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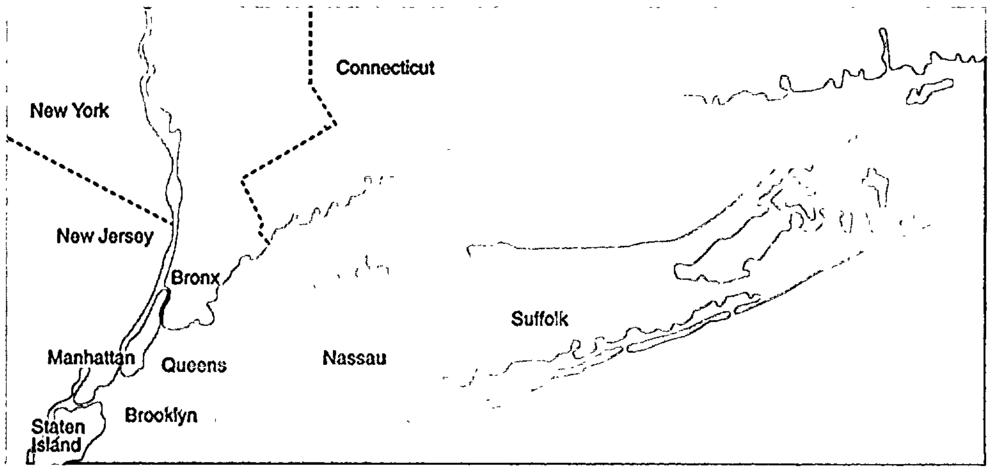
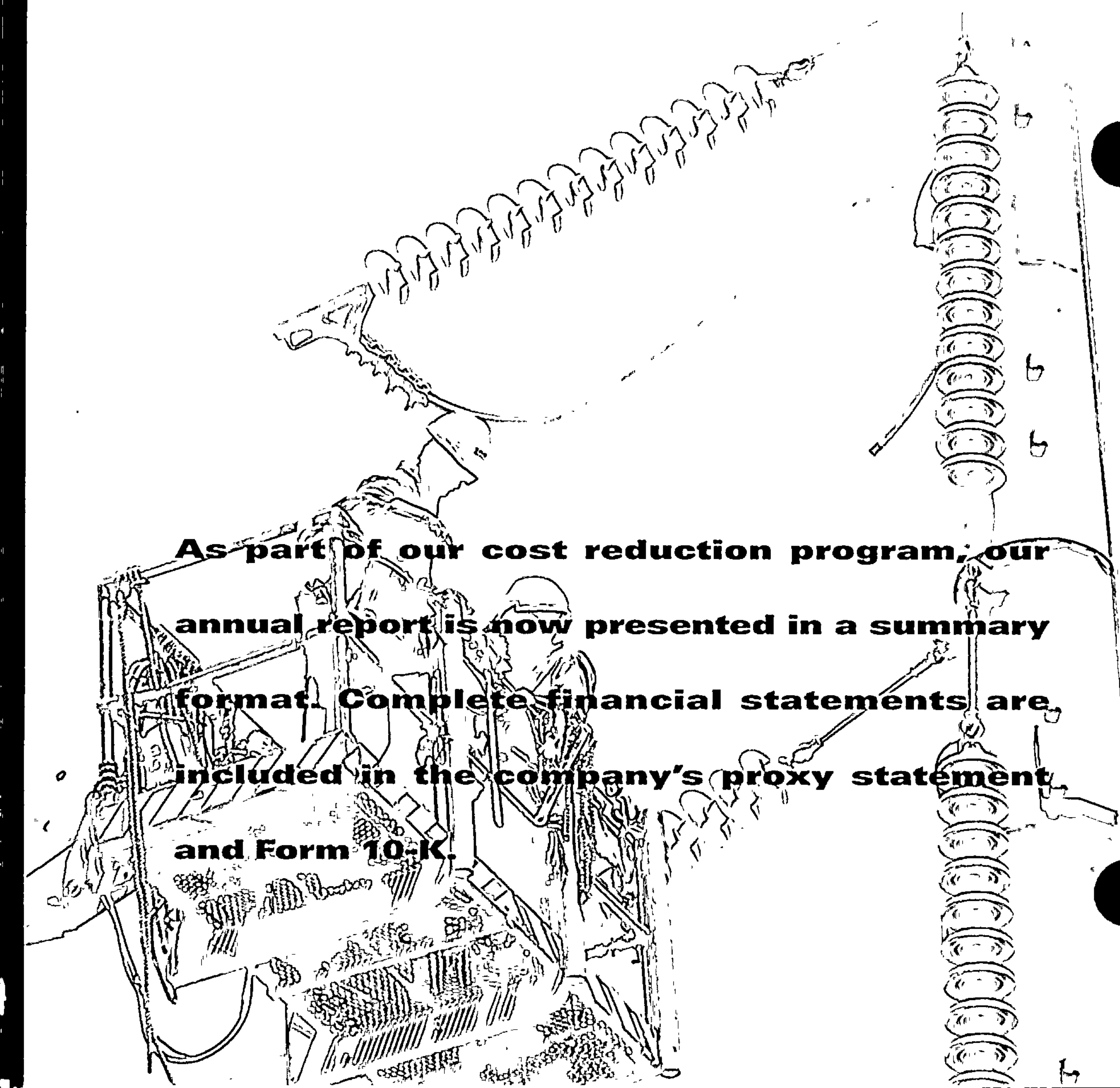
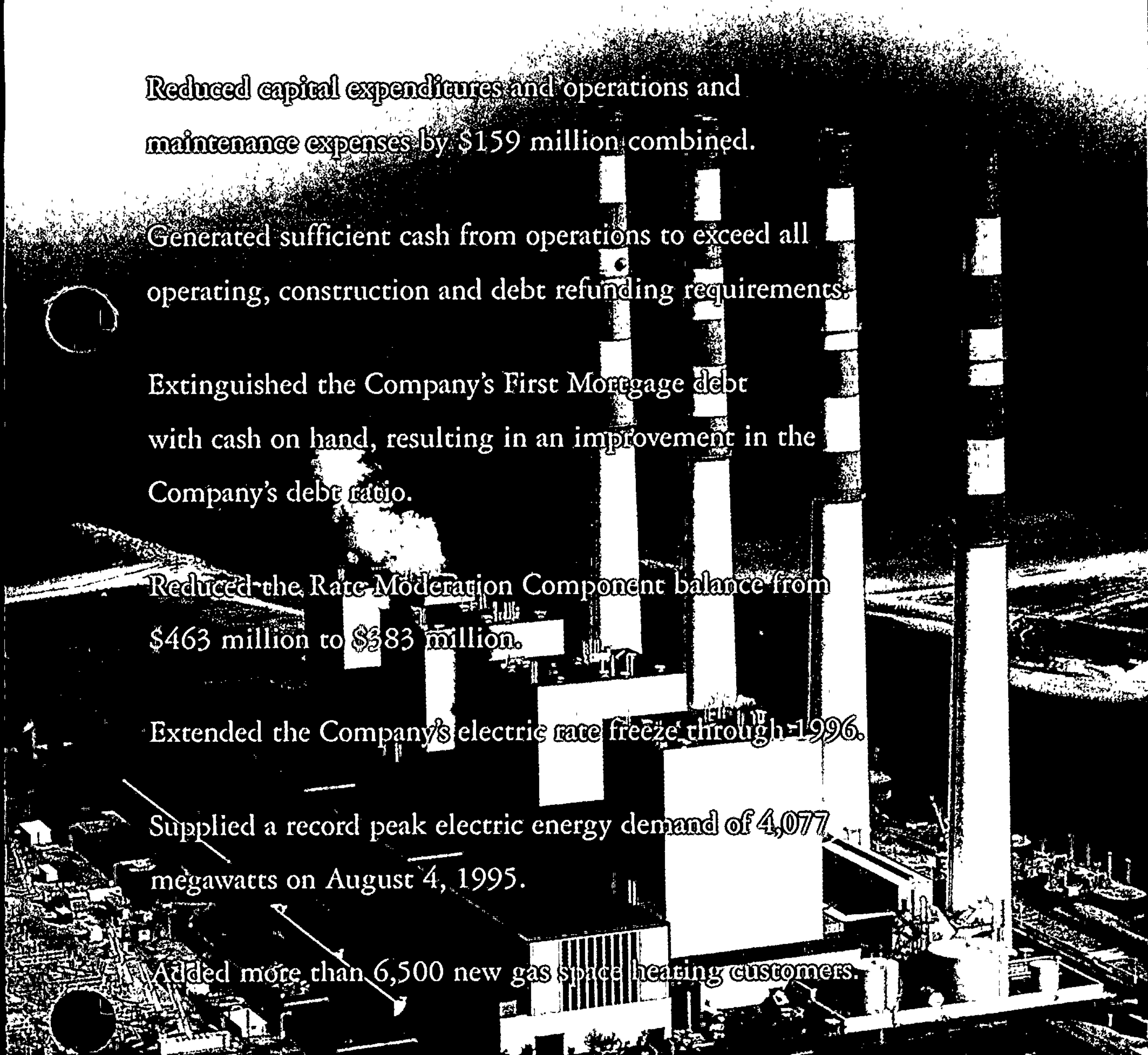


The Long Island Lighting Company's 5,688 employees provide electric and gas service to more than 1 million customers in Nassau and Suffolk Counties and on the Rockaway Peninsula in Queens County. LILCO's service territory covers 1,230 square miles with a population of approximately 2.7 million people.



As part of our cost reduction program, our annual report is now presented in a summary format. Complete financial statements are included in the company's proxy statement and Form 10-K.

1995 company highlights



Reduced capital expenditures and operations and maintenance expenses by $159 million combined.

Generated sufficient cash from operations to exceed all operating, construction and debt refunding requirements.

Extinguished the Company's First Mortgage debt with cash on hand, resulting in an improvement in the Company's debt ratio.

Reduced the Rate Moderation Component balance from $463 million to $383 million.

Extended the Company's electric rate freeze through 1996.

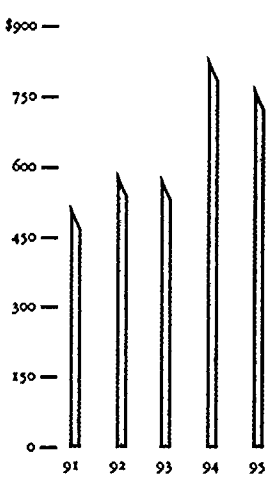
Supplied a record peak electric energy demand of 4,077 megawatts on August 4, 1995.

Added more than 6,500 new gas space heating customers.

Despite the politically charged atmosphere that surrounded the Company in 1995, LILCO made great strides in rate stability and service improvements, while enhancing its financial position. I am pleased to report our accomplishments to you in this summary report.

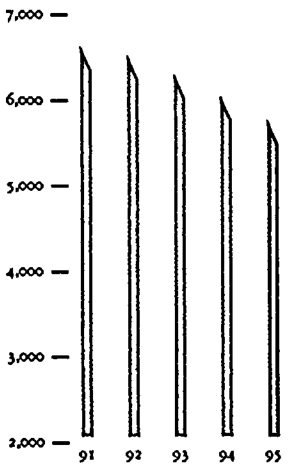
For the second consecutive year, the Company generated sufficient cash flow from operations to meet all requirements for construction and operations. Earnings were $2.10 per common share in 1995 on revenues of $3.1 billion, despite the New York State Public Service Commission (PSC) electric rate order that lowered the Company's allowed rate of return on common equity from 11.6 percent to 11.0 percent and eliminated certain performance-based incentive awards for the electric business. These two actions alone had the effect of reducing the Company's earnings by 15 cents per common share compared to earnings in 1994; however, aggressive cost containment efforts helped reduce the rate order's impact on 1995 earnings. The Company maintained its annual common stock dividend at $1.78 per share.

CASH GENERATED FROM OPERATIONS *(in millions)*

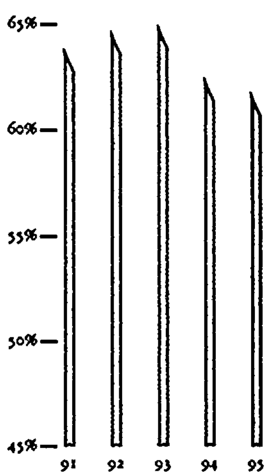


In 1995, the Company cut its operating and maintenance (O&M) costs by approximately $29 million and its capital expenditures by $130 million.

Full-time Employees



Debt Ratio



INCREASING FINANCIAL STABILITY

Cutting costs to hold down rates continued to be of primary importance in 1995, as LILCO implemented long-term strategies to increase the Company's financial stability. With electric rates frozen at 1994 levels, we are working to extend the freeze into 1997 and beyond. The Company also intends to implement a freeze on gas rates now that the final increase of a three-year rate settlement approved by the PSC in 1993 has become effective.

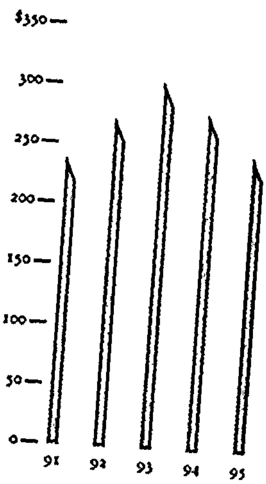
In conjunction with freezing rates, LILCO has worked to reduce costs through operating efficiencies. In 1995, the Company cut its operating and maintenance (O&M) costs by approximately $29 million and its capital expenditures by $130 million. By streamlining operating procedures, the Company is providing more efficient and effective service with fewer employees. LILCO reduced its employee population last year by five percent, for a five-year reduction of 13 percent, or 857 employees. At the same time, we have cut overtime costs by 61 percent, and costs for contractors and outside services by 46 percent.

We have recently negotiated a five-year union contract to increase the stability of our workforce while helping to define O&M expenses through 2001. We believe that the additional costs of the contract can be offset by employee attrition, and the security provided will increase employee satisfaction and productivity.

The reductions in O&M and capital expenditures significantly enhanced the Company's cash flow, enabling LILCO to redeem all outstanding First Mortgage bonds with cash on hand. The Company's debt to equity ratio improved from 62.5 percent in 1994 to 61.8 percent in 1995, and in 1996, we anticipate retiring an additional $415 million of maturing debt with cash on hand, which should further decrease the long-term debt ratio to 59.6 percent.

SHOREHAM TAX LITIGATION

Construction Expenditures *(in millions)*



In May 1995, the New York State Court of Appeals declined to review a lower court's 1992 decision in LILCO's tax certiorari case against Suffolk County and the Town of Brookhaven for the years 1976-1983 (excluding 1979, which was settled separately). In January 1996, LILCO received payment on the $81 million judgment, including interest. The entire judgment, after legal fees, will be used to lower rates. We have asked the PSC for permission to use these funds to reduce the Rate Moderation Component of the Shoreham settlement agreement, which, at the end of 1995, represented $383 million in deferred revenue as a result of the 10-year rate phase-in plan. We believe that this is the most effective way to provide long-term rate stability for our customers.

The trial of the second phase of the property tax case, which covers the tax years 1984-1992, ended in June 1995, and a final decision in the case is expected in 1996.

Gov floats LILCO breakup plan

Program calls for a cut of 10% in rates.

By SAMSON MULUGETA

The Long Island Lighting Co., would be taken over by the state, dismantled and parts of it sold to private companies under a plan Gov. Pataki says would cut utility rates 10% to 12%.

Under the takeover plan—to be unveiled at a Long Island Power Authority meeting today—the state would sell off the utility's gas business and five power generators but retain its transmission and distribution system.

The purchase would be financed through the sale of $4.5 billion in tax-exempt bonds.

... very sound and well-thought-out ...

proposal as a "leveraged buyout" and expressed grave concerns.

"You are basically selling off the revenue-producing parts of the company and getting stuck with the rest," Silver said. "We have to look at what's best for the working people of Long Island and consider all the proposals submitted to LIPA, including the one by the previous [Democratic-controlled] board."

But Pataki said a key element of the latest proposal is its effort to create "a climate for competition."

"One of the things we will be doing is having LIPA continue to o... transmission so that co...

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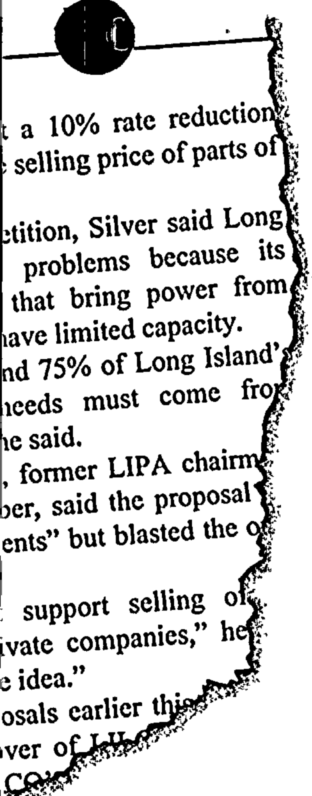
"I wo... generato... "That's a...

Kesse... $9 billi... purchas... Pataki...

THE TAKEOVER PLANS

With energy issues still in the forefront of local and state politics in 1995, proposals for a state takeover of LILCO continued to be discussed throughout the year. Shortly after taking office in January 1995, newly elected New York State Governor Pataki rejected the takeover proposal offered in October 1994 by his predecessor, Mario Cuomo. A subsequent proposal presented by the Long Island Power Authority (LIPA) in June also garnered little support from Pataki's office. But in September 1995, the Governor announced that he had charged a newly reconstituted LIPA board with developing a plan that met four specific criteria: producing double-digit rate reduction, protecting Long Islanders' property taxes, providing a framework for long-term competition in the electric power markets, and "dissolving" LILCO. On December 6, LIPA emerged with its proposed plan.


t a 10% rate reduction
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etition, Silver said Long
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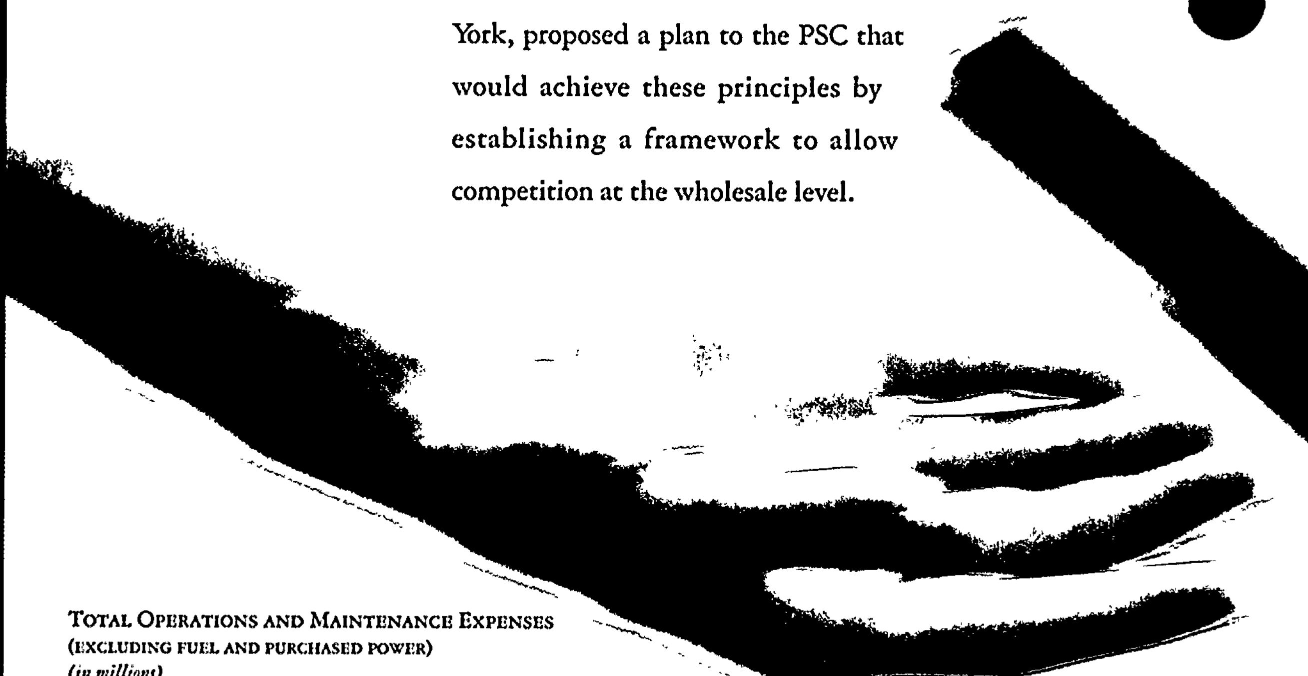
Under the proposal, LIPA would negotiate with LILCO to purchase the Company's electric transmission and distribution system and its Shoreham-related assets with financing obtained by issuing tax-exempt bonds. As part of the transaction, LILCO would sell its gas business to a single private owner, and its generating units to multiple private owners. According to LIPA, the plan would provide a 12 percent reduction in rates.

LILCO has pledged its cooperation in working with the Governor on any proposal that would reduce rates for our customers and protect the interests of our shareowners and employees. We believe that the LIPA plan, as proposed, contains fundamental flaws that would make the transaction unattractive to customers, employees and shareowners. We have publicly expressed our concerns that breaking up the Company could impair system reliability and the quality of service provided to Long Islanders.

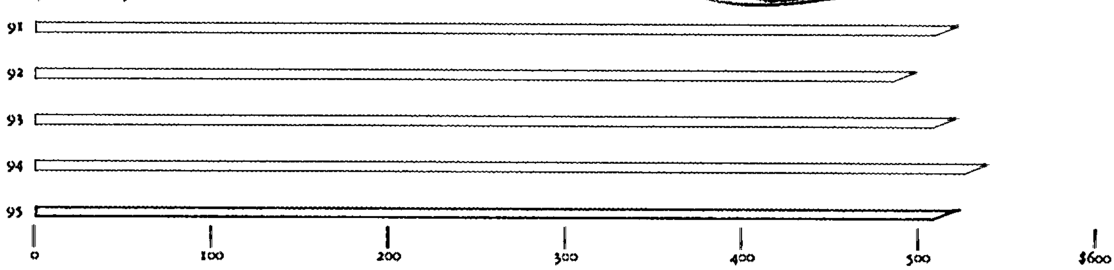
ADDRESSING COMPETITIVE OPPORTUNITIES

The electric industry today is undergoing fundamental changes as regulators and customers seek to lower energy costs. In 1995, the PSC continued the second phase of its Competitive Opportunities Proceedings, investigating how to best move the industry toward a more competitive model. Over the last year, the PSC adopted a series of principles that it will use to guide the transition of New York's electric industry from a regulated to a more market-driven model. In general, the principles stated that any model adopted should provide a reasonable opportunity for customers to save money; ensure an affordable, safe, reliable electric system; and allow for utilities to recover prudent investments made to meet the obligations of their service territories.

In October, LILCO, along with the other investor-owned utility members of the Energy Association of New York, proposed a plan to the PSC that would achieve these principles by establishing a framework to allow competition at the wholesale level.



TOTAL OPERATIONS AND MAINTENANCE EXPENSES
(EXCLUDING FUEL AND PURCHASED POWER)
(in millions)

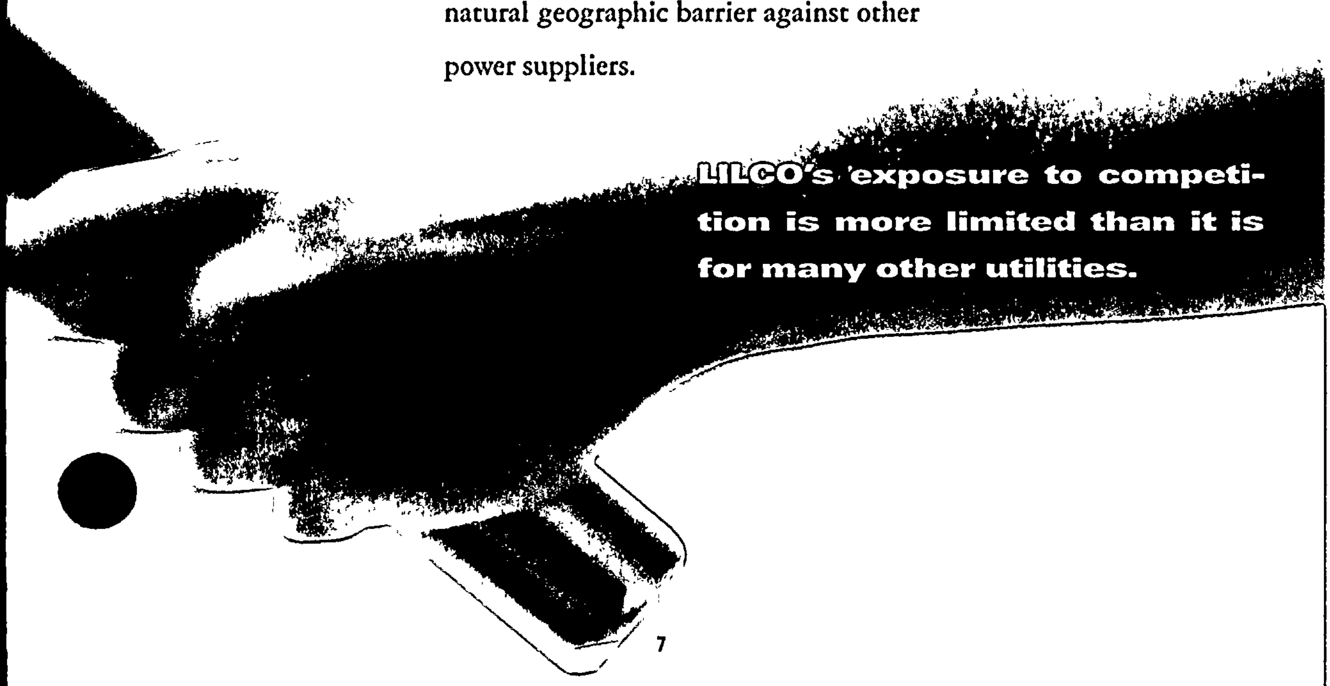


POOLING OUR RESOURCES

The plan advocates a "pool market mechanism," in which utilities would separate their generation and transmission systems, and all generation facilities would contribute to a pool of wholesale electric power. Each transmission and distribution system would then have the ability to purchase power from the pool at the lowest price available. This structure could provide the benefits of competition to all customers while protecting the utilities' prudent investments.

In December, a PSC administrative law judge recommended to the Commission a competitive model that would transition the electric utility industry to full retail competition in two stages. The first stage involves a competitive wholesale model similar to the pool mechanism supported by LILCO. The second stage would move the industry toward full retail competition by offering customers the opportunity to purchase electricity directly from the pool. Utilities were asked to file long-term proposals addressing the recommendation; a proposed electric deregulation plan is expected to be issued by the PSC later this year.

LILCO's exposure to competition is more limited than it is for many other utilities because within a year or two, there will be no excess capacity on the Island and our service territory has a natural geographic barrier against other power suppliers.

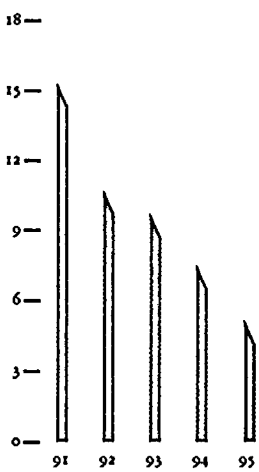


There are a limited number of interconnections that could be used for transporting electricity from the mainland to Long Island, and these interconnections are almost fully utilized already. Since the cost for building new interconnections is uneconomic, there is little opportunity for increasing the amount of power imported to Long Island.

In the gas industry, deregulation is already under way. Wholesale competition has existed since 1993, when the Federal Energy Regulatory Commission separated the selling of natural gas from its transportation. On November 6, LILCO filed a request with the PSC to allow our customers to purchase gas from a supplier of their choice. If the request is approved this spring, it would mark the beginning of retail energy competition on Long Island.

Because we pass along the commodity cost of natural gas to our customers without profit, we are confident that we can successfully compete for Long Islanders' business. In fact, we are currently exploring ways to open up pipeline and storage costs to competition, the next step in providing increased choice in the natural gas market.

Barrels of Fuel Oil Consumed *(in millions)*



EXPANDING OUR BUSINESS

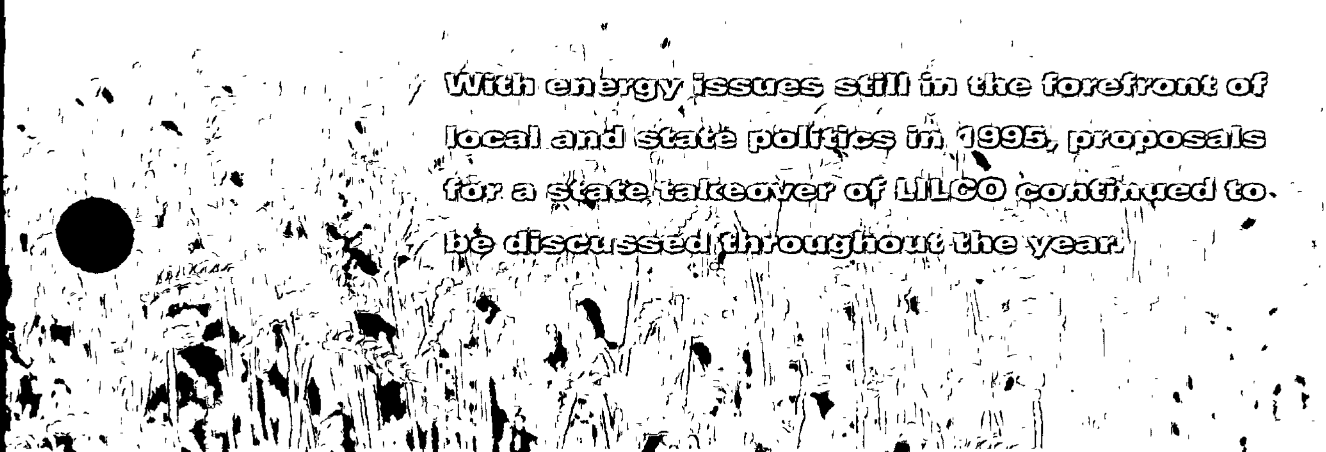
LILCO's electric sales have mirrored Long Island's economic recovery. Even with the loss of our second largest customer to cogeneration in 1995, we saw an increase in electric sales of approximately one percent. LILCO continues to work as a partner with local and state organizations to improve the business environment in our community. Our Economic Development and Major Accounts departments have expanded their efforts to help to attract, expand and retain businesses in our region.

The economic development programs we offer stress energy efficiency to help companies lower their operating costs and improve their competitive position. The Major Accounts teams work one-on-one with our largest customers to find solutions to their individual energy needs. Helping businesses to prosper on Long Island allows LILCO to increase its revenue base, which spreads the fixed costs over a larger sales base. The growth in sales has helped us to freeze our rates and even provide for a slight decrease in 1997.

LILCO is also promoting the "smart sale" of electricity, targeting technologies that improve productivity and lower costs to customers, while increasing electric use during "off-peak" or low-use periods for our generating units. Examples of these efficient electrotechnologies include fluorescent outdoor security lighting and geothermal heat pumps.

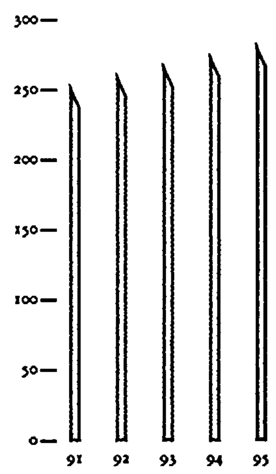
On the gas side of our business, we have seen a three percent growth in sales over the last year on a weather-normalized basis. With research showing that customers have an overwhelmingly positive view of LILCO's gas service, we have been positioning our product as the most reliable, convenient and versatile heating choice. As the economy improves further and Long Islanders begin to have more disposable income, we believe there is tremendous opportunity for expansion in the gas heating market.

LILCO has also been aggressively pursuing off-system gas sales to increase revenues. The Company has been successfully marketing products such as gas options, storage, and fuel management services

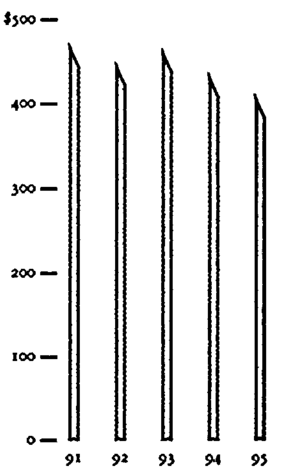


With energy issues still in the forefront of local and state politics in 1995, proposals for a state takeover of LILCO continued to be discussed throughout the year.

Gas Space Heating Customers *(in thousands)*



Interest on Long-term Debt *(in millions)*



since 1993. These products combine LILCO's knowledge of the gas marketplace with the assets of the gas business, such as our storage fields and liquefied natural gas plant, in innovative ways to capitalize on previously unexplored revenue opportunities.

A SOLID FOUNDATION

LILCO is a different company today than it was just a few years ago. Although the Shoreham settlement agreement gave us the framework for financial recovery, LILCO faced an uphill challenge to return to financial health.

As a result of a great deal of hard work, LILCO's financial position has improved significantly. LILCO is currently generating sufficient cash flow from operations to meet all of our operating and construction requirements for the foreseeable future, and we are reducing our debt ratio at a faster rate than originally projected.

These accomplishments mean that LILCO is financially and strategically prepared to meet the challenges of our changing industry marketplace. We have the ability to respond to both competition and a proposed takeover from a much stronger position than we could have just a few years ago.

Your support has made it possible for us to overcome the obstacles of the last decade and has instilled in us the confidence to deal with our current challenges. On behalf of the board of directors, officers and the employees of LILCO, I thank you for your continued support.

Sincerely,

W.J. Catacosinos

William J. Catacosinos
Chairman, President and Chief Executive Officer

1995

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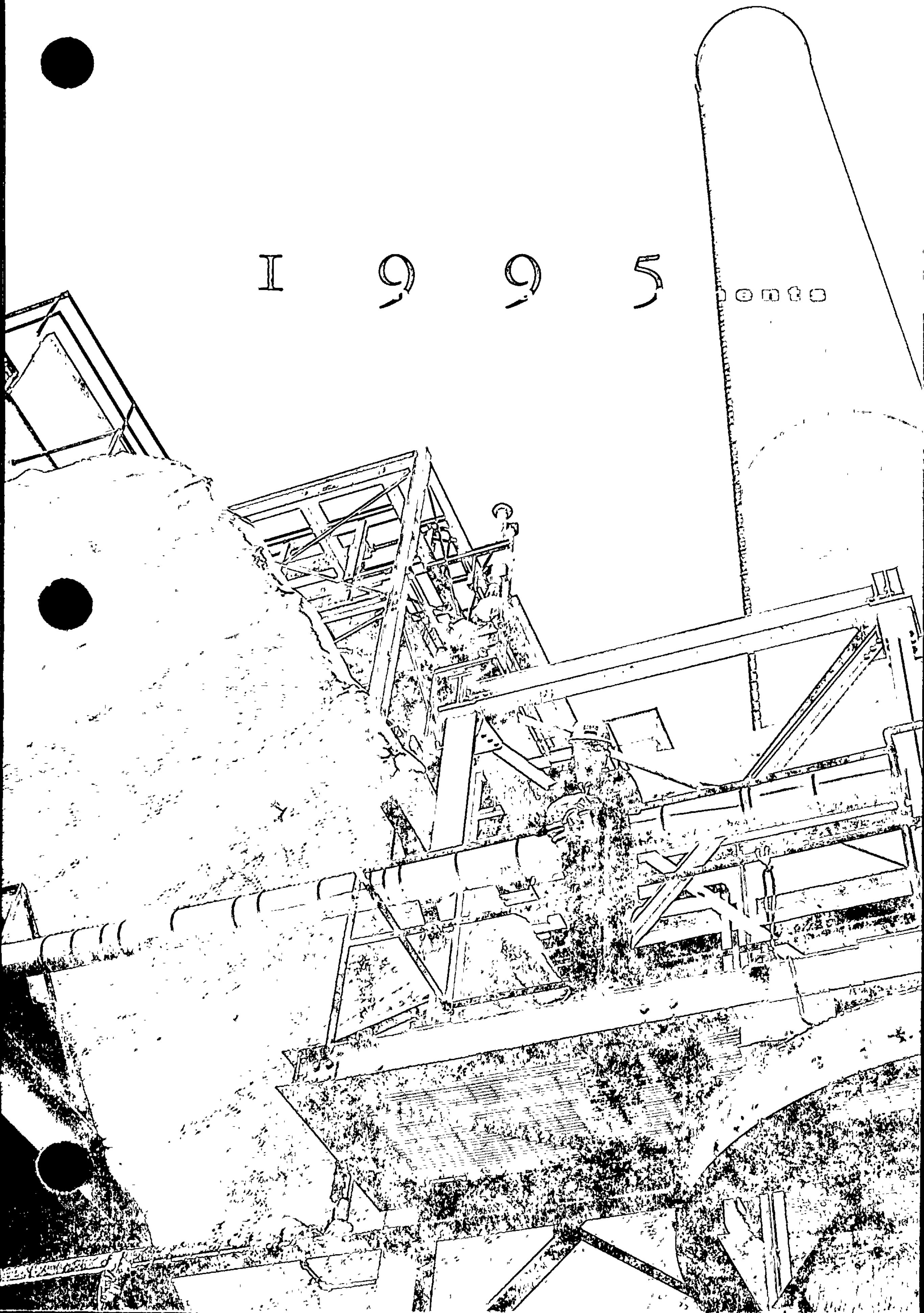


Balance Sheet

Assets	At December 31	
(In thousands of dollars)	1995	1994
Utility Plant		
Electric	$ 3,786,540	$ 3,657,178
Gas	1,086,145	994,742
Common	244,828	232,346
Construction work in progress	100,521	129,824
Nuclear fuel in process and in reactor	16,456	23,251
	5,234,490	5,037,341
Less — Accumulated depreciation and amortization	1,639,492	1,538,995
Total Net Utility Plant	3,594,998	3,498,346
Regulatory Assets		
Base financial component (less accumulated amortization of $656,311 and $555,340)	3,382,519	3,483,490
Rate moderation component	383,086	463,229
Shoreham post settlement costs	968,999	922,580
Shoreham nuclear fuel	71,244	73,371
Unamortized cost of issuing securities	222,567	254,482
Postretirement benefits other than pensions	383,642	412,727
Regulatory tax asset	1,802,383	1,831,689
Other	230,663	250,804
Total Regulatory Assets	7,445,103	7,6[illegible]
Nonutility Property and Other Investments	16,030	[illegible]
Current Assets		
Cash and cash equivalents	351,453	185,451
Special deposits	63,412	27,614
Customer accounts receivable (less allowance for doubtful accounts of $24,676 and $23,365)	282,218	245,125
LRPP receivable	69,558	54,512
Other accounts receivable	107,387	14,030
Accrued unbilled revenues	184,440	164,379
Materials and supplies at average cost	63,595	74,777
Fuel oil at average cost	32,090	37,723
Gas in storage at average cost	53,076	68,447
Deferred tax asset	191,000	213,996
Prepayments and other current assets	8,986	5,327
Total Current Assets	1,407,215	1,091,381
Deferred Charges	21,023	172,768
Total Assets	$12,484,369	$12,478,910

Capitalization and Liabilities	At December 31	
(In thousands of dollars)	1995	1994
Capitalization		
Long-term debt	$ 4,722,675	$ 5,162,675
Unamortized discount on debt	(16,075)	(17,278)
	4,706,600	5,145,397
Preferred stock — redemption required	639,550	644,350
Preferred stock — no redemption required	63,934	63,957
Total Preferred Stock	703,484	708,307
Common stock	598,277	592,083
Premium on capital stock	1,114,508	1,101,240
Capital stock expense	(50,751)	(52,175)
Retained earnings	790,919	752,480
Total Common Shareowners' Equity	2,452,953	2,393,628
Total Capitalization	7,863,037	8,247,332
Regulatory Liabilities		
Regulatory liability component	277,757	357,117
1989 Settlement credits	136,655	145,868
Regulatory tax liability	116,060	111,218
[illegible]	132,694	147,041
Total Regulatory Liabilities	663,166	761,244
Current Liabilities		
Current maturities of long-term debt	415,000	25,000
Current redemption requirements of preferred stock	4,800	4,800
Accounts payable and accrued expenses	260,879	241,775
Accrued taxes (including federal income tax of $28,736 and $28,340)	60,498	58,133
Accrued interest	158,325	149,929
Dividends payable	57,899	57,367
Class Settlement	45,833	35,833
Customer deposits	29,547	28,474
Total Current Liabilities	1,032,781	601,311
Deferred Credits		
Deferred federal income tax	2,337,732	2,204,023
Class Settlement	129,809	151,604
Other	8,708	9,774
Total Deferred Credits	2,476,249	2,365,401
Operating Reserves		
Pensions and other postretirement benefits	396,490	453,016
Claims and damages	52,646	50,606
Total Operating Reserves	449,136	503,622
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$12,484,369	$12,478,910

Statement of Income

(In thousands of dollars except per share amounts)	For year ended December 31 1995	1994	1993
Revenues			
Electric	$2,484,014	$2,481,637	$2,352,109
Gas	591,114	585,670	528,886
Total Revenues	3,075,128	3,067,307	2,880,995
Operating Expenses			
Operations — fuel and purchased power	834,979	847,986	827,591
Operations — other	383,238	406,014	387,808
Maintenance	128,155	134,640	133,852
Depreciation and amortization	145,357	130,664	122,471
Base financial component amortization	100,971	100,971	100,971
Rate moderation component amortization	21,933	197,656	88,667
Regulatory liability component amortization	(79,359)	(79,359)	(79,359)
1989 Settlement credits amortization	(9,214)	(9,214)	(9,214)
Other regulatory amortization	161,605	4,328	(18,044)
Operating taxes	447,507	406,895	385,847
Federal income tax — current	14,596	10,784	6,324
Federal income tax — deferred and other	193,742	170,997	178,530
Total Operating Expenses	2,343,510	2,322,362	2,125,444
Operating Income	731,618	744,945	7[illegible]
Other Income and (Deductions)			
Rate moderation component carrying charges	25,274	32,321	40,004
Other income and deductions, net	34,400	35,343	38,997
Class Settlement	(21,669)	(22,730)	(23,178)
Allowance for other funds used during construction	2,898	2,716	2,473
Federal income tax — deferred and other	2,800	5,069	12,578
Total Other Income and (Deductions)	43,703	52,719	70,874
Income Before Interest Charges	775,321	797,664	826,425
Interest Charges			
Interest on long-term debt	412,512	437,751	466,538
Other interest	63,461	62,345	67,534
Allowance for borrowed funds used during construction	(3,938)	(4,284)	(4,210)
Total Interest Charges	472,035	495,812	529,862
Net Income	303,286	301,852	296,563
Preferred stock dividend requirements	52,620	53,020	56,108
Earnings for Common Stock	$ 250,666	$ 248,832	$ 240,455
Average Common Shares Outstanding (000)	119,195	115,880	112,057
Earnings per Common Share	$ 2.10	$ 2.15	$ 2.15
Dividends Declared per Common Share	$ 1.78	$ 1.78	$ 1.76

Statement of Cash Flows

(In thousands of dollars)	For year ended December 31 1995	1994	1993
Operating Activities			
Net Income	$ 303,286	$ 301,852	$ 296,563
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	145,357	130,664	122,471
Base financial component amortization	100,971	100,971	100,971
Rate moderation component amortization	21,933	197,656	88,667
Regulatory liability component amortization	(79,359)	(79,359)	(79,359)
1989 Settlement credits amortization	(9,214)	(9,214)	(9,214)
Other regulatory amortization	161,605	4,328	(18,044)
Rate moderation component carrying charges	(25,274)	(32,321)	(40,004)
Amortization of cost of issuing and redeeming securities	39,589	46,237	52,063
Class Settlement	21,669	22,730	23,178
Provision for doubtful accounts	17,751	19,542	18,555
Federal income tax — deferred and other	190,942	165,928	165,952
Other	61,576	46,531	9,228
Changes in operating assets and liabilities			
Accounts receivable	(67,213)	(17,353)	(65,898)
Class Settlement	(33,464)	(30,235)	(25,302)
Accrued unbilled revenues	(20,061)	5,663	(26,870)
Accounts payable and accrued expenses	19,100	(44,598)	(8,800)
Other	(77,194)	6,727	(22,144)
Net Cash Provided by Operating Activities	772,000	835,749	582,013
Investing Activities			
Construction and nuclear fuel expenditures	(243,586)	(276,954)	(302,220)
Shoreham post settlement costs	(70,589)	(167,367)	(207,114)
Other investing activities	8,019	(1,349)	(934)
Net Cash Used in Investing Activities	(306,156)	(445,670)	(510,268)
Financing Activities			
Proceeds from issuance of securities	68,726	449,434	1,305,802
Redemption of securities	(104,800)	(639,858)	(1,165,600)
Common stock dividends paid	(211,630)	(205,086)	(195,794)
Preferred stock dividends paid	(52,667)	(52,927)	(56,727)
Other financing activities	529	(4,723)	(20,379)
Net Cash Used in Financing Activities	(299,842)	(453,160)	(132,698)
Net Increase (Decrease) in Cash and Cash Equivalents	$ 166,002	$ (63,081)	$ (60,953)
Cash and cash equivalents at January 1	$ 185,451	$ 248,532	$ 309,485
Net increase (decrease) in cash and cash equivalents	166,002	(63,081)	(60,953)
Cash and Cash Equivalents at December 31	$ 351,453	$ 185,451	$ 248,532
Interest paid, before reduction for the allowance for borrowed funds used during construction	$ 427,988	$ 446,340	$ 469,978
Federal income tax — paid	$ 14,200	$ 10,780	$ 6,000
Federal income tax — refunded	$ —	$ —	$ 1,000

Statement of Retained Earnings

(In thousands of dollars)	1995	1994	1993
Balance at January 1	$ 752,480	$ 711,432	$667,988
Net income for the year	303,286	301,852	296,563
	1,055,766	1,013,284	964,551
Deductions			
Cash dividends declared on common stock	212,181	207,794	197,236
Cash dividends declared on preferred stock	52,647	53,046	55,861
Other	19	(36)	22
Balance at December 31	$ 790,919	$ 752,480	$711,432

Report of Independent Auditors on Condensed Financial Statements

To the Shareowners and Board of Directors of Long Island Lighting Company

We have audited, in accordance with generally accepted auditing standards, the balance sheet of Long Island Lighting Company and the related statement of capitalization as of December 31, 1995 and 1994 and the related statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1995 (not presented separately herein); and in our report dated February 7, 1996, we expressed an unqualified opinion on those financial statements. In our opinion, the information set forth in the accompanying condensed financial statements is fairly stated in all material respects in relation to the financial statements from which it has been derived.

Ernst + Young LLP

Melville, New York
February 7, 1996

Selected Financial Data

(In thousands of dollars except per share amounts)

Summary of Operations	1995	1994	1993	1992	1991
Revenues	$ 3,075,128	$ 3,067,307	$ 2,880,995	$2,621,839	$2,547,729
Operating expenses	2,343,510	2,322,362	2,125,444	1,880,734	1,762,449
Operating income	$ 731,618	$ 744,945	$ 755,551	$ 741,105	$ 785,280
Net income	$ 303,286	$ 301,852	$ 296,563	$ 301,974	$ 305,538
Earnings for common stock	$ 250,666	$ 248,832	$ 240,455	$ 238,020	$ 239,144
Earnings per common share	$ 2.10	$ 2.15	$ 2.15	$ 2.14	$ 2.15
Common stock dividends declared per share	$ 1.78	$ 1.78	$ 1.76	$ 1.72	$ 1.60
Book value per common share at December 31	$ 20.50	$ 20.21	$ 19.88	$ 19.58	$ 19.13
Common shares outstanding at December 31 (000)	119,655	118,417	112,332	111,600	111,365
Common shareowners of record at December 31	93,088	96,491	94,877	86,111	90,435
Operations and Maintenance Expense Details					
Payroll and employee benefits charged to operations	$ 274,988	$ 280,064	$ 288,334	$ 288,850	$ 282,072
Fuel and purchased power	834,979	847,986	827,591	741,784	768,702
All other	236,405	260,590	233,326	209,095	240,687
Total Operations and Maintenance Expense	$ 1,346,372	$ 1,388,640	$ 1,349,251	$1,239,729	$1,291,461
Full-time Employees at December 31	5,688	5,947	6,215	6,438	6,538
Balance Sheet					
Net utility plant	$ 3,594,998	$ 3,498,346	$ 3,347,557	$3,161,148	$3,002,733
Regulatory assets	7,445,103	7,692,372	7,721,359	5,386,295	5,146,150
Nonutility property and other investments	16,030	24,043	23,029	20,730	9,788
Current assets	1,407,215	1,091,381	1,075,561	961,532	859,242
Deferred charges	21,023	172,768	286,005	323,418	681,347
Total Assets	$12,484,369	$12,478,910	$12,453,511	$9,853,123	$9,699,260
Capitalization and Liabilities					
Long-term debt	$ 4,706,600	$ 5,145,397	$ 4,870,340	$4,741,002	$4,986,166
Preferred stock	703,484	708,307	713,188	712,176	679,283
Common shareowners' equity	2,452,953	2,393,628	2,232,950	2,184,775	2,130,491
Total Capitalization	7,863,037	8,247,332	7,816,478	7,637,953	7,795,940
Regulatory liabilities	663,166	761,244	848,760	782,847	843,559
Current liabilities	1,032,781	601,311	1,188,972	1,177,130	492,895
Deferred credits	2,476,249	2,365,401	2,166,145	237,893	559,559
Operating reserves	449,136	503,622	433,156	17,300	7,307
Total Capitalization and Liabilities	$12,484,369	$12,478,910	$12,453,511	$9,853,123	$9,699,260
Construction Expenditures*					
Electric	$ 145,472	$ 136,041	$ 137,583	$ 141,752	$ 129,643
Gas	79,536	120,019	124,859	104,028	89,950
Common	21,477	23,610	42,251	27,124	17,958
Total Construction Expenditures	$ 246,485	$ 279,670	$ 304,693	$ 272,904	$ 237,551

* Includes non-cash allowance for other funds used during construction and excludes Shoreham post settlement costs.

Electric Operating Income *(In thousands of dollars)*	1995	1994	1993	1992	1991
Revenues					
Residential	$1,204,987	$1,202,124	$1,145,891	$1,045,799	$1,047,490
Commercial and industrial	1,194,014	1,196,422	1,132,487	1,076,302	1,070,098
Other system revenues	52,472	52,477	49,790	49,395	47,838
Total system revenues	2,451,473	2,451,023	2,328,168	2,171,496	2,165,426
Other revenues	32,541	30,614	23,941	23,136	31,142
Total Revenues	2,484,014	2,481,637	2,352,109	2,194,632	2,196,568
Expenses					
Fuel and purchased power	570,697	568,738	579,032	559,583	593,656
Operations and maintenance	399,215	418,011	417,881	400,250	424,244
Operating taxes	375,164	336,263	326,407	331,122	338,429
Other	494,816	484,597	355,397	223,442	72,147
Total Expenses	1,839,892	1,807,609	1,678,717	1,514,397	1,428,476
Electric Operating Income	$ 644,122	$ 674,028	$ 673,392	$ 680,235	$ 768,092

Electric Sales and Customers					
Sales — millions of kWh					
Residential	7,156	7,159	7,118	6,788	7,022
Commercial and industrial	8,336	8,394	8,257	8,181	8,322
Other	460	457	449	471	[illegible]
Total system sales	15,952	16,010	15,824	15,440	[illegible]
Sales to other utilities	620	372	304	227	598
Total Sales	16,572	16,382	16,128	15,667	16,411
Customers — monthly average					
Residential	915,162	908,490	905,997	902,885	898,974
Commercial and industrial	103,669	102,490	102,254	101,838	101,740
Other	4,549	4,583	4,553	4,593	4,540
Total Customers — Monthly Average	1,023,380	1,015,563	1,012,804	1,009,316	1,005,254
Customers at December 31	1,025,107	1,016,739	1,011,965	1,009,028	1,005,363

Electric Operations					
Energy — millions of kWh					
Net generation	10,744	10,034	10,514	10,592	13,570
Power purchased	7,143	7,640	7,023	6,438	4,236
Total Energy Available	17,887	17,674	17,537	17,030	17,806
System sales	15,952	16,010	15,824	15,440	15,813
Company use and unaccounted for	1,315	1,292	1,409	1,363	1,395
Total system energy requirements	17,267	17,302	17,233	16,803	17,208
Sales to other utilities	620	372	304	227	598
Total Energy Available	17,887	17,674	17,537	17,030	17,806
System peak demand — MW	4,077	3,882	3,967	3,611	3,904
Total system capability — MW	4,873	4,868	4,799	4,711	[illegible]

Gas Operating Income *(In thousands of dollars)*	1995	1994	1993	1992	1991
Revenues					
Residential — space heating	$323,729	$326,474	$310,109	$243,950	$190,976
Residential — other	42,046	42,263	39,515	33,035	29,383
Commercial and industrial — space heating	130,964	126,092	106,140	90,363	70,938
Commercial and industrial — other	34,293	35,275	33,181	29,094	25,515
Total firm revenues	531,032	530,104	488,945	396,442	316,812
Other revenues	60,082	55,566	39,941	30,765	34,349
Total Revenues	591,114	585,670	528,886	427,207	351,161
Expenses					
Fuel	264,282	279,248	248,559	182,201	175,046
Operations and maintenance	112,178	122,643	103,779	97,695	98,515
Operating taxes	72,343	70,632	59,440	57,866	49,951
Other	54,815	42,230	34,949	28,575	10,461
Total Expenses	503,618	514,753	446,727	366,337	333,973
Gas Operating Income	$ 87,496	$ 70,917	$ 82,159	$ 60,870	$ 17,188

Gas Sales and Customers					
Sales — thousands of dth					
Residential — space heating	35,336	35,693	37,191	35,089	29,687
Residential — other	2,929	3,151	3,297	3,203	3,195
Commercial and industrial — space heating	16,170	15,679	14,366	13,662	11,636
Commercial and industrial — other	4,269	4,366	4,329	4,338	4,171
Total firm sales	58,704	58,889	59,183	56,292	48,689
Interruptible sales	9,176	6,914	5,920	5,090	4,538
Off-system sales	7,743	7,232	2,894	—	—
Total Sales	75,623	73,035	67,997	61,382	53,227
Customers — monthly average					
Residential — space heating	245,452	239,857	233,882	227,834	220,562
Residential — other	162,114	163,608	166,974	169,189	171,581
Commercial and industrial — space heating	35,027	33,776	32,783	31,666	30,453
Commercial and industrial — other	10,313	10,448	10,631	10,777	11,003
Interruptible	623	576	542	531	472
Total Customers — Monthly Average	453,529	448,265	444,812	439,997	434,071
Customers at December 31	455,869	449,906	446,384	442,117	436,853

Gas Operations					
Energy — thousands of dth					
System sales	67,880	65,803	65,103	61,382	53,227
Off-system sales	7,743	7,232	2,894	—	—
Company use and unaccounted for	2,054	2,516	1,905	3,577	2,412
Total Company Requirements	77,677	75,551	69,902	64,959	55,639
Maximum day sendout — dth	564,874	585,227	485,896	448,726	435,050
Total capability — dth	717,035	705,597	682,284	682,284	635,544
Heating degree days (30-year average 4,969)	4,906	4,839	4,899	5,066	4,378

Corporate Information

Executive Offices
175 East Old Country Road
Hicksville, New York 11801
516-545-4914

Common Stock Listed
New York Stock Exchange
Pacific Stock Exchange

Ticker Symbol: LIL

Transfer Agent and Registrar
Common Stock and Preferred Stock
The Bank of New York
Shareholder Services Department
Church Street Station
PO Box 11277
New York, New York 10286-1612
1-800-524-4458

Shareowners' Agent for Automatic Dividend Reinvestment Plan
The Bank of New York
Dividend Reinvestment Department
Church Street Station
PO Box 11277
New York, New York 10286-1612
1-800-524-4458

Dividend Reinvestment
Registered common and non-convertible preferred stock shareowners who wish to acquire additional shares of common stock are eligible to participate in the Company's Automatic Dividend Reinvestment Plan (the Plan). There are no brokerage fees charged for the purchase of shares pursuant to the Plan, but nominal fees are charged upon the sale of Plan shares or withdrawal from the Plan. Upon joining the Plan, shareowners authorize the Company's transfer agent to purchase shares of the Company's common stock by automatically reinvesting all of the shareowner's quarterly dividends. Shareowners may also make optional cash payments to purchase shares of common stock. However, full quarterly dividend reinvestment is required for all Plan participation, including the purchase of shares with optional cash payments. For further information, please contact our transfer agent.

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

Annual Meeting
The Annual Meeting of Shareowners will be held on Thursday, May 9, 1996 at 3:00 p.m. In connection with this meeting proxies will be solicited by the Company.

Common Stock Prices and Dividends
The common stock of the Company is traded on the New York Stock Exchange and the Pacific Stock Exchange. Certain of the Company's preferred stock series are traded on the New York Stock Exchange. The quoted market prices and the dividends declared for the Company's common stock for the years 1995 and 1994 were as follows:

Quarter	1995			1994		
	High	Low	Dividend	High	Low	Dividend
First	$16¾	$13¼	$0.445	$24¾	$21½	[illegible]
Second	17⅛	14⅜	0.445	22⅞	17½	[illegible]
Third	17¾	15⅝	0.445	19⅝	15	0.445
Fourth	17¾	15⅝	0.445	18⅝	15¼	0.445

Form 10-K Annual Report
You can obtain a copy of the Company's Annual Report on Form 10-K, including detailed financial information, as filed with the Securities and Exchange Commission by writing to:

Investor Relations
Long Island Lighting Company
175 East Old Country Road
Hicksville, New York 11801

If you have a question about the Company or your stock, please call our Investor Relations Department at 516-545-4914, weekdays from 8 a.m. to 5 p.m.

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

Printed on recycled paper

Directors

William J. Catacosinos
Chairman of the Board,
President and
Chief Executive Officer
Long Island Lighting Company

A. James Barnes
Dean
School of Public and
Environmental Affairs
Indiana University

George Bugliarello
Chancellor
Polytechnic University

Renso L. Caporali
Senior Vice President
Government and Commercial
Marketing
R[illegible] Company

Peter O. Crisp
President
Venrock, Inc.
Venture Capital Investments

Vicki L. Fuller
Senior Vice President
Emerging Markets
and High Yield
Alliance Capital Management
Corporation

Katherine D. Ortega
Former Treasurer
of the United States

Basil A. Paterson
Partner
Meyer, Suozzi, English
& Klein, PC
Law

Richard L. Schmalensee
Director
Center for Energy and
Environmental Policy Research
Massachusetts Institute
of Technology

George J. Sideris
Retired Senior Vice President
Finance
Long Island Lighting Company

John H. Talmage
Partner
H.R. Talmage & Son
Agriculture

Phyllis S. Vineyard
Representative to
Non-Governmental
Organization of
the United Nations

Officers

William J. Catacosinos
Chairman of the Board,
President and
Chief Executive Officer

James T. Flynn
Executive Vice President
and Chief Operating Officer

Arthur C. Marquardt
Senior Vice President
Gas Business Unit

Anthony Nozzolillo
Senior Vice President Finance
and Chief Financial Officer

Edward J. Youngling
Senior Vice President
Electric Business Unit

Robert X. Kelleher
Vice President
Human Resources

John D. Leonard, Jr.
Vice President
Engineering and Construction

Adam M. Madsen
Vice President
Corporate and Strategic Planning

Kathleen A. Marion
Vice President
Corporate Services
and Corporate Secretary

Brian R. McCaffrey
Vice President
Administration

Joseph W. McDonnell
Vice President
External Affairs

Richard Reichler
Vice President
Financial Planning
and Taxation
and Deputy General Counsel

William G. Schiffmacher
Vice President
Customer Relations

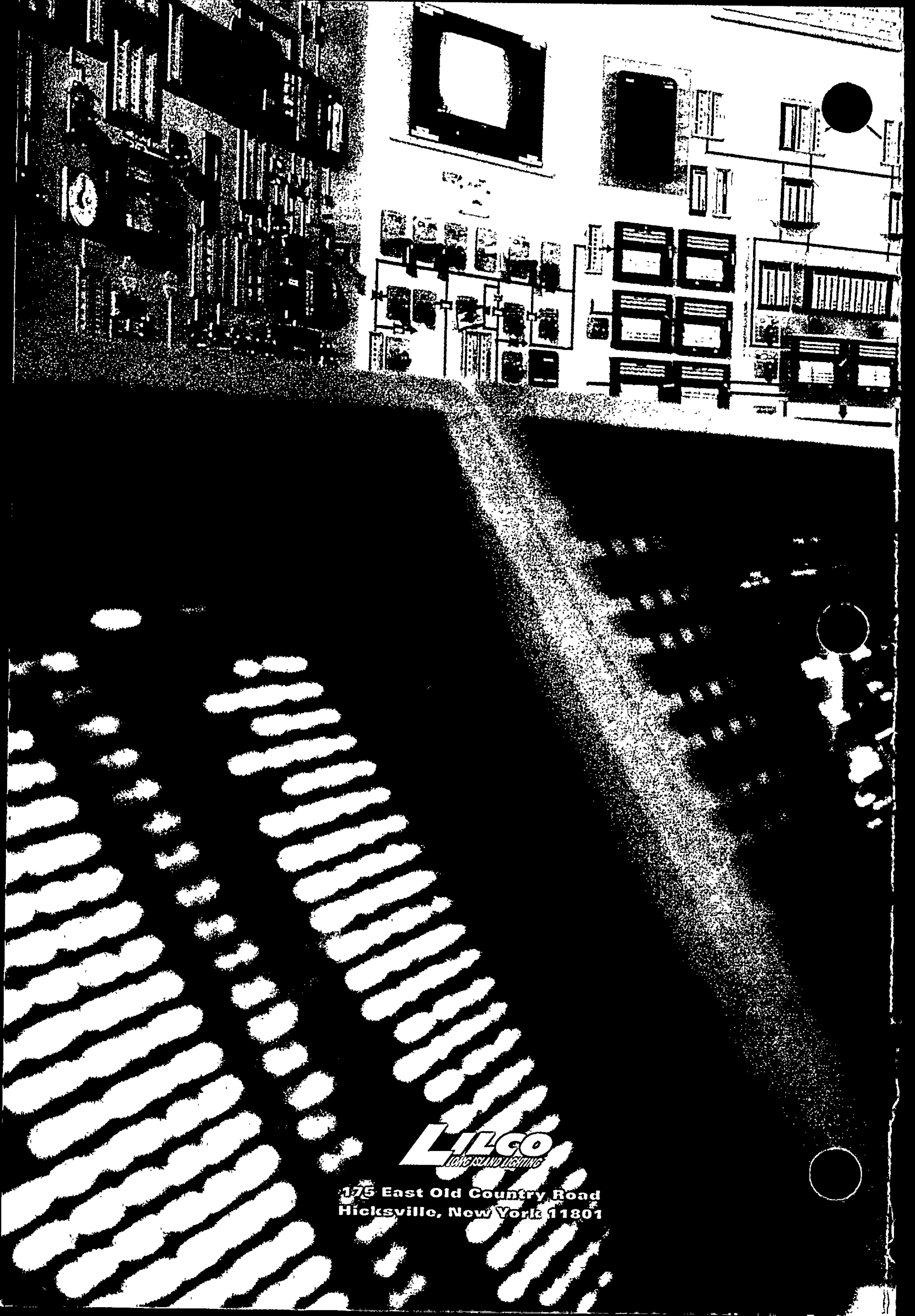
Robert B. Steger
Vice President
Electric Operations

William E. Steiger, Jr.
Vice President
Fossil Production

Leonard P. Novello
General Counsel

Theodore A. Babcock
Treasurer and
Assistant Corporate Secretary

Joseph E. Fontana
Controller


LILCO
LONG ISLAND LIGHTING
175 East Old Country Road
Hicksville, New York 11801

• Competition • Customer Choice • PowerChoice •

• Customer Choice • Flexibility To Grow • Competition •

• Flexibility To Grow • Competition • Customer Choice •

• Competition • Customer Choice • Flexibility To Grow •

• Customer Choice • Flexibility To Grow • Competition •

• *PowerChoice*

• Competition

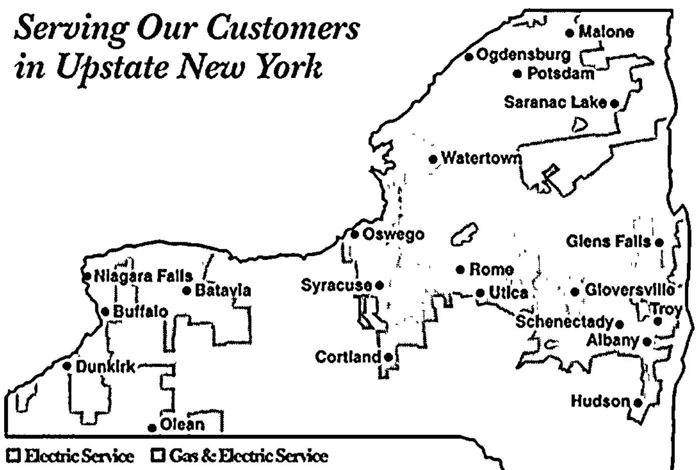
• Flexibility

1995 Annual Report

Niagara Mohawk Power Corporation

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.

Printed on recycled paper

This report was produced by Niagara Mohawk employees.

Corporate Information

Annual Meeting
The Annual Meeting of shareholders will be held at The Desmond, 660 Albany-Shaker Road, Albany, NY, at 10:30 a.m., Tuesday, May 7, 1996. 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 [illegible] the Securities and Exchange Commission, is available without charge by writing the Investor Relations Department at 300 Erie Boulevard West, Syracuse, NY 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 the 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, NY 13202	Bonds: Marine Midland Bank, N.A. 140 Broadway New York, NY 10015

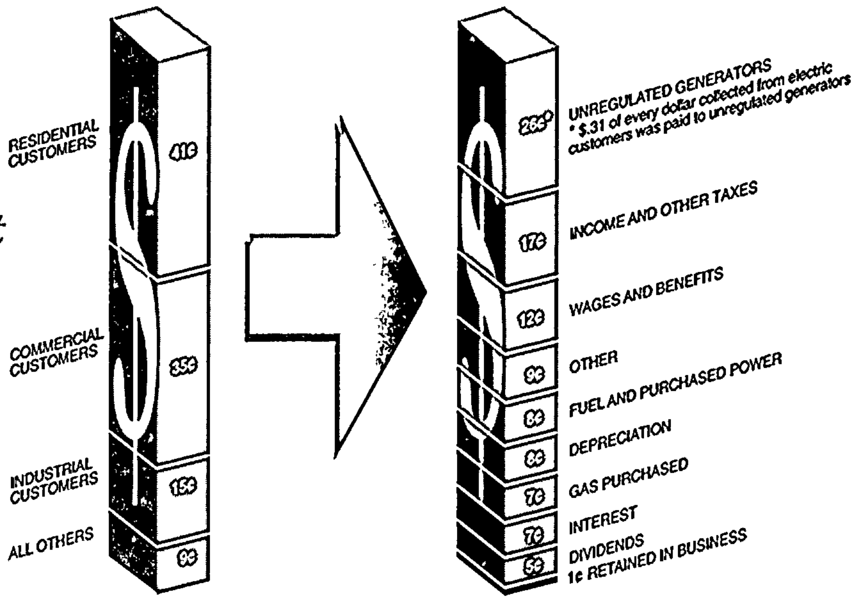
Transfer Agent and Registrars

Common and preferred stocks: The Bank of New York P.O. Box 11002 Church Street Station New York, NY 10286	Bonds: Marine Midland Bank[illegible] 140 Broadway New York, NY 10015

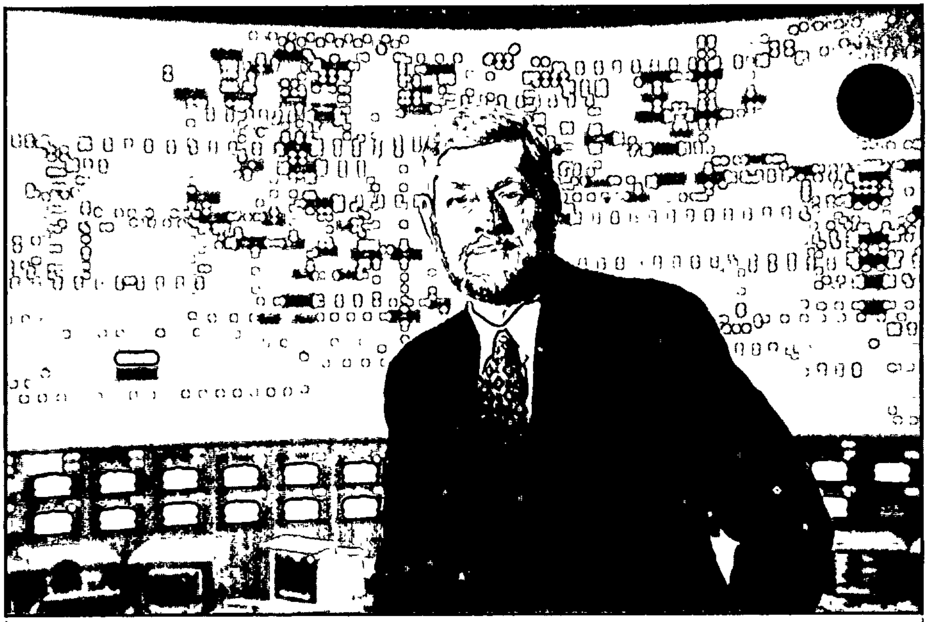
Highlights

	1995	1994	%Change
Total operating revenues	$ 3,917,338,000	$ 4,152,178,000	(5.7)
Income available for common stockholders	$ 208,440,000	$ 143,311,000	45.4
Earnings per common share	$ 1.44	$ 1.00	44.0
Dividends per common share	$ 1.12	$ 1.09	2.8
Common shares outstanding (*average*)	144,329,000	143,261,000	0.7
Utility plant (*gross*)	$10,649,301,000	$10,485,339,000	1.6
Construction work in progress	$ 289,604,000	$ 481,335,000	(39.8)
Gross additions to utility plant	$ 345,804,000	$ 490,124,000	(29.4)
Public kilowatt-hour sales	33,228,000,000	34,006,000,000	(2.3)
Total kilowatt-hour sales	37,684,000,000	41,599,000,000	(9.4)
Electric customers at end of year	1,568,000	1,559,000	0.6
Electric peak load (*kilowatts*)	6,211,000	6,458,000	(3.8)
Natural gas sales (*dekatherms*)	78,481,000	85,615,000	(8.3)
Natural gas transported (*dekatherms*)	144,613,000	85,910,000	68.3
Gas customers at end of year	518,000	512,000	1.2
Maximum day gas deliveries (*dekatherms*)	1,211,252	995,801	21.6

The 1995 Revenue Dollar and Where it Went



A Letter to Our Shareholders



Chairman and CEO William E. Davis

"Our chief objective is to reestablish the company as a viable long-term investment. Through PowerChoice, we have developed a plan to ensure the success of Niagara Mohawk as a regulated energy provider and to position the company to take advantage of emerging unregulated business opportunities."

Dear Shareholder:

During 1995, the broad outlines of the coming competitive electricity marketplace began to emerge. Plans for the transition were advanced at the federal level and in nearly every state. Among many parties, there is a developing consensus as to the basic market structure necessary to secure the benefits of competition while avoiding undue harm to any stakeholder.

Many individual utilities furthered preparations for competition, some through mergers, others through restructuring. With the October announcement of our *PowerChoice* proposal, Niagara Mohawk opted to accelerate the introduction of competition and reconfigure the company to take advantage of future opportunities. The proposal is also intended to help resolve the problems created, both for Niagara Mohawk and for New York's economy, by more than 20 years of failed state and federal energy policies.

Our chief objective is to reestablish the company as a viable long-term investment. Through *PowerChoice,* we have developed a plan to ensure the success of Niagara Mohawk as a regulated energy provider and to position the company to take advantage of emerging unregulated business opportunities.

As we began the year, pressure continued to mount from two tenacious problems I have written about in the past: rising payments for power we are required to buy from unregulated generators, and New York's very heavy utility tax burden. We continued our cost-containment efforts, completing a 27 percent reduction in overall staffing, eliminating some functions, and consolidating others. But our internal cost reductions were outpaced by the growth in externally imposed costs. Combined, unregulated generator contracts and taxes now represent nearly half of all our costs, and have raised our electricity prices to well above the national average.

PowerChoice

Our *PowerChoice* proposal would create a fully competitive generation marketplace and restructure Niagara Mohawk to compete in the new competitive environment. It would freeze for five years average electricity prices for each customer class and cut prices for industrial customers to help preserve existing jobs and create new ones. We also indicated that we would be willing to sacrifice to make *PowerChoice* a reality, but only if unregulated generators and the state did their share to reduce costs as well.

Here is how *PowerChoice* would address several key issues:

• **Disaggregation** – As the transition to competition goes forward, vertically integrated utilities will be under increasing pressure to separate generation from the rest of their business, principally because of concerns over market power and the potential for self-dealing if those who own most of the generation also control access to customers through ownership of the transmission and distribution systems.

It is our view that generation will eventually become fully deregulated, as will many marketing and related service functions for customers with choice. Transmission and distribution are likely to remain natural monopolies and therefore will remain regulated.

Anticipating the future structure of the marketplace, *PowerChoice* proposes to split Niagara Mohawk into two parts – a generating company that would also administer those purchased power contracts that are not restructured, and a holding company that would incorporate all remaining utility functions, as well as emerging unregulated businesses. Planning under way in many states contemplates at least functional separation of generation.

• **Reliability** – To maintain service reliability, the new competitive generation marketplace as envisioned in *PowerChoice* would be administered by an independent system operator. The recommended decision in New York's Competitive Opportunities case (detailed on page 5) and a recent decision by the California Public Utilities Commission also recommend a competitive generation market administered by an independent system operator.

• **Stranded costs** – Depending on how competition is introduced, the new economics of the marketplace might not allow full recovery of investments prudently made in the pursuit of reliable electric service for all customers. Niagara Mohawk, like many other utilities, has made investments in generating capacity that might be stranded because the current oversupply of electricity has lowered the price on the open market to a level that would not allow full recovery.

PowerChoice asserts Niagara Mohawk's right to recover all stranded costs but, in the interest of resolving the growing purchased power problem, offers to forego full recovery if unregulated generators are similarly willing to write down proportionate amounts.

Response to PowerChoice

PowerChoice has received national notice and has put Niagara Mohawk at the forefront of the national industry restructuring debate.

Some in the financial community have been skeptical of our ability to gain the concessions from others – including unregulated generators and the state of New York – that our proposal contemplates. In this regard, we began negotiations with the state and other affected parties soon after filing *PowerChoice*, and we remain hopeful of a successful outcome.

There was also understandable discomfort with our disclosure of the possibility of bankruptcy if *PowerChoice* is not achieved. Unfortunately, some focused more on this possibility than on the development of a viable solution to the difficulties facing our company and our service territory.

PowerChoice would require a degree of sacrifice by Niagara Mohawk, by unregulated generators, and by others. The sacrifice is, however, necessary. The alternative is continued reliance on an outmoded system of regulation that will perpetuate the current untenable situation.

Our 1995 financial and electricity sales results provided additional confirmation of the need for the fundamental change envisioned in *PowerChoice*. Earnings of $208.4 million, or $1.44 per share, compare to 1994 earnings of $143.3 million, or $1.00 per share. However, 1994 earnings were reduced by a fourth-quarter charge for the costs of the company's voluntary employee reduction program of $196.6 million, or $0.89 per share.

Continued weak economic conditions had a negative impact on revenues and sales of both electricity and natural gas in 1995. Electric revenues in 1995 were $3.3 billion, a decrease of $193.4 million, or 5.5 percent from a year earlier. Retail sales of electricity were down 2.3 percent. Total electricity sales fell 9.4 percent, reflecting a significant drop in wholesale sales.

Gas revenues for the year were $581.8 million, down $41.4 million, or 6.6 percent from 1994, primarily due to decreased retail sales. Total gas delivered, which includes natural gas transported to end users, increased 29.9 percent. Gas margins were also up in 1995, increasing by approximately $600,000 over 1994 figures.

continued...

These results underscore the need to maintain the company's financial stability as we pursue necessary changes. Accordingly, your Board of Directors voted in January 1996, to omit the dividend on common stock. Dividends were declared on all series of preferred stock.

Although we have already implemented significant cost-saving measures over the past several years, more is needed. As such, officer salaries will be frozen for two years and further austerity measures will be implemented.

> *"I want to thank you for standing by Niagara Mohawk during these challenging times, especially those of you who have taken time to write to New York's government officials and regulators in support of our efforts. You have our utmost gratitude and our assurance that protecting and enhancing your investment is our foremost concern."*

At the time we filed *PowerChoice*, we also indicated that without the plan, unregulated generator costs, taxes, and declining sales would continue to push up electricity prices. Accordingly, we filed for an average 4.1 percent price increase for 1996 and a 4.2 percent increase for 1997 to protect shareholders from further erosion of their investment if *PowerChoice* is not implemented. If and when *PowerChoice* receives approval – especially the proposals calling for concessions from unregulated generators – we would move to terminate these proceedings.

Other Highlights

Though *PowerChoice* consumed a great deal of attention last year, there were other important developments. In March, Albert J. Budney, Jr. joined Niagara Mohawk as president, bringing a wealth of experience and knowledge in many phases of the utility industry.

Our nuclear operations continued to perform well, as evidenced by a listing on the honor rolls of the Nuclear Energy Institute and The General Electric Company for both Nine Mile Point units, based on 1994 performance. For 1995, capacity factors for Unit One and Unit Two were 87 percent and 78 percent respectively, and both plants underwent successful refueling outages during 1995.

And few of us will ever forget the summer storm of 1995, which devastated much of our service territory but proved that a solid work ethic and dedication to service are alive and well at Niagara Mohawk.

The efficiency of our nuclear units and the exemplary performance of employees in restoring p[illegible]wer after the storm are only two examples of a larg[illegible]y: the continued commitment to excellence [illegible]e people of Niagara Mohawk. These past few years have been difficult and worrisome for our employees, but nevertheless they have persevered in accomplishing every task set before them, as I am sure they will continue to do in the future. They are deserving of our appreciation, and our pledge to do our best to reward their efforts.

We will push hard for approval of *PowerChoice* in 1996, and we will keep you informed as developments occur. I want to thank you for standing by Niagara Mohawk during these challenging times, especially those of you who have taken time to write to New York's government officials and regulators in support of our efforts. You have our utmost gratitude and our assurance that protecting and enhancing your investment is our foremost concern.

William E. Davis

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

Competition

Niagara Mohawk's *PowerChoice* proposal is intended both to prepare the company for coming competition, and to shape the competitive marketplace so that it provides maximum benefit for consumers. The plan embodies the company's long-held belief that competition can benefit end users by holding down rates and increasing the breadth and quality of services.

Competition will be beneficial for those energy providers who are prepared, and requires providers to place their focus on meeting customer needs. It makes competitors work harder, smarter and more efficiently.

A key provision of the proposal calls for establishment of an open, competitive electricity generation market that would allow customers to choose their power suppliers. By opening the market to all electricity suppliers, our plan calls for creation of a new wholesale market – under the supervision of the Federal Energy Regulatory Commission – that would be coordinated by an independent system operator.

Restructuring to Compete

This market will be best served, Niagara Mohawk believes, by a generation company independent of all other market functions. While final separation must await the implementation of *PowerChoice*, the company has already put in place an interim generation organization in anticipation of full separation.

This latest reconfiguration has been made easier by Niagara Mohawk's restructuring five years ago into strategic business units. The interim Generation Business Group combines the company's two nuclear facilities with the four fossil-fueled plants and 73 hydroelectric units. Fossil and hydro were previously in the Electric Supply & Delivery SBU. Heading the Generation Business Group is Executive Vice President B. Ralph Sylvia, previously in charge of the Nuclear SBU.

The Energy Distribution Business Group, under Senior Vice President Darlene D. Kerr, combines all electricity transmission and distribution functions, including those that will eventually be transferred to the independent system operator. Natural gas transmission and distribution is also managed by this group.

The electricity and natural gas services expected to be unregulated would be conducted by a new entity, Plum Street Enterprises. Under the direction of President Albert J. Budney, Jr., Plum Street Enterprises consists of four divisions: Ventures and Consulting Services, Energy Marketing and Brokering, Mass Market Services, and Land Management & Development/Investment Recovery.

PowerChoice Consistent with PSC's Competitive Opportunities Decision

In December 1995, the New York Public Service Commission received an Administrative Law Judge's recommended decision in its Competitive Opportunities case. The recommended decision will be accepted, rejected or revised by the PSC commissioners, probably before mid-1996.

The recommended decision envisions a competitive marketplace quite similar to the company's *PowerChoice* vision, with the generation segment functionally separate, and a marketplace in which transactions are coordinated by an independent system operator. The decision also allows for recovery of utilities' strandable costs.

Niagara Mohawk has expressed the view that nothing in the PSC recommended decision would require alteration of *PowerChoice*. After the Commission's final decision is rendered, the state's utilities will be asked to file their own plans for restructuring to conform to the decision, something Niagara Mohawk has already done through *PowerChoice*.

Customer Choice

A major challenge for Niagara Mohawk in moving toward a competitive marketplace for electricity has been to prepare for a business environment where customers can choose their supplier. When customers have choice, suppliers who can provide services that customers want at prices they are willing to pay will grow and thrive.

PowerChoice envisions an open generation market in which, eventually, all customers would choose their suppliers. Customers would be able to purchase from the market, or from marketers, brokers, or energy service companies, under any terms and conditions they could negotiate. Only delivery services provided by the transmission and distribution company would be subject to regulation.

Pending approval of other aspects of *PowerChoice*, direct access by retail customers would begin as soon as the competitive generation market is operational. As specified in our proposal, large customers would have access by January 1, 1997, and all customers, including residential customers, would have access by January 1, 2000.

PowerChoice envisions an open generation market in which, eventually, all customers would choose their suppliers. Customers would be able to purchase from the market, or from marketers, brokers, or energy service companies, under any terms and conditions they could negotiate. ... Pending approval of other aspects of PowerChoice, direct access by retail customers would begin as soon as the competitive generation market is operational.

Customer Service

No matter who they choose as their supplier, Niagara Mohawk would continue to provide its customers with a wide range of services, from distributing electricity to responding to inquiries. During 1995, the company took several steps to improve its customer service performance and to broaden the scope of services it provides.

- Niagara Mohawk became one of the first utilities in the nation to back up its pledge of excellent customer service with written guarantees. Covering timely service connection, respect for property, product satisfaction, and courtesy, the guarantees include monetary restitution or a specific course of action to fulfill a guarantee that is not satisfactorily met.
- To serve all customers better, in 1995 the company introduced a toll-free number for customers whose primary language is Spanish. This is in addition to offering bills in braille or recorded on audio cassette tape, which the company has made available for several years to customers who request this service.
- Through Plum Street Enterprises, its unregulated subsidiary, the company is developing a comprehensive array of services to meet the growing needs of commercial and industrial customers. These wide-ranging unregulated business opportunities are discussed on page 7.
- This past year was the first full year of operation at the consolidated Customer Service Center in Syracuse, and significant progress was made to improve overall customer service. Particularly impressive were fourth-quarter 1995 results of the customer satisfaction survey: an 80.6 percent satisfaction rating represented a 3.7 percent increase over third-quarter figures, the largest single-quarter improvement ever recorded.

Flexibility To Grow

The unregulated marketplace envisioned in *PowerChoice* would provide Niagara Mohawk with a wide variety of opportunities to offer services and enter business ventures not normally associated with a traditional vertically integrated utility. This will be done through Plum Street Enterprises, the unregulated subsidiary created as part of *PowerChoice.*

With revenues from electricity and natural gas projected to remain relatively flat in the near term, business opportunities in the unregulated arena have the potential to increase profits and grow shareholder value. Free from the regulatory constraints that now limit the company, Plum Street Enterprises is beginning to make inroads into several areas with the potential to bolster profits in the future.

> *The strategy of Plum Street Enterprises is to develop a company capable of quickly tapping emerging markets and creating innovative products and services.*

The strategy of Plum Street Enterprises is to develop a company capable of quickly tapping emerging markets and creating innovative products and services. The subsidiary's operating arms would pursue independent strategies, seeking business in parts of the country and the world previously unavailable to traditional U.S. utilities.

In creating Plum Street Enterprises, Niagara Mohawk joins a growing number of utilities nationwide that have established a separate subsidiary to explore new energy-related, entrepreneurial profit centers.

Developing a Business Focus

Initially, Plum Street Enterprises plans to concentrate on four areas:

1. **Ventures and Consulting Services** would provide technological solutions and technical skills to the energy market. Among the areas this group would focus on are: wholesale energy services offering engineering and design, construction, maintenance, and operations services for bulk energy systems; technology solutions such as demand-side management, renewable energy, and distributed generation; and international energy business development to bring world-class supply and distribution systems to countries with developing economies.

2. **Energy Marketing and Brokering** would focus on electric and gas bulk and retail marketing, forward and real-time trading, and risk management services. This group would be responsible for marketing and reselling excess energy and capacity – including independent power under contract to Niagara Mohawk. Another key area of business would be natural gas and electricity portfolio management for other utilities and customers.

3. **Mass Market Services** would use technology, telecommunications, and information to provide new solutions to customers' emerging demands for greater efficiency and convenience. Targeting virtually any customer – with a focus on the residential end-user – this group would offer a wide range of products and services, some of which were previously offered in our bundled regulated tariffs, and others yet to be developed.

4. **Land Management & Development/Investment Recovery** would expand the scope and scale of existing land management and investment recovery activities into new markets. Activities would include the sale and development of non-essential real estate assets, greenways and conservation projects, timber harvesting, and recycling.

The evolution of the energy industry can be expected to yield new opportunities to grow revenues in unregulated activities. Plum Street Enterprises plans to offer high-quality, in-demand energy services and products for customers in both national and international markets.

New President Brings Experience and Leadership

Albert J. Budney, Jr.
President

The first year as Niagara Mohawk's new president has been anything but routine for Albert J. Budney, Jr. But the excitement and unpredictability of the utility industry is nothing new for him.

"Niagara Mohawk's demonstrated commitment to shaping the industry structure that we will compete in tomorrow is one of the primary reasons I joined the company," said Budney. "Our *PowerChoice* proposal gives us the opportunity to take a leadership role in the continuing transformation of this industry. I look at it as a chance to be part of something that is truly remarkable."

Aside from his key role in shaping *PowerChoice,* Budney's first few months on the job also gave him a first-hand look at how unpredictable and devastating upstate New York weather can be in the wake of the July 15 storm. "It was a real education seeing not only the damage wrought by the storm, but also the incredible work ethic and skill demonstrated by our employees in restoring service," he said.

Budney brings a wealth of top-level experience to the job. Immediately prior to joining Niagara Mohawk, he was corporate managing vice president of UtiliCorp Power Services Group, a unit of UtiliCorp United Inc., of Kansas City, Mo. In that position he was responsible for transforming a regulated generation business into a competitive enterprise. He also worked closely with a business unit similar to Plum Street Enterprises, the company's recently formed unregulated subsidiary, where he learned valuable lessons about non-traditional business opportunities that will play a critical role in shaping Niagara Mohawk's future.

Prior to that, Budney served as president of UtiliCorp's largest operating division, Missouri Public Service, an electric and gas utility. Previously, he was vice president of Stone & Webster Engineering Corp., where he managed the engineering firm's Boston Business Development Department and headed the Total Quality Steering Committee. He also was vice president of Stone and Webster Management Consultants, an international utility consulting firm.

A Philadelphia native, Budney holds a master's degree in business administration from Harvard Business School and an engineering degree from Princeton University. He is a veteran of the U.S. Navy and served as a lieutenant aboard a nuclear-powered ballistic-missile submarine.

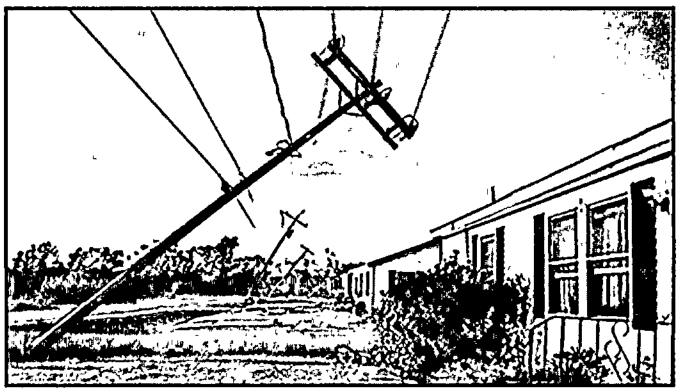
Storm Brings Outstanding Employee Response to Record Outages

For many of Niagara Mohawk's employees and customers, the events of July 15, 1995, will never be forgotten.

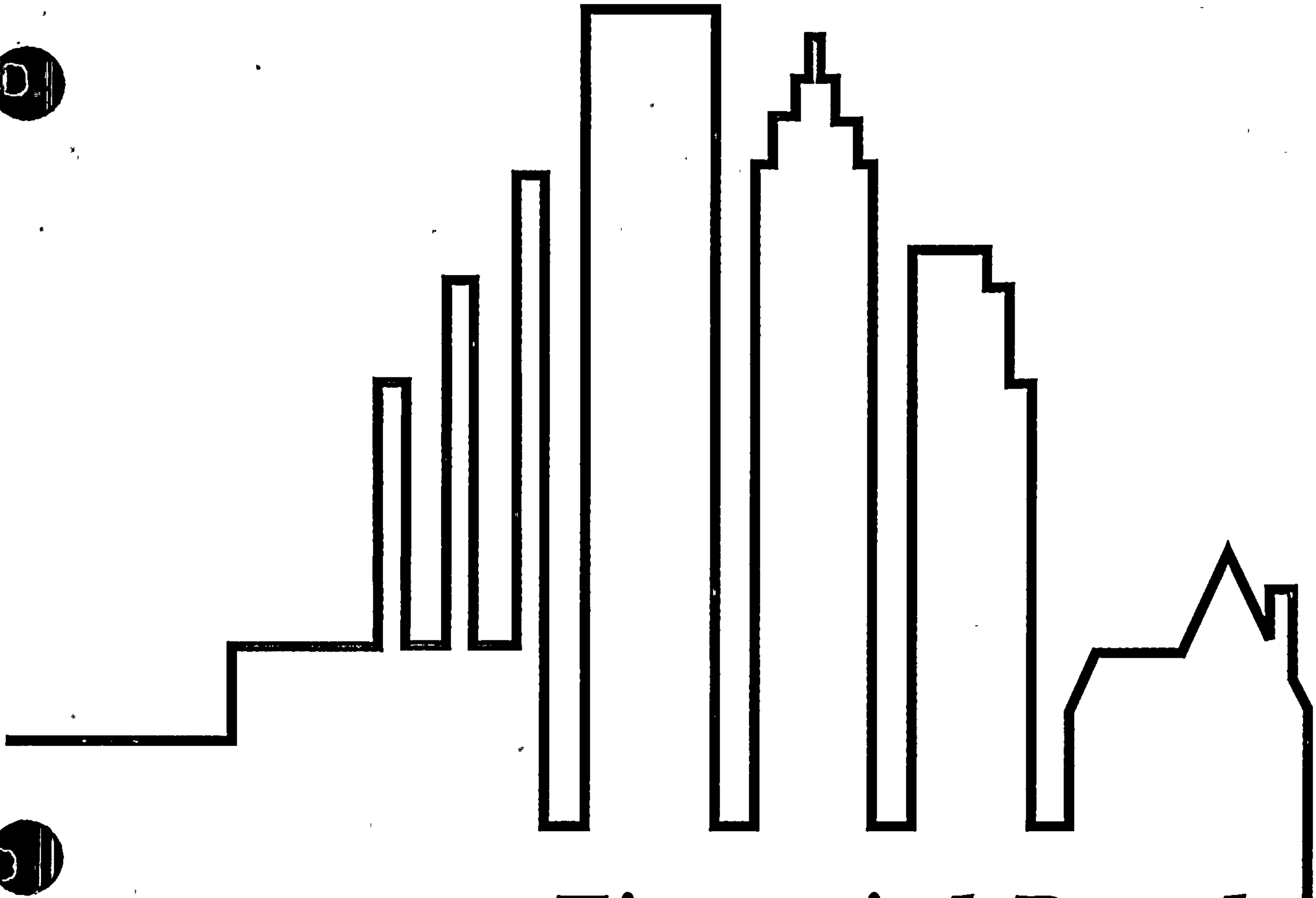
In the early morning hours of that Saturday, an unexpected wind and lightning storm struck Central, Northern, and Eastern New York with unprecedented speed and fury. In the wake of the violent storm, 230,000 customers were left without electricity – the largest single outage in Niagara Mohawk's 45-year history.

When the severe weather passed, employees were faced with a restoration effort unlike any seen before. Adding to the difficulty of the task was record-breaking heat and the fact that much of the heaviest damage occurred in extremely remote parts of the company's service territory.

Within hours, employees were organized and heading to the hardest-hit areas. Assisted by workers from utilities around the Northeast and Canada, a work force that grew to nearly 650 line and tree crews performed tirelessly to restore electricity. Two days after the storm hit, power was back on to all but 30,000 customers. In some communities, entire power delivery systems had to be rebuilt from the ground up.



The Storm of 1995 provided indisputable confirmation that the dedication of Niagara Mohawk employees – from customer service representatives to regional power control personnel to the crews working in the field – has never been stronger.



Financial Results

Contents

The Company's common stock and certain of its preferred series are listed on the New York Stock Exchange (NYSE). 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 estimates that none of the 1995 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 (NYSE) and dividends per share for the Company's common stock:

1995	Dividends Paid Per Share	Price Range High	Price Range Low
1st Quarter	$.28	$15⅝	$13⅜
2nd Quarter	.28	15⅛	13⅝
3rd Quarter	.28	14¾	11¼
4th Quarter	.28	13⅜	9½
1994			
1st Quarter	$.25	$20⅝	$17¾
2nd Quarter	.28	19	14⅝
3rd Quarter	.28	17½	12
4th Quarter	.28	14⅜	12⅞

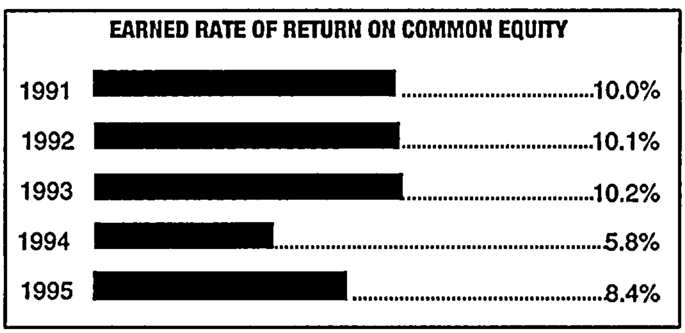
On January 25, 1996, the board of directors omitted the common stock dividend for the first quarter of 1996. This action was taken to help stabilize the Company's financial condition and provide flexibility as the Company addresses growing pressure from mandated power purchases and weaker sales. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" below. In making future dividend decisions, the board will evaluate, along with standard business considerations, the level and timing of future rate relief, the progress of renegotiating contracts with unregulated generators (UGs) within the context of its *PowerChoice* proposal, the degree of competitive pressure on its prices, and other strategic considerations.

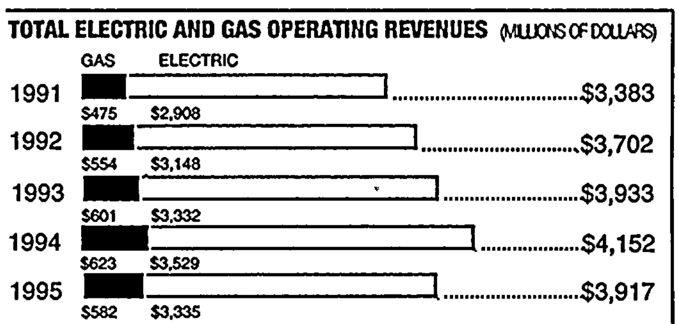
Other Stockholder Matters: The holders of common stock are entitled to one vote per share and may not cumulate their votes for the election of Directors. Whenever dividends on preferred stock are in default in an amount equivalent to four full quarterly dividends and thereafter until all dividends thereon 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, there were approximately 84,600 holders of record of common stock of the Company and about 5,700 holders of record of 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	34,975	977,436
100 to 999	44,871	11,155,890
1,000 or more	4,780	132,198,797
	84,626	144,332,123


EARNED RATE OF RETURN ON COMMON EQUITY

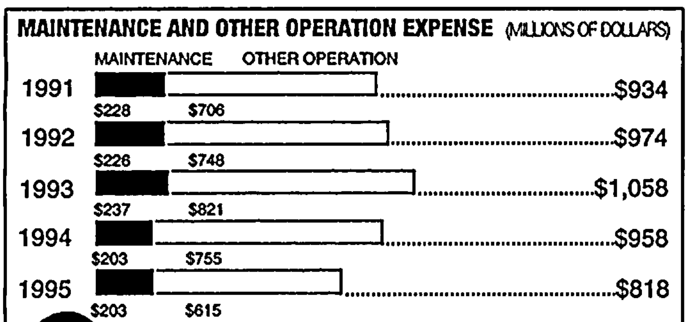

TOTAL ELECTRIC AND GAS OPERATING REVENUES (MILLIONS OF DOLLARS)

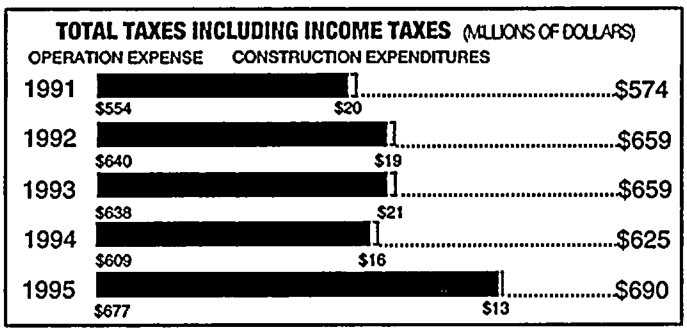
Selected Consolidated Financial Data

The following table sets forth selected financial information of the Company for each of the five years during the period ended December 31, 1995, which has been derived from the audited financial statements of the Company, and should be read in connection therewith. As discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Notes to Consolidated Financial Statements," the following selected financial data may not be indicative of the Company's future financial condition or results of operations:

	1995	1994	1993	1992	1991
Operations: (000's)					
Operating revenues	$3,917,338	$4,152,178	$3,933,431	$3,701,527	$3,382,518
Net income	248,036	176,984	271,831	256,432	243,369
Common stock data:					
Book value per share at year end	$17.42	$17.06	$17.25	$16.33	$15.54
Market price at year end	9 1/2	14 1/4	20 1/4	19 1/8	17 7/8
Ratio of market price to book value at year end	54.5%	83.5%	117.4%	117.1%	115.0%
Dividend yield at year end	11.8%*	7.9%	4.9%	4.2%	3.6%
Earnings per average common share	$ 1.44	$ 1.00	$ 1.71	$ 1.61	$ 1.49
Rate of return on common equity	8.4%	5.8%	10.2%	10.1%	10.0%
Dividends paid per common share	$ 1.12 *	$ 1.09	$ .95	$ .76	$ .32
Dividend payout ratio	77.8%*	109.0%	55.6%	47.2%	21.5%
Capitalization: (000's)					
Common equity	$2,513,952	$2,462,398	$2,456,465	$2,240,441	$2,115,542
Non-redeemable preferred stock	440,000	440,000	290,000	290,000	290,000
Mandatorily redeemable preferred stock	96,850	106,000	123,200	170,400	212,600
Long-term debt	3,582,414	3,297,874	3,258,612	3,491,059	3,325,028
Total	6,633,216	6,306,272	6,128,277	6,191,900	5,943,170
Long-term debt maturing within one year	65,064	77,971	216,185	57,722	175,501
Total	$6,698,280	$6,384,243	$6,344,462	$6,249,622	$6,118,671
Capitalization ratios:					
(including long-term debt maturing within one year)					
Common stock equity	37.5%	38.6%	38.7%	35.8%	34.6%
Preferred stock	8.0	8.5	6.5	7.4	8.2
Long-term debt	54.5	52.9	54.8	56.8	57.2
Financial ratios:					
Ratio of earnings to fixed charges	2.29	1.91	2.31	2.24	2.09
Ratio of earnings to fixed charges without AFC	2.26	1.89	2.26	2.17	2.03
Ratio of AFC to balance available for common stock	4.3%	6.3%	6.8%	9.7%	9.3%
Ratio of earnings to fixed charges and preferred stock dividends	1.90	1.63	2.00	1.90	1.77
Other ratios – % of operating revenues:					
Fuel, purchased power and purchased gas	40.3%	39.6%	36.1%	34.1%	32.1%
Other operation expenses and maintenance	20.9	23.1	26.9	26.3	27.6
Depreciation and amortization	8.1	7.4	7.0	7.4	7.7
Total taxes, incl. real property, income and revenue taxes	17.3	14.7	16.2	17.3	16.4
Operating income	13.5	10.4	13.3	14.2	15.5
Balance available for common stock	5.3	3.5	6.1	5.9	6.0
Miscellaneous: (000's)					
Gross additions to utility plant	$ 345,804	$ 490,124	$ 519,612	$ 502,244	$ 522,474
Total utility plant	10,649,301	10,485,339	10,108,529	9,642,262	9,180,212
Accumulated depreciation and amortization	3,641,448	3,449,696	3,231,237	2,975,977	2,741,004
Total assets	9,477,869	9,649,816	9,471,327	8,590,535	8,241,476

* On January 25, 1996, the Board of Directors omitted the common stock dividend.





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

Overview

Earnings in 1995 were $208.4 million or $1.44 per share. Earnings in 1994 were $143.3 million or $1.00 per share and included $101.2 million or 46 cents per share of electric margin recorded under the Niagara Mohawk Electric Revenue Adjustment Mechanism (NERAM), as well as a charge of about $197 million (89 cents per share) for nearly all of the cost of the Voluntary Employee Reduction Program (VERP). NERAM was a surcharge which assured that the Company's margin on electric sales would equal the margin assumed in establishing rates. In January 1995 NERAM was discontinued. 1995 earnings were negatively impacted by lower sales of electricity and natural gas, compared to amounts used to establish 1995 prices, due primarily to continuing weak economic conditions in upstate New York, loss of industrial load to New York Power Authority (NYPA) and discounts. However, cost reduction efforts begun in 1994 through the VERP helped 1995 earnings. The Company's 1995 earned return on common equity was 8.4%, which was below the 11.0% that the New York State Public Service Commission (PSC) authorized on electric utility operations due to, among other things: sales below those forecast in determining rates; about $20 million of negotiated customer discounts in excess of the approximately $42 million reflected in rates; the inability to achieve stringent wholesale margin targets set by the PSC; and fuel target penalties caused by low hydro production due to dry weather. The Company expects the trend of weak sales to continue, given the poor economic condition of the Company's service territory.

In the long term, the Company's earnings will depend substantially on the outcome of the Company's *PowerChoice* proposal discussed below, which was filed with the PSC in October 1995. The Company filed for price increases of 4.1% for 1996 and 4.2% for 1997 and earnings for these years will depend on the outcome of the rate requests. The 1996 rate filing is for temporary rate relief for which the Company has asked for immediate action. On February 16, 1996, the PSC issued an order that, among other things, established a schedule with respect to temporary rates that would have the case certified directly to the PSC within 60 days of the order. The 1997 filing will preserve the Company's right to traditional cost-based rates in the event that an acceptable regulatory solution cannot be achieved through negotiation of the *PowerChoice* proposal. While negotiations are continuing on *PowerChoice*, in view of increasing UG payments, discounts and continued weak sales expectations, the Company has found it necessary to seek these price increases. Without any form of rate relief in 1996 and 1997, the Company would expect to earn a return on equity substantially below that earned in 1995. The Company is implementing additional reductions in non-essential programs (not related to safety and reliability) to reduce costs.

On January 25, 1996, the board of directors omitted the common stock dividend for the first quarter of 1996. This action was taken to help stabilize the Company's financial condition and provide flexibility as the Company addresses growing pressure from mandated power purchases and weaker sales. In making future dividend decisions, the board will evaluate, along with standard business considerations, the level and timing of future rate relief, the progress of renegotiating contracts with UGs within the context of its *PowerChoice* proposal, the degree of competitive pressure on its prices, and other strategic considerations.

Following the announcement of the *PowerChoice* proposal, Standard & Poor's (S&P) and Moody's Investors Service (Moody's) downgraded all of the Company's credit ratings to "below investment grade," and placed the Company's securities on "Credit Watch" with negative implications. The downgrade of the Company's security ratings reflects concerns regarding the uncertainty and potential negative impact of the *PowerChoice* proposal on the Company, as well as the potential for bankruptcy. The Company is committed to pursuing *PowerChoice* as a positive response to competitive threats and to stabilize and improve the financial condition of the Company. The Company will also consider pursuing other actions, such as requesting rate relief or evaluating solutions other than *PowerChoice*, to maintain the financial viability of the Company.

Due, in part, to the negative response to the *PowerChoice* proposal from rating agencies, the prices of the Company's common stock, preferred stock and bonds declined sharply. The downgrading of the Company's bonds can be expected to make it more difficult and expensive for the Company to finance in the manner it has used in the past. Consequently, the Company is borrowing under its bank revolving credit agreement. In order to further satisfy anticipated financing needs, including those which may be necessary as a result of potential changes to the structure of New York State electricity markets, the Company is currently renegotiating its bank credit facilities and filed a petition with the PSC in December 1995 for authority to enter into a senior debt facility. The proposed senior debt facility totals $815 million and would consolidate and replace certain of the Company's existing working capital lines of credit and letter of credit facilities, as well as provide additional reserves of bank credit. There can be no assurance that the Company will be successful in putting this facility in place; in the event the facility is not completed, the Company believes that the elimination of the common dividend, the implementation of reductions in non-essential programs and the year end 1995 cash position, in combination with alternative sources of credit the Company believes are available if necessary, will be sufficient to fund cash requirements for 1996. Current market conditions preclude the Company from issuing stock in 1996 due to the downgrading of the Company's security ratings. See "Financial Position, Liquidity and Capital Resources."

The Company faces significant challenges in its efforts to maintain its financial condition in the face of expanding competition and weak sales. While utilities across the nation must address these concerns to varying degrees, the Company believes that it is more financially vulnerable than others to competitive threats. The factors contributing to this vulnerability include a large industrial customer base, accounting for about 21% of total electric Kwh sales, an oversupply of high cost mandated power purchases from UGs, an excess supply of wholesale power at relatively low prices, a high tax burden, a stagnant economy in the Company's service territory and significant investments in nuclear plants. Moreover, solving the problems the Company faces, including the implementation of *PowerChoice*, requires the cooperation and agreement of third parties. Accordingly, the outcome cannot be assured and the possibility of restructuring under Chapter 11 of the U.S. Bankruptcy Code cannot be ruled out.

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

Changing Competitive Environment

The accelerating pace of competition is driving dramatic changes throughout the utility industry. In addition, the Company is challenged by state-imposed burdens, especially state-mandated contracts that require the Company to buy electricity from UGs in amounts that exceed customer needs and at prices that are above the Company's own cost of providing electricity. In addition, the Company and other New York utilities bear an excessive tax burden that is more than twice the average for utilities nationwide.

The Company has pursued a number of actions to mitigate the impact of these factors on prices. These actions have included renegotiating and buying out some UG contracts and canceling others when contract terms were not being adhered to. The Company has also been actively seeking reductions in its state and local tax obligations. Nevertheless, mandated UG purchases and high taxes have combined to create an irrational energy market in the Company's service territory — despite an oversupply of generating capacity, prices are rising. Further price increases would make it more difficult for the Company to retain its customers in the longer term and an increasing number of customers are pursuing other supply options including self-generation, alternate supply sources, and municipalization. As a result, electric margins are narrowing and sales are eroding, damaging the Company's financial condition and putting further pressure on the Company to seek even more rate increases under traditional cost-of-service ratemaking.

The Company has responded to these factors by, among other actions, sharply reducing internal costs. The Company has reduced the size of its work force by about 3,200 employees, or 27%, in the past three years, and has eliminated, consolidated or modernized many of its operations. The Company has also sharply reduced capital spending. Electric construction spending in future years is expected to be limited to the level of depreciation expense, thereby resulting in little growth in rate base.

These cost control efforts have produced significant savings. However, the savings are being outpaced by continuing escalation in the externally imposed costs discussed above. Recognizing that major changes in the electricity marketplace in New York State were needed, the Company undertook an exhaustive analytical process with the goal of creating a rational energy market that would link supply, demand and price, provide customers with better and broader services, and provide greater opportunities for building shareholder value. That process resulted in the filing of the Company's *PowerChoice* proposal on October 6, 1995.

PowerChoice is the Company's proposal for stable retail prices, customer choice and an open, competitive electric generation market. The proposal includes, among other things, a five-year price freeze for residential and commercial customers, a price cut for industrial customers to help create jobs and spur economic activity, and restructuring of the Company's businesses. The Company would separate its electrical generation operations, along with the UG contracts not restructured, into a different company that would compete in a deregulated power market. The remaining company would have regulated and unregulated subsidiaries that would transmit and distribute power and engage in new business opportunities with growth potential.

The Company believes that *PowerChoice* is the best course of action to deal with emerging competition and address the factors that have been pushing up prices. However, the success of *PowerChoice* and its associated price freeze depends upon the willingness of UGs and the Company to make substantial reductions in embedded costs (i.e., sunk generation costs, regulatory assets and future obligations under UG contracts). In addition, the Company believes that the state must play a role in reducing costs, particularly by reducing or eliminating the state gross receipts tax, which taxes revenue rather than income. State involvement with the Company's nuclear plants would also be needed for all aspects of the plan to succeed and achieve a price freeze. Addressing these issues will be difficult and will almost certainly require judicial, regulatory and/or legislative action. However, the Company believes that the implementation of *PowerChoice* is achievable.

When *PowerChoice* was announced, the Company said that failure to approve the plan would mean continued price escalation under traditional regulation, or failing that, further deterioration in the Company's financial condition. The Company filed for price increases of 4.1% for 1996 and 4.2% for 1997 and earnings for these years depend on the outcome of the rate requests. The

1996 rate filing is for temporary rate relief for which the Company has asked for immediate action. On February 16, 1996, the PSC issued an order that, among other things, established a schedule with respect to temporary rates that would have the case certified directly to the PSC within 60 days of the order. The 1997 filing will preserve the Company's right to traditional cost-based rates in the event that an acceptable regulatory solution cannot be achieved through negotiation of the *PowerChoice* proposal. While negotiations are continuing on *PowerChoice*, in view of increasing UG payments, discounts and continued weak sales expectations, the Company has found it necessary to seek these price increases. The Company expects that the PSC will approve cost-of-service based rate increases until such time as implementation of a new competitive market model becomes probable.

The Company's current electricity and gas prices reflect traditional utility regulation. As such, the Company's electricity prices include state-mandated purchased power costs from UGs, at costs far exceeding the Company's actual avoided costs, as well as the costs of high taxes in New York. Without legislative or regulatory action, the Company is severely limited in its ability to control or reduce these purchased power costs and taxes, which are major causes of the Company's recent increases in prices.

While the Company is experiencing rising prices, rapid technological advances are significantly reducing the price of new generation and significantly improving the performance of smaller scale generating unit technology. In addition, the current excess supply of generating capacity has driven down the prices a competitive market would support. Actions taken by other utilities throughout the country to lower their prices, including those in areas with already relatively low prices, increase the threat of industrial relocation and the need to offer discounts to industrial customers.

The Company continues to take aggressive action to both prevent the loss of certain industrial customers, and to attract new business. In 1995, the Company granted approximately $62 million of discounts. Discounts are expected to increase in 1996 and 1997, but will depend on energy price levels in the marketplace and other competitive activity. See "Customer Discounts."

The Company also faces the continued threat of municipalization. A growing number of municipalities within the Company's service territory are investigating the possibility of acquiring less expensive sources of electricity by forming their own utility operations. If successfully established as legitimate wholesale entities, these new utilities would have open access to transmission and would be able to by-pass the Company's generation system. The municipalities exploring this possibility are generally in the early stages of inquiry and represent a small percentage of Company sales. Municipalization has the potential to adversely affect the Company's customer base and profitability, although rules proposed by the Federal Energy Regulatory Commission (FERC), as discussed below, would greatly mitigate any negative economic effects on the Company.

PowerChoice Proposal

The PSC's 1995 rate order directed the Company and other interested parties to address several key issues regarding long-range rate proposals. These issues were to include: improving the Company's competitive position by addressing uneconomic utility generation and the high price of many UG contracts; eliminating, if possible, the fuel adjustment clause and other billing mechanisms; addressing property tax issues with local authorities; improving operating efficiency; and identifying governmental mandates that are no longer warranted in a competitive environment. No proposal under this directive could create anti-competitive effects or lead to a deterioration in safe and adequate service. The PSC also said any multi-year plan should ensure that the Company has an investment-grade bond rating (although the Company is currently below investment grade), and include protection for low-income customers. Finally, the PSC directed that the plan should propose changes in the regulatory approach for the Company that support fair competition in the electric generation market consistent with the PSC's determination in its generic competitive opportunities proceeding (COPS), discussed below.

Following the PSC's directives, the parties engaged in a collaborative process in which the Company has made a series of presentations describing its views of the transition to competition and the options it presents the Company.

On October 6, 1995, the Company filed its *PowerChoice* proposal with the PSC. The proposal was offered as an integrated package (although certain details are subject to modification) and included these key elements:

- **Creation of a competitive wholesale electricity market and direct access by retail customers.** To give customers their choice of power suppliers and pricing terms, the Company will open its system to competing electricity generators as early as 1997. The timing of full implementation depends on resolution of technical, administrative and regulatory issues. Envisioned is the formation of a competitive wholesale spot market in the Company's service area under the supervision of the FERC that is consistent with proposals announced October 5, 1995 by the Energy Association of New York. Beginning in 1997 with its largest customers, the Company would allow full direct access to alternative suppliers of electricity. The Company would deliver that power over its transmission and distribution system. Access for the remaining customers would be phased in over the years 1997-2000.
- **Separation of the Company's power generation business.** The Company has initially proposed that one company would own and operate its present power plants and any unregulated generator contracts that are not restructured. All the Company's assets and businesses other than generation would be held by a holding

company that would provide cost-based rate regulated transmission, distribution and gas services through a regulated subsidiary and through a second subsidiary would provide competitive unregulated services, such as energy marketing and other services. Both companies would be financially restructured so that stockholders and other constituencies would be treated in a fair and equitable fashion. Any release of assets under the Company's mortgage indenture would involve the substitution of other collateral of equivalent value. The Company believes NYPA or New York state can be helpful in this restructuring process, through the purchasing or refinancing of the Company's nuclear plants or through the use of other risk-mitigation strategies associated with those facilities.

- **Relief from overpriced unregulated generator contracts that were mandated by public policy, along with equitable write-downs of above-market Company assets.** As a result of state and federal policy, the Company entered into over 220 contracts, of which there are over 150 remaining, to buy power from UGs at above-market prices, even when the power is not needed. The Company's payments to UGs have increased from less than $200 million in 1990 to nearly $1 billion in 1995, and will continue to grow by an average of approximately $60 million per year over the next five years as contract prices increase. To create an open and competitive market and achieve a price freeze, the Company has offered to negotiate new contracts with UGs.

  If negotiations fail, the Company has proposed to take possession of these projects and compensate their owners through the Company's power of eminent domain. The Company would then resell the projects, allowing the projects to sell electricity into the competitive pool at market prices. Some of the costs related to the Company and UGs that would be "stranded" or unrecoverable in a competitive market would be written off (see discussion below). The remaining stranded costs would be recovered through a contract with the distribution company which, in turn, would recover these costs through a generally non-bypassable fee tied to distribution services.

- **A price freeze or cut for all customer classes.** If the proposal is agreed to by all necessary parties, the average prices paid by residential and commercial class customers could be frozen for five years. Prices for industrial customers, who now subsidize other customers, would be reduced.

The price freeze and restructuring of the Company's markets and business envisioned in the *PowerChoice* proposal are contingent on substantial cost reductions, which depend in turn on the willingness of the UGs and the Company to absorb the losses required to make substantial reductions in the Company's embedded cost structure. The Company's *PowerChoice* proposal would reduce its embedded cost structure through substantial write-downs if, and only if, the UGs agree to cost reductions that are proportional to their relative responsibility for strandable costs. The Company proposes that reduction in its fixed costs of service be made by mutual contribution of the Company's shareholders and UGs that are in the same proportion as the contribution of each to the problem of strandable costs, which the Company calculates to be $4 of UG strandable cost for every $1 of Company strandable cost. Achieving a five-year price freeze, as the Company proposes, would require financial concessions of approximately $2 billion (in nominal dollars) over five years, consisting of approximately $400 million by the Company and $1.6 billion by the UGs. The Company has proposed that the remaining strandable costs be recoverable by the Company and the UGs through surcharges on rates for remaining distribution and transmission services. To ensure full recovery of these costs, the Company has proposed that the remaining strandable costs be recovered in rates in a manner which minimizes the Company's exposure due to sales volume variations. Recovery of remaining strandable costs by the new owner of the Company's generation facilities is intended to be structured so as not to impede each unit from being an efficient participant in the competitive generation market.

The Company is also pursuing other courses of action to support the objectives of restructuring. The Company filed a petition with the PSC in December 1995 seeking an order that certain projects post firm security to ensure performance of their obligations (see "Demand for Adequate Assurance"). The Company is also actively pursuing various forms of tax relief (see "Tax Initiatives"). The timely and successful implementation of *PowerChoice*, including, most importantly, the restructuring of the energy market and of UG contracts, will most likely occur only through negotiations and with the full and active support of the state. The Company is actively negotiating the *PowerChoice* proposal with a broad range of interested parties. Separate negotiations are also under way with the UGs and involve state representatives. Alternatives to *PowerChoice* may be proposed during negotiations that could, in the Company's view, be in the best interests of shareholders, customers and bondholders. The outcome of *PowerChoice* and the Company's other initiatives cannot be assured and the possibility of restructuring under Chapter 11 of the U.S. Bankruptcy Code cannot be ruled out.

Under *PowerChoice*, the successor to all the Company's assets and businesses other than generation would be an unregulated holding company that would provide cost-based rate regulated transmission, distribution and gas services through one subsidiary and would provide through a second subsidiary competitive unregulated services, such as energy marketing and other services. The Company believes the regulated subsidiary would continue to account for its assets and costs, based on ratemaking conventions as approved by the PSC and FERC, and in accordance with Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71).

Effective for the year commencing January 1, 1996, this accounting standard, under which the Company reports its financial condition and results of operations, is amended by Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" (SFAS No. 121). As discussed in Note 2 of Notes to Consolidated Financial Statements, the Company believes there is no impairment of its investment in generating plant assets under the provisions of SFAS No. 121 under either the *PowerChoice* proposal or traditional cost-based ratemaking.

As further discussed in Note 2 of Notes to Consolidated Financial Statements, the Company believes that it continues to meet the requirements for application of SFAS No. 71 and that its regulatory assets are currently probable of recovery in future rates charged to customers. However, the Company's *PowerChoice* proposal described above (or a similar proposal) may require a write off of the approximately $400 million of regulatory assets related to generation. There are a number of events that could change these conclusions in 1996 and beyond, which could result in material adverse effects on the Company's financial condition and results of operations.

Multi-Year Gas Rate Proposal. The Company also filed a proposal to adopt a "performance-based regulation" mechanism, including a gas cost incentive mechanism, for its gas operations. The proposal provides for a complete unbundling of the Company's sales service, allowing customers to choose alternative gas suppliers. Increases for gas distribution services would be subject to a price index through the year 2000. The price index, which is based on inflation associated with gas service-related costs, would be applied to existing 1995 prices after consideration of the service restructuring. A gas cost incentive mechanism is also being proposed, along with discontinuation of the weather normalization clause. Flexibility in pursuing unregulated opportunities related to the gas business is also being sought. In November 1995, the Company filed for a 5.8% gas rate increase, under traditional cost-based regulation, in the event negotiations on the multi-year gas rate proposal are unsuccessful. If approved, such rates would become effective on October 1, 1996. In either case, the Company believes its gas operations will continue to be cost-of-service rate regulated.

Federal and State Regulatory Initiatives

FERC NOPR on Stranded Investment. In March 1995, the FERC issued two notices of proposed rulemaking (NOPR) to facilitate the development of competitive wholesale electric markets by opening up transmission services and to address the transition costs, or "stranded costs," associated with open transmission access. Stranded costs are utility costs that may become unrecoverable due to a change in the regulatory environment.

In a supplemental NOPR on stranded costs, the FERC has established the principle that utilities are entitled to the full recovery of "legitimate, prudent, and verifiable" stranded costs at both the state and federal level. The NOPR also concludes that the FERC should be the principal forum for addressing the recovery of stranded costs due to potential municipalization or similar situations where former retail customers become wholesale customers, as well as for wholesale stranded costs. For stranded costs that result from retail wheeling, the FERC proposes that state regulatory authorities assume responsibility, except in the narrow circumstance where state regulatory authorities lack the authority to address the recovery of such costs.

The FERC continues to seek comments with respect to the complex issues raised by power pools. The New York Power Pool (NYPP), of which the Company is a member, is actively evaluating the effect of wholesale competition and the NOPR on NYPP operations and pricing policies. While changes to existing NYPP arrangements are expected, the extent and nature of these changes and their possible effects on the Company are uncertain.

The Company responded to the NOPR, both individually and as a member of several utility groups, in support of the FERC's position with respect to the recovery of stranded costs caused by wholesale and retail wheeling, but has urged the FERC not to abdicate its responsibility for retail stranded costs. It is anticipated that a final rule will be issued in 1996. The Company cannot predict the outcome of this matter or its effects on the Company's results of operations or financial condition.

PSC Competitive Opportunities Proceeding - Electric. In June 1994, the PSC instituted Phase II of COPS with the overall objective "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 a June 1995 order, the PSC adopted principles to guide the transition to competition. The first principle states that competition in the electric power industry will further the economic and environmental well-being of New York state. Other adopted principles address various issues, including: safety and reliability, customer service, economic efficiency, economic development and stranded costs. The June 1995 order stated that utilities should have a reasonable opportunity to recover prudent and verifiable expenditures and commitments made pursuant to their legal obligations, consistent with all of the principles. In addition, the June 1995 order encourages "respect" for the reasonable expectations of UGs and confirms the need for utilities and UGs to share responsibility for mitigating the costs of transition to a more competitive market. Issues related to both wholesale and retail competition are being examined in this proceeding.

On October 25, 1995, the PSC staff filed a proposal in COPS to restructure New York State's electric industry. Under the PSC staff's proposal, which is similar in many respects to the Company's *PowerChoice* proposal, utilities and UGs would share the responsibility for reducing the current high electric system costs. The PSC staff proposed that electric utilities would absorb a portion of their current generation investments that might become "stranded" or unrecoverable in a competitive market and that the UGs would need to cooperatively restructure their high-cost power contracts with utilities. In addition, the PSC staff's proposal would allow customers to choose among competing energy suppliers, beginning the transition to a competitive retail market by early 1998. A key element of the model for wholesale and retail competition in the proposal is the separation of most generating operations from transmission and distribution services. However, it recommended that the electric delivery system, which includes substations, power lines and a central power pool, continue to be operated by regulated entities. The Company's *PowerChoice* proposal includes the separation of generation from transmission and distribution into distinct entities.

In December 1995, the New York PSC Administrative Law Judge (ALJ) issued a recommended decision in COPS (ALJ plan), which is similar in many respects to the Company's *PowerChoice* proposal. The ALJ plan includes a competitive model in which an Independent System Operator (ISO) would oversee a spot market of electricity supplied by generators competing in an open market which would be functionally separated from other utility functions. The ISO would dispatch generators selling into the spot market and acquire services needed to maintain reliability.

The ALJ plan recommends that competition initially be limited to the wholesale level, largely because of concerns about the reliability of electricity supply. If wholesale competition works, the state would extend competition to the retail level.

As with the *PowerChoice* proposal, transmission and distribution would remain regulated. Consideration would be given, during the wholesale phase, to the development of effective competition among energy service companies.

In addition, the ALJ plan calls for a non-bypassable "wire charge" to be imposed by distribution companies to help utilities recover "strandable" costs. It advocates generic rules for defining and measuring such costs, requirements for possible reductions, a preferable recovery mechanism, and a standard for recovery. The actual amount of stranded costs to be recovered by each utility, and the timing of recovery, would be left to individual rate cases, to begin in 1996 if the ALJ plan is given final approval. The ALJ plan requires that strandable costs be determined to be prudent, verifiable and incapable of being reduced before recovery is allowed. The ALJ further suggests that a careful balancing of customer and utility interests and expectations is necessary, and the level of strandable cost recovery may vary utility by utility.

The Company responded to the ALJ plan, as a member of the Energy Association of New York State (Energy Association). The Energy Association includes the Company and seven other investor owned utilities as members. The Energy Association expressed concern that the ALJ's plan might not allow utilities a reasonable opportunity to fully recover strandable costs and noted the failure of the plan to address and recommend lawful changes which would make possible reductions in electric prices both in the short and long term.

After a comment period, the Commissioners will review the ALJ plan and other plans submitted by interested parties, and ultimately accept, modify or reject it. A decision is expected by mid-1996.

Assemblyman Silver's Proposed Plans. New York State Assembly Speaker Sheldon Silver introduced a plan on January 2, 1996, that would freeze electric rates immediately and set a goal of cutting them 25% through the introduction of competition among utilities. Key components of the proposal include assurances that reliability, quality and safety levels are maintained, the dislocation of utility workers is minimized, no guarantee of stranded cost recovery, a reduction in the costs of UGs and the continued encouragement of environmental protection efforts. Utilities would be required to divest generation by 2002. The Company is unable to predict whether legislation will be introduced in support of this plan, and if introduced and enacted, the effect, if any, on the Company's financial condition and results of operations.

FERC Order 636 and PSC Competitive Opportunities Proceeding - Gas. Portions of the natural gas industry have undergone significant structural changes in recent years. 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 service from pipeline transportation service. This has enabled 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. Such flexibility should allow the Company to protect its existing market and to expand its core and non-core market offerings. With these expanded opportunities come increased competition from gas marketers and other utilities.

Other Company Efforts to Address Competitive Challenges

Unregulated Generator Initiatives are discussed in a separate section below.

Tax Initiatives. The Company is working with utility and state representatives to explain the negative impact that all taxes, including the Gross Receipts Tax (GRT), are having on rates and the state of the economy. Governor Pataki and other state officials have identified changes in the GRT as an element in improving the business climate in New York. At the same time, the Company is contesting the high real estate taxes it is assessed by many taxing authorities, particularly compared to the taxes assessed on UGs.

As noted above, the Company has reduced its work force over the past three years, resulting in a decrease in the amount of payroll taxes incurred over that period. Meanwhile, the reduction in revenues experienced by the Company resulting from reduced sales and an increase in customer discounts, combined with a phase out of the GRT surcharge, has caused the amount of GRT paid by the Company to be reduced. The following table sets forth a summary of the components of other taxes (exclusive of income taxes) incurred by the Company in the years 1993 through 1995:

	In millions of dollars		
	1995	1994	1993
Property tax paid	$264.8	$262.6	$246.7
Sales tax	20.1	17.5	19.7
Payroll tax	37.3	42.5	44.3
Gross Receipts tax	190.2	198.1	200.7
Other taxes	5.2	4.3	4.2
Total tax payments	517.6	525.0	515.6
Charged to construction, subsidiaries and regulatory recognition	(.1)	(28.1)	(24.2)
Total other taxes	$517.5	$496.9	$491.4

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 or attractive energy prices elsewhere have contributed to customer decisions to relocate or close.

In addressing the threat of further loss of industrial load, the PSC established guidelines to govern flexible electric rates offered by utilities to retain qualified industrial customers. Under these guidelines, the Company filed for a new service tariff in August 1994, under which all new contract rates are administered 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 are for terms not to exceed seven years without PSC approval.

The Company has granted discounts to a number of industrial customers and expects others to seek discounts through negotiating long-term contracts. Many of these contracts may result in increased load that could be revenue enhancing. The Company also offers economic development rates, which can result in discounts for existing, as well as, new load. In 1995, the Company granted approximately $62 million of discounts which exceeded by $20 million the approximately $42 million that were anticipated in setting rates for 1995. As of January 3, 1996, electric commercial and industrial customers have signed 67 discount agreements with an average term of four years. In addition, the average discount negotiated in 1995 was 21% below tariff prices. The Company expects discounts to increase in 1996 to approximately $87 million, 80% of which the Company seeks to recover in its February 1996 rate filing. As was the case in 1995, the Company would absorb the impact of any discounts in excess of amounts reflected in rates.

The increase in the Company's prices over the past four years, which is largely due to mandated purchases from UGs, has made cogeneration and self-generation by many industrial and large commercial customers more attractive. The Company believes the pricing flexibility mentioned above was a necessary first step to prevent erosion of its customer base. Price pressure in the longer term, 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 to the Company at wholesale from its 1,040 megawatt (MW) 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. Beginning in 1995, the fee was approximately $3.05 million. The Company had argued for compensation, which would have assured 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.

A Company appeal in State Supreme Court, Albany County, contending that the April 1994 PSC Order is a violation of legal procedure and precedent and should be reversed, was dismissed in February 1996. Although the Company's appeal of Sithe's ability to sell to a retail customer and the level of compensation involved was denied, the PSC's 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.

Generating Asset Management Studies – The Company continues as a matter of course to examine the economic and strategic issues related to operation of all its generating units. As a result of economic studies that the Company has performed (most recently in 1994), it has presently determined that it is economically advantageous to continue operation of Nine Mile Point Nuclear Station Unit No. 1 (Unit 1) over the remaining term of its license.

The Company also has, and continues to, study the economics of continued operation of its fossil-fueled generating plants, given current forecasts of excess capacity. Growth in UG supply sources, compliance requirements of the Clean Air Act Amendment of 1990 (Clean Air Act) and low wholesale market prices are key considerations in evaluating the Company's internal generation needs. Due to projected excess capacity and Clean Air Act requirements, a total of 340 MW's of aging coal fired capacity is expected 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. These decisions will be revisited as facts and circumstances change. These actions 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, 1995 (of which approximately $180 million relates to the facility in cold standby) is currently being recovered in rates through depreciation under traditional ratemaking; recovery would also be provided under *PowerChoice*. See Note 2 of Notes to Consolidated Financial Statements.

These asset management studies have enabled the Company to make significant reductions in capital spending, and with increased output and lower operating costs, to improve the cost-efficiency of the units which is important as the Company continues to examine its competitive situation and future strategic direction.

Regulatory Agreements/Proposals

1995 Rate Order. See Note 2 of Notes to the Consolidated Financial Statements.

Through its Brief Opposing Exceptions dated March 2, 1995, the Company requested an increase in 1995 electric revenues of approximately $110 million (3.5%) and an increase in 1995 gas revenues of $16.4 million (2.7%).

On April 21, 1995, the Company received a rate decision (1995 rate order) from the PSC which approved an approximately $47 million increase in electric revenues and a $4.9 million increase in gas revenues, an expected bill increase of 1.1% for electric customers (a 3.4% increase for residential and a 1.6% decrease for large industrial) and an 0.8% increase for gas customers.

The 1995 rate order allows the Company to retain its fuel adjustment clause (FAC) mechanism, but NERAM, which permitted the Company to recover revenue shortfalls during future periods, was discontinued. See "Results of Operations."

The 1995 rate order includes performance-based penalties related to customer service quality and demand-side management programs. In December 1995, the Company estimated and recorded a customer service penalty for 1995 of $4.8 million, or 2 cents per share, since it did not maintain certain customer service goals at 1994 levels. The final amount of the penalty will be subject to audit by the PSC.

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 NERAM and the Measured Equity Return Incentive Term (MERIT). See Note 1 of Notes to the Consolidated Financial Statements.

NERAM required the Company to reconcile actual results to the forecasted electric public sales gross margin used in establishing rates. NERAM was discontinued in 1995. Approximately $101.2 million of NERAM revenues were recorded in 1994 and $65.7 million in 1993. Substantially all of the remaining balance of NERAM revenues recorded of approximately $48.8 million will be collected in 1996.

The MERIT program is an incentive mechanism. Overall goal targets and criteria for the 1993-1995 MERIT periods were results-oriented and intended to measure improvement in key performance areas. The total possible awards are $34 million and $41 million for 1994 and 1995, respectively. The Company has recognized approximately $20.3 million, $20.8 million and $16.9 million of MERIT revenues in 1993, 1994 and 1995, respectively. The recorded 1995 award represents the objectively determinable portion of the anticipated earned award, with the balance to be recorded in 1996 when approved.

Unregulated Generators

In recent years, the leading cause of higher customer bills and the deterioration of the Company's competitive position has been the requirement to buy power from UGs in excessive quantities at an average price which is more than twice as high as the cost of power that could be purchased in the wholesale market.

By the end of 1994, the Company had virtually all UG capacity scheduled to come into service on line and selling power, which at December 31, 1995, consisted of 151 facilities with a combined capacity of 2,708 MW. Of these, 2,390 MW are considered firm capacity. UG purchases were approximately $736 million in 1993, $960 million in 1994 and $980 million in 1995. In the absence of UG contract restructuring under *PowerChoice* or any similar proposal, the Company estimates that purchase power payments to UGs will continue to escalate at an average annual rate of about 6% through the year 2000.

The Company has initiated a series of actions to deal with the growth of supply and to realign its supply with demand, but cannot predict the outcomes. These actions include mothballing and retiring Company-owned generating facilities (see "Generating Asset Management Studies") and buyouts of UG projects, as well as the implementation of an aggressive wholesale marketing effort. Such actions have succeeded in reducing installed capacity reserve margins to normal planning levels. The Company is actively pursuing other initiatives to reduce its UG costs. The Company also filed its *PowerChoice* proposal with the PSC as part of its multi-year electric rate proceeding (see "*PowerChoice* Proposal") in an attempt to address this problem.

FERC Proceeding. On January 11, 1995, in a case involving Connecticut Light & Power (CL&P), FERC ruled that the Public Utility Regulatory Policy Act (PURPA) forbids states from requiring utilities to pay more than avoided cost to qualifying facilities (QFs) for electric power. However, FERC also said it would not invalidate any prior contracts, but would apply its ruling prospectively or to contracts that were subject to a pending challenge (instituted at the time of signing) by a utility. On the same day, FERC ordered that an ongoing challenge by the Company to the New York law requiring utilities to pay QFs a minimum of six cents per Kwh for electric power ("Six Cent Law") was moot in light of a 1992 amendment to that law prohibiting future contracts that require utilities to pay more than avoided costs. The latter proceeding began in 1987. In April 1988, FERC had ruled in the Company's favor, finding that states could not impose rates exceeding avoided cost for purchases from QFs. FERC then stayed its 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 petition was denied. The Company then asked U.S. Court of Appeals for the District of Columbia to review FERC's denial. FERC and other parties moved to dismiss for lack of jurisdiction. These motions remain pending. On May 11, 1995, the Company filed complaints in the U.S. District Court for the Northern District of New York against the FERC and the PSC, contending the FERC unlawfully ruled that its decision in CL&P does not apply to purchases of power under existing agreements. The PSC was named in this complaint on the basis that its policies required the Company to enter into the above-market-value agreements. In July 1995, various parties to these actions, including the FERC and the PSC, moved to dismiss the case. The motions remain pending.

Curtailment Procedures. On August 18, 1992, the Company filed a petition with the PSC calling for the implementation of "curtailment procedures." Under existing FERC and PSC policy, this petition would allow the Company to limit its purchases from UGs during light load periods as contemplated in FERC regulations. Also, the Company has negotiated settlements with certain UGs regarding curtailment provisions of power purchase agreements. On April 5, 1994, after informing the PSC of its progress, or lack thereof, in settlement discussions, the Company asked the PSC to expedite its review of the 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 of the Company's demand for adequate assurance that the owners will fulfill all future obligations, including the obligation to deliver electricity at prices below the Company's avoided cost. These nine projects have contracts that provide for initial purchase of power by the Company at rates above avoided cost.

The projects at issue total 429 MW. The Company's demand is based on its assessment of the amount of payments above avoided cost to be accumulated under the terms of the contracts. The Company believes it needs adequate assurance because the projects' future obligations to deliver electricity at prices below avoided costs to offset these accumulated account balances would involve operating losses that would cause the owners to abandon the projects. The Company has been sued in three separate actions by the owners of six UG projects which challenge the Company's right to demand adequate assurance. Court decisions in February 1996 in two of these actions found that the Company does not have the legal right to demand adequate assurance. The Company intends to appeal these decisions.

In December 1995, the Company filed a petition with the PSC seeking an order that eight UGs post fi[illegible] security to ensure performance of their obligations and thereby, protect customers' interests under UG contracts. Alternatively, the Company asked that the PSC should cancel these contracts if such security is not provided. The Company estimates that the above-market payments to these eight UGs, which will amount to more than $100 million in 1996, will grow to approximately $3.3 billion in a little more than a decade.

The Company cannot predict the outcome of its petition or of the legal actions regarding adequate assurance but because the Company and its customers continue to bear the substantial burden these contracts impose, the Company will continue to press for adequate assurance that the owners of these projects will honor their obligations.

Results of Operations

Earnings for 1995 were $208.4 million, or $1.44 per share, as compared to $143.3 million, or $1.00 per share, in 1994, and $240.0 million, or $1.71 per share, in 1993. 1994 earnings included $101.2 million, or 46 cents per share, of electric margin recorded under NERAM, but were adversely affected by the charge to earnings of approximately $197 million (89 cents per share) for nearly all of the cost of the VERP. The VERP was ini[illegible]ed in 1994 to bring the Company's staff levels and w[illegible] practices into line with peer utilities and to create a more competitive cost structure. Since January 1, 1993, the Company has reduced its employment by approximately 3,200, or 27%, as of December 31, 1995. About 70% of the Company's work force is subject to a collective bargaining agreement with the International Brotherhood of Electrical Workers. This thirty-three month agreement expired February 29, 1996, and is currently in negotiation.

1995 earnings were hurt by lower sales quantities of electricity and natural gas, as compared with amounts used to establish 1995 prices. Sales were primarily affected by the continuing weak economic conditions in upstate New York, loss of industrial customers' load to NYPA and discounts granted. In January 1995 NERAM was discontinued. The Company's 1995 earned return on common equity was 8.4%, compared to 5.8% (10.7% without the VERP charge) in 1994 and 10.2% in 1993. The Company's return on common equity authorized in the rate setting process for the year ended December 31, 1995, provided an electric return on equity of 11.0% and a return on equity for gas of 11.4%. Factors contributing to earnings below authorized levels in 1995 included, among other things: sales below those forecasted in determining rates; about $20 million more in customer discounts than those reflected in rates; the inability to achieve stringent wholesale margin targets set by the [illegible] and fuel target penalties for low hydro production caused by dry weather. The Company expects the trend of weak sales to continue, given weak economic conditions in the Company's service territory.

The following discussion and analysis highlights items that significantly affected operations during the three-year period ended December 31, 1995. This discussion and analysis may not be indicative of future operations or earnings. It 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 decreased by $193.4 million, or 5.5%, in 1995, and increased by $196.5 million, or 5.9%, in 1994. As shown in the following table, electric operating revenues decreased in 1995 primarily due to the elimination of NERAM after 1994, and the decrease in sales to other electric systems and in sales to ultimate consumers. In addition, FAC revenues decreased $86.4 million, in part due to a decrease in fuel and purchased power costs that are recoverable through the FAC as compared to 1994. Despite a decrease in fuel costs, the Company absorbed a loss of approximately $11.8 million in 1995, since its actual costs in 1995 were higher than the amounts forecasted in rates. In 1994, the Company retained a maximum benefit of $15 million, since its actual costs were lower than the amounts forecasted in rates. The amount forecasted in rates in 1995 reflected a lower fuel cost than 1994. The decrease in FAC revenues also reflects a higher amount of transmission revenues ($21.6 million) passed on to customers. These decreases were partially offset by higher electric rates that took effect April 26, 1995, and by the recording of $71.5 million unbilled, non-cash revenues in 1995 in accordance with the 1995 rate order. The increase in demand side management (DSM) revenues relates to a one-time, non-cash adjustment of prior years' DSM incentives, partially offset by a reduction in the DSM rebate cost program.

The $196.5 million, or 5.9%, increase in electric operating revenues in 1994 was primarily due to higher recoveries through the operation of the FAC mechanism, increased sales to other electric systems, NERAM revenues and rate increases (mainly reflecting the pass through of increases in mandated purchases of UG power and rising taxes).

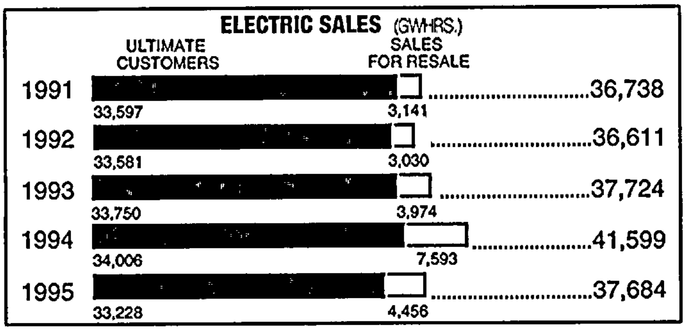
	Increase (decrease) from prior year (In millions of dollars)			
Electric revenues	1995	1994	1993	Total
Amortization of unbilled revenues	$ 71.5	$ —	$ —	$ 71.5
Increase in base rates	68.2	36.0	193.1	297.3
Fuel adjustment clause revenues	(86.4)	108.3	(42.6)	(20.7)
Changes in volume and mix of sales to ultimate consumers	(57.5)	(13.6)	11.0	(60.1)
Sales to other electric systems	(71.3)	62.1	11.7	2.5
DSM revenue	1.4	(27.7)	(30.3)	(56.6)
Miscellaneous operating revenues	(18.1)	(4.1)	17.9	(4.3)
NERAM revenues	(101.2)	35.5	24.0	(41.7)
	$(193.4)	$196.5	$184.8	$187.9

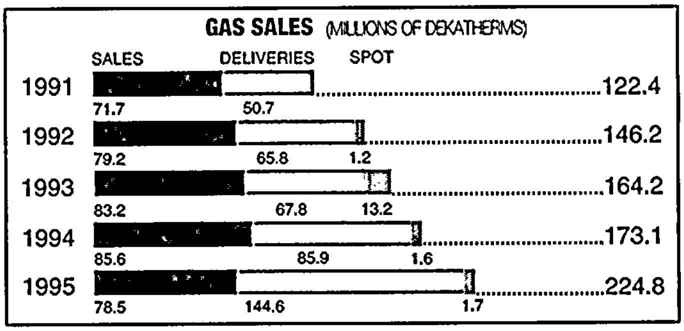
Changes in FAC revenues are generally margin-neutral (subject to an incentive mechanism discussed in Note 1 of Notes to Consolidated Financial Statements), while sales to other utilities, because of regulatory sharing mechanisms and relatively low prices, generally result in low margin contributions to the Company. Thus, fluctuations in these revenue components do not generally have a significant impact on net operating income. Electric revenues reflect the billing of a separate factor for DSM programs, which provide for the recovery of program related rebate costs.

Electric kilowatt-hour sales were 37.7 billion in both years 1995 and 1993, and 41.6 billion in 1994. The 1995 decrease of 3.9 billion kilowatt-hours (Kwh), or 9.4% as compared to 1994, reflects a 41.3% decrease in sales to other electric systems and a 2.3% decrease in sales to ultimate consumers. The decline reflects reduced demand due to the continued stagnant economy, loss of several large industrial customers due primarily to relocations and closings, loss of Alcan to Sithe, loss of sales to NYPA, and more competitive pricing caused by excess supply. The 1994 increase reflected increased sales to other electric systems, while sales to ultimate consumers were generally flat. See Electric and Gas Statistics — Electric Sales. The lost electric margin effect of sales in 1994 was adjusted by NERAM except for the large industrial customer class, within which the Company absorbed 20% of the variance from the NERAM sales forecast. This adjustment was not made in 1995, since NERAM was discontinued. Industrial-Special sales are NYPA allocations of low-cost power to specified customers, from which the Company earns a transportation charge. While these sales decreased slightly in 1995 as compared to 1994, usage as a percentage of capacity increased resulting in an increase in revenues.

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

Class of service	1995 % of Electric Revenues	% Increase (decrease) from prior years 1995 Revenues	1995 Sales	1994 Revenues	1994 Sales	1993 Revenues	1993 Sales
Residential	36.6%	(1.0)%	(2.5)%	5.2%	(0.6)%	6.9%	0.8%
Commercial	37.2	(2.4)	(1.1)	2.5	(2.2)	7.0	3.9
Industrial	15.8	(8.7)	(4.3)	4.3	5.0	(6.0)	(5.2)
Industrial - Special	1.7	14.3	(1.6)	14.5	5.9	9.1	0.8
Municipal service	1.5	(0.9)	—	(1.3)	(2.3)	0.6	(3.1)
Total to ultimate consumers	92.8	(2.7)	(2.3)	3.9	0.8	4.3	0.5
Other electric systems	2.9	(42.7)	(41.3)	59.1	91.1	12.6	31.2
Miscellaneous	4.3	(19.9)	—	8.2	—	40.6	—
Total	100.0%	(5.5)%	(9.4)%	5.9%	10.3%	5.9%	3.0%





As indicated in the table below, internal generation from fossil-fuel sources declined in 1995, principally at the Oswego oil-fired facility. The decrease in fuel costs reflects a decrease in Company generation due to reduced demand, which reduced the need to operate the fossil plants, even after taking into account the 1995 Nine Mile Point Nuclear Station Units No. 1 (Unit 1) and No. 2 (Unit 2) scheduled refueling and maintenance outages. Quantities purchased from UGs decreased in 1995, due in part to the low water supply which limited the amount of power the hydroelectric UGs could produce. Although gigawatt-hours (GwHrs) decreased, total costs escalated due to renegotiated contracts that required payments to be made to the UGs for schedulable capacity. See Note 9 of Notes to the Consolidated Financial Statements – "Contracts for the Purchase of Electric Power."

(In millions of dollars)	1995 GwHrs.	1995 Cost	1994 GwHrs.	1994 Cost	1993 GwHrs.	1993 Cost	% Change from prior year 1995 to 1994 GwHrs.	1995 to 1994 Cost	1994 to 1993 GwHrs.	1994 to 1993 Cost
Fuel for electric generation:										
Coal	6,841	$ 97.9	6,783	$ 107.3	7,088	$ 113.0	0.9%	(8.8)%	(4.3)%	(5.0)%
Oil	537	21.3	1,245	40.9	2,177	74.2	(56.9)	(47.9)	(42.8)	(44.9)
Natural gas	996	20.2	700	16.1	548	12.5	42.3	25.5	27.7	28.8
Nuclear	7,272	43.3	8,327	49.5	7,303	43.3	(12.7)	(12.5)	14.0	14.3
Hydro	2,971	—	3,485	—	3,530	—	(14.7)	—	(1.3)	—
	18,617	182.7	20,540	213.8	20,646	243.0	(9.4)	(14.5)	(0.5)	(12.0)
Electricity purchased:-										
Unregulated generators:										
Capacity	—	181.2	—	84.6	—	20.3	—	114.2	—	316.7
Energy and taxes	14,023	798.7	14,794	875.5	11,720	715.4	(5.2)	(8.8)	26.2	22.4
Total UG purchases	14,023	979.9	14,794	960.1	11,720	735.7	(5.2)	2.1	26.2	30.5
Other	9,463	126.5	10,382	140.3	9,046	118.1	(8.9)	(9.8)	14.8	18.8
	23,486	1,106.4	25,176	1,100.4	20,766	853.8	(6.7)	0.5	21.2	28.9
Total generated and purchased	42,103	1,289.1	45,716	1,314.2	41,412	1,096.8	(7.9)	(1.9)	10.4	19.8
Fuel adjustment clause	—	14.8	—	12.7	—	(2.2)	—	16.5	—	(677.3)
Losses/Company use	4,419	—	4,117	—	3,688	—	7.3	—	11.6	—
	37,684	$1,303.9	41,599	$1,326.9	37,724	$1,094.6	(9.4)%	(1.7)%	10.3%	2[illegible]

Gas revenues decreased by $41.4 million, or 6.6%, in 1995, and increased by $22.2 million, or 3.7%, in 1994. As shown by the table below, gas revenues decreased in 1995 primarily due to decreased sales to ultimate customers, which reflects reduced demand due to the weak economy and warmer weather, and lower gas adjustment clause recoveries. This decrease was partially offset by an increase in revenues from the transportation of customer-owned gas of approximately $9.9 million which was primarily caused by the Sithe gas-fired generating project coming on-line in the Company's service territory and an increase in base rates of $4.7 million in accordance with the 1995 rate order. Rates for transported gas yield lower margins than gas sold directly by the Company. Therefore, increases in the volume of gas transportation services have not had a proportionate impact on earnings. In addition, changes in purchased gas adjustment clause revenues are generally margin-neutral.

In 1994, the revenue increase was primarily attributable to increased sales to ultimate customers, increased base rates, and gas adjustment clause recoveries. This increase was partially offset by a decline in spot market sales, because the abundance and price of spot gas made it more difficult to earn sufficient margins 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.

Gas revenues	Increase (decrease) from prior year (*In millions of dollars*) 1995	1994	1993	Total
Increase in base rates	$ 4.7	$ 7.1	$ 7.3	$19.1
Transportation of customer-owned gas	9.9	3.5	(9.7)	3.7
Purchased gas adjustment clause revenues	(10.7)	7.7	12.2	9.2
Spot market sales	(1.3)	(25.4)	27.2	0.5
Miscellaneous operating revenues	(3.5)	6.3	(5.0)	(2.2)
Changes in volume and mix of sales to ultimate consumers	(40.5)	23.0	15.1	(2.4)
	$(41.4)	$22.2	$47.1	$27.9

Gas sales, excluding transportation of customer-owned gas and spot market sales, were 78.5 million dekatherms (dth) in 1995, an 8.3% decrease from 1994 and a 5.7% decrease from 1993 (see Electric and Gas Statistics – Gas Sales). The decrease in 1995 was in all ultimate consumer classes, which reflects the continuing weak economic conditions in upstate New York. The Company has added approximately 25,000 new customers since 1992, primarily in the residential class, an increase of 5.1%, and expects a continued increase in new customers in 1996 at levels slightly lower than previous levels. During 1995, there was also a shift from the industrial sales class to the transportation sales class. Even though gas sales and revenues decreased in 1995, corresponding reductions in purchased gas expense enabled a slight improvement in margin on gas sales.

In 1995, the Company transported 144.6 million dth, or 68.3% increase, for customers purchasing gas directly from producers. A continued increase in transportation volumes is expected in 1996, leading to a forecast increase in total gas transported in 1996 of approximately 8% above 1995. Factors affecting this forecast 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 dth sales by customer group are detailed in the table below:

Class of service	1995 % of Gas Revenues	% Increase (decrease) from prior years 1995 Revenues	1995 Sales	1994 Revenues	1994 Sales	1993 Revenues	1993 Sales
Residential	63.3%	(7.5)%	(8.2)%	7.5%	2.9%	4.6%	1.8%
Commercial	24.7	(9.7)	(7.6)	9.9	8.6	9.2	6.5
Industrial	2.0	(21.0)	(14.1)	(21.0)	(28.2)	84.8	143.6
Total to ultimate consumers.	90.0	(8.5)	(8.3)	7.1	2.9	7.4	6.4
Other gas systems	0.1	(34.3)	(34.0)	8.7	4.3	(77.5)	(80.3)
Transportation of customer-owned gas	8.3	25.9	68.3	10.1	26.8	(18.5)	2.9
Spot market sales	0.5	(29.2)	9.6	(85.3)	(88.1)	1,056.1	1,053.8
Miscellaneous	1.1	(16.7)	—	423.3	—	(79.4)	—
Total	100.0%	(6.6)%	29.9%	3.7%	5.4%	8.5%	12.3%

The total cost of gas purchased decreased 12.5% in 1995 and 3.2% in 1994, and increased 13.6% in 1993. The cost fluctuations generally correspond to sales volume changes, particularly in 1993, as spot market sales activity increased. The Company sold 1.7, 1.6 and 13.2 million dth on the spot market in 1995, 1994 and 1993, respectively. In 1993, this activity accounted for two-thirds of the 1993 purchased gas expense increase. The purchased gas cost decrease associated with purchases for ultimate consumers in 1995 resulted from a 4.3 million decrease in dth purchased and withdrawn from storage for ultimate consumer sales ($15.1 million) and a 10.8% decrease in the average cost per dth purchased ($32.8 million). This was partially offset by an increase of $10.1 million in purchased gas costs and certain other items recognized and recovered through the purchased gas adjustment clause (GAC). Gas purchased for spot market sales decreased $1.4 million and $24.4 million in 1995 and 1994, respectively. The purchased gas cost increase associated with purchases for ultimate consumers in 1994 resulted from a 1.5% increase in dth 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 GAC. The Company's net cost per dth sold, as charged to expense and excluding spot market purchases, decreased to $3.17 in 1995 from $3.44 in 1994 and was $3.34 in 1993.

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 FAC provides for a 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 amount absorbed in 1993 was not material, the Company retained the maximum benefit of $15 million in 1994 and absorbed a loss of approximately $11.8 million in 1995.

Other operation expense decreased in 1995 by $139.8 million, or 18.5%, as compared to a decrease of $66.6 million, or 8.1% in 1994. Despite the costs related to the 1995 scheduled nuclear refueling outages of Units 1 and 2 of approximately $36 million, other operation expense decreased in 1995 primarily as a result of the Company's cost reduction program. In addition to lower labor costs, the Company also reduced 1995 non-labor costs, such as research and development expenditures ($21 million), general office expenses ($8 million), and DSM rebate costs ($19 million). The 1994 decrease relates primarily to decreases in nuclear costs associated with the Unit 1 and Unit 2 refueling and maintenance outages in 1993 ($27 million) and the decrease in amortization of regulatory deferrals ($49 million) which expired in 1993.

Other items, net decreased by $13.0 million in 1995 and increased by $8.0 million in 1994. The 1995 decrease was primarily due to the recognition of customer service penalties, certain other items disallowed in rates and lower subsidiary earnings, offset in part by the gain recognized on the sale of HYDRA-CO Enterprises, Inc. (HYDRA-CO). The 1994 increase primarily related to increased earnings of subsidiaries which included a nonrecurring gain on the sale of an investment for $9 million.

Net Federal and foreign income taxes increased in 1995 by approximately $47.9 million due to an increase in pre-tax income, which included the increase related to the sale of HYDRA-CO. In 1994, the decrease of approximately $35.6 million was due to lower pre-tax income, which included a charge to earnings of approximately $197 million in 1994 for nearly all of the costs of VERP. The increase in Other taxes increased in 1995 primarily as a result of an increase in the amortization of amounts deferred in prior years ($19.7 million) related to real estate taxes. This increase was partially offset by a reduction of approximately $7.9 million in gross receipts taxes as a result of lower revenues in 1995 as compared to 1994, and a reduction in the gross receipts tax surcharge during 1995, as well as, a reduction in payroll taxes ($5.2 million) due to a decrease in employees. In 1994, the increase was principally due to an increase in real estate taxes ($15.9 million).

Net interest charges remained fairly constant for the years 1993 through 1995. However, dividends on preferred stock increased during this time by $1.8 million and $5.9 million in 1994 and 1995, respectively. Dividends on preferred stock increased $5.9 million in 1995 primarily as a result of an increase in the cost of variable rate issues and increased $1.8 million in 1994 due to the issuance of $150 million of preferred stock issued in August 1994. The weighted average long-term debt interest rate and preferred dividend rate paid, reflecting the actual cost of variable rate issues, changed to 7.77% and 7.19%, respectively, in 1995 from 7.79% and 6.84%, respectively, in 1994, and from 7.97% and 6.70%, respectively, in 1993.

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 than now. 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 non-nuclear 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 with identical assets 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 cost of providing service if new generating facilities were installed. The Company will seek additional revenue or reallocate resources, if possible, to cover the costs of maintaining service as assets are replaced or retired.

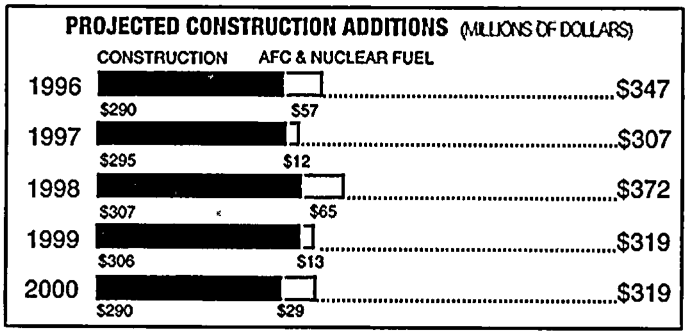
Financial Position, Liquidity and Capital Resources

Financial Position. The Company's capital structure at December 31, 1995 was 54.5% long-term debt, 8.0% preferred stock and 37.5% common equity, as compared to 52.9%, 8.5% and 38.6%, respectively, at December 31, 1994. Book value of the common stock was $17.42 per share at December 31, 1995, as compared to $17.06 per share at December 31, 1994. Market analysts have observed that the Company's low market to book ratio, 54.5% at December 31, 1995, results from a weak New York State economy and regulatory attitudes, and from uncertainty about the pace of regulatory change, which could increase competition and reduce prices, rendering the Company particularly vulnerable. In addition, market analysts have expressed concern about the uncertainty and potential negative impact of the *PowerChoice* proposal on the Company, as well as the possibility of bankruptcy. As indicated elsewhere, the Company believes the *PowerChoice* proposal is in the best interests of shareholders, bondholders and customers. However, the Company is committed to taking necessary courses of action to improve its financial profile, including consideration of other alternatives to *PowerChoice* that may represent better value to these constituencies.

The 1995 ratio of earnings to fixed charges was 2.29 times. The ratios of earnings to fixed charges for 1994 and 1993 were 1.91 times and 2.31 times, respectively. Security rating firms have begun to impute certain items to the Company's interest coverage calculations and capital structure, the most significant of which is the inclusion of a "leverage" factor for UG contracts. The rating firms believe the financial structure of the UGs (which typically have very high debt-to-equity ratios) and the character of their power-purchase agreements increase the financial risk to 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 UG purchases, the imputation has had, and will continue to have, a materially negative impact on the Company's financial ratings. Management expects that the reduced commitments for UG purchases, as proposed in *PowerChoice*, would reduce the inclusion of the "coverage factor" for UG contracts and reduce the financial risk of the Company.

Common Stock Dividend. On January 25, 1996, the board of directors omitted the common stock dividend for the first quarter of 1996. This action was taken to help stabilize the Company's financial condition and provide flexibility as the Company addresses growing pressure from mandated power purchases and weaker sales. In making future dividend decisions, the board will evaluate, along with standard business considerations, the level and timing of future rate relief, the progress of renegotiating contracts with UGs within the context of its *PowerChoice* proposal, the degree of competitive pressure on prices, and other strategic considerations.

Construction and Other Capital Requirements. The Company's total capital requirements consist of amounts for the Company's construction program, compliance with the Clean Air Act and other environmental requirements (as discussed below and in Note 9 of Notes to the Consolidated Financial Statements – "Environmental Contingencies"), nuclear decommissioning funding requirements (see Note 3 of Notes to the Consolidated Financial Statements – "Nuclear Plant Decommissioning"), working capital needs, maturing debt issues and sinking fund provisions on preferred stock, as well as requirements to accomplish restructuring contemplated by the *PowerChoice* proposal. Annual expenditures for the years 1993 to 1995 for construction and nuclear fuel, including related allowance for funds used during construction (AFC)and overheads capitalized, were $519.6 million, $490.1 million and $345.8 million, respectively, and are expected to be approximately $347 million for 1996 and to range between $307 million - $372 million for each of the subsequent four years.



Mandatory debt and preferred stock retirements and other requirements are expected to add approximately another $70 million to the 1996 estimate of capital requirements and significant additional capital may be required if the New York State Energy and Development Authority (NYSERDA) bonds discussed below need to be refinanced. The estimate of construction additions included in capital requirements for the period 1996 to 2000 will be reviewed by management during 1996 with the objective of further reducing these amounts where possible. See discussion in "Liquidity and Capital Resources" section below, which describes how management intends to meet its financing needs for this five-year period.

The provisions of the 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 complied with Phase I of the Clean Air Act, which includes reductions of nitrogen oxides and sulfur dioxide. Phase I became effective on January 1, 1995 and will continue through 1999. The Company spent approximately $5 million and $32 million in 1995 and 1994, respectively, on projects at the fossil generation plants associated with Phase I compliance. The Company has included $15 million in its 1996 through 1999 construction forecast for Phase II compliance which will become effective January 1, 2000. The Company anticipates that additional expenditures of approximately $74 million may be necessary for Phase III to be incurred beyond 2000. The asset management studies, described above, consider spending estimates for Clean Air Act compliance.

Liquidity and Capital Resources. Following the *PowerChoice* proposal, Standard & Poor's (S&P) lowered its ratings on the Company's senior secured debt to BB from BBB-, senior unsecured debt to B+ from BB+, preferred stock to B from BB+, and commercial paper to B from A-3. The present ratings are "below investment grade." In addition, S&P's ratings of the Company's securities are on "Credit Watch" with negative implications. The downgrade of the Company's security ratings reflects S&P's stated concern regarding the uncertainty and potential negative impact of the *PowerChoice* proposal on the Company. Further, S&P stated that the ultimate possibility of restructuring under Chapter 11 of the U.S. Bankruptcy Code cannot be ruled out, based on the Company's statements in that regard. In December 1995, S&P assigned a private placement rating of "2-plus" to the Company's first mortgage bonds. Private placement ratings evaluate the extent of potential loss to an investor following default, whereas S&P's traditional debt ratings measure the risk of default in timely payment. S&P stated the rating (based on a scale of one to six, with "1-plus" the most favorable) "reflects the strong asset protection and recovery value and low likelihood that first mortgage bondholders would suffer any ultimate loss, even in the event of a default by the issuer."

Moody's Investors Service (Moody's) lowered its ratings below investment grade for the Company's senior secured debt, to Ba1 from Baa3; senior unsecured debt to Ba2 from Ba1; its preferred stock to ba3 from ba1; and its short-term rating for commercial paper to Not Prime from Prime -3. Moody's is also maintaining these ratings under review for possible further downgrade. Moody's cited the necessity for agreement by third parties significantly diminishes the likelihood that the *PowerChoice* proposal will survive intact and increases uncertainty about the Company's future over the interim period, as related negotiations proceed. Moody's further stated that the Company's apparent willingness to consider restructuring under Chapter 11 of the U.S. Bankruptcy Code raises serious doubts as to the Company's financial stability. Moody's stated that its continued review will consider responses to the *PowerChoice* proposal, the likelihood of the proposal being adopted and the effect any interim or final agreement may have on bondholders.

Fitch Investors Services, Inc. (Fitch) also downgraded below investment grade the Company's first mortgage bonds and secured pollution control bonds rating from BBB to BB and its preferred stock rating from BBB- to B+ and noted a declining credit trend. Fitch's stated concerns are similar to those expressed by S&P and Moody's.

A summary of the Company's securities ratings at December 31, 1995, was:

	Secured Debt	Preferred Stock	Commercial Paper	Unsecured Debt
Standard & Poor's Corporation	BB	B	B	B+
Moody's Investors Service	Ba1	ba3	Not Prime	Ba2
Fitch Investors Service	BB	B+	Not applicable	Not applicable

These rating agencies have cited the increased risk and uncertainty and the potential for bankruptcy as reasons for downgrade. The Company believes these reasons likewise increase the risk to third party UGs and their security ratings. The Company believes its *PowerChoice* proposal is in the best interests of its stockholders, customers and bondholders. In the event *PowerChoice* is not adopted, and comparable solutions are not available, the Company will undertake any other actions necessary to act in the best interests of stockholders and other constituencies. To that end, on February 12, 1996, the Company filed for rate relief for 1996 and 1997 and the Company has implemented a reduction of non-essential programs to reduce its costs. See "Changing Competitive Environment," "*PowerChoice* Proposal" and "Common Stock Dividend."

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 1995, the Company raised approximately $[illegible] million from external sources, consisting of $275 million of 7¾% First Mortgage Bonds due May 2006 issued during May 1995 and an increase of $71 million issued under the Company's Revolving Credit Agreement.

The Company received approximately $207 million in January 1995, related to the sale of the Company's subsidiary HYDRA-CO, the proceeds of which were used to repay short-term debt. The after-tax gain on the sale of HYDRA-CO was approximately $11.3 million. In addition, the Company received $50 million from the sale of customer receivables in the fourth quarter of 1995. See Note 9 of Notes to the Consolidated Financial Statements – "Sale of Customer Receivables."

Ordinarily, construction related short-term borrowings are refunded with long-term securities on a periodic basis. This approach generally results in the Company showing a working capital deficit. Working capital deficits may also be a result 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. Recently the Company has experienced a deterioration in its collections as compared to prior years' experience and is taking steps to improve collection. The Company believes it has sufficient borrowing capacity to fund such deficits as necessary in the near term. The Company's existing revolving credit facility, which the Company is in the process of renegotiating as described below, expires in April 199[illegible]

The Company's capital structure continues to be weak, and the Company's ability to issue more common stock to improve its capital structure is essentially precluded by the uncertainties that have depressed its stock price. The Company is unlikely to pursue a new issue offering unless the common stock price is closer to book value and these uncertainties are mitigated. The reduction to below investment grade ratings on the Company's bonds and preferred stock can be expected to make it more difficult and expensive for the Company to finance in the manner it has used in the past.

External financing plans are subject to periodic revision as underlying assumptions are changed to reflect developments, market conditions and, most importantly, the Company's rate proceedings. The ultimate level of financing during the period 1996 through 1999 will reflect, among other things: the outcome of the 1996 and 1997 rate requests; the outcome of the restructuring envisioned in the *PowerChoice* proposal, including whether the Company proceeds with exercising its right of eminent domain with respect to UG contracts; levels of common dividend payments, if any, and preferred dividend payments; the Company's competitive position and the extent to which competition penetrates the Company's markets; uncertain energy demand due to the weather and economic conditions; and the extent to which the Company reduces non-essential programs and manages its cash flow during this period. In the longer term, in the absence of *PowerChoice* or some reasonably equivalent solution, financing will depend on the amount of rate relief that may be granted.

The Company is renegotiating its bank credit facilities to ensure, to the extent possible, adequate financial resources to satisfy its financing needs over the period 1996 through June 1999. These facilities by their terms would terminate upon adoption of *PowerChoice*.

As a result of the Company's ongoing negotiations with its banks, the Company entered into a commitment letter with Citibank, N.A., Morgan Guaranty Trust Company of New York and Toronto Dominion Bank, as co-syndication agents (the Agent Banks), for the provision of a senior debt facility totaling $815 million for the purpose of consolidating and refinancing certain of the Company's existing credit agreements and letter of credit facilities and providing additional reserves of bank credit. The proposed senior debt facility will consist of a $380 million term loan and revolving credit facility and a $435 million letter of credit facility. The letter of credit facility will provide credit support for $414 million of outstanding pollution control revenue bonds issued through NYSERDA whose current letter of credit support expires between April 1996 and January 1997. In the absence of this support the Company would seek to remarket these NYSERDA bonds collateralized by its first mortgage bonds.

The interest rate applicable to the senior debt facility will be variable based on certain rate options available under the agreement and is currently expected to approximate 8% (but capped at 15%). The commitment of the Agent Banks to proceed with the senior debt financing will expire on the earlier of (i) fifteen days after the senior debt financing is approved by the PSC or (ii) March 31, 1996. As contemplated by the commitment, the term loan and revolving credit facility and the letter of credit facility will be collateralized by the Company's first mortgage bonds and will expire on the earlier of June 30, 1999 or the implementation of the Company's *PowerChoice* restructuring proposal or any other significant restructuring plan. The Company expects that the first mortgage bonds to be issued as security will be based on additional property under the earnings test required under the mortgage trust indenture; the bonds could also be issued on the basis of previously retired bonds without regard to an earnings test.

This commitment for the senior debt facility is subject to the preparation and execution of loan documentation agreeable to the parties and the approval of the PSC.

The Company believes that this commitment on behalf of the Agent Banks to provide this senior debt facility is an important step in establishing a firm financial basis for negotiating the Company's *PowerChoice* restructuring proposal. The Company is seeking PSC approval on its petition in March, 1996. In the event the petition is not approved, the Company believes the elimination of the common dividend, the implementation of reductions in non-essential programs and the year end 1995 cash position, in combination with alternative sources of credit the Company believes are available if necessary, will be sufficient to fund cash requirements for 1996. Sufficient rate relief, if granted, would provide adequate funds for 1997. The Company can provide no assurances beyond 1997 as cash flow will depend on sales, the implementation of *PowerChoice*, including UG contract renegotiation, levels of cash rate relief, approval of the senior debt bank facility agreement, levels of common and preferred dividends and the ability to further reduce costs, among other things. As of December 31, 1995, the Company could issue an additional $2,272 million aggregate principal amount of first mortgage bonds under the applicable tests set forth in the Company's mortgage trust indenture. This includes approximately $1,311 million from retired bonds without regard to an interest coverage test and approximately $961 million supported by additional property currently certified and available, assuming a 10% interest rate. In the event of a significant write-down in the future, the Company will likely be precluded from issuing first mortgage bonds based on additional property and the earnings test, for at least the twelve months subsequent to such write-down.

The Company also has $200 million of Preference Stock authorized for sale. Current market conditions preclude the Company from issuing preferred or preference stock in 1996 due to the downgrading of the Company's security ratings. The Company's charter also limits the amount of unsecured indebtedness that may be incurred by the Company to 10% of consolidated capitalization plus $50 million. At December 31, 1995, this charter restriction is approximately $683 million and the Company's unsecured debt outstanding is $200 million.

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 that 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 its 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, 1995 and 1994, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1995, 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 2, the Company believes that it continues to meet the requirements for application of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71) and that its regulatory assets are currently probable of recovery in future rates charged to customers. There are a number of events that could change these conclusions in 1996 and beyond, resulting in material adverse effects on the Company's financial condition and results of operations. As also discussed in Note 2, the Company has filed its *PowerChoice* proposal with the Public Service Commission for restructuring the Company to facilitate a transition to a competitive electric generation market. If it becomes probable that the proposal (or a similar proposal) will be implemented and certain other conditions are met by third parties, the Company would discontinue application of (SFAS No. 71) with respect to the electric generation business and write off the related regulatory assets, currently approximately $392 million. Such an outcome would have a material adverse effect on the Company's results of operations and financial condition.

Price Waterhouse LLP

Syracuse, New York

January 25, 1996

Consolidated Statements of Income and Retained Earnings

	In thousands of dollars		
Year ended December 31,	1995	1994	1993
Operating revenues:			
Electric	$3,335,548	$3,528,987	$3,332,464
Gas	581,790	623,191	600,967
	3,917,338	4,152,178	3,933,431
Operating expenses:			
Operation:			
Fuel for electric generation	165,929	219,849	231,064
Electricity purchased	1,137,937	1,107,133	863,513
Gas purchased	276,232	315,714	326,273
Other operation expenses	614,930	754,695	821,247
Employee reduction program	—	196,625	—
Maintenance	202,967	202,682	236,333
Depreciation and amortization (*Note 1*)	317,831	308,351	276,623
Federal and foreign income taxes (*Note 7*)	156,008	117,834	162,515
Other taxes	517,478	496,922	491,363
	3,389,312	3,719,805	3,408,931
Operating income	528,026	432,373	524,500
Other income and deductions:			
Allowance for other funds used during construction (*Note 1*)	1,063	2,159	7,119
Federal and foreign income taxes (*Note 7*)	(3,385)	6,365	15,440
Other items (net)	2,006	15,045	7,035
	(316)	23,569	29,594
Income before interest charges	527,710	455,942	554,094
Interest charges:			
Interest on long-term debt	267,019	264,891	279,902
Other interest	20,642	20,987	11,474
Allowance for borrowed funds used during construction	(7,987)	(6,920)	(9,113)
	279,674	278,958	282,263
Net income	248,036	176,984	271,831
Dividends on preferred stock	39,596	33,673	31,857
Balance available for common stock	208,440	143,311	239,974
Dividends on common stock	161,650	156,060	133,908
	46,790	(12,749)	106,066
Retained earnings at beginning of year	538,583	551,332	445,266
Retained earnings at end of year	$ 585,373	$ 538,583	$ 551,332
Average number of shares of common stock outstanding (*in thousands*)	144,329	143,261	140,417
Balance available per average share of common stock	$ 1.44	$ 1.00	$ 1.71
Dividends paid per share	$ 1.12	$ 1.09	$ .95

( ) Denotes deduction

Consolidated Balance Sheets

	In thousands of dollars	
At December 31,	**1995**	1994
ASSETS		
Utility plant (*Note 1*)		
Electric plant	$ 8,543,429	$ 8,285,263
Nuclear fuel	517,681	504,320
Gas plant	1,017,062	922,459
Common plant	281,525	291,962
Construction work in progress	289,604	481,335
Total utility plant	10,649,301	10,485,339
Less: Accumulated depreciation and amortization	3,641,448	3,449,696
Net utility plant	7,007,853	7,035,643
Other property and investments	218,417	224,039
Current assets:		
Cash, including temporary cash investments of $114,415 and $50,052, respectively	153,475	94,330
Accounts receivable (less allowance for doubtful accounts of $20,000 and $3,600, respectively) (*Notes 1 and 9*)	463,234	513,982
Electric margin recoverable	8,208	66,796
Materials and supplies, at average cost:		
Coal and oil for production of electricity	27,509	31,652
Gas storage	26,431	30,931
Other	141,820	150,186
Prepaid taxes	17,239	43,249
Other	45,834	45,189
	883,750	976,315
Regulatory assets (*Note 2*)		
Regulatory tax asset	470,198	465,109
Deferred finance charges	239,880	239,880
Deferred environmental restoration costs (*Note 9*)	225,000	240,000
Unamortized debt expense	92,548	105,457
Postretirement benefits other than pensions	68,933	67,48[illegible]
Other	204,253	227,542
	1,300,812	1,345,474
Other assets	67,037	68,345
	$ 9,477,869	$ 9,649,816

Consolidated Balance Sheets

	In thousands of dollars	
mber 31,	1995	1994
ALIZATION AND LIABILITIES		
Capitalization (*Note 5*)		
Common stockholders' equity:		
Common stock, issued 144,332,123 and 144,311,466 shares, respectively	$ 144,332	$ 144,311
Capital stock premium and expense	1,784,247	1,779,504
Retained earnings	585,373	538,583
	2,513,952	2,462,398
Non-redeemable preferred stock	440,000	440,000
Mandatorily redeemable preferred stock	96,850	106,000
Long-term debt	3,582,414	3,297,874
Total capitalization	6,633,216	6,306,272
Current liabilities:		
Short-term debt (*Note 6*)	—	416,750
Long-term debt due within one year (*Note 5*)	65,064	77,971
Sinking fund requirements on redeemable preferred stock (*Note 5*)	9,150	10,950
Accounts payable	268,603	277,782
Payable on outstanding bank checks	36,371	64,133
Customers' deposits	14,376	14,562
Accrued taxes	14,770	43,358
Accrued interest	64,448	63,639
Accrued vacation pay	35,214	36,550
Other	57,748	64,687
	565,744	1,070,382
Regulatory liabilities (*Note 2*):		
Deferred finance charges	239,880	239,880
Other	2,712	16,580
	242,592	256,460
liabilities:		
ulated deferred income taxes (*Notes 1 and 7*)	1,388,799	1,258,463
yee pension and other benefits (*Note 8*)	245,047	248,872
Deferred pension settlement gain	32,756	50,261
Unbilled revenues (*Note 1*)	28,410	93,668
Other	116,305	125,438
	1,811,317	1,776,702
Commitments and contingencies (*Notes 2 and 9*)		
Liability for environmental restoration	225,000	240,000
	$9,477,869	$9,649,816

Consolidated Statements of Cash Flows

Increase (Decrease) in Cash

For the year ended December 31,	1995	1994	1993
	In thousands of dollars		
Cash flows from operating activities:			
Net income	$248,036	$176,984	$271,831
Adjustments to reconcile net income to net cash provided by operating activities:			
Amortization of nuclear replacement power cost disallowance	—	(23,081)	(23,720)
Depreciation and amortization	317,831	308,351	276,623
Amortization of nuclear fuel	34,295	37,887	35,971
Provision for deferred income taxes	114,917	7,866	30,067
Electric margin recoverable	58,588	(45,428)	(9,773)
Employee reduction program	—	196,625	—
Deferred recoverable energy costs	46,489	4,748	(5,688)
Gain on sale of subsidiary	(11,257)	—	(5,490)
Unbilled revenues	(71,258)	—	—
Sale of accounts receivable	50,000	—	—
(Increase) decrease in net accounts receivable	6,748	(59,145)	(36,972)
Decrease in materials and supplies	13,663	6,290	43,581
Increase (decrease) in accounts payable and accrued expenses	(47,048)	(5,991)	15,716
Increase (decrease) in accrued interest and taxes	(35,440)	(19,914)	3,996
Changes in other assets and liabilities	(33,974)	12,029	19,251
Net cash provided by operating activities	691,590	597,221	615,393
Cash flows from investing activities:			
Construction additions	(332,443)	(439,289)	(506,267)
Nuclear fuel	(13,361)	(46,134)	(12,296)
Less: Allowance for other funds used during construction	1,063	2,159	7,119
Acquisition of utility plant	(344,741)	(483,264)	(511,444)
Decrease in materials and supplies related to construction	3,346	5,143	3,837
Increase (decrease) in accounts payable and accrued expenses related to construction	(7,112)	(1,498)	3,929
Increase in other investments	(115,818)	(23,375)	(26,77[illegible]
Proceeds from sale of subsidiary (net of cash sold)	161,087	—	95,40[illegible]
Other	26,234	(17,979)	(15,260)
Net cash used in investing activities	(277,004)	(520,973)	(450,304)
Cash flows from financing activities:			
Proceeds from sale of common stock	304	29,514	116,764
Proceeds from long-term debt	346,000	424,705	635,000
Issuance of preferred stock	—	150,000	—
Redemption of preferred stock	(10,950)	(33,450)	(47,200)
Reductions of long-term debt	(65,000)	(526,584)	(641,990)
Net change in short-term debt	(416,750)	48,734	50,318
Dividends paid	(201,246)	(189,733)	(165,765)
Other	(7,799)	(9,455)	(31,759)
Net cash used in financing activities	(355,441)	(106,269)	(84,632)
Net increase (decrease) in cash	59,145	(30,021)	80,457
Cash at beginning of year	94,330	124,351	43,894
Cash at end of year	$153,475	$ 94,330	$124,351
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest	$290,352	$300,242	$300,791
Income taxes	$ 47,378	$136,876	$106,202

Notes to Consolidated Financial Statements

NOTE 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 (GAAP), as applied to regulated public utilities, and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities (see Note 2). In order to be in conformity with GAAP, management is required to use estimates in the preparation of the Company's financial statements.

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, 1995 was 7.47%. 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 both years 1995 and 1994, and 3.2% for 1993. The Company performs depreciation studies to determine service lives of classes of property and adjusts the depreciation reserves and rates when necessary.

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) is expected to issue an exposure draft in February 1996 entitled "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets" (formerly Accounting for Nuclear Decommissioning). The scope of the original project has broadened and will now include the Company's fossil and hydro plants, as well as nuclear plants. If approved as drafted, the exposure draft would require the cost of closure and removal obligations to be accounted for as a liability and accrued as the obligation is incurred. The recognition of the liability would result in an increase to the cost of the related asset and would be reported based upon discounted future cash flows as opposed to current cost. The Company would not be allowed to net the balance of funds accumulated in the nuclear decommissioning trust funds against the nuclear plant closure and removal obligation. Additionally, the exposure draft would allow the Company to establish a regulatory asset for the difference between costs of closure and removal obligations recognized and the costs allowable for rate-making purposes, subject to the provisions of SFAS No. 71. As noted above, the Company currently recognizes the liability for nuclear decommissioning over the service life of the plant and as an increase to accumulated depreciation based on amounts allowed in rates. The Company currently does not reflect the closure and removal obligation associated with its fossil and hydro plants in the financial statements. As such, the annual provisions for depreciation could increase. Under traditional cost based regulation such accounting changes would not have an adverse effect on the results of operations of the Company. However, with the filing of the Company's *PowerChoice* proposal and the expectation the generating assets associated with this obligation will face competition in the future and the issuance of Statement of Financial Accounting Standards No. 121 (SFAS No. 121) entitled "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" (discussed in Note 2), the Company cannot currently predict the impact this exposure draft may have on the Company's future results of operations.

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, 1995 and 1994, approximately $5.2 million and $71.8 million, respectively, of unbilled electric revenues remained unrecognized in results of operations, are included in Other liabilities and may be used to reduce future revenue requirements. In 1995, the Company used $71.5 million of electric unbilled revenues to reduce the 1995 revenue requirement. At December 31, 1995 and 1994, $23.2 million and $21.9 million, respectively, of unbilled gas revenues remain unrecognized in results of operations and may similarly be used to reduce future gas revenue requirements. The unbilled revenues included in accounts receivable at December 31, 1995 and 1994, were $202.7 million and $196.7 million, respectively.

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 1993 through 1995 were not material.

From 1991 through 1994, the Company's rate agreements provided for NERAM, which permitted 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. 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.

Rate agreements since 1991 also included MERIT under which the Company had 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 provided 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 expired at the end of 1995, but collections of allowed awards will continue into 1997.

The Company's *PowerChoice* proposal, which the Company filed in October 1995 as part of its multi-year electric rate proceeding, proposed to eliminate all surcharges, including the FAC, NERAM and MERIT surcharges.

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 cl[illegible] adjustments were not significant to 1995 gas revenue[illegible] As part of the Company's *PowerChoice* proposal, as well as the formal gas rate filing made in November 1995 (see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Multi-Year Gas Rate Proposal"), the Company proposed elimination of the weather normalization clause. These surcharges would be reflected in base rates as part of the Company's proposal to freeze overall prices.

Allowance for Doubtful Accounts: The allowance for doubtful accounts receivable on the consolidated balance sheets amounted to $20.0 million and $3.6 million at December 31, 1995 and 1994, respectively. The Company increased its allowance for doubtful accounts in 1995 and recorded a regulatory asset of $16.4 million, which reflects the amount that the Company expects to recover in rates. Previously, the Company netted expected rate recoveries for bad debt expense from expected uncollectible accounts in determining its allowance for doubtful accounts, which was consistent with the manner in which this item is treated in its ratemaking.

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 1995 presentation.

NOTE 2. Rate and Regulatory Issues and Contingencies

The Company's financial statements conform to GAAP, as applied to regulated public utilities and reflect the application of SFAS No. 71. Substantively, SFAS No. 71 permits a public utility regulated on a cost-of-service basis to defer certain costs when authorized to do so by the regulator which would otherwise be charged to expense. These deferred costs are known as regulatory assets, which in the case of the Company are approximately $1,058 million, net of approximately $242 million of regulatory liabilities at December 31, 1995. The portion of the $1,058 million which has been allocated to the electric business is approximately $890 million. Generally, regulatory assets and liabilities were allocated to the portion of the business that incurred the underlying transaction that resulted in the recognition of the regulatory asset or liability. The allocation methods used between electric and gas were consistent with those used in prior regulatory proceedings.

While the allocation of regulatory assets and liabilities at December 31, 1995 is based on management's assessment, a final determination can only be made at the time the Company, or a portion thereof, discontinues the application of SFAS No. 71. Currently, substantially all of the Company's regulatory assets have been approved by the PSC and are being amortized to expense as they are being recovered in rates as last established in April 1995.

Rate Filing. The Company filed in February 1996 a request to increase electric rates. This rate increase request of 4.1% for 1996 and 4.2% for 1997 was based on the Company's cost of providing services. The Company requested that its 4.1% increase for 1996 be implemented immediately with a provision that rates charged will be subject to refund if later it is determined that some portion of the request is not allowed by the PSC. These rate increases are predicated on a requested rate of return on common stock equity of approximately 11% on an annual basis and recover the Company's cost of providing electric service. On February 16, 1996, the PSC issued an order that, among other things, established a schedule with respect to temporary rates that would have the case certified directly to the PSC within 60 days of the order. The Company believes that the PSC will approve rate increases on a timely basis in levels sufficient to enable it to earn a reasonable return on equity in 1996 and 1997. As a result the Company believes that it will continue to be regulated on a cost-of-service basis which will enable it to continue to apply SFAS No. 71. Accordingly, the Company believes its regulatory assets are currently probable of recovery. While various proposals have been made to develop a new regulatory model, including the Company's *PowerChoice* proposal, none of these proposals are currently probable of implementation since a number of parties are required to act on the change in the regulatory model. The Company expects that the PSC will approve cost-of-service based rate increases that will result in the Company earning a reasonable return on common equity until such time as implementation of a new competitive market model becomes probable.

While the Company believes that it continues to meet the requirements for the application of SFAS No. 71 to the electric business, there are a number of events that could change that conclusion during 1996 and beyond. Those future events include: inaction or inadequate action on the Company's rate request by the PSC; a decision by the Company in the future not to pursue the rate requests filed; unanticipated reduction in electricity usage by customers; unanticipated customer discounts; adverse results of litigation; and a change in the regulatory model becoming probable.

As discussed in the Management's Discussion and Analysis of Financial Condition and Results of Operations, the Company has been unable to earn its allowed rate of return in 1995 and 1994. Additionally, if the Company's rate increase proposals with respect to 1996 and 1997 are not approved, then the Company will, more likely than not, be unable to earn a reasonable return on its common equity for such years. The inability of the Company to earn a reasonable rate of return on common equity over a sustained period would indicate that its rates are not based on its cost of service. In such a case, application of SFAS No. 71 would be discontinued. The resulting charges against income would reduce or possibly eliminate retained earnings, the balance of which is currently approximately $585 million. Various tests under applicable law and corporate instruments, including those with respect to issuance of debt and equity securities, payment of preferred and common dividends and certain types of transfers of assets could be adversely impacted by any such write-downs. In addition, such write-downs could preclude it from borrowing additional amounts under its current revolving credit facility, which is planned to be replaced by the proposed senior debt facility (see Note 6) whose terms are intended to accommodate the discontinuance of SFAS No. 71 as it applies to the Company's electric business.

Competition. The public utility industry in general, and the Company in particular, is facing increasing competitive threats. As competition penetrates the marketplace, it is possible that the Company may no longer be able to continue to apply the fundamental accounting principles of SFAS No. 71. The Company believes that in the future some form of market-based pricing may replace cost-based pricing in certain aspects of its business. In that regard, in October 1995, the Company filed its *PowerChoice* proposal with the PSC. *PowerChoice,* further described in the Management Discussion and Analysis – "*PowerChoice* Proposal," would:

- Create a competitive wholesale electricity market and allow direct access by retail customers.
- Separate the Company's power generation business from the remainder of the business.
- Provide relief from overpriced unregulated generator contracts that were mandated by public policy, along with equitable write-downs of above-market company assets.
- Freeze or cut prices for all Company electric customers for a period of 5 years.

The separated generation business proposed in *PowerChoice* would no longer be rate-regulated and, accordingly, existing regulatory assets related to the generation business, amounting to $392 million, net of approximately $242 million of regulatory liabilities at December 31, 1995 (management's assessment), would be charged against income if and when *PowerChoice* (or a similar proposal) is probable of implementation. Under *PowerChoice*, the Company's electric transmission and distribution business is proposed to continue to be rate regulated on a cost-of-service basis and, accordingly, continue to apply SFAS No. 71. The *PowerChoice* proposal also includes provisions for recovery of "stranded costs" by the generation business and unregulated generators through surcharges on rates for transmission and distribution customers. Stranded costs are those costs of utilities that may become unrecoverable due to a change in the regulatory environment and include costs related to the Company's generating plants, regulatory assets and overpriced unregulated generator contracts.

Critical to the price freeze and restructuring of the Company's markets and business envisioned in the *PowerChoice* proposal are substantial reductions in the Company's embedded cost structure. Such cost reductions depend in turn on the willingness of the UGs and the Company to absorb substantial write-offs. The Company's proposal expresses its willingness if, and only if, the UGs agree to cost reductions that are proportional to their relative responsibility for strandable cost. The Company proposes a reduction in its fixed costs of service be made by mutual contribution of the Company's shareholders and UGs that are in the same proportion as the contribution of each to the problem of strandable costs, which the Company calculates to be $4 of UG strandable cost for every $1 of Company strandable cost. Under the Company's proposal, the aggregate contribution would be approximately $2 billion, consisting of $400 million by the Company and $1.6 billion by the UGs. The Company's *PowerChoice* proposal faces opposition, principally from unregulated generators. The Company does not presently expect that its *PowerChoice* proposal or any other alternative proposal could be fully effective before sometime in 1997, at the earliest.

There are also other proposals to introduce competition into the utility marketplace presently before the PSC. In addition, the FERC has pending proposals before it relating to open access to the nation's transmission system and the recovery of stranded costs.

Impairment of Long-Lived Assets: In March 1995, the FASB issued SFAS No. 121. This Statement, which the Company will adopt in 1996, requires that long-lived assets and certain identifiable intangibles to be held and used by an entity, be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. In performing the review for recoverability, the Company is required to estimate future undiscounted cash flows expected to result from the use of the asset and its eventual disposition. Furthermore, this Statement amends SFAS No. 71 to clarify that regulatory assets should be charged against earnings if the assets are no longer considered probable of recovery rather than probable of loss. While the Company is unable to predict the outcome of its *PowerChoice* proposal, or various FERC and PSC initiatives, it has analyzed the provisions of SFAS No. 121, as it relates to the impairment of its investment in generating plant, under two scenarios: traditional cost-based ratemaking and its *PowerChoice* proposal, as filed. As a result of these analyses, the Company does not believe the effects of adopting SFAS No. 121, as it relates to the impairment of its investment in generating plant, will currently have an effect on its results of operations and financial condition. In addition, the Company expects that the PSC will approve cost-of-service based rate increases until such time as a new competitive regulatory model is developed. As a result, the Company believes currently that its regulatory assets are probable of recovery. However, if in the future management can no longer conclude that existing regulatory assets are probable of recovery, then all or a portion of such regulatory assets would have to be charged to income, which could have a material adverse effect on the Company's financial position and results of operations.

The Company has recorded the following regulatory assets on its Consolidated Balance Sheets reflecting the rate actions of its regulators:

Regulatory tax asset 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. This amount is primarily timing differences related to depreciation. 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.

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 w 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 will 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.

Deferred environmental restoration costs represent the Company's share of the estimated minimum costs to investigate and perform certain remediation activities at both Company-owned sites and non-owned sites with which it may be associated. Prior to 1995, the Company recovered 100% of its costs associated with site investigation and restoration. In the Company's 1995 rate order, costs incurred during 1995 for the investigation and restoration of Company-owned sites and sites with which it is associated were subject to 80%/20% (ratepayer/Company) sharing. In 1995, the Company incurred $11.5 million of such costs, resulting in a disallowance of $2.3 million (before tax), which the Company has recorded as a loss in Other items (net) on the Consolidated Statements of Income. The PSC stated in its full opinion, dated December 1995, its decision to require sharing was "on a one-time, short-term basis only, pending its further evaluation of the issue in future proceedings." The Company has recorded a regulatory asset representing the remediation obligations to be recovered from ratepayers. See Note 9 – "Environmental Contingencies."

Unamortized debt expense represents the costs to issue and redeem certain long-term debt securities which were retired prior to maturity. These amounts are amortized as interest expense ratably over the lives of the related issues in accordance with PSC directives.

Postretirement benefits other than pensions 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.

NOTE 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 1,143 MW Unit 2. The remaining ownership interests are Long Island Lighting Company (LILCO) - 18%, New York State Electric and Gas Corporation (NYSEG) - 18%, Rochester Gas and Electric Corporation (RG&E) - 14%, and Central Hudson Gas and Electric Corporation (Central Hudson) - 9%. Unit 1 was placed in commercial operation in 1969 and Unit 2 in 1988.

In December 1995, a state utility board appointed by Governor George E. Pataki developed a plan to dismantle LILCO. The plan delayed making any recommendation as to LILCO's ownership interest in Unit 2, but otherwise recommends the creation of a competitive generation market on Long Island, through the sale of existing generating capacity by LILCO. The Company is unable to predict what effects, if any, this proposal may have on its results of operations or financial condition, since there are many uncertainties related to this proposal. It is estimated that the earliest time such a plan could be completed is one to two years.

Unit 1 Status: On February 8, 1995, Unit 1 was taken out of service for a planned refueling and maintenance outage and returned to service on April 4, 1995. Its next refueling and maintenance outage is scheduled to begin in February 1997. Using the net design electric rating as a basis, Unit 1's capacity factor for 1995 was approximately 80%. Using Nuclear Regulatory Commission (NRC) guidelines, which reflect net maximum dependable capacity during the most restrictive seasonal conditions, Unit 1's capacity factor was approximately 87%.

Unit 2 Status: On April 8, 1995, Unit 2 was taken out of service for a planned refueling and maintenance outage and returned to service on June 2, 1995. Its next refueling and maintenance outage is scheduled for Fall 1996. During the 1995 refueling outage the Company completed its power uprate project, installed new turbine rotors and made other operational improvements enabling the plant to increase its capacity from 1,062 MW to 1,143 MW. Using the net design electric rating as a basis, Unit 2's capacity factor for 1995 was approximately 75%. Using NRC guidelines as described above, Unit 2's capacity factor was approximately 78%.

Nuclear Plant Decommissioning: The Company's site specific cost estimates for decommissioning Unit 1 and its ownership interest in Unit 2 at December 31, 1995 are as follows:

	Unit 1	Unit 2
Site Study (year)	1995	1995
End of Plant Life (year)	2009	2026
Radioactive Dismantlement to Begin (year)	2026	2028
Method of Decommissioning	Delayed Dismantlement	Immediate Dismantlement
Cost of Decommissioning (in 1996 dollars)	*In millions of dollars*	
Radioactive Components	$409	$187
Non-radioactive Components	111	45
Fuel Dry Storage/Continuing Care	113	40
	$633	$272

The Company estimates that by the time decommissioning is completed, the above costs will ultimately amount to $1.7 billion and $1.1 billion for Unit 1 and

Unit 2, respectively, using 3.5% as an annual inflation factor.

In addition to the costs mentioned above, the Company expects to incur post-shutdown costs for plant rampdown, insurance and property taxes. In 1996 dollars, these costs are expected to amount to $99 million and $59 million for Unit 1 and the Company's share of Unit 2, respectively. The amounts will escalate to $182 million and $190 million for Unit 1 and the Company's share of Unit 2, respectively.

Based upon a 1994 study, the Company had previously estimated the cost to decommission Unit 1 to be approximately $565 million in 1996 dollars. In addition, post-shutdown costs were estimated to be $118 million, also in 1996 dollars. While both estimates assume a delayed dismantlement to coincide with Unit 2, the 1995 estimate of $633 million differs from the 1994 estimate primarily due to an increase in burial costs and the labor associated with the non-radioactive dismantlement, partially offset by lower waste volumes. The delayed dismantlement approach should be the most economic after applying the Company's weighted average cost of capital.

The Company had previously estimated the cost to decommission its share of Unit 2 by extrapolating data from the 1994 Unit 1 decommissioning cost estimate. The extrapolated estimate of $311 million, in 1996 dollars, differs from the 1995 study of $272 million primarily due to the estimate being based upon plant specifics rather than extrapolated values.

NRC regulations require owners of nuclear power plants to place funds into an external trust to provide for the cost of decommissioning radioactive portions of nuclear facilities and establish minimum amounts that must be available in such a trust at the time of decommissioning. The annual allowance for Unit 1 and the Company's share of Unit 2 for the years ended December 31, 1995, 1994 and 1993 was approximately $23.7 million, $18.7 million and $18.7 million, respectively. The amount for 1995 was based upon the NRC minimum decommissioning cost requirements of $408 million and $185 million (in 1996 dollars) for Unit 1 and the Company's share of Unit 2, respectively. The amounts for 1994 and 1993 were based upon site studies performed in 1989. In the 1995 rate order, the Company was authorized, until the PSC orders otherwise, to continue to fund to the NRC minimum requirements. In the 1997 rate filing, the Company has requested, for both units, rate recovery for all radioactive and non-radioactive components (including post-shutdown costs) based upon the amounts estimated in the 1995 site specific studies described 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 under traditional ratemaking and *PowerChoice*.

Decommissioning costs recovered in rates are reflected in Accumulated depreciation and amortization on the Consolidated Balance Sheets and amount to $183.4 million and $134.1 million at December 31, 1995 and 1994, respectively for both Units. Additionally at December 31, 1995, the fair value of funds accumulated in the Company's external trusts were $108.8 million for U[illegible] and $28.8 million for its share of Unit 2. The trusts [illegible] included in Other property and investments. Earnings on the external trust aggregated $20.9 million through December 31, 1995 and, because the earnings are available to fund decommissioning, have also been included in Accumulated depreciation and amortization. Amounts recovered for non-radioactive dismantlement are accumulated in an internal reserve fund which has an accumulated balance of $39.8 million at December 31, 1995.

The FASB is expected to issue an exposure draft in February 1996 on accounting for certain liabilities related to closure or removal of long-lived assets. See Note 1 – "Depreciation, Amortization and Nuclear Generating Plant Decommissioning Costs."

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 limit 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% su[illegible]charge discussed below. This limit would be funded [illegible] assessments of up to $75.5 million for each of the 11[illegible] 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 maximum 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 $2,250 million in excess of the $500 million primary nuclear insurance with Nuclear Electric Insurance Limited (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 $17.7 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 a 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. The Company currently uses the Barnwell, South Carolina waste disposal facility for low level radioactive waste, however access to Barnwell was denied by the State of South Carolina to out of region low level waste generators, including New York State from July 1, 1994 to July 1, 1995. The Company also 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 U.S. 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 the year in which the Company initially plans to ship irradiated fuel to an approved DOE disposal facility. 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 that will extend to the year 2044. 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 incurring additional costs, which the Company has included in its decommissioning estimates for both Unit 1 and its share of Unit 2. The Company does not believe that the possible unavailability of the DOE disposal facility until 2010 will inhibit operation of either Unit.

NOTE 4. Jointly-Owned Generating Facilities

The following table reflects the Company's share of jointly-owned generating facilities at December 31, 1995. 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	$ 95,540	$ 48,385	$1,345
Oswego Steam Station Unit No. 6 *(b)*	76	$ 271,472	$ 111,631	$ 782
Nine Mile Point Nuclear Station Unit No. 2 *(c)*	41	$1,519,351	$272,888	$5,105

(a) The remaining ownership interests are Central Hudson, the operator of the plant (35%), and Consolidated Edison Company of New York, Inc. (40%). 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 RG&E (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 LILCO (18%), NYSEG (18%), RG&E (14%), and Central Hudson (9%). Output of Unit 2, which has a capability of 1,143,000 kw., is shared in the same proportions as the cotenants' respective ownership interests.

NOTE 5. 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 1993, 1994 and 1995:

	Common Stock $1 par value		Preferred Stock $100 par value			Preferred Stock $25 par value			Capital Stock Premium and Expense (Net)*
	Shares	Amount*	Shares	Non-Redeemable*	Redeemable*	Shares	Non-Redeemable*	Redeemable*	
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	$230,000	$89,350 *(a)*	$1,779,504
Issued	20,657	21	—	—	—	—	—	—	283
Redemptions			(18,000)	—	(1,800)	(366,000)	—	(9,150)	1,319
Foreign currency translation adjustment									3,[illegible]
December 31, 1995:	**144,332,123**	**$144,332**	**2,358,000**	**$210,000**	**$25,800** *(a)*	**12,408,005**	**$230,000**	**$80,200** *(a)*	**$1,78[illegible]**

* *In thousands of dollars*
(a) Includes sinking fund requirements due within one year.

The cumulative amount of foreign currency translation adjustment at December 31, 1995 was $(10,172).

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	1995 (*In thousands of dollars*)	1994 (*In thousands of dollars*)	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				
9.50%	6,000,000	150,000	150,000	25.00 *(a)*
Series A	1,200,000	30,000	30,000	25.00
Series C	2,000,000	50,000	50,000	25.00
		$440,000	$440,000	

(a) Not redeemable until 1999.

Mandatorily Redeemable Preferred Stock

At December 31, the Company has certain issues of preferred stock, as detailed below, which provide for mandatory and optional redemption. 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. The Company's five year mandatory sinking fund redemption requirements for preferred stock, in thousands, for 1996 through 2000 are as follows: $9,150; $10,120; $10,120; $7,620; and $7,620, respectively.

	Shares		*In thousands of dollars*		Redemption price per share *(Before adding accumulated dividends)*	
Series	1995	1994	1995	1994	1995	Eventual minimum
Preferred $100 par value:						
7.45%	258,000	276,000	$ 25,800	$ 27,600	$102.17	$100.00
Preferred $25 par value:						
7.85%	914,005	914,005	22,850	22,850	*(a)*	25.00
8.375%	300,000	400,000	7,500	10,000	25.22	25.00
8.70%	—	200,000	—	5,000	—	—
9.75%	144,000	210,000	3,600	5,250	25.00	25.00
Adjustable Rate						
Series B	1,850,000	1,850,000	46,250	46,250	25.00	25.00
			106,000	116,950		
Less sinking fund requirements			9,150	10,950		
			$ 96,850	$106,000		

(a) Not redeemable until 1997.

Long-Term Debt

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

Series	Due	*In thousands of dollars* 1995	1994
First mortgage bonds:			
5 7/8%	1996	$ 45,000	$ 45,000
6 1/4%	1997	40,000	40,000
6 1/2%	1998	60,000	60,000
9 1/2%	2000	150,000	150,000
6 7/8%	2001	210,000	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
7 3/4%	2006	275,000	—
*6 5/8%	2013	45,600	45,600
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	115,705
Total First Mortgage Bonds		2,886,305	2,611,305

Series	*In thousands of dollars* 1995	1994
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 1995-2004	30,000	45,000
Swiss Franc Bonds due		
December 15, 1995	—	50,000
Revolving Credit Agreement	170,000	99,000
Other	159,198	169,421
Unamortized premium (discount)	(11,785)	(12,641)
TOTAL LONG-TERM DEBT	3,647,478	3,375,845
Less long-term debt due within one year	65,064	77,971
	$3,582,414	$3,297,874

**Tax-exempt pollution control related issues*

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 securities 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 3.81% for 1995 and 2.76% for 1994 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 (see Note 6).

Other long-term debt in 1995 consists of obligations under capital leases of approximately $36.8 million, a liability to the U.S. Department of Energy for nuclear fuel disposal of approximately $103.1 million and liabilities for unregulated generator contract terminations of approximately $19.3 million.

The aggregate maturities of long-term debt for the five years subsequent to December 31, 1995, excluding capital leases, are approximately $61 million, $216 million, $66 million, $0 and $155 million, respectively.

NOTE 6. Bank Credit Arrangements

At December 31, 1995, the Company had $310 million of bank credit arrangements with 14 banks. These credit arrangements consisted of $200 million in commitments under a Revolving Credit Agreement, $99 million in one-year commitments under Credit Agreements and $11 million in lines of credit. 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.

In order to enhance the Company's financial flexibility during the period 1996 through 1999, the Company entered into a commitment letter with Citibank, N.A., Morgan Guaranty Trust Company of New York and Toronto Dominion Bank, as co-syndication agents (Agent Banks), for the provision of a senior debt facility totaling $815 million for the purpose of consolidating and refinancing certain of the Company's existing working capital lines of credit and letter of credit facilities and providing additional reserves of bank credit. The proposed senior debt facility will consist of a $380 million term loan and revolving credit facility and a $435 million letter of credit facility, with such letter of credit facility to provide credit support for the pollution control revenue bonds issued through NYSERDA discussed in Note 5. The interest rate applicable to the facility will be variable based on certain rate options available under the agreement and is currently expected to approximate 8% (capped at 15%). The commitment by the Agent Banks to proceed with the senior debt financing will expire on the earlier of (i) fifteen days after the senior debt financing is approved by the PSC or (ii) March 31, 1996. As contemplated by the commitment, the term loan and revolving credit facility and the letter of credit facility will be collateralized by the Company's first mortgage bonds and will expire on the earlier of June 30, 1999 or the implementation of the Company's *PowerChoice* restructuring proposal or any other significant restructuring plan.

This commitment for the senior debt facility will be subject to the preparation and execution of loan documentation agreeable to the parties, as well as the approval of the PSC.

The Company is seeking PSC approval on its petition in March, 1996. In the event the petition is not approved, the Company believes that the elimination of the common dividend, the implementation of reductions in non-essential programs and the year end 1995 cash position, in combination with alternative sources of credit the Company believes are available if necessary, will be sufficient to fund cash requirements for 1996. Sufficient rate relief, if granted, would provide adequate funds for 1997. The Company can provide no assurances beyond 1997 as cash flow will depend on sales, the implementation of *PowerChoice*, including UG contract renegotiations, levels of cash rate relief, approval of bank facility agreement, levels of common and preferred dividends and the ability to further reduce costs.

The Company pays fees for substantially all of its bank credit arrangements. The following table summarizes additional information applicable to short-term debt:

	In thousands of dollars	
At December 31,	**1995**	**1994**
Short-term debt:		
Commercial paper	$ —	$ 84,750
Notes payable	—	321,000
Bankers acceptances	—	11,000
	$ —	$416,750
Weighted average interest rate *(a)*	—	6.21%
For Year Ended December 31,		
Daily average outstanding	$179,505	$342,801
Monthly weighted average interest rate *(a)*	6.43%	4.71%
Maximum amount outstanding	$459,700	$497,700

(a) Excluding fees

NOTE 7. *Federal and Foreign Income Taxes*

Note 9 – "Tax Assessments."

ponents of United States and foreign income before income taxes:

	In thousands of dollars		
	1995	1994	1993
United States	$400,087	$291,501	$438,914
Foreign	17,609	15,475	(24,845)
Consolidating eliminations	(10,267)	(18,523)	4,837
Income before income taxes	$407,429	$288,453	$418,906

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		
		1995	1994	1993
Components of Federal and foreign income taxes:				
Current tax expense:	Federal	$ 67,563	$117,314	$118,918
	Foreign	3,900	4,423	8,445
		71,463	121,737	127,363
Deferred tax expense:	Federal	82,323	(6,931)	35,152
	Foreign	2,222	3,028	—
		84,545	(3,903)	35,152
Income taxes included in Operating Expenses		156,008	117,834	162,515
Current Federal and foreign income tax credits included in Other Income and Deductions		(197)	(11,507)	(16,061)
d Federal and foreign income tax expense luded in Other Income and Deductions		3,582	5,142	621
Total		$159,393	$111,469	$147,075
Reconciliation between Federal and foreign income taxes and the tax computed at prevailing U.S. statutory rate on income before income taxes:				
Computed tax		$142,601	$100,959	$146,617
Reduction (increase) attributable to flow-through of certain tax adjustments:				
Depreciation		(31,033)	(33,328)	(35,153)
Cost of removal		9,247	8,908	7,822
Deferred investment tax credit amortization		8,589	8,018	8,018
Other		(3,595)	5,892	18,855
		(16,792)	(10,510)	(458)
Federal and foreign income taxes		$159,393	$111,469	$147,075

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

	In thousands of dollars	
	1995	1994
Alternative minimum tax	$ (82,869)	$ (93,893)
Unbilled revenue	(77,675)	(98,201)
Other	(248,275)	(258,621)
Total deferred tax assets	(408,819)	(450,715)
Depreciation related	1,456,949	1,398,695
Investment tax credit related	91,458	95,325
Other	249,211	215,158
Total deferred tax liabilities	1,797,618	1,709,178
Accumulated deferred income taxes	$1,388,799	$1,258,463

NOTE 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 program cost the Company approximately $208 million of which $11.4 million, related to the gas business, was deferred with recovery anticipated to occur over a five year period, beginning in 1995.

Net pension cost for 1995, 1994 and 1993 included the following components:

	In thousands of dollars		
	1995	1994	1993
Service cost — benefits earned during the period	$ 22,500	$ 30,400	$ 30,100
Interest cost on projected benefit obligation	73,000	62,700	54,200
Actual return on plan assets	(215,600)	7,700	(106,100)
Net amortization and deferral	140,300	(63,600)	38,700
Net pension cost	20,200	37,200	16,900
VERP costs	—	114,000	—
Regulatory asset	—	(6,200)	—
Total pension cost *(1)*	$ 20,200	$145,000	$ 16,900

(1) $4.1 million for 1995, $5.9 million for 1994 and $5.6 million for 1993 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,	1995	1994
Actuarial present value of accumulated benefit obligations:		
Vested benefits	$ 777,584	$640,689
Non-vested benefits	64,383	69,642
Accumulated benefit obligations	841,967	710,331
Additional amounts related to projected pay increases	135,115	222,667
Projected benefits obligation for service rendered to date	977,082	932,998
Plan assets at fair value, consisting primarily of listed stocks, bonds, other fixed income obligations and insurance contracts	(1,074,333)	(893,313)
Plan assets (in excess of) less than projected benefit obligations	(97,251)	39,685
Unrecognized net obligation at January 1, 1987 being recognized over approximately 19 years	(21,500)	(27,122)
Unrecognized net gain from actual return on plan assets different from that assumed	198,035	58,379
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions amortized over 10 years	46,982	67,857
Prior service cost not yet recognized in net periodic pension cost	(41,291)	(44,421)
Pension liability included in the consolidated balance sheets	$ 84,975	$ 94,378
Principle Actuarial Assumptions (%):		
Discount Rate	7.50	8.00
Rate of increase in future compensation levels (plus merit increases)	2.50	3.25
Long-term rate of return on plan assets	9.25	8.75

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 conform with SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions". The Company has established various trusts to fund its future postretirement benefit obligation. In 1995, the Company made contributions to such trusts of approximately $53.1 million, which represented the amount received in rates, certain capital portions of the postretirement benefit obligation and amounts received from co-tenants. In 1994 and 1993, the Company contributed $24 million and $12 million, respectively, which represented the amount received in rates.

Net postretirement benefit cost for 1995, 1994 and 1993 included the following components:

	In thousands of dollars		
	1995	1994	1993
Service cost — benefits attributed to service during the period	$12,600	$ 15,000	$12,300
Interest cost on accumulated benefit obligation	45,400	40,200	32,800
Actual return on plan assets	(11,200)	(900)	—
Amortization of the transition obligation over 20 years	18,800	20,200	20,400
Net amortization	14,600	8,900	—
Net postretirement benefit cost	80,200	83,400	65,500
VERP costs	—	80,200	—
Regulatory asset	—	(4,300)	—
Total postretirement benefit cost	$80,200	$159,300	$65,500

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,	**1995**	1994
Actuarial present value of accumulated benefit obligations:		
Retired and surviving spouses	$214,367	$371,223
Active eligible	24,374	20,400
Active ineligible	397,547	208,900
Accumulated benefit obligations	636,288	600,523
Plan assets at fair value, consisting primarily of listed stocks, bonds and other fixed obligations	(101,721)	(36,754)
Accumulated postretirement benefit obligation in excess of plan assets	534,567	563,769
Unrecognized net gain from actual return on plan assets different from that assumed	8,713	—
Unrecognized net loss from past experience different from that assumed and effects of changes in assumptions	(64,612)	(71,939)
Unrecognized transition obligation to be amortized over 20 years	(318,596)	(337,336)
Accrued postretirement benefit liability included in the consolidated balance sheets	$160,072	$154,494
Principle actuarial assumptions (%):		
Discount Rate	7.50	8.00
Long-term rate of return on plan assets	9.25	8.75
Health care cost trend rate:		
Pre-65	8.25	9.75
Post-65	5.25	6.75

At December 31, 1995, the assumed health cost trend rates gradually decline to 5.0% in 1999. If the health care cost trend rate was increased by one percent, the accumulated postretirement benefit obligation as of December 31, 1995 would increase by approximately 10.9% and the aggregate of the service and interest cost component of net periodic postretirement benefit cost for the year would increase by approximately 13.6%.

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. At December 31, 1995 and 1994, the Company's postemployment benefit obligation is approximately $12.5 million and $26.3 million, respectively, including the portion of the obligation related to the VERP. At December 31, 1995, the Company has recorded a regulatory asset of approximately $10.4 million, the majority of which will be recovered over three years beginning in 1995.

NOTE 9. Commitments and Contingencies

See Note 2 and Note 6.

Long-term Contracts for the Purchase of Electric Power: At January 1, 1996, 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	951,000 *(a)*	$25,200,000
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 *(b)*	110,000 *(c)*	7,900,000
		1,435,000	$41,900,000

(a) 943,000 kw for summer of 1996; 951,000 kw for winter of 1996-97.
(b) The Company has agreed to not terminate or reduce purchases before May 1, 1997 if NYPA does not increase rates.
(c) 72,000 kw for summer of 1996; 110,000 kw for winter of 1996-97.

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 $92.5 million, $85.1 million, and $72.2 million for the years 1995, 1994 and 1993, 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. The Company has virtually all unregulated generator capacity on line, amounting to approximately 2,708 MW of capacity at December 31, 1995. Of this amount 2,390 MW is considered firm. The following table shows the payments for fixed capacity costs, and energy and related taxes 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			
	Schedulable Fixed Costs			
Year	Capacity	Other	Energy	Total
1996	$201,000	$40,000	$ 863,000	$1,104,000
1997	213,000	41,000	921,000	1,175,000
1998	237,000	42,000	947,000	1,226,000
1999	241,000	43,000	981,000	1,265,000
2000	229,000	44,000	1,020,000	1,293,000

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 [illegible] approximately 708 MW of capacity, with contract l[illegible] ranging from 20 to 35 years. The terms of these co[illegible]cts 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 $7.7 billion over their terms, using escalated contract rates. Contracts relating to the remaining facilities in service at December 31, 1995, require the Company to pay only when energy is delivered. The Company currently recovers schedulable capacity through base rates and energy payments, taxes and other schedulable fixed costs through the FAC.

The Company paid approximately $980 million, $960 million and $736 million in 1995, 1994 and 1993 for 14,000,000 MWh, 14,800,000 MWh and 11,720,000 MWh, respectively, of electric power under all unregulated generator contracts.

In an effort to reduce the costs associated with unregulated generators, at December 31, 1995, the Company had agreed to buy out 17 projects consisting of 457 MW of capacity. 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 UGs when demand is low or otherwise provide cost reductions or operational benefits. The Company expects to continue efforts of these types into the future, to control its power supply and related costs, but at [illegible] time cannot predict the outcome of such efforts. ([illegible] "Management's Discussion and Analysis of Financia[illegible] Condition and Results of Operations - Unregulated Generators").

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. The agreement was amended in September 1995 to allow for sale of an additional $50 million of customer receivables. The Company sold this additional $50 million in the fourth quarter of 1995, thereby bringing the total amount of receivables sold under the agreement to $250 million. 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.

At December 31, 1995 and 1994, $250 million and $200 million, respectively, 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. Under the terms of the agreement, a formula determines the amount of the loss reserve. At December 31, 1995, the amount of additional receivables assigned to the purchaser, as a loss reserve, was approximately $78.3 million. Althoug[illegible] represents the formula-based amount of credit exp[illegible] at December 31, 1995 under the agreement, historical losses have been substantially less.

To the extent actual loss experience of the pool receivables exceeds the loss reserve, the purchaser [illegible]s the excess. Concentrations of credit risk to the purchaser with respect to accounts receivable are limited due to the Company's large, diverse customer base within its service territory. The Company generally does not require collateral, i.e., customer deposits.

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 under traditional ratemaking. The Company is currently attempting to negotiate a settlement of these issues with the Appeals Division of the IRS.

In addition, the IRS is currently examining the years 1989 and 1990. The Company received a Revenue Agents' Report in late January 1996. The IRS has raised the issue concerning the deductibility of advance payments made to UGs in accordance with certain contracts that include a provision for an Advance Payment Account. The IRS proposes to disallow a current deduction for amounts paid in excess of the avoided costs by the Company. Although the Company believes that any such disallowance for the years 1989 and 1990 will not have a material impact on its financial position or results of operations, it believes that a disallowance for these above-market payments for the years subsequent to 1990 could have a material adverse affect on its cash flows. The Company is vigorously defending its position on this issue.

Litigation: The Company is unable to predict the ultimate disposition of the lawsuits referred to below. However, 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. Accordingly, no provision for liability, if any, that may result from these lawsuits has been made in the Company's financial statements.

(a) In March 1993, Inter-Power of New York, Inc. (Inter-Power), filed a complaint against the Company and certain of its officers and employees in the Supreme Court of the State of New York, Albany County (NYS Supreme Court). Inter-Power alleged, 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 early 1994, the NYS Supreme Court dismissed two of the plaintiff's claims; this dismissal was upheld by the Appellate Division, Third Department of the NYS Supreme Court. Subsequently, the NYS Supreme Court granted the Company's motion for summary judgment on the remaining causes of action in Inter-Power's complaint. In August 1994, Inter-Power appealed this decision and on July 27, 1995, the Appellate Division, Third Department affirmed the granting of summary judgment as to all counts, except for one dealing with an alleged breach of the power purchase agreement relating to the Company's having declared the agreement null and void on the grounds that Inter-Power had failed to provide it with information regarding its fuel supply in a timely fashion. In August 1995, the Company filed a motion to reargue or for leave to appeal to the Court of Appeals. The Company's motion was denied on October 25, 1995.

(b) In November 1993, Fourth Branch Associates Mechanicville (Fourth Branch) filed an action against the Company and several of its officers and employees in the NYS Supreme Court, seeking compensatory damages of $50 million, punitive damages of $100 million and injunctive and other related relief. The lawsuit 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 Company filed a motion to dismiss Fourth Branch's complaint. By order dated November 7, 1995, the court granted the Company's motion to dismiss the complaint in its entirety. Fourth Branch has filed an appeal from the Court's order. Fourth Branch has filed for protection under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court for the Northern District of New York. On January 5, 1996, Fourth Branch vacated the Mechanicville site.

(c) On June 8, 1994, Medina Power Company (Medina) filed a lawsuit against the Company in the New York State Supreme Court, Erie County. Medina alleges, among other claims, that the Company violated various New York State antitrust laws in connection with a contract that the Company has with Medina. On July 11, 1995 Medina amended its complaint and removed the allegation of antitrust violations, and is now seeking unspecified damages.

The Company had previously entered into a contract with Medina, an unregulated generator, for the purchase of electricity. The original contract required Medina to be a qualifying facility (QF) under federal law or face a contractual penalty. Having come on-line without a thermal 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. The Company believes Medina's lawsuit is without merit, but cannot predict the outcome of this action.

(d) 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 short-run avoided cost (under Service Class No. 6) for all such overgeneration rather than the price which the unregulated generators contend is applicable under the contracts. At December 31, 1995, this amount of overgeneration adjustments in dispute that the Company estimates it has not paid or accrued is approximately $32 million, exclusive of interest. The Company cannot predict the outcome of these actions, but will continue to aggressively press its position.

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 also been advised that various Federal, state or local agencies believe certain properties require investigation and has prioritized the sites based on available information in order to enhance the management of investigation and remediation, if necessary.

The Company is currently aware of 88 sites with which it has been or may be associated, including 46 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) if necessary, determine the appropriate remedial actions required for site restoration and (3) where appropriate, identify other parties who should bear some or all of the cost of remediation. Legal action against such other parties will be initiated where appropriate. 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, 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 United States 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 in the amount of $2[illegible] million and $240 million, which is reflected in the Company's balance sheets at December 31, 1995 and 1994, respectively. The liability was reduced in 1995 to reflect the Company's current estimate, which incorporates the recent availability of better information regarding the cost to remediate one of its major sites, the Saratoga Springs manufactured gas plant site, since a Record of Decision was issued by the EPA at that site. The Saratoga Springs site is included on the National Priority's List. This liability represents 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 $930 million, including approximately $430 million in the unlikely event the Company is required to assume 100% responsibility at non-owned sites.

Prior to 1995, the Company recovered 100% of its costs associated with site investigation and restoration. In the Company's 1995 rate order, costs incurred during 1995 for the investigation and restoration of Company-owned sites and sites with which it is associated were subject to 80%/20% (ratepayer/Company) sharing. In 1995, the Company incurred $11.5 million of such costs, resulting in a disallowance of $2.3 million (before tax), which the Company has recognized as a loss in Other items (net) on the Consolidated Statements of Income. The PSC stated in its opinion, dated December 1995, its decision to require sharing was "on a one-time, short-term basis only, pending its further evaluation of the issue in future proceedings." The Company has recorded a regulatory asset representing the remediation obligations to be recovered from ratepayers.

Where appropriate, the Company has provided 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.

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 1996 through 2000 will require approximately $1.5 billion, excluding AFC and nuclear fuel. For the years 1996 through 2000, the estimates are $290 million, $295 million, $307 million, $306 million and $290 million, respectively, which includes $42 million, $46 million, $58 million, $49 million and $40 million, respectively, related to generation. These amounts are reviewed by management as circumstances dictate.

NOTE 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.

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

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

Long-term debt and mandatorily redeemable preferred stock: The fair value of fixed rate long-term debt and redeemable preferred stock is estimated using quoted market prices where available or discounting remaining cash flows at the Company's incremental borrowing rate. 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			
	1995		1994	
At December 31,	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and short-term investments	$ 153,475	$ 153,475	$ 94,330	$ 94,330
Short-term debt	—	—	416,750	416,750
Mandatorily redeemable preferred stock	106,000	92,676	116,950	134,692
Long-term debt: First Mortgage bonds	2,866,305	2,815,206	2,611,305	2,367,755
Medium-term notes	30,000	31,826	45,000	45,783
NYSERDA bonds	413,760	413,760	413,760	413,760
Swiss franc bond	—	—	50,000	83,682
Other	292,436	292,436	224,107	224,107

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 consist of 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"), short-term investments held by Opinac (a subsidiary) and a trust fund for certain pension benefits. 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, 1995. The proceeds from the sale of investments were $70.3 million and $104.6 million in 1995 and 1994, respectively. Net realized and unrealized gains and losses related to the nuclear decommissioning trust are reflected in Accumulated depreciation and amortization on the Consolidated Balance Sheets, which is consistent with the method used by the Company to account for the decommissioning costs recovered in rates. The unrealized gains and losses related to the investments held by Opinac and the pension trust are included, net of tax, in stockholders' equity on the Consolidated Balance Sheets, while the realized gains and losses are included in Other items (net) on the Consolidated Income Statements.

The recorded fair values and cost basis of the Company's investments in debt and equity securities is as follows:

At December 31,	1995				1994			
	In thousands of dollars							
Security Type	Cost	Gross Unrealized Gain	Gross Unrealized (Loss)	Fair Value	Cost	Gross Unrealized Gain	Gross Unrealized (Loss)	Fair Value
U.S. Government Obligations	$ 16,271	$ 3,009	$ —	$ 19,280	$15,165	$ 19	$ (325)	$14,859
Commercial Paper	47,105	1,019	—	48,124	—	—	—	—
Tax Exempt Obligations	66,155	3,830	(72)	69,913	45,029	659	(1,778)	43,910
Corporate Obligations	45,279	5,399	(344)	50,334	27,407	9	(1,253)	26,163
Other	10,022	945	—	10,967	8,121	28	(348)	7,801
	$184,832	$14,202	$(416)	$198,618	$95,722	$715	$(3,704)	$92,733

Using the specific identification method to determine cost, the gross realized gains and gross realized losses were:

Year Ended December 31	1995	1994
	In thousands of dollars	
Realized gains	$2,523	$1,123
Realized losses	328	1,637

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

At December 31, 1995:	Fair Value	Cost
	In thousands of dollars	
Less than 1 year	$48,124	$47,105
1 year to 5 years	10,308	9,689
5 years to 10 years	31,759	30,066
Due after 10 years	83,112	75,348

NOTE 11. Quarterly Financial Data (Unaudited)

Operating revenues, operating income, net income and earnings per common share by quarters from 1995, 1994 and 1993, 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.

Quarter Ended	Operating revenues	Operating income (loss)	Net income (loss)	Earnings (loss) per common share
	In thousands of dollars			
December 31, 1995	**$ 966,478**	**$113,510**	**$ 27,874**	**$.13**
1994	1,018,110	(10,536)	(77,422)	(.61)
1993	988,195	95,623	30,955	.16
September 30, 1995	**$ 887,231**	**$114,126**	**$ 46,941**	**$.26**
1994	918,810	108,937	48,383	.27
1993	879,952	108,539	48,595	.29
June 30, 1995	**$ 938,816**	**$121,985**	**$ 54,485**	**$.31**
1994	979,700	130,624	67,559	.42
1993	929,245	132,669	65,325	.41
March 31, 1995	**$1,124,813**	**$178,405**	**$118,736**	**$.75**
1994	1,235,558	203,348	138,464	.92
1993	1,136,039	187,669	126,956	.86

In the fourth quarter of 1994 the Company recorded $196.6 million (89 cents per common share) for the electric expense allocation of the VERP. In the third quarter of 1993 and the fourth quarters of 1994 and 1995, the Company recorded $10.3 million (5 cents per common share), $12.3 million (6 cents per common share), and $16.9 million (8 cents per common share), respectively, for MERIT earned in accordance with the 1991 Agreement.

NOTE 12. Information Regarding the Electric and Gas Businesses

The Company is engaged principally in the business of production, purchase, transmission, distribution and sale of electricity and the purchase, distribution, sale and transportation of gas in New York State. The Company provides electric service to the public in an area of New York State having a total population of about 3,500,000, including among others, the cities of Buffalo, Syracuse, Albany, Utica, Schenectady, Niagara Falls, Watertown and Troy. The Company distributes or transports natural gas in areas of central, northern and eastern New York having a total population of about 1,700,000 nearly all within the Company's electric service area. Certain information regarding the Company's electric and natural gas 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. At December 31, 1995, total plant assets consisted of 24.1% Nuclear, 16.7% Generation, 41.5% Transmission and Distribution, 4.5% Hydro and 10.3% Gas and 2.9% Common.

	In thousands of dollars		
	1995	1994	1993
Operating revenues:			
Electric	$3,335,548	$3,528,987	$3,332,464
Gas	581,790	623,191	600,967
Total	$3,917,338	$4,152,178	$3,933,431
Operating income before taxes:			
Electric	$ 587,282	$ 466,978*	$ 625,852
Gas	96,752	83,229	61,163
Total	$ 684,034	$ 550,207	$ 687,015
Pretax operating income, including AFC:			
Electric	$ 595,970	$ 475,694	$ 641,435
Gas	97,114	83,592	61,812
Total	693,084	559,286	703,247
Income taxes, included in operating expenses:			
Electric	129,861	97,417	148,695
Gas	26,147	20,417	13,820
Total	156,008	117,834	162,515
Other (income) and deductions	1,379	(21,410)	(22,475)
Interest charges	287,661	285,878	291,376
Net income	$ 248,036	$ 176,984	$ 271,831
Depreciation and amortization:			
Electric	$ 292,995	$ 283,694	$ 255,718
Gas	24,836	24,657	20,905
Total	$ 317,831	$ 308,351	$ 276,623
Construction expenditures (including nuclear fuel):			
Electric	$ 285,722	$ 376,159	$ 429,265
Gas	60,082	113,965	90,347
Total	$ 345,804	$ 490,124	$ 519,612
Identifiable assets:			
Electric	$7,592,287	$7,759,549	$7,700,888
Gas	1,123,045	1,093,812	1,008,272
Total	8,715,332	8,853,361	8,709,160
Corporate assets	762,537	796,455	762,167
Total assets	$9,477,869	$9,649,816	$9,471,327

* Includes $196,625 of VERP expenses.

Electric and Gas Statistics

ELECTRIC CAPABILITY

December 31,	1995 (Thousands of kilowatts)	%	1994	1993
Owned:				
Coal	1,316	16.0	1,285	1,285
Oil	636	7.7	646	1,496
Dual Fuel — Oil/Gas	700	8.5	700	700
Nuclear	1,082	13.2	1,048	1,048
Hydro	665	8.1	700	700
Natural Gas	—	—	—	74
	4,399	53.5	4,379	5,303
Purchased:				
New York Power Authority				
— Hydro	1,325	16.1	1,300	1,302
— Nuclear	110	1.3	74	65
Unregulated generators	2,390	29.1	2,273	2,253
	3,825	46.5	3,647	3,620
Total capability	8,224	100.0	8,026	8,923
Electric peak load	6,211		6,458	6,191

*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.

ELECTRIC STATISTICS

	1995	1994	1993
Electric sales *(Millions of kw-hrs.)*			
Residential	10,150	10,415	10,475
Commercial	11,684	11,813	12,079
Industrial	7,126	7,445	7,088
Industrial – Special	4,053	4,118	3,888
Municipal service	215	215	220
Other electric systems	4,456	7,593	3,974
	37,684	41,599	37,724
Electric revenues *(Thousands of dollars)*			
Residential	$1,221,105	$1,233,007	$1,171,787
Commercial	1,241,479	1,272,234	1,241,743
Industrial	527,244	577,473	553,921
Industrial – Special	56,250	49,217	42,988
Municipal service	49,543	50,007	50,642
Other electric systems	95,812	167,131	105,044
Miscellaneous	144,115	179,918	166,339
	$3,335,548	$3,528,987	$3,332,464
Electric customers *(Average)*			
Residential	1,411,953	1,405,343	1,398,756
Commercial	145,965	144,249	143,078
Industrial	2,159	2,105	2,132
Industrial – Special	83	82	76
Other	1,497	2,318	3,438
	1,561,657	1,554,097	1,547,480
Residential *(Average)*			
Annual kw-hr. use per customer	7,189	7,411	7,489
Cost to customer per kw-hr.	12.03¢	11.84¢	11.19¢
Annual revenue per customer	$864.83	$877.37	$837.74

GAS STATISTICS

	1995	1994	1993
Gas sales *(Thousands of dekatherms)*			
Residential	51,842	56,491	[illegible]
Commercial	23,818	25,783	23,743
Industrial	2,660	3,097	4,316
Other gas systems	161	244	234
Total sales	78,481	85,615	83,201
Spot market	1,723	1,572	13,223
Transportation of customer-owned gas	144,613	85,910	67,741
Total gas delivered	224,817	173,097	164,165
Gas revenues *(Thousands of dollars)*			
Residential	$368,391	$398,257	$370,565
Commercial	143,643	159,157	144,834
Industrial	11,530	14,602	18,482
Other gas systems	762	1,159	1,066
Spot market	3,096	4,370	29,782
Transportation of customer-owned gas	48,290	38,346	34,843
Miscellaneous	6,078	7,300	1,395
	$581,790	$623,191	$600,967
Gas customers *(Average)*			
Residential	471,948	463,933	455,629
Commercial	40,945	40,256	39,662
Industrial	225	256	233
Other	1	1	1
Transportation	652	661	673
	513,771	505,107	496,198
Residential *(Average)*			
Annual dekatherm use per customer	109.8	121.8	120.5
Cost to customer per dekatherm	$7.11	$7.05	$6.75
Annual revenue per customer	$780.58	$858.44	$813.30
Maximum day gas sendout (dekatherms)	1,211,252	995,801	929,285

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(Effective April 3, 1995)

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Energy Distribution

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Finance and Corporate Services

Michael P. Ranalli
Senior Vice President
Electric Supply and Delivery
(Retired October 31, 1995)

[illegible] B. Abbott
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General Manager-Nuclear
(Effective December 14, 1995)

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Customer Service

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President
(Effective April 3, 1995)

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Nuclear Operations, San Diego, CA

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Montpelier, VT

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Of Counsel, Hiscock & Barclay
Attorneys-at-Law, Syracuse, NY

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B. Member, Committee on Corporate Public Policy and Environmental Affairs
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D. Member, Executive Committee
E. Member, Finance Committee
F. Member, Nuclear Oversight Committee

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