company absorbing a portion of increases or retaining a portion of decreases up to a maximum of $15 million per rate year. Thereafter, 100% of the fluctuation is passed on to ratepayers. The Company also shares with ratepayers fluctuations from amounts forecast for net resale margin and transmission benefits, with the Company retaining/absorbing 40% and passing 60% through to ratepayers. The amounts retained or absorbed in 1992 through 1994 were not material.

In the Company's current rate proceeding the Company has proposed to eliminate the FAC and replace it with the fuel adjustment mechanism (FAM). If this is implemented, the portion of fuel and purchase power cost fluctuations, from amounts forecast, that the Company would retain or absorb could reach a maximum of $20 million per rate year. For the additional years of the rate proceeding's five-year plan (1996-1999), the 1995 monthly fuel cost would form the basis for the forecast.

Beginning in 1991, the Company's rate agreements provided for NERAM, which permits the Company to reconcile actual results to forecast electric public sales gross margin as defined and utilized in establishing rates. Depending on the level of actual sales, a liability to customers was created if sales exceed the forecast and an asset recorded for a sales shortfall, thereby generally preserving recorded electric gross margin at the level forecast in established rates. The 1994 rate settlement provided for the operation of the NERAM through December 31, 1994. Recovery or refund of accruals pursuant to the NERAM is accomplished by a surcharge (either plus or minus) to customers over a twelve-month period, to begin when cumulative amounts reach certain specified levels. While the NERAM may be terminated in 1995, the recovery period of the outstanding balance as of December 31, 1994 will not be affected.

In February 1994, the Company implemented a weather normalization clause for retail customers who use gas for heating to reflect the impact of variations from normal weather on a billing month basis for the months of October through May, inclusive. Normal weather is defined as the 30 year average daily high and low temperatures for the Company's main gas service territory. The weather normalization clause will only be activated if the actual weather deviates 2.2% or more from the normal weather. Weather normalization clause adjustments were not significant to 1994 gas revenues.

Rate agreements since 1991 also include MERIT, under which the Company has the opportunity to achieve earnings above its allowed return on equity based on attainment of specified goals associated with its self-assessment process. The MERIT program provides for specific measurement periods and reporting for PSC approval of MERIT earnings. Approved MERIT awards are billed to customers over a period not greater than twelve months. The Company records MERIT earnings when attainment of goals is approved by the PSC or when objectively measured criteria are achieved. MERIT expires at the end of 1995.

Federal Income Taxes: As directed by the PSC, the Company defers any amounts payable pursuant to the alternative minimum tax rules. Deferred investment tax credits are amortized to Other Income and Deductions over the useful life of the underlying property.

Statement of Cash Flows: The Company considers all highly liquid investments, purchased with a remaining maturity of three months or less, to be cash equivalents.

Reclassifications: Certain amounts from prior years have been reclassified on the accompanying Consolidated Financial Statements to conform with the 1994 presentation.

Exposure Draft on Impairment of Assets: In November 1993, the FASB issued an Exposure Draft on "Accounting for the Impairment of Long-Lived Assets." The Exposure Draft would require companies, including utilities, to assess the need to recognize a loss whenever events or circumstances occur which indicate that the carrying amount of an asset may not be fully recoverable. An impairment loss would be recognized if the sum of the future undiscounted net cash flows expected to be generated by an asset is less than its book value. The amount of the loss would be based on a comparison of book value to fair value. The Exposure Draft would also amend Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation," (SFAS No. 71) to require writeoff of a regulatory asset if it is no longer probable that future revenues will recover the cost of the asset.

The Exposure Draft, which is expected to become applicable in 1996, may have consequences to a number of utilities, including the Company, which are facing growing competitive threats that may erode future prices, and which have relatively high-cost nuclear generating assets and unregulated generator contracts. The Company is also faced with ratemaking proposals by the PSC Staff in the current 1995 and multi-year rate cases, and by the Administrative Law Judges (ALJ's) Recommended Decision in the 1995 case, that would likely result in asset impairment issues under the Exposure Draft provisions if the PSC Staff's proposals or the Recommended Decision are adopted by the PSC. See Management's Discussion and

Analysis – "Regulatory Agreements/Proposals" for a more extensive discussion of the competitive threats facing the Company and of the PSC Staff's proposals and the ALJ's Recommended Decision.

While the Company is unable to determine the financial consequences of applying the provisions of the Exposure Draft, if the PSC Staff's proposals and/or the ALJ's Recommended Decision are adopted, they would have a material adverse effect on the Company's financial position and results of operations.

2 Rate and Regulatory Issues and Contingencies

In accordance with SFAS No. 71, the Company's financial statements reflect assets and costs based on ratemaking conventions, as approved by the PSC and the FERC. Certain expenses and credits, normally reflected in income as incurred, are only recognized when included in rates and recovered from or refunded to customers. Historically, all costs of this nature which are determined by the regulators to have been prudently incurred have been recoverable through rates in the course of normal ratemaking procedures and the Company believes that the items detailed below will be afforded similar treatment.

Continued accounting under SFAS No. 71 requires, among other things, that rates be designed to recover specific costs of providing regulated services and products and that it be reasonable to assume that rates are set at levels that will recover a utility's costs and can be charged to and collected from customers. When a utility determines it can no longer apply the provisions of SFAS No. 71 to all or a part of its operation, it must eliminate from its balance sheet, the effects of actions of regulators that had been recorded previously as assets and liabilities pursuant to SFAS No. 71 but which would have not been so accounted for by enterprises in general.

The Company's proposed multi-year rate plan for 1995-1999 contemplates no change in this approach to such reporting, even though the plan recognizes that in a more competitive environment an effective response to the general pressure to manage costs and preserve or expand markets is vital to maintaining profitability. The Company's proposed plan includes the establishment of rates for 1995 on a cost of service basis, followed by an index-based approach to rates for 1996 through 1999. The index is based on inflation factors believed to be indicative of cost increases to be experienced by the Company. The proposal for 1996-1999 also includes adjustment factors related to events outside the Company's control and a mechanism for resetting rates if the expected return on equity falls below a minimum threshold. Therefore, the Company believes that it can continue to apply SFAS No. 71 under its multi-year rate proposal.

The PSC Staff has proposed a multi-year ratesetting plan which the Company believes would require writedown of certain assets, would not permit the continued application of SFAS No. 71 to its generation operations and may similarly jeopardize application of SFAS No. 71 to its transmission and distribution operations under certain circumstances. The ALJ's Recommended Decision proposes to disallow from recovery approximately $18 million of unregulated generator costs, recommends a prudence investigation of the Company's unregulated generator contract practices absent a multi-year rate plan, proposes to reduce the level of departmental expenses and gross margin because of "lack of support" and states that the VERP savings could be used to further reduce the rate increase recommended. See Management's Discussion and Analysis of Financial Condition and Results of Operations - "Regulatory Agreements/Proposals" for a discussion of the PSC Staff's and ALJ's proposals and potential financial consequences. In the event that the Company is required to writedown its assets, recognize a loss on uneconomic unregulated generator contracts and/or could no longer apply SFAS No. 71 to either its generation operations or to its entire electric business, a material adverse effect on its financial condition and results of operations would result.

The Company believes the financial consequences to be of an order of magnitude that would adversely affect the Company's financial position and results of operations, its ability to access the capital markets on reasonable and customary terms, its dividend paying capacity, its ability to continue to make payments to unregulated generators and its ability to maintain current levels of service to its customers.

The Company has recorded the following regulatory and other assets:

At December 31,	In thousands of dollars 1994	1993
Income taxes recoverable	$ 465,109	$ 558,771
Recoverable environmental restoration costs	240,000	240,000
Deferred finance charges	239,880	239,880
Unamortized debt expense	153,047	154,210
Deferred postretirement benefit costs	67,486	30,741
Deferred recoverable energy costs	62,884	67,632
Deferred unregulated generators' contract termination costs	38,286	50,680
Deferred gas pipeline costs	17,000	31,000
Other	129,750	91,313
Total	$1,413,442	$1,464,227

Income taxes recoverable represents the expected future recovery from ratepayers of the tax consequences of temporary differences between the recorded book bases and the tax bases of assets and liabilities. These amounts are amortized and recovered as the related temporary differences reverse. In January 1993, the PSC issued a Statement of Interim Policy on Accounting and Ratemaking Procedures that required adoption of Statement of Financial Accounting Standards No. 109 – "Accounting for Income Taxes" (SFAS No. 109) on a revenue-neutral basis.

Recoverable environmental restoration costs represent the Company's share of the estimated costs to investigate and perform certain remediation activities at both Company-

owned sites and non-owned sites with which it may be associated. Current rates provide an annual allowance to recover anticipated annual expenditures.

Deferred finance charges represent the deferral of the discontinued portion of AFC related to construction work in progress (CWIP) at Unit 2 which was included in rate base. In 1985, pursuant to PSC authorization, the Company discontinued accruing AFC on CWIP for which a cash return was being allowed. This amount, which was accumulated in deferred debit and credit accounts up to the commercial operation date of Unit 2, awaits future disposition by the PSC. A portion of the deferred credit could be utilized to reduce future revenue requirements over a period shorter than the life of Unit 2, with a like amount of deferred debit amortized and recovered in rates over the remaining life of Unit 2.

Unamortized debt expense represents the costs to issue long-term debt securities including premiums on certain debt retirements prior to maturity. These amounts are amortized as interest expense ratably over the lives of the related issues in accordance with PSC directives.

Deferred postretirement benefit costs represent the excess of such costs recognized in accordance with Statement of Financial Accounting Standards No. 106 – "Employers' Accounting for Postretirement Benefits Other Than Pensions" (SFAS No. 106) over the amount received in rates. In accordance with the PSC policy statement, postretirement benefit costs other than pensions are being phased-in to rates over a five-year period and amounts deferred will be amortized and recovered over a period not to exceed 20 years.

Deferred recoverable energy costs includes the difference between actual fuel costs and the fuel revenues received through the Company's fuel adjustment clause. The balance also includes the unamortized portion of the Company's mandated contribution to decommission the Department of Energy's (DOE) uranium enrichment facilities. The costs to decommission DOE facilities result from the Energy Policy Act of 1992, which requires domestic utilities to contribute amounts, escalated for inflation, based upon the amount of uranium enriched by DOE for each utility. The fuel costs are amortized as they are collected from customers while the costs to decommission the DOE facilities are being amortized and recovered, as a fuel cost, over a period ending in 2006.

Deferred unregulated generators' contract termination costs represent the Company's cost to buy out certain unregulated generator projects. Approximately $15 million of these costs are currently being recovered over a three-year period beginning in 1994. The remaining costs are being addressed in the Company's current rate filing.

Deferred gas pipeline costs represent the estimated restructuring costs the Company anticipates incurring as a result of FERC Order No. 636. These costs are treated as a cost of purchased gas and are recoverable through the operation of the gas adjustment clause mechanism, or direct surcharge to transportation customers over a period of approximately 7 years beginning in 1994, with recovery more heavily weighted in the first 3 years.

All other regulatory assets are generally being amortized over various periods or addressed in the Company's current rate filing under a provision which proposes recovery using a one-year rate surcharge.

The above regulatory assets are generally not included in rate base (and therefore do not earn a return) either because an outlay of funds has not yet occurred or as a result of regulatory policy.

3 Nuclear Operations

The Company is the owner and operator of the 613 MW Unit 1 and the operator and a 41% co-owner of the 1,062 MW Unit 2. Unit 1 was placed in commercial operation in 1969 and Unit 2 in 1988.

Unit 1 Economic Study: Under the terms of a previous regulatory agreement, the Company agreed to prepare and update studies of the advantages and disadvantages of continued operation of Unit 1. The 1990 study recommended continued operation of Unit 1 over the next fuel cycle, and the 1992 study indicated that the Unit could continue to provide benefits for the term of its license (2009) if operating costs could be reduced and generating output improved above its then historical average.

The 1994 study again confirmed that continued operation over the remaining term of its license is warranted. The Company will continue as a matter of course to examine the economic and strategic issues related to operation of all its generating units.

The operating experience at Unit 1 has improved substantially since the prior study. At December 31, 1994, Unit 1's capacity factor has been about 94% since the 1993 refueling outage.

The Company's net investment in Unit 1 is approximately $575 million, exclusive of decommissioning costs.

Unit 1 Status: A scheduled refueling outage began on February 8, 1995. Using the net design electric rating as a basis, Unit 1's capacity factor for 1994 was approximately 92%. Using NRC guidelines, which reflect net maximum dependable capacity during the most restrictive seasonal conditions, Unit 1's capacity factor was approximately 99%.

Unit 2 Status: The next refueling outage is scheduled to begin in April 1995. Using the net design electric rating as a basis, Unit 2's capacity factor for 1994 was approximately 90%. Using NRC guidelines as described above, Unit 2's capacity factor was approximately 96%.

Nuclear Plant Decommissioning: The Company estimates the cost of decommissioning Unit 1 and its ownership interest in Unit 2 at December 31, 1994 as follows:

	Unit 1	Unit 2
Site Study (year)	1994	1989 *(a)*
End of Plant Life (year)	2009	2026
Radioactive Dismantlement to Begin (year)	2026	2029
Method of Decommissioning	Delayed Dismantlement	Immediate Dismantlement
Cost of Decommissioning (in 1994 dollars)	*In millions of dollars*	
Radioactive Components	$344	$207
Non-radioactive Components	51	33
Fuel Dry Storage/Continuing Care	132	50
	$527	$290

(a) The estimate of Unit 2's decommissioning costs was updated by extrapolating data from the updated Unit 1 decommissioning estimate. The Unit 2 estimate should be considered preliminary, as the Company expects to perform a more detailed study in 1995.

The Company estimates by the time decommissioning is completed, the above costs will ultimately amount to $1.4 billion and $1.0 billion for Unit 1 and Unit 2, respectively, using 2.3% as an initial inflation factor. This factor increases gradually, reaching a maximum of 3.4% in the year 2004 and for the years thereafter.

In addition to the costs mentioned above, the Company expects to incur post-shutdown costs for plant rampdown, insurance and property taxes. In 1994 dollars, these costs are expected to amount to $110 million and $80 million for Unit 1 and the Company's share of Unit 2, respectively. The amounts will escalate to $235 million and $405 million for Unit 1 and the Company's share of Unit 2, respectively.

Based upon a 1989 study the Company had previously estimated the cost to decommission Unit 1 to be approximately $416 million in 2009 ($263 million in 1994 dollars). In addition, non-radioactive dismantlement costs were estimated to be $25 million in 1994 dollars. The 1989 estimate was based upon a dismantlement of Unit 1 at the end of its useful life in 2009. The $527 million estimate assumes a delayed dismantlement to coincide with Unit 2 and was prepared in connection with the Economic Study discussed above. The estimate differs from the 1989 estimate primarily due to an increase in burial costs and the inclusion of nuclear fuel storage charges and costs for continuing care. The delayed dismantlement approach should be the most economic after applying the Company's current weighted average cost of capital.

The Company, in a 1989 study, estimated its 41% share of the cost to decommission Unit 2 to be $316 million in 2026 dollars ($112 million in 1994 dollars). In addition, the Company's share of non-radioactive dismantlement cost were estimated to be $18 million (in 1994 dollars). The $290 million estimate differs from the 1989 study primarily due to an increase in burial costs and the inclusion of nuclear fuel storage charges and costs for continuing care.

Decommissioning costs recovered in rates are reflected in Accumulated Depreciation and Amortization on the Balance Sheet and amount to $134.1 million and $113.9 million at December 31, 1994 and 1993, respectively for both Units. The annual allowance for Unit 1 and the Company's share of Unit 2 for the years ended December 31, 1994, 1993 and 1992 was approximately $18.7, $18.7 and $23.1 million, respectively. These amounts were based on the 1989 study. The FASB has added to its agenda a project on accounting for obligations for decommissioning of nuclear power plants. See Note 1 – "Depreciation, Amortization and Nuclear Generating Plant Decommissioning Costs."

NRC regulations require owners of nuclear power plants to place funds into an external trust to provide for the cost of decommissioning contaminated portions of nuclear facilities and establish minimum amounts that must be available in such a trust at the time of decommissioning. As of December 31, 1994, the fair value of funds accumulated in the Company's external trusts were $74.0 million for Unit 1 and $18.7 million for its share of Unit 2. The investments are included in Other property and investments. Earnings on the external trust aggregated $13.1 million through December 31, 1994 and, because they are available to fund decommissioning, have also been included in Accumulated Depreciation and Amortization See Note 10 – Disclosures about Fair Value of Financial Instruments. Amounts recovered for non-radioactive dismantlement are accumulated in an internal reserve fund which has an accumulated balance of $37.1 million at December 31, 1994.

The NRC minimum decommissioning cost calculation is based upon a 1986 cost estimate escalated by increases in labor, energy, and burial cost factors. A substantial increase in burial costs, partly offset by reduced estimates in the volumes of waste to be disposed, increased the NRC minimum requirement for Unit 1 to $381 million in 1994 dollars and the Company's share of Unit 2 to $173 million in 1994 dollars. The Company's 1995 rate filing includes an aggregate increase of $8 million in decommissioning allowances to reflect funding to the increased NRC minimum requirements. In its next rate filing the Company intends to seek decommissioning allowances necessary to fund to the Company's 1994 decommissioning estimates discussed above. There is no assurance that the decommissioning allowance recovered in rates will ultimately aggregate a sufficient amount to decommission the units. The Company believes that if decommissioning costs are higher than currently estimated, the costs would ultimately be included in the rate process.

Nuclear Liability Insurance: The Atomic Energy Act of 1954, as amended, requires the purchase of nuclear liability insurance from the Nuclear Insurance Pools in amounts as determined by the NRC. At the present time, the Company maintains the required $200 million of nuclear liability insurance.

In 1993, the statutory liability limits for the protection of the public under the Price-Anderson Amendments Act of 1988 (the Act) were further increased. With respect to a nuclear incident at a licensed reactor, the statutory limit,

which is in excess of the $200 million of nuclear liability insurance, is currently $8.3 billion without the 5% surcharge discussed below. This limit would be funded by assessments of up to $75.5 million against each of the 110 presently licensed nuclear reactors in the United States, payable at a rate not to exceed $10 million per reactor per year. Such assessments are subject to periodic inflation indexing and to a 5% surcharge if funds prove insufficient to pay claims.

The Company's interest in Units 1 and 2 could expose it to a potential loss, for each accident, of $111.8 million through assessments of $14.1 million per year in the event of a serious nuclear accident at its own or another licensed U.S. commercial nuclear reactor. The amendments also provide, among other things, that insurance and indemnity will cover precautionary evacuations, whether or not a nuclear incident actually occurs.

Nuclear Property Insurance: The Nine Mile Point Nuclear Site has $500 million primary nuclear property insurance with the Nuclear Insurance Pools (ANI/MRP). In addition, there is $1.4 billion, in excess of the $500 million primary nuclear insurance, with Nuclear Electric Insurance Limited (NEIL) and $850 million, which is also in excess of the $500 million primary and the $1.4 billion excess nuclear insurance, also with NEIL. The total nuclear property insurance is $2.75 billion. NEIL is a utility industry-owned mutual insurance company chartered in Bermuda. NEIL also provides insurance coverage against the extra expense incurred in purchasing replacement power during prolonged accidental outages. The insurance provides coverage for outages for 156 weeks, after a 21-week waiting period.

NEIL insurance is subject to retrospective premium adjustment under which the Company could be assessed up to approximately $15.8 million per loss.

Low Level Radioactive Waste: The Federal Low Level Radioactive Waste Policy Act as amended in 1985 requires states to join compacts or to individually develop their own low level radioactive waste disposal site. In response to the Federal law, New York State decided to develop its own site because of the large volume of low level radioactive waste it generates, and committed to develop a plan for the management of low level radioactive waste in New York State during the interim period until a disposal facility is available.

New York State is still developing disposal methodology and acceptance criteria for a disposal facility. The latest New York State low level radioactive waste site development schedule now assumes two possible siting scenarios, a volunteer approach and a non-volunteer approach, either of which would begin operation in 2001. Effective July 1, 1994, access to the Barnwell, South Carolina waste disposal facility was denied by the state of South Carolina, to out-of-region low level radioactive waste generators, including New York State. The Company has implemented a low level radioactive waste management program so that Unit 1 and Unit 2 are prepared to properly handle interim on-site storage of low level radioactive waste for at least a 10 year period.

Nuclear Fuel Disposal Cost: In January 1983, the Nuclear Waste Policy Act of 1982 (the Nuclear Waste Act) established a cost of $.001 per kilowatt-hour of net generation for current disposal of nuclear fuel and provides for a determination of the Company's liability to the Department of Energy (DOE) for the disposal of nuclear fuel irradiated prior to 1983. The Nuclear Waste Act also provides three payment options for liquidating such liability and the Company has elected to delay payment, with interest, until 1998, the year in which the Company had initially planned to ship irradiated fuel to an approved DOE disposal facility. See Note 6 – Capitalization. Progress in developing the DOE facility has been slow and it is anticipated that the DOE facility will not be ready to accept deliveries until at least 2010. The Company does not anticipate that the DOE will accept all of its spent fuel immediately upon opening of the facility, but rather expects a transfer period of as long as 20 years. The Company has several alternatives under consideration to provide additional storage facilities, as necessary. Each alternative will likely require NRC approval, may require other regulatory approvals and would likely require the incurrence of additional costs. The Company does not believe that the possible unavailability of the DOE disposal facility until 2010 will inhibit operation of either Unit.

4 Jointly-Owned Generating Facilities

The following table reflects the Company's share of jointly-owned generating facilities at December 31, 1994. The Company is required to provide its respective share of financing for any additions to the facilities. Power output and related expenses are shared based on proportionate ownership. The Company's share of expenses associated with these facilities is included in the appropriate operating expenses in the Consolidated Statements of Income.

		In thousands of dollars		
	Percentage Ownership	Utility Plant	Accumulated Depreciation	Construction Work in Progress
Roseton Steam Station				
Units No. 1 & 2 *(a)*...	25	$ 93,090	$ 46,625	$ 2,679
Oswego Steam Station				
Unit No. 6 *(b)*.....	76	$ 270,498	$106,343	$ 5,143
Nine Mile Point Nuclear Station				
Unit No. 2 *(c)*.....	41	$1,504,185	$252,747	$12,029

(a) The remaining ownership interests are Central Hudson Gas and Electric Corporation, the operator of the plant (35%), and Consolidated Edison Company of New York, Inc. (40%). On March 30, 1994, the Company and Central Hudson Gas and Electric Corporation (CHG&E) terminated and cancelled the 1987 agreement where CHG&E had agreed to acquire the Company's 25% interest in the plant in ten equal installments of 2.5% (30 mw.) starting on December 31, 1994 and on each December 31 thereafter. The cancellation agreement is subject to PSC approval. Output of Roseton Units No. 1 and 2, which have a capability of 1,200,000 kw., is shared in the same proportions as the cotenants' respective ownership interests.

(b) The Company is the operator. The remaining ownership interest is Rochester Gas and Electric Corporation (24%). Output of Oswego Unit No. 6, which has a capability of 850,000 kw., is shared in the same proportions as the cotenants' respective ownership interests.

(c) The Company is the operator. The remaining ownership interests are Long Island Lighting Company (18%), New York State Electric and Gas Corporation (18%), Rochester Gas and Electric Corporation (14%), and Central Hudson Gas and Electric Corporation (9%). Output of Unit 2, which has a capability of 1,062,000 kw., is shared in the same proportions as the cotenants' respective ownership interests.

5 Bank Credit Arrangements

At December 31, 1994, (excluding HYDRA-Co Enterprises, Inc. which was sold January 9, 1995), the Company had $580 million of bank credit arrangements with 16 banks. These credit arrangements consisted of $200 million in commitments under a Revolving Credit Agreement, $199 million in one-year commitments under Credit Agreements, $111 million in lines of credit and $70 million under a Bankers Acceptance Facility Agreement. The Revolving Credit Agreement extends into 1997 and the interest rate applicable to borrowing is based on certain rate options available under the Agreement. All of the other bank credit arrangements are subject to review on an ongoing basis with interest rates negotiated at the time of use. The Company also issues commercial paper. Unused bank credit facilities are held available to support the amount of commercial paper outstanding. In addition to these credit arrangements, the Company had outstanding at December 31, 1994, $161 million in bank loans which expire in 1995 and which the Company expects to renew.

The Company pays fees for substantially all of its bank credit arrangements. The Bankers Acceptance Facility Agreement, which is used to finance the fuel inventory for the Company's generating stations, provides for the payment of fees only at the time of issuance of each acceptance. The following table summarizes additional information applicable to short-term debt:

	In thousands of dollars	
At December 31,	**1994**	**1993**
Short-term debt:		
Commercial paper	$ 84,750	$210,016
Notes payable	321,000	153,000
Bankers acceptances.....	11,000	5,000
	$416,750	$368,016
Weighted average interest rate *(a)*.....	6.21%	3.60%
For Year Ended December 31,		
Daily average outstanding	$342,801	$165,458
Monthly weighted average interest rate *(a)*.....	4.71%	3.72%
Maximum amount outstanding.....	$497,700	$368,016

(a) Excluding fees

6 Capitalization

Capital Stock

The Company is authorized to issue 185,000,000 shares of common stock, $1 par value; 3,400,000 shares of preferred stock, $100 par value; 19,600,000 shares of preferred stock, $25 par value; and 8,000,000 shares of preference stock, $25 par value. The table below summarizes changes in the capital stock issued and outstanding and the related capital accounts for 1992, 1993 and 1994:

	Common Stock $1 par value		Preferred Stock						Capital Stock Premium and Expense (Net)*
			$100 par value			$25 par value			
	Shares	Amount*	Shares	Non-Redeemable*	Redeemable*	Shares	Non-Redeemable*	Redeemable*	
December 31, 1991:	136,099,654	$136,100	2,490,000	$210,000	$39,000 *(a)*	11,222,005	$80,000	$200,550 *(a)*	$1,650,312
Issued	1,059,953	1,060	—	—	—	—	—	—	18,401
Redemptions			(78,000)	—	(7,800)	(1,366,000)	—	(34,150)	796
Foreign currency translation adjustment									(11,494)
December 31, 1992:	137,159,607	137,160	2,412,000	210,000	31,200 *(a)*	9,856,005	80,000	166,400 *(a)*	1,658,015
Issued	5,267,450	5,267	—	—	—	—	—	—	111,497
Redemptions			(18,000)	—	(1,800)	(1,816,000)	—	(45,400)	(2,471)
Foreign currency translation adjustment									(4,335)
December 31, 1993:	142,427,057	142,427	2,394,000	210,000	29,400 *(a)*	8,040,005	80,000	121,000 *(a)*	1,762,706
Issued	1,884,409	1,884	—	—	—	6,000,000	—	150,000	27,630
Redemptions			(18,000)	—	(1,800)	(1,266,000)	—	(31,650)	(4,619)
Foreign currency translation adjustment									(6,213)
December 31, 1994:	144,311,466	$144,311	2,376,000	$210,000	$27,600 *(a)*	12,774,005	$80,000	$239,350 *(a)*	$1,779,504

* *In thousands of dollars*

(a) Includes sinking fund requirements due within one year.

The cumulative amount of foreign currency translation adjustment at December 31, 1994 was $(13,313).

Non-Redeemable Preferred Stock (Optionally Redeemable)

The Company has certain issues of preferred stock which provide for optional redemption at December 31, as follows:

Series	Shares	*In thousands of dollars* 1994	1993	Redemption price per share *(Before adding accumulated dividends)*
Preferred $100 par value:				
3.40%	200,000	$ 20,000	$ 20,000	$103.50
3.60%	350,000	35,000	35,000	104.85
3.90%	240,000	24,000	24,000	106.00
4.10%	210,000	21,000	21,000	102.00
4.85%	250,000	25,000	25,000	102.00
5.25%	200,000	20,000	20,000	102.00
6.10%	250,000	25,000	25,000	101.00
7.72%	400,000	40,000	40,000	102.36
Preferred $25 par value:				
Adjustable Rate				
Series A	1,200,000	30,000	30,000	25.00
Series C	2,000,000	50,000	50,000	25.75*(1)*
		$290,000	$290,000	

(1) Eventual minimum $25.00

Mandatorily Redeemable Preferred Stock

The Company has certain issues of preferred stock which provide for mandatory and optional redemption at December 31, as follows:

	Shares		*In thousands of dollars*		Redemption price per share *(Before adding accumulated dividends)*	
Series	1994	1993	1994	1993	1994	Eventual minimum
Preferred $100 par value:						
7.45% *(a)*	276,000	294,000	$27,600	$ 29,400	$102.41	$100.00
Preferred $25 par value:						
7.85% *(a)*	914,005	914,005	22,850	22,850	*(b)*	25.00
8.375% *(a)*	400,000	500,000	10,000	12,500	25.33	25.00
8.70% *(a)*	200,000	600,000	5,000	15,000	25.25	25.00
8.75%	—	600,000	—	15,000	25.25	25.00
9.50%	6,000,000	—	150,000	—	*(c)*	25.00
9.75% *(a)*	210,000	276,000	5,250	6,900	25.13	25.00
Adjustable Rate Series B *(a)*	1,850,000	1,950,000	46,250	48,750	25.00	25.00
			266,950	150,400		
Less sinking fund requirements			10,950	27,200		
			$256,000	$123,200		

(a) These series require mandatory sinking funds for annual redemption and provide optional sinking funds through which the Company may redeem, at par, a like amount of additional shares (limited to 120,000 shares of the 7.45% series). The option to redeem additional amounts is not cumulative.

(b) Not redeemable until 1996.

(c) Not redeemable until 1999.

The Company's five year mandatory sinking fund redemption requirements for preferred stock, in thousands, for 1995 through 1999 are as follows: $10,950; $9,150; $10,120; $10,120; and $7,620, respectively.

Long-Term Debt

Long-term debt at December 31, consisted of the following:

		In thousands of dollars	
Series	Due	1994	1993
First mortgage bonds:			
8 7/8%	1994	$ —	$ 150,000
4 5/8%	1994	—	40,000
5 7/8%	1996	45,000	45,000
6 1/4%	1997	40,000	40,000
6 1/2%	1998	60,000	60,000
10 1/4%	1999**	—	100,000
10 3/8%	1999**	—	100,000
9 1/2%	2000	150,000	150,000
6 7/8%	2001	210,000	—
9 1/4%	2001	100,000	100,000
5 7/8%	2002	230,000	230,000
6 7/8%	2003	85,000	85,000
7 3/8%	2003	220,000	220,000
8%	2004	300,000	300,000
6 5/8%	2005	110,000	110,000
9 3/4%	2005	150,000	150,000
*6 5/8%	2013	45,600	45,600
*11 1/4%	2014**	—	75,690
*11 3/8%	2014**	—	40,015
9 1/2%	2021	150,000	150,000
8 3/4%	2022	150,000	150,000
8 1/2%	2023	165,000	165,000
7 7/8%	2024	210,000	210,000
*8 7/8%	2025	75,000	75,000
*7.2%	2029	115,705	—
Total First Mortgage Bonds		2,611,305	2,791,305
Promissory notes:			
*Adjustable Rate Series due			
July 1, 2015		100,000	100,000
December 1, 2023		69,800	69,800
December 1, 2025		75,000	75,000
December 1, 2026		50,000	50,000
March 1, 2027		25,760	25,760
July 1, 2027		93,200	93,200
Unsecured notes payable:			
Medium Term Notes, Various rates, due 1994-2004		45,000	55,500
Swiss Franc Bonds due December 15, 1995		50,000	50,000
Revolving Credit Agreement		99,000	—
Other		169,421	176,888
Unamortized premium (discount)		(12,641)	(12,656)
TOTAL LONG-TERM DEBT		3,375,845	3,474,797
Less long-term debt due within one year		77,971	216,185
		$3,297,874	$3,258,612

**Tax-exempt pollution control related issues* ***Retired prior to maturity*

Several series of First Mortgage Bonds and Notes were issued to secure a like amount of tax-exempt revenue bonds issued by the New York State Energy Research and Development Authority (NYSERDA). Approximately $414 million of such bonds bear interest at a daily adjustable interest rate (with a Company option to convert to other rates, including a fixed interest rate which would require the Company to issue First Mortgage Bonds to secure the debt) which averaged 2.76% for 1994 and 2.14% for 1993 and are supported by bank direct pay letters of credit. Pursuant to agreements between NYSERDA and the Company, proceeds from such issues were used for the purpose of financing the construction of certain pollution control facilities at the Company's generating facilities or to refund outstanding tax-exempt bonds and notes.

The $115.7 million of tax-exempt bonds due 2014 were refinanced at 7.2% during 1994 pursuant to a forward refunding agreement entered into in 1992.

Notes payable include a Swiss franc bond issue maturing in 1995 equivalent to $50 million in U.S. funds. Simultaneously with the sale of these bonds, the Company entered into a currency exchange agreement to fully hedge against currency exchange rate fluctuations.

Other long-term debt in 1994 consists of obligations under capital leases of approximately $44.3 million, a liability to the U.S. Department of Energy for nuclear fuel disposal of approximately $97.4 million (see Note 3 – "Nuclear Fuel Disposal Costs") and liabilities for unregulated generator contract terminations of approximately $27.7 million (see Note 9 – "Long-term Contracts for the Purchase of Electric Power").

Certain of the Company's debt securities provide for a mandatory sinking fund for annual redemption. The aggregate maturities of long-term debt for the five years subsequent to December 31, 1994, excluding capital leases, are approximately $73 million, $61 million, $145 million, $164 million and $0, respectively.

7 Federal and Foreign Income Taxes

At December 31, the deferred tax liabilities (assets) were comprised of the following:

	In thousands of dollars	
	1994	1993
Alternative minimum tax	$ (93,893)	$ (95,071)
Unbilled revenue	(98,201)	(82,829)
Other	(258,621)	(163,256)
Total deferred tax assets	(450,715)	(341,156)
Depreciation related	1,398,695	1,387,244
Investment tax credit related	95,325	108,140
Other	215,158	190,031
Total deferred tax liabilities	1,709,178	1,685,415
Accumulated deferred income taxes	$1,258,463	$1,344,259

Components of United States and foreign income before income taxes:

	In thousands of dollars		
	1994	1993	1992
United States	$291,501	$438,914	$410,283
Foreign	15,475	(24,845)	18,394
Consolidating eliminations	(18,523)	4,837	(16,741)
Income before income taxes	$288,453	$418,906	$411,936

Following is a summary of the components of Federal and foreign income tax and a reconciliation between the amount of Federal income tax expense reported in the Consolidated Statements of Income and the computed amount at the statutory tax rate:

SUMMARY ANALYSIS:

		In thousands of dollars		
		1994	1993	1992
Components of Federal and foreign income taxes:				
Current tax expense:	Federal	$117,314	$118,918	$119,929
	Foreign	4,423	8,445	915
		121,737	127,363	120,844
Deferred tax expense:	Federal	(6,931)	35,152	54,858
	Foreign	3,028	—	7,531
		(3,903)	35,152	62,389
Income taxes included in Operating Expenses		117,834	162,515	183,233
Current Federal and foreign income tax credits included in Other Income and Deductions		(11,507)	(16,061)	(31,787)
Deferred Federal and foreign income tax expense included in Other Income and Deductions		5,142	621	4,058
Total		$111,469	$147,075	$155,504
Reconciliation between Federal and foreign income taxes and the tax computed at prevailing U.S. statutory rate on income before income taxes:				
Computed tax		$100,959	$146,617	$140,058
Reduction (increase) attributable to flow-through of certain tax adjustments:				
Depreciation		(33,328)	(35,153)	(37,543)
Allowance for funds used during construction		3,291	2,951	11,205
Cost of removal		8,908	7,822	6,845
Deferred investment tax credit amortization		8,018	8,018	8,024
Other		2,601	15,904	(3,977)
		(10,510)	(458)	(15,446)
Federal and foreign income taxes		$111,469	$147,075	$155,504

8 Pension and Other Retirement Plans

The Company and certain of its subsidiaries have non-contributory, defined-benefit pension plans covering substantially all their employees. Benefits are based on the employee's years of service and compensation level. The Company's general policy is to fund the pension costs accrued with consideration given to the maximum amount that can be deducted for Federal income tax purposes.

During 1994, the Company offered an early retirement program and a voluntary separation program (together the VERP) to reduce the Company's staffing levels and streamline operations. The VERP, which included both represented and non represented employees, was accepted by approximately 1,400 employees. The following table sets forth the components and allocation of the costs of the programs:

	In thousands of dollars		
Plan	Electric	Gas	Total
Pension benefits	$107,800	$ 6,200	$114,000
Other Postretirement benefits	75,900	4,300	80,200
Other Postemployment benefits	16,800	900	17,700
	200,500	11,400	211,900
Less: allocation to cotenant and other ventures	3,900	—	3,900
Cost	$196,600	$11,400	$208,000

Included in 1994 operating expenses is a one-time charge of $196.6 million, representing the cost of the VERP allocable to electric customers. The Company has recorded a regulatory asset for the portion of the VERP cost allocable to gas customers of approximately $11.4 million, which it has proposed to recover over a five-year period beginning in 1995.

Net pension cost for 1994, 1993 and 1992 included the following components:

	In thousands of dollars		
	1994	1993	1992
Service cost — benefits earned during the period	$ 30,400	$ 30,100	$ 27,100
Interest cost on projected benefit obligation	62,700	54,200	48,800
Actual return on plan assets	7,700	(106,100)	(59,600)
Net amortization and deferral	(63,600)	38,700	6,900
Net pension cost	37,200	16,900	23,200
VERP costs	114,000	—	—
Regulatory asset	(6,200)	—	—
Total pension cost *(1)*	$145,000	$ 16,900	$ 23,200

(1) $5.9 million for 1994, $5.6 million for 1993 and $6.2 million for 1992 was related to construction labor and, accordingly, was charged to construction projects.

The following table sets forth the plan's funded status and amounts recognized in the Company's Consolidated Balance Sheets:

	In thousands of dollars	
At December 31,	1994	1993
Actuarial present value of accumulated benefit obligations:		
Vested benefits	$640,689	$501,900
Non-vested benefits	69,642	64,973
Accumulated benefit obligations	710,331	566,873
Additional amounts related to projected pay increases	222,667	236,906
Projected benefits obligation for service rendered to date	932,998	803,779
Plan assets at fair value, consisting primarily of listed stocks, bonds, other fixed income obligations and insurance contracts	893,313	913,200
Plan assets in excess of (less than) projected benefit obligations	(39,685)	109,421
Unrecognized net obligation at January 1, 1987 being recognized over approximately 19 years	27,122	32,392
Unrecognized net gain from actual return on plan assets different from that assumed	(58,379)	(114,536)
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions amortized over 10 years	(67,857)	(39,652)
Prior service cost not yet recognized in net periodic pension cost	44,421	49,613
Pension asset (liability) included in the consolidated balance sheets	$(94,378)	$ 37,238
Principle Actuarial Assumptions (%):		
Discount Rate	8.00	7.30
Rate of increase in future compensation levels (plus merit increases)	3.25	3.25
Long-term rate of return on plan assets	8.75	9.00

In addition to providing pension benefits, the Company and its subsidiaries provide certain health care and life insurance benefits for active and retired employees and dependents. Under current policies, substantially all of the Company's employees may be eligible for continuation of some of these benefits upon normal or early retirement.

The Company accounts for the cost of these benefits in accordance with PSC policy requirements which generally comply with SFAS No. 106. This Statement, which was implemented beginning in 1993, requires accrual accounting by employers for postretirement benefits other than pensions reflecting currently earned benefits. The 1992 cost of these benefits was approximately $16.7 million. The Company has various trusts to fund its future OPEB obligation. The Company made contributions to such trusts, equal to the amount received in rates, of approximately $24 million and $12 million in 1994 and 1993, respectively.

Net postretirement benefit cost for 1994 and 1993 included the following components:

	In thousands of dollars	
	1994	1993
Service cost — benefits attributed to service during the period	$ 15,000	$12,300
Interest cost on accumulated benefit obligation	40,200	32,800
Actual return on plan assets	(900)	—
Amortization of the transition obligation over 20 years	20,200	20,400
Net amortization	8,900	—
Net postretirement benefit cost	83,400	65,500
VERP costs	80,200	—
Regulatory asset	(4,300)	—
Total postretirement benefit cost	$159,300	$65,500

The following table sets forth the plan's funded status and amounts recognized in the Company's Consolidated Balance Sheet:

	In thousands of dollars	
At December 31,	1994	1993
Actuarial present value of accumulated benefit obligations:		
Retired and surviving spouses	$371,223	$224,936
Active eligible	20,400	73,474
Active ineligible	208,900	220,420
Accumulated benefit obligations	600,523	518,830
Plan assets at fair value, consisting primarily of listed stocks, bonds and other fixed obligations	36,754	11,967
Accumulated postretirement benefit obligation in excess of plan assets	563,769	506,863
Unrecognized net loss from past experience different from that assumed and effects of changes in assumptions	71,939	82,756
Unrecognized transition obligation to be amortized over 20 years	337,336	388,600
Accrued postretirement benefit liability included in the consolidated balance sheets	$154,494	$ 35,507
Principle actuarial assumptions (%):		
Discount Rate	8.00	7.30
Long-term rate of return on plan assets	8.75	—
Health care cost trend rate:		
Pre-65	12.00	10.05
Post-65	9.00	7.05

At December 31, 1994, the assumed health cost trend rates gradually decline to 5.75% in 1999. If the health care cost trend rate was increased by one percent, the accumulated postretirement benefit obligation as of December 31, 1994 would increase by approximately 11.2% and the aggregate of the service and interest cost component of net periodic postretirement benefit cost for the year would increase by approximately 12.7%.

On January 1, 1994, the Company adopted Statement of Financial Accounting Standards No. 112, "Employers' Accounting for Postemployment Benefits" (SFAS No. 112). This Statement requires employers to recognize the obligation to provide postemployment benefits if the obligation is attributable to employees' past services, rights to those benefits are vested, payment is probable and the amount of the benefits can be reasonably estimated. The Company previously accounted for such costs on a cash basis. At December 31, 1994, the Company's postemployment benefit obligation is approximately $26.3 million, including the portion of the obligation related to the VERP. The Company has absorbed in 1994 earnings, $16.8 million related to the postemployment benefit portion of VERP costs allocated to the electric business and has recorded a regulatory asset of approximately $9.5 million, the majority of which is expected to be recovered equally over three years beginning in 1995.

9 Commitments and Contingencies

Construction Program: The Company is committed to an ongoing construction program to assure delivery of its electric and gas services. The Company presently estimates that the construction program for the years 1995 through 1999 will require approximately $1.7 billion, excluding AFC and nuclear fuel. For the years 1995 through 1999, the estimates are $341 million, $341 million, $343 million, $344 million and $344 million, respectively. These amounts are reviewed by management as circumstances dictate.

Sale of Customer Receivables: The Company has an agreement whereby it can sell an undivided interest in a designated pool of customer receivables, including accrued unbilled electric revenues, up to a maximum of $200 million. At December 31, 1994 and 1993, respectively, $200 million of receivables had been sold under this agreement. The undivided interest in the designated pool of receivables was sold with limited recourse. The agreement provides for a loss reserve pursuant to which additional customer receivables are assigned to the purchaser to protect against bad debts. To the extent actual loss experience of the pool receivables exceeds the loss reserve, the purchaser absorbs the excess. For receivables sold, the Company has retained collection and administrative responsibilities as agent for the purchaser. As collections reduce previously sold undivided interests, new receivables are customarily sold.

Long-term Contracts for the Purchase of Electric Power: At January 1, 1995, the Company had long-term contracts to purchase electric power from the following generating facilities owned by the New York Power Authority (NYPA):

Facility	Expiration Date of Contract	Purchased Capacity in kw.	Estimated Annual Capacity Cost
Niagara hydroelectric project.....	2007	926,000 *(a)*	$23,200,000
St. Lawrence hydroelectric project.....	2007	104,000	1,300,000
Blenheim-Gilboa pumped storage generating station	2002	270,000	7,500,000
Fitzpatrick nuclear plant	year-to-year basis	74,000 *(b)*	7,900,000
		1,374,000	$39,900,000

(a) 926,000 kw for summer of 1995; 951,000 kw for winter of 1995-96.

(b) 74,000 kw for summer of 1995; 110,000 kw for winter of 1995-96.

The purchase capacities shown above are based on the contracts currently in effect. The estimated annual capacity costs are subject to price escalation and are exclusive of applicable energy charges. The total cost of purchases under these contracts was approximately $85.1 million, $72.2 million and $64.4 million for the years 1994, 1993 and 1992, respectively.

Under the requirements of the Federal Public Utility Regulatory Policies Act of 1978, the Company is required to purchase power generated by unregulated generators, as defined therein. At December 31, 1994, the Company had virtually all unregulated generator capacity scheduled to come into service on line, totaling approximately 2,592 MW of capacity of which 2,273 MW is considered firm. The following table shows the payments for fixed capacity costs and energy the Company estimates it will be obligated to make under these contracts. The payments are subject to the tested capacity and availability of the facilities, scheduling and price escalation.

	In thousands of dollars		
Year	Fixed Costs	Energy	Total
1995	$201,000	$840,000	$1,041,000
1996	232,000	859,000	1,091,000
1997	246,000	906,000	1,152,000
1998	269,000	944,000	1,213,000
1999	271,000	991,000	1,262,000

The fixed costs relate to contracts with 10 facilities where the Company is required to make fixed payments, including payments when a facility is not operating but available for service. These 10 facilities account for approximately 708 MW of capacity, with contract lengths ranging from 20 to 35 years. The terms of these contracts allow the Company to schedule energy deliveries from the facilities and then pay for the energy delivered. The Company estimates the fixed payments under these contracts will aggregate to approximately $7.5 billion over their terms. Contracts relating to the remaining facilities in service at December 31, 1994, require the Company to pay only when energy is delivered. The Company currently recovers both capacity and energy payments to unregulated generators through base rates and/or through the FAC. The Company has proposed to recover such costs through the FAM beginning in 1995.

The Company paid approximately $960 million, $736 million and $543 million in 1994, 1993 and 1992 for 14,800,000 mwhrs, 11,720,000 mwhrs and 8,632,000 mwhrs, respectively, of electric power under all unregulated generator contracts.

In an effort to reduce the costs associated with unregulated generators, at December 31, 1994, the Company had agreed to buy out 15 projects consisting of 453 MW of capacity. See Note 2 – Rate and Regulatory Issues and Contingencies and Note 6 – Capitalization. Additionally, the Company has entered into agreements with 41 projects, comprising 1,153 MW of capacity, which allow the Company to curtail purchases from these unregulated generators when demand is low. The Company expects to continue efforts of these types into the future, to control its power supply and related costs, but at this time cannot predict the outcome of such efforts.

Tax assessments: The Internal Revenue Service (IRS) has conducted an examination of the Company's Federal income tax returns for the years 1987 and 1988 and has submitted a Revenue Agents' Report to the Company. The IRS has proposed various adjustments to the Company's federal income tax liability for these years which could increase Federal income tax liability by approximately $80 million, before assessment of penalties and interest. Included in these proposed adjustments are several significant issues involving Unit 2. The Company is vigorously defending its position on each of the issues, and submitted a protest to the IRS in 1993. Pursuant to the Unit 2 settlement entered into with the PSC in 1990, to the extent the IRS is able to sustain adjustments, the Company will be required to absorb a portion of any assessment. The Company believes any such disallowance will not have a material impact on its financial position or results of operations.

Litigation: In March 1993, a complaint was filed in the Supreme Court of the State of New York, Albany County, against the Company and certain of its officers and employees. The plaintiff, Inter-Power of New York, Inc. (Inter-Power), alleges, among other matters, fraud, negligent misrepresentation and breach of contract in connection with the Company's alleged termination of a power purchase agreement in January 1993. The plaintiff sought enforcement of the original contract or compensatory and punitive damages in an aggregate amount that would not exceed $1 billion, excluding pre-judgment interest.

In July 1994, the New York Supreme Court dismissed Inter-Power's complaint for lack of merit and denied Inter-Power's cross-motion to compel disclosure. In August 1994, Inter-Power filed a notice of appeal of this decision which was rejected. Inter-Power is pursuing further appeals of this decision. The Company believes it has meritorious defenses and will continue to defend the lawsuit vigorously.

In November 1993, Fourth Branch Associates Mechanicville (Fourth Branch) filed suit against the Company and several of its officers and employees in the New York Supreme Court, Albany County, seeking compensatory damages of $50 million, punitive damages of $100 million and injunctive and other related relief. The suit grows out of the Company's termination of a contract for Fourth Branch to operate and maintain a hydroelectric plant the Company owns in the Town of Halfmoon, New York. Fourth Branch's complaint also alleges claims based on the inability of Fourth Branch and the Company to agree on terms for the purchase of power from a new facility that Fourth Branch hoped to construct at the Mechanicville site. In January 1994, the defendants filed a joint motion to dismiss Fourth Branch's complaint. This motion has yet to be decided. The Company understands that Fourth Branch has filed for bankruptcy.

In October 1994, Fourth Branch petitioned the PSC to direct the Company to sell the Mechanicville facility to Fourth Branch for fair value and to relinquish its FERC license, or in the alternative, to require the Company to turn over to Fourth Branch its rate base investment in the plant. The Company has opposed this petition.

The Medina Power Company is an independent power project with a contract requiring it to be a qualifying facility (QF) under federal law or face a contractual penalty. Having come on-line without a steam host, Medina did not meet this QF requirement, subjecting it to a 15% rate reduction. The Company advised Medina that it had exercised its contract right and reduced the rate accordingly. Medina is seeking $40 million in compensatory damages, a trebling of this amount to $120 million under the New York State antitrust laws, and $100 million in punitive damages. The Company believes Medina's case is without merit, but cannot predict the outcome of this action.

The Company is involved in a number of court cases regarding the price of energy it is required to purchase in excess of contract levels from certain unregulated generators ("overgeneration"). The Company has paid the unregulated generators based on its long-run avoided cost for all such overgeneration rather than the price which the unregulated generators contend is applicable under the contracts. The Company cannot predict the outcome of these actions, but will continue to aggressively press its position.

The Company believes it has meritorious defenses and intends to defend these lawsuits vigorously, but can neither provide any judgment regarding the likely outcome nor provide any estimate or range of possible loss.

Environmental Contingencies: The public utility industry typically utilizes and/or generates in its operations a broad range of potentially hazardous wastes and by-products. The Company believes it is handling identified wastes and by-products in a manner consistent with Federal, state and local requirements and has implemented an environmental audit program to identify any potential areas of concern and assure compliance with such requirements. The Company is also currently conducting a program to investigate and restore, as necessary to meet current environmental standards, certain properties associated with its former gas manufacturing process and other properties which the Company has learned may be contaminated with industrial waste, as well as investigating identified industrial waste sites as to which it may be determined that the Company contributed. The Company has been advised that various Federal, state or local agencies believe certain properties require investigation and has prioritized the sites to enhance the management of investigation and remediation, if necessary.

The Company is currently aware of 89 sites with which it has been or may be associated, including 47 which are Company-owned. With respect to non-owned sites, the Company may be required to contribute some proportionate share of remedial costs.

Investigations at each of the Company-owned sites are designed to (1) determine if environmental contamination problems exist, (2) determine the extent, rate of movement and concentration of pollutants, (3) if necessary, determine

the appropriate remedial actions required for site restoration and (4) where appropriate, identify other parties who should bear some or all of the cost of remediation. Legal action against such other parties, if necessary, will be initiated. After site investigations are completed, the Company expects to determine site-specific remedial actions and to estimate the attendant costs for restoration. However, since technologies are still developing and the Company has not yet undertaken any full-scale remedial actions at any identified sites, nor have any detailed remedial designs been prepared or submitted to appropriate regulatory agencies, the ultimate cost of remedial actions may change substantially.

Estimates of the cost of remediation and post-remedial monitoring are based upon a variety of factors, including identified or potential contaminants, location, size and use of the site, proximity to sensitive resources, status of regulatory investigation and knowledge of activities at similarly situated sites and the Environmental Protection Agency (EPA) figure for average cost to remediate a site. Actual Company expenditures are dependent upon the total cost of investigation and remediation and the ultimate determination of the Company's share of responsibility for such costs, as well as the financial viability of other identified responsible parties since clean-up obligations are joint and several. The Company has denied any responsibility in certain of these Potentially Responsible Party (PRP) sites and is contesting liability accordingly.

As a consequence of site characterizations and assessments completed to date and negotiations with PRPs, the Company has accrued a liability of $240 million, representing the low end of the range of its share of the estimated cost for investigation and remediation. The potential high end of the range is presently estimated at approximately $1 billion, including approximately $500 million in the unlikely event the Company was required to assume 100% responsibility at non-owned sites.

The Company believes that costs incurred in the investigation and restoration process for both Company-owned sites and sites with which it is associated will be recoverable in the ratesetting process. See Note 2 – Rate and Regulatory Issues and Contingencies. Rate agreements in effect since 1991 provide for recovery of anticipated investigation and remediation expenditures. The Company has proposed in its multi-year rate case net recovery of $13.5 million for 1995 for site investigation and remediation. The PSC Staff reserves the right to review the appropriateness of the costs incurred. While the PSC Staff has not challenged any remediation costs to date, the PSC Staff asserted in the current gas rate proceeding that the Company must, in future rate proceedings, justify why it is appropriate that remediation costs associated with non-utility property owned by the Company be recovered from ratepayers. Based upon management's assessment that remediation costs will be recovered from ratepayers, a regulatory asset has been recorded representing the future recovery of remediation obligations accrued to date.

The Company is currently providing notices of insurance claims to carriers with respect to the investigation and remediation costs for manufactured gas plant, industrial waste sites and sites for which the Company has been identified as a PRP. The Company is unable to predict whether such insurance claims will be successful.

10 Disclosures about Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

Cash and short-term investments: The carrying amount approximates fair value because of the short maturity of the financial instruments.

Long-term investments: The carrying value and market value are not material to the financial statements.

Short-term debt: The carrying amount approximates fair value because of the short-term nature of the borrowings.

Mandatorily redeemable preferred stock: Fair value of the mandatorily redeemable preferred stock has been determined by one of the Company's brokers.

Long-term debt: The fair value of the Company's long-term debt has been estimated by one of the Company's brokers. The carrying value of NYSERDA bonds and other long-term debt are considered to approximate fair value.

The financial instruments held or issued by the Company are for purposes other than trading. The estimated fair values of the Company's financial instruments are as follows:

	In thousands of dollars			
	1994		1993	
At December 31,	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and short-term investments	$ 94,330	$ 94,330	$ 124,351	$ 124,351
Short-term debt	416,750	416,750	368,016	368,016
Mandatorily redeemable preferred stock	266,950	277,072	150,400	155,326
Long-term debt: First Mortgage Bonds	2,611,305	2,367,755	2,791,305	2,969,228
Medium Term Notes	45,000	45,783	55,500	62,458
NYSERDA bonds	413,760	413,760	413,760	413,760
Swiss franc bond	50,000	83,682	50,000	73,794
Other	224,107	224,107	131,587	131,587

In addition, off balance sheet financial instruments, consisting of a currency exchange agreement used to fully hedge against currency exchange rate fluctuations related to the Swiss Franc bond, had a fair value of $31.7 and $20.1 million at December 31, 1994 and 1993, respectively. As a result of this agreement, at December 31, 1994, the Company's net obligation due at maturity on December 15, 1995, of the Swiss Franc bond is estimated to be approximately $50 million.

On January 1, 1994, the Company adopted Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments in Debt and Equity Securities." This statement addresses the accounting and reporting for investments in equity securities that have readily determinable fair values and for all investments in debt securities. The Company's investments in debt and equity securities are held in trust funds for the purpose of funding the nuclear decommissioning of Unit 1 and its share of Unit 2. See Note 3 – "Nuclear Plant Decommissioning." The Company has classified all investments in debt and equity securities as available for sale and has recorded all such investments at their fair market value at December 31, 1994. The proceeds from the sale of investments were $104.6 million in 1994. Using the specific identification method to determine cost, the gross realized gains and gross realized losses on those sales were $1.1 and $1.6 million, respectively. Net realized and unrealized gains and losses are reflected in Accumulated Depreciation and Amortization on the Balance Sheet, which is consistent with the method used by the Company to account for the decommissioning costs recovered in rates. The recorded fair values and cost basis of the Company's investments in debt and equity securities is as follows:

At December 31, 1994:	*In thousands of dollars*			
Security Type	Cost	Gross Unrealized Gain	Gross Unrealized (Loss)	Fair Value
U. S. Government Obligations	$15,165	$ 19	$ (325)	$14,859
Tax Exempt Obligations	45,029	659	(1,778)	43,910
Corporate Obligations	27,407	9	(1,253)	26,163
Other	8,121	28	(348)	7,801
	$95,722	$715	$(3,704)	$92,733

The contractual maturities of the Company's investments in debt securities is as follows:

	In thousands of dollars	
At December 31, 1994:	Fair Value	Cost
1 year to 5 years	$11,197	$11,429
5 years to 10 years	20,111	20,778
Due after 10 years	57,689	59,591

11 Information Regarding the Electric and Gas Businesses

The Company is engaged in the electric and natural gas utility businesses. Certain 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 the practice established for regulatory purposes. Identifiable assets include net utility plant, materials and supplies, deferred finance charges, deferred recoverable energy costs and certain other regulatory and other assets. Corporate assets consist of other property and investments, cash, accounts receivable, prepayments, unamortized debt expense and certain other regulatory and other assets.

	In thousands of dollars		
	1994	1993	1992
Operating revenues:			
Electric	$3,528,987	$3,332,464	$3,147,676
Gas	623,191	600,967	553,851
Total	$4,152,178	$3,933,431	$3,701,527
Operating income before taxes:			
Electric	$ 466,978*	$ 625,852	$ 645,696
Gas	83,229	61,163	61,863
Total	$ 550,207	$ 687,015	$ 707,559
Pretax operating income, including AFC:			
Electric	$ 475,694	$ 641,435	$ 666,269
Gas	83,592	61,812	62,721
Total	559,286	703,247	728,990
Income taxes, included in operating expenses:			
Electric	97,417	148,695	176,901
Gas	20,417	13,820	6,332
Total	117,834	162,515	183,233
Other (income) and deductions	(21,410)	(22,475)	(11,391)
Interest charges	285,878	291,376	300,716
Net income	$ 176,984	$ 271,831	$ 256,432
Depreciation and amortization:			
Electric	$ 283,694	$ 255,718	$ 255,256
Gas	24,657	20,905	18,834
Total	$ 308,351	$ 276,623	$ 274,090
Construction expenditures (including nuclear fuel):			
Electric	$ 376,159	$ 429,265	$ 442,741
Gas	113,965	90,347	59,503
Total	$ 490,124	$ 519,612	$ 502,244
Identifiable assets:			
Electric	$7,162,118	$7,042,762	$7,000,659
Gas	1,009,566	926,648	783,766
Total	8,171,684	7,969,410	7,784,425
Corporate assets	1,477,755	1,501,917	806,110
Total assets	$9,649,439	$9,471,327	$8,590,535

* Includes $196,625 of VERP expenses.

12 Quarterly Financial Data (Unaudited)

Operating revenues, operating income, net income and earnings per common share by quarters from 1994, 1993 and 1992, respectively, are shown in the following table. The Company, in its opinion, has included all adjustments necessary for a fair presentation of the results of operations for the quarters. Due to the seasonal nature of the utility business, the annual amounts are not generated evenly by quarter during the year. The Company's quarterly results of operations reflect the seasonal nature of its business, with peak electric loads in summer and winter periods. Gas sales peak in the winter.

	In thousands of dollars			
Quarter Ended	Operating revenues	Operating income (loss)	Net income (loss)	Earnings (loss) per common share
December 31, 1994	$1,018,110	$ (10,536)	$(77,422)	$(.61)
1993	988,195	95,623	30,955	.16
1992	963,629	119,181	41,835	.24
September 30, 1994	$ 918,810	$108,937	$ 48,383	$ .27
1993	879,952	108,539	48,595	.29
1992	822,530	89,658	40,401	.23
June 30, 1994	$ 979,700	$130,624	$ 67,559	$ .42
1993	929,245	132,669	65,325	.41
1992	881,427	137,515	71,734	.46
March 31, 1994	$1,235,558	$203,348	$138,464	$ .92
1993	1,136,039	187,669	126,956	.86
1992	1,033,941	177,972	102,462	.68

In the fourth quarter of 1994 the Company recorded $196.6 million ($.89 per common share) for the electric expense allocation of the VERP. In the second quarter of 1992, the third quarter of 1993, and the fourth quarter of 1994 the Company recorded $22.8 million ($.11 per common share), $10.3 million ($.05 per common share) and $12.3 million ($.06 per common share), respectively, for MERIT earned in accordance with the 1991 Agreement. In the first and fourth quarters of 1992 the Company recorded $21 million ($.09 per common share) and $24 million ($.09 per common share), respectively, to writedown its subsidiary investment in oil and gas properties.

Electric and Gas Statistics

ELECTRIC STATISTICS

	1994	1993	1992
Electric sales *(Millions of kw-hrs.)*:			
Residential	10,415	10,475	10,392
Commercial	11,813	12,079	11,628
Industrial	7,445	7,088	7,477
Industrial – Special	4,118	3,888	3,857
Municipal service	215	220	227
Other electric systems	7,593	3,974	3,030
	41,599	37,724	36,611
Electric revenues *(Thousands of dollars)*:			
Residential	$1,233,007	$1,171,787	$1,096,418
Commercial	1,272,234	1,241,743	1,160,643
Industrial	577,473	553,921	589,258
Industrial – Special	49,217	42,988	39,409
Municipal service	50,007	50,642	50,327
Other electric systems	167,131	105,044	93,283
Miscellaneous	179,918	166,339	118,338
	$3,528,987	$3,332,464	$3,147,676
Electric customers *(Average)*:			
Residential	1,405,343	1,398,756	1,389,470
Commercial	144,249	143,078	142,345
Industrial	2,105	2,132	2,197
Industrial – Special	82	76	72
Other	2,318	3,438	3,262
	1,554,097	1,547,480	1,537,346
Residential *(Average)*:			
Annual kw-hr. use per customer	7,411	7,489	7,479
Cost to customer per kw-hr.	11.84¢	11.19¢	10.55¢
Annual revenue per customer	$877.37	$837.74	$789.09

GAS STATISTICS

	1994	1993	1992
Gas sales *(Thousands of dekatherms)*:			
Residential	56,491	54,908	53,945
Commercial	25,783	23,743	22,289
Industrial	3,097	4,316	1,772
Other gas systems	244	234	1,190
Total sales	85,615	83,201	79,196
Spot market	1,572	13,223	1,146
Transportation of customer-owned gas	85,910	67,741	65,845
Total gas delivered	173,097	164,165	146,187
Gas revenues *(Thousands of dollars)*:			
Residential	$398,257	$370,565	$354,429
Commercial	159,157	144,834	132,609
Industrial	14,602	18,482	10,001
Other gas systems	1,159	1,066	4,737
Spot market	4,370	29,782	2,576
Transportation of customer-owned gas	38,346	34,843	42,726
Miscellaneous	7,300	1,395	6,773
	$623,191	$600,967	$553,851
Gas customers *(Average)*:			
Residential	463,933	455,629	446,571
Commercial	40,256	39,662	38,675
Industrial	256	233	234
Other	1	1	1
Transportation	661	673	673
	505,107	496,198	486,154
Residential *(Average)*:			
Annual dekatherm use per customer	121.8	120.5	120.8
Cost to customer per dekatherm	$7.05	$6.75	$6.57
Annual revenue per customer	$858.44	$813.30	$793.67
Maximum day gas sendout (dekatherms)	995,801	929,285	905,872

ELECTRIC CAPABILITY

December 31,	Thousands of kilowatts 1994	%	1993	1992
Owned:				
Coal	1,285	16.0	1,285	1,285
Oil	646	8.1	1,496	1,496
Dual Fuel — Oil/Gas	700	8.7	700	700
Nuclear	1,048	13.1	1,048	1,059
Hydro	700	8.7	700	706
Natural Gas	—	—	74	108
	4,379	54.6	5,303	5,354
Purchased:				
New York Power Authority (NYPA)				
— Hydro	1,300	16.2	1,302	1,302
— Nuclear	74	0.9	65	67
Unregulated generators	2,273	28.3	2,253	1,549
	3,647	45.4	3,620	2,918
Total capability *	8,026	100.0	8,923	8,272
Electric peak load	6,458		6,191	6,205

*Available capability can be increased during heavy load periods by purchases from neighboring interconnected systems. Hydro station capability is based on average December stream-flow conditions.

Corporate Information

Annual Meeting
The Annual Meeting of shareholders will be held at The Amherst Marriott, 1340 Millersport Highway, Buffalo, N.Y. at 10:30 a.m., Tuesday, May 2, 1995. A notice of the meeting, proxy statement and form of proxy will be sent in March to holders of common stock.

SEC Form 10-K Report
A copy of the company's Form 10-K report, filed annually with the Securities and Exchange Commission, is available without charge by writing the Investor Relations Department at 300 Erie Boulevard West, Syracuse, N.Y. 13202.

Shareholder Inquiries
Questions regarding shareholder accounts may be directed to the company's Shareholder Services Department:
(315) 428-6750
(Syracuse)

1-800-448-5450
(elsewhere in continental U.S.)

Analyst Inquiries
Analyst inquiries should be directed to Leon T. Mazur, Director-Investor Relations, (315) 428-5876

Stock Exchange Listings
Ticker Symbol: NMK
Common stock and most preferred series are listed and traded on the New York Stock Exchange.

Bonds are traded on the New York Stock Exchange.

Disbursing Agent
Common and Preferred Stocks:
Niagara Mohawk Power Corp.
300 Erie Boulevard West
Syracuse, N.Y. 13202

Bonds:
Marine Midland Bank, N.A.
140 Broadway
New York, N.Y. 10015

Transfer Agent and Registrars
Common and Preferred Stock:
The Bank of New York
P.O. Box 11002
Church Street Station
New York, N.Y. 10286

Bonds:
Marine Midland Bank, N.A.
140 Broadway
New York, N.Y. 10015

Officers

William E. Davis
Chairman of the Board and
Chief Executive Officer

John M. Endries
President

B. Ralph Sylvia
Executive Vice President
Nuclear

David J. Arrington
Senior Vice President
Human Resources

Darlene D. Kerr
Senior Vice President
Electric Customer Service

Gary J. Lavine
Senior Vice President
Legal and Corporate Relations

Robert J. Patrylo
Senior Vice President
Gas Customer Service
(Resigned August 1, 1994)

John W. Powers
Senior Vice President
Finance and Corporate Services

Michael P. Ranalli
Senior Vice President
Electric Supply and Delivery

Joseph T. Ash
Vice President
Special Projects

Nicholas J. Ashooh
Vice President
Public Affairs and Corporate Communications

Thomas H. Baron
Vice President
Fossil and Hydro Generation

Harold J. Bogan
Corporate Secretary
(Retired September 1, 1994)

Michael J. Bovalino
Vice President
Electric Marketing and Rates
(Effective August 22, 1994)

Michael J. Cahill
Vice President
Economic and Business Development

Norman E. Crowe, Jr.
Vice President
Electric Customer Service
(Retired October 1, 1994)

Edward J. Dienst
Vice President
Regional Operations
(Effective April 1, 1994)

Thomas R. Fair
Vice President
Environmental Affairs

Theresa A. Flaim
Vice President
Corporate Strategic Planning

Edward F. Hoffman
Vice President
Electric Supply and Delivery Support

Paul J. Kaleta
Vice President
Law and General Counsel

Samuel F. Manno
Vice President
Purchasing and Corporate Services

Martin J. McCormick, Jr.
Vice President
Nuclear Safety Assessment and Support
(Effective January 1, 1994)

Douglas R. McCuen
Vice President
Government and Regulatory Relations

Clement E. Nadeau
Vice President
Power Transactions and Planning

James A. Perry
Vice President
Quality Assurance

Kapua A. Rice
Corporate Secretary
(Effective September 1, 1994)

Arthur W. Roos
Vice President-Treasurer

Richard H. Ryczek
Vice President
Gas Customer Service Operations

Louis F. Storz
Vice President
Nuclear Generation
(Effective March 1, 1994)

William J. Synwoldt
Vice President
Information Systems and
Chief Information Officer

Steven W. Tasker
Vice President-Controller

Carl D. Terry
Vice President
Nuclear Engineering

Andrew M. Vesey
Vice President
Power Delivery

Stanley W. Wilczek, Jr.
Vice President
Customer Service

Directors

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President and Chief Executive Officer,
Welch Allyn, Inc., Skaneateles Falls, N.Y.

Lawrence Burkhardt, III (F)
Former Executive Vice President
Nuclear Operations

Douglas M. Costle (D, F)
Distinguished Senior Fellow,
Institute for Sustainable Communities
Montpelier, Vt.

Edmund M. Davis (A, B, D, E)
Partner, Hiscock & Barclay
Attorneys-at-Law, Syracuse, N.Y.

William E. Davis (A)
Chairman of the Board and
Chief Executive Officer

William J. Donlon
Former Chairman of the Board and
Chief Executive Officer

Edward W. Duffy (A, B, F)
Former Chairman of the Board and
Chief Executive Officer,
Marine Midland Banks, Inc.
Sarasota, Fla.

John M. Endries
President

Dr. Bonnie Guiton Hill (C, D, G)
Dean, McIntire School of Commerce
University of Virginia,
Charlottesville, Va.

John G. Haehl, Jr.
Former Chairman of the Board and
Chief Executive Officer

Henry A. Panasci, Jr. (B, E, G)
Chairman of the Board and
Chief Executive Officer,
Fay's Incorporated, Liverpool, N.Y.

Dr. Patti McGill Peterson (A, C, D)
President,
St. Lawrence University, Canton, N.Y.

Donald B. Riefler (A, C, E, F)
Financial Market Consultant
Vero Beach, Fla.

Stephen B. Schwartz (B, E)
Former IBM Senior Vice President
Palm Beach Gardens, Fla.

John G. Wick (C, D, E)
East Amherst, N.Y.

A. Member of the Executive Committee
B. Member of the Compensation and Succession Committee
C. Member of the Audit Committee
D. Member of the Committee on Corporate Public Policy and Environmental Affairs
E. Member of the Finance Committee
F. Member of the Nuclear Oversight Committee
G. Member of the Special Committee

Niagara Mohawk Power Corporation
300 Erie Boulevard West
Syracuse, New York 13202