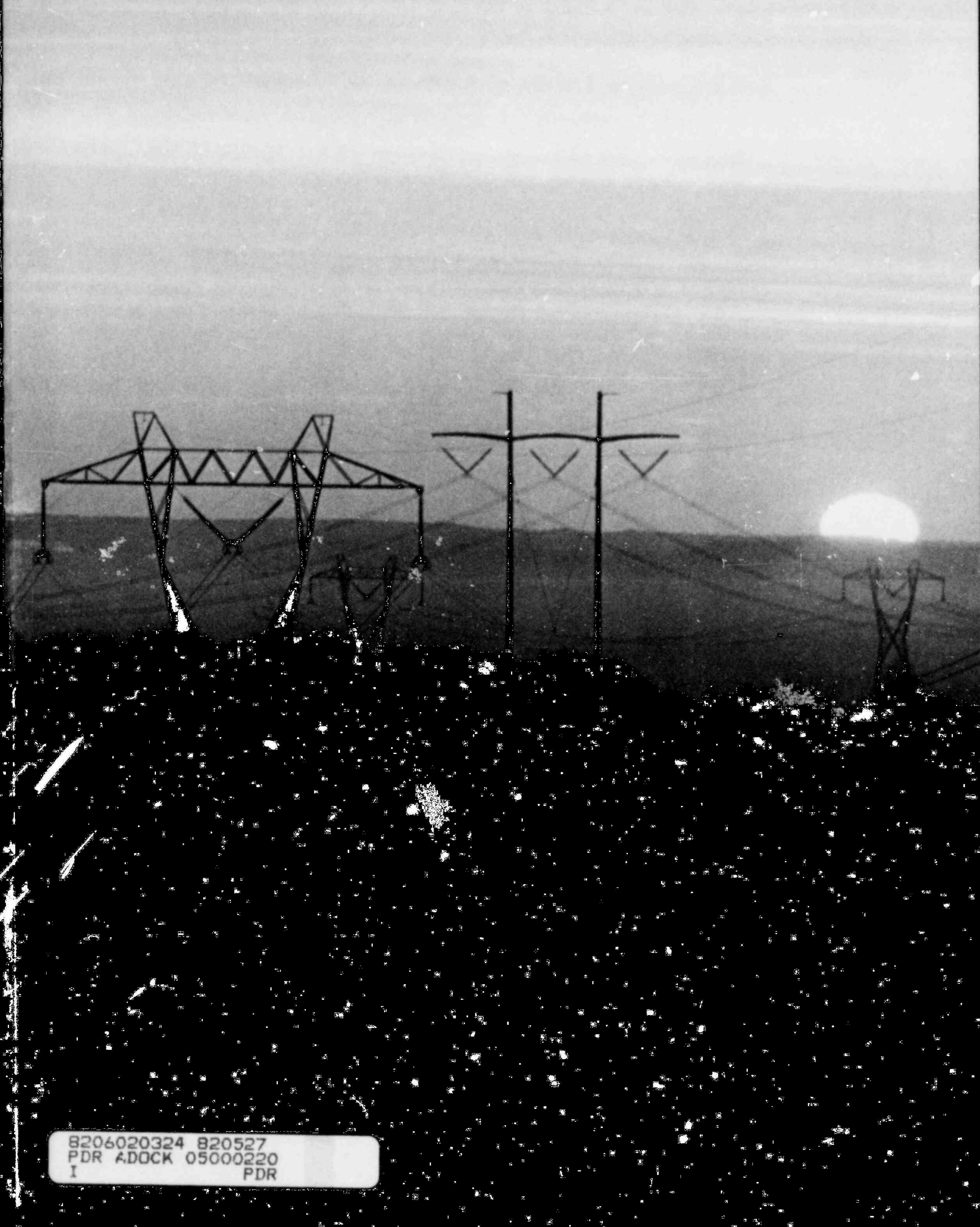
Niagara Mohawk Power Corporation 1981 Annual Report



Contents

COVER
Radiant sunrise finds Niagara Mohawk transmission structures standing like sentinels in morning mist. These 345,000-volt carriers cross lush Mohawk Valley terrain from Edic Substation to New Scotland and represent only a small segment of our far-reaching upstate New York energy network.
Photo by Cornelius G. Moynihan

Highlights of 1981

	1981	1980	% Change
Total operating revenues	**$2,150,718,000**	$1,777,115,000	21
Income available for common stockholders	**$ 186,358,000**	$ 133,201,000	40
Earnings per common share	**$2.35**	$1.87	26
Dividends per common share	**$1.61**	$1.50	7
Common shares outstanding *(average)*	**79,204,000**	71,257,000	11
Utility plant *(gross)*	**$4,985,315,000**	$4,563,309,000	9
Gross additions to utility plant	**$ 457,415,000**	$ 378,503,000	21
Kilowatt-hour sales	**32,890,000,000**	32,588,000,000	1
Electric customers at end of year	**1,361,000**	1,360,000	–
Electric peak load *(kilowatts)*	**5,616,000**	5,543,000	1
Natural gas sales *(dekatherms)*	**109,758,000**	101,321,000	8
Gas customers at end of year	**428,000**	423,000	1
Maximum day gas sendout *(dekatherms)*	**824,777**	740,594	11

THE 1981 REVENUE DOLLAR

33¢ Residential customers
32¢ Commercial customers
24¢ Industrial customers
11¢ All others

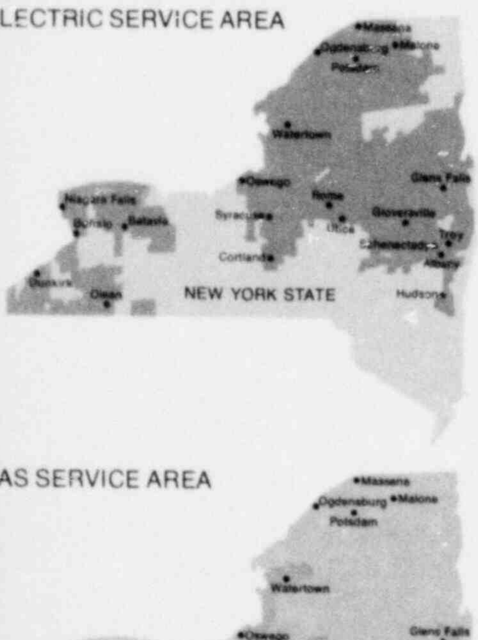
AND WHERE IT WENT

39¢ Fuel for the production of electricity and electricity purchased
14¢ Gas purchased
11¢ Wages, salaries, employee benefits
11¢ Income and other taxes
10¢ Interest and other costs—net
7¢ Dividends to stockholders
5¢ Depreciation
3¢ Retained in business

Our service area

Niagara Mohawk Power Corp., one of the nation's major investor-owned utilities, has the largest and most diverse service territory in New York State. A massive electric system extending from Lake Erie to New England's borders, to Canada and Pennsylvania, serves the energy needs of 1,361,000 customers. A natural gas system serves 428,000 customers in central, eastern and northern New York, nearly all within the Company's electric service area. Two Canadian subsidiaries, St. Lawrence Power Co. and Canadian Niagara Power Company, Ltd., provide electric service to parts of southern Ontario. Other subsidiaries are Hydra-Co Enterprises, Inc., N M Uranium, Inc. and Niagara Mohawk Finance, N.V. Our corporate headquarters are 300 Erie Boulevard West, Syracuse, NY 13202.

ELECTRIC SERVICE AREA



GAS SERVICE AREA

To our stockholders:

We are pleased to report a 26 percent earnings increase to $2.35 per share of common stock in 1981, compared with relatively depressed earnings of $1.87 per share at the close of 1980.

This substantial improvement indicates the Corporation's management can and will meet the needs and interests of both consumers and investors in today's complex times. A key to this effort is the continuing strict management of costs and expenses, coupled with a developing understanding of the Company's problems by regulators.

In 1981, the Board of Directors declared an eight percent increase in our common stock dividend, bringing the indicated annual dividend up to $1.64 from the previous $1.52. Dividends paid have increased every year for the past ten years, demonstrating our continuing efforts to provide our stockholders a proper return on their investment.

Assessing sales growth for Niagara Mohawk, our natural gas business is most promising. In 1981, industrial gas sales climbed by an impressive 24 percent over 1980, with many customers converting from more expensive oil. Our wholesale supplier assures us of more than enough of the fuel to meet demands well into the future, the result of new estimates of available gas from varied sources. In light of encouraging prospects — and with virtually all previous restrictions on gas usage now lifted — we are examining our service area for both customary and non-traditional market growth opportunities.

Although long-range forecasts for electric load growth continue to remain at 1 to 1.5 percent annually, industrial redevelopment stirrings were evidenced again in 1981 by plans for a number of significant production, milling and manufacturing expansions announced or initiated by industries in our service territory.

Another positive note for Niagara Mohawk came late in 1981 when the Public Service Commission Administrative Law Judge in our current rate case recommended electric and gas increases totaling $231 million annually,

John G. Haehl, Jr.

William J. Donlon

or about 85 percent of the total $273 million originally requested. Items included in the Judge's recommendation were the raising of the Company's rate of return on common equity, the initiation of upgraded cash-flow considerations and more realistic depreciation allowances. The recommendation also provides for incorporation of a separate decision by the Commission in another proceeding that would enable the Company to recover its investment in the Sterling Nuclear Station, for which planning ceased in 1980 when the State Siting Board withdrew the permit for construction. The Sterling cost recovery will extend over a 36-month period starting with the general rate adjustment, scheduled for a final decision in March 1982.

As this report approached press time, the Public Service Commissioners reached a consensus in support of completing Nine Mile Point Nuclear Unit No. 2, under construction on Lake Ontario. Following thousands of pages of expert testimony and arguments presented at public hearings, the Commissioners' action upheld their Staff's recommendation and the co-tenants' position that completion of the unit is warranted. The action is a major step toward concluding the prolonged regulatory proceeding that has kept a cloud of uncertainty over the project. Cited in New York State's Master Energy Plan, Unit No. 2 will be a vital addition to our varied electric generation mix, moving us closer to the goal of independence from costly OPEC oil.

Creativity and innovation continued to prove fruitful in efforts to improve the Corporation's strength and productivity. Hydra-Co Enterprises, Inc., a wholly owned unregulated subsidiary, was formed as a pioneering diversification venture to engage in co-generation and small hydro projects; our oil-fired Albany Steam Station was modified to burn either oil or natural gas; geographic regionalization of our service area was initiated to streamline field operations; additional sophisticated new computer systems were installed; and, for the first time, leveraged preferred stock and overseas Eurobonds were sold to help keep financing costs down. Further, while planning always has been a very prominent activity in our business, additional emphasis has resulted in a highly significant achievement — the development of a comprehensive and integrated strategic plan for guiding our management of the Company's future.

The year's financing totaled $346 million, with proceeds applied to construction and to refunding $151 million of maturing securities. Total financing is estimated at approximately $300 million in 1982.

As noted later in this report, the Corporation experienced new levels of progress in energy conservation and environmental affairs. Many of our ongoing, richly diverse research ventures are now advancing toward actual demonstration and commercial application, including a number of projects dedicated to air, land and water quality.

Important to consumers, Niagara Mohawk's residential electric rates are still lowest of all principal New York State utilities and below the national average. Serving our customers dependable, reasonably priced electricity and gas while raising earnings to more reasonable, equitable levels poses a constant challenge — this we welcome.

All of us at Niagara Mohawk pledge to make 1982 a more successful year. As always, we are deeply grateful for the loyalty and support of our stockholders and the thousands of employees whose devotion to Niagara Mohawk results in service to consumers of which we are justifiably proud.

John G. Haehl, Jr.

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

William J. Donlon

William J. Donlon
President

February 18, 1982

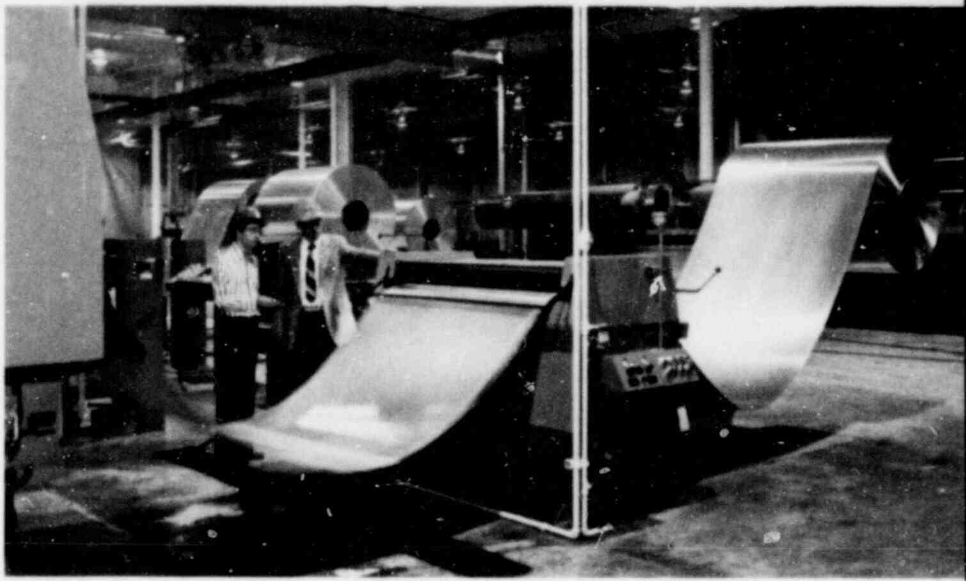
Markets

With the rest of the nation, Niagara Mohawk's vast upstate New York service area was overshadowed by clouds of economic recession in 1981. However, during the year some promising signs of entirely new or enlarged industrial and commercial energy markets appeared that may well brighten our long-range horizons.

By 1982, growth plans were announced by a broad spectrum of manufacturing and business firms, with at least 70 plant facilities or expansion projects proposed or under construction on our lines. In total, these developments amount to an estimated $270 million in capital outlay and will provide employment and jobs for some 2,700. Targeted for our service territory in the early 1980s alone are: an $80-million brass mill, a $36-million mobile radio equipment plant, $29-million liquid oxygen and nitrogen production plant, $11-million food processing facility, $8-million offset printing plant, $9-million electric motor factory, $9-million small appliance production plant, $5-million technical center, $3-million research center and a $5-million foundry.

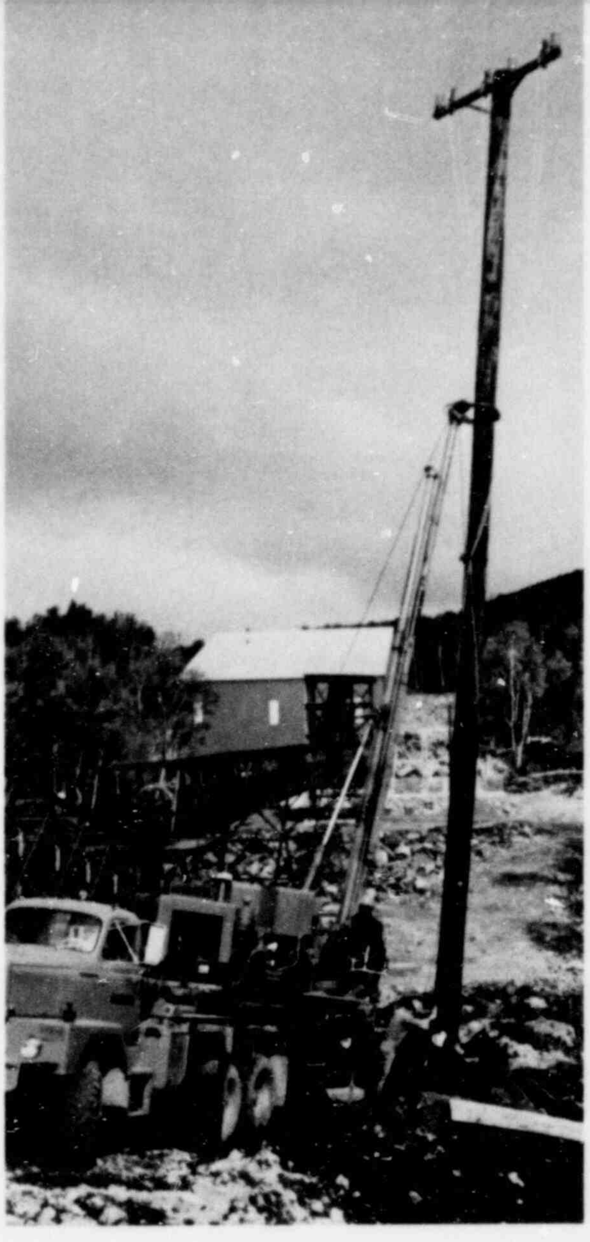
Moreover, at the start of 1982 the Company initiated a program for ultimate redistribution of 111,250 kilowatts of so-called "replacement power" in the Niagara Frontier available to Niagara Mohawk from the Niagara Project of the N.Y. State Power Authority. Extending over the next seven years, this energy will bring about the expansion of production facilities by E. I. du Pont de Nemours & Co., Carborundum Corp. and SKW Alloys, all in Niagara Falls. Construction expenditures by these firms alone are estimated at $155 million and will require some 2,000 construction workers and produce 200 permanent jobs.

Whatever energy trends the future may bring, Niagara Mohawk must have and will have capacity to respond effectively to any electrical demands. The timing, planning and construction of major generation and transmission projects, discussed in detail on pages



Aluminum for production of beverage cans speeds through machinery at Ball Metal Container plant in Saratoga Springs, one of Niagara Mohawk's larger industrial customers to go on line in 1981. Employing 250, Ball produces three million cans per year, requiring 124,000 MCF of natural gas and 18 million KWH of electricity.

Growth and vitality are evident in skyline view up Buffalo's Main Street, where concrete rail beds have just been emplaced for Niagara Frontier Transportation Authority system. In left foreground is Main Place Mall, with M & T Bank Plaza at right.



Crew installs pole to carry new 34,500-volt line servicing Barton Mines Corp. garnet operation in eastern Adirondacks. Mine is largest producer in U.S. of technical grade garnet, valued as abrasive mineral.

5 through 7, are based upon this overriding responsibility, keyed to our best growth information.

Our level load-growth forecast, however, continues to allow for the deferral — most likely until the 1990s — of a proposed 850,000-kilowatt coal-fired unit on Lake Erie south of Dunkirk. The project site was certified by the N.Y. State Board on Electric Generation Siting and the Environment following extensive proceedings and public hearings.

During the year, in an innovative move to diversify into familiar fields of established expertise, Hydra-Co Enterprises, Inc., a wholly owned subsidiary, was formed by Niagara Mohawk. Hydra-Co will specialize in marketing and constructing co-generation steam-electric energy plants for industries as well as developing small hydroelectric projects.

Co-generation entails the production of steam for industries, with electricity as a by-product. While natural gas may serve as boiler fuel initially (depending upon the location of the participating industry and prevailing fuel economics) coal, oil or wood may also be used in the co-generation. Hydra-Co, not subject to regulation by the Public Service Commission, is expected to produce financial returns for Niagara Mohawk while helping to meet the nation's objective of independence from imported oil. Its headquarters, established late in 1981, are One Lincoln Center, Suite 1225, Syracuse, NY 13202.

Impressive overall sales gains of 8.3 percent over 1980 highlighted the year for Niagara Mohawk's natural gas system.

Applications for new gas attachments were received from more than 4,700 residential, 725 commercial and industrial and 10 major industrial customers. Up to 4 million MCF (thousands of cubic feet) of gas will be used annually by new General Electric Company upstate manufacturing facilities and Albany Mall will be served an additional 2.3 million MCF. In addition, expansions by copper and brassware, brewing, food processing, paper, abrasive products and building materials firms will consume an anticipated 4.6 million MCF per year.

Our construction budget for gas system improvements and facilities in 1982 totals some $19.9 million, primarily for installation of mains and service laterals. Despite almost inevitable cost increases seen in the wake of threatened accelerated federal deregulation, continuing sales growth and an encouraging gas supply picture make this an ideal, favorably priced fuel when matched with oil.■

Construction

Construction of Nine Mile Point Nuclear Unit No. 2 neared the halfway mark toward 1986 commercial operation as 1982 began.

At a February 9 Public Service Commission meeting, a majority of the Commissioners rejected arguments and proposals to abandon the 1.08-million kilowatt project and concurred with PSC Staff's recommendation and the co-tenants' position on the advisability of finishing the unit. The Commissioners also indicated that the PSC will closely monitor construction activities. A formal PSC decision is expected pending review of the feasibility of formulating a yet undefined incentive plan that could possibly vary the return on a portion of investment in the unit. Commission proceedings on the matter, creating widespread public attention and news media coverage, were to "test the conclusions and recommendations" of both a PSC Staff Report and an earlier, year-long study by an independent consulting firm retained by the PSC. Both of these reports indicated the

Corridor for 345,000-volt line erected south of Syracuse to Binghamton area is inspected as part of Niagara Mohawk's environmental management plan for transmission rights-of-way. Helicopter speeds installation of line and reduces impact of work on terrain.

Nine Mile Point Nuclear Unit No. 2, center, is alive with construction activity in this aerial view of Lake Ontario shoreline east of Oswego. Cranes hover over reactor containment structure, at right of station, while huge circular base to support cooling tower is visible in foreground. Building and stack at left are for Unit No. 1, in service since 1969.

importance of timely completion of the unit, based on critical economic and financial considerations and other key factors.

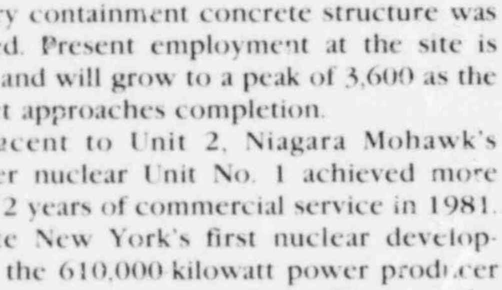
Niagara Mohawk and the unit's four other co-tenant utilities estimate its cost at $3.7 billion, including construction financing. The plant is expected to save up to 30,000 barrels of imported oil daily when in service, or about $900,000 daily at current oil prices. Nuclear fuel to power the project is significantly lower in cost than fossil fuels.

The Company, which serves as agent for construction and operation of the unit, is 41 percent owner. The other participants in its construction and output are Long Island Lighting Co., 18%; New York State Electric & Gas Corp., 18%; Rochester Gas and Electric Corp., 14%; and Central Hudson Gas & Electric Corp., 9%.

Late in 1981, a major construction milestone was achieved on Unit 2 as the reactor primary containment concrete structure was finished. Present employment at the site is 3,100 and will grow to a peak of 3,600 as the project approaches completion.

Adjacent to Unit 2, Niagara Mohawk's pioneer nuclear Unit No. 1 achieved more than 12 years of commercial service in 1981. Upstate New York's first nuclear development, the 610,000-kilowatt power producer was shut down temporarily in the spring for routine refueling and maintenance. In addition, a number of modifications were performed to improve reliability and to meet new U.S. Nuclear Regulatory Commission (NRC) requirements. The refueling included replacement of 200 of the 500 uranium fuel assemblies in the reactor core, enough to continue plant operation until March 1983. Operations resumed in July and Unit 1 operated continuously throughout the remainder of the year at almost full capacity, breaking its own generation records.

ELECTRICITY GENERATED AND PURCHASED BY TYPE OF FUEL, 1981



Fiberglass pipe receives finishing touches before installation at Bennetts Bridge Hydro Station on Salmon River. Replacement of 1½-mile wooden pipeline, in service since 1913, and other refinements improved station's power capacity by 12 percent.

An extensive emergency exercise, with hundreds taking part, was conducted in September to test the ability of Niagara Mohawk, the State of New York and Oswego County to respond to a hypothetical radiation-release accident at Nine Mile Point. The realistic, day-long drill, a post-Three Mile Island requirement by the Nuclear Regulatory Commission, was the first of its kind in New York State. For its leading role in the effort, Niagara Mohawk received positive appraisals from both the NRC and the Federal Emergency Management Agency, coordinator of the overall exercise.

Efforts to expand and upgrade waterpower opportunities wherever feasible in the service area continued through 1981. Complete reconstruction of the Granby Hydro Station on the Oswego River progressed on schedule and by year-end a new power house was in place, with installation of two 5,000-kilowatt generating units set for early 1982. Formerly rated at only 4,600 kilowatts, Granby is expected to commence commercial service in 1983 at more than double its former capacity. Old hydro units replaced in this project date back as far as 1884.

Other hydro-related tasks included replacement of intake structures and a new two-mile long fiberglass feedwater pipeline at the 24,000-kilowatt Bennetts Bridge Station on the Salmon River. These substantial modifications were accomplished working in especially close cooperation with the State Department of Environmental Conservation, Oswego County Lake Ontario Sports Fishery

News media representatives cover briefing by Company at Nine Mile Point nuclear emergency drill, the first such exercise in the state under new federal regulations. Old Naval Militia Building on Oswego waterfront served as temporary public information nerve center and press headquarters during the realistic, day-long event. Involved regulatory agencies graded Niagara Mohawk's performance favorably.

Advisory Board and other organizations with a protective interest in the Salmon River's nationally renowned trout and salmon resources. The changes yield greater water discharge capacity, enabling Bennetts Bridge to generate more kilowatt-hours than previously. In another hydro modification, a section of an impoundment dam serving water storage needs of the 5,150-kilowatt Ephratah Hydro Station near Gloversville was replaced, upgrading plant output and efficiency. These projects are among many in a comprehensive, 15-year hydro expansion program by Niagara Mohawk.

Linking generation sources with the consumer, the Company's power transmission and distribution system is continually undergoing refinements and additions. The projected in-service date for a new 345,000-volt line from Lafayette, south of Syracuse, to Oakdale, near Binghamton, is September 1982. This 65-mile intertie is a joint effort with the neighboring New York State Electric and Gas Corp. Also, preliminary field work will begin in spring 1982 on a circuit to operate at 345,000 volts between Volney, south of Nine Mile Point, and Marcy, near Utica, while several transmission switchyards and other lines are proposed or under construction to maintain power reliability and supply to the many communities the Company serves. A transmission hallmark in the 1980s will be a complex major Energy Management System (described on page 8) envisioned by Niagara Mohawk.■

View of Granby Hydro Station under construction on Oswego River shows just-completed powerhouse substructure, left, and intake and forebay complex at right. Targeted for early 1983 startup at 10,000 kilowatts, Granby is among first of projects taking shape in Niagara Mohawk's extensive hydro expansion and development into the 1990s on upper New York State waterways.

Productivity

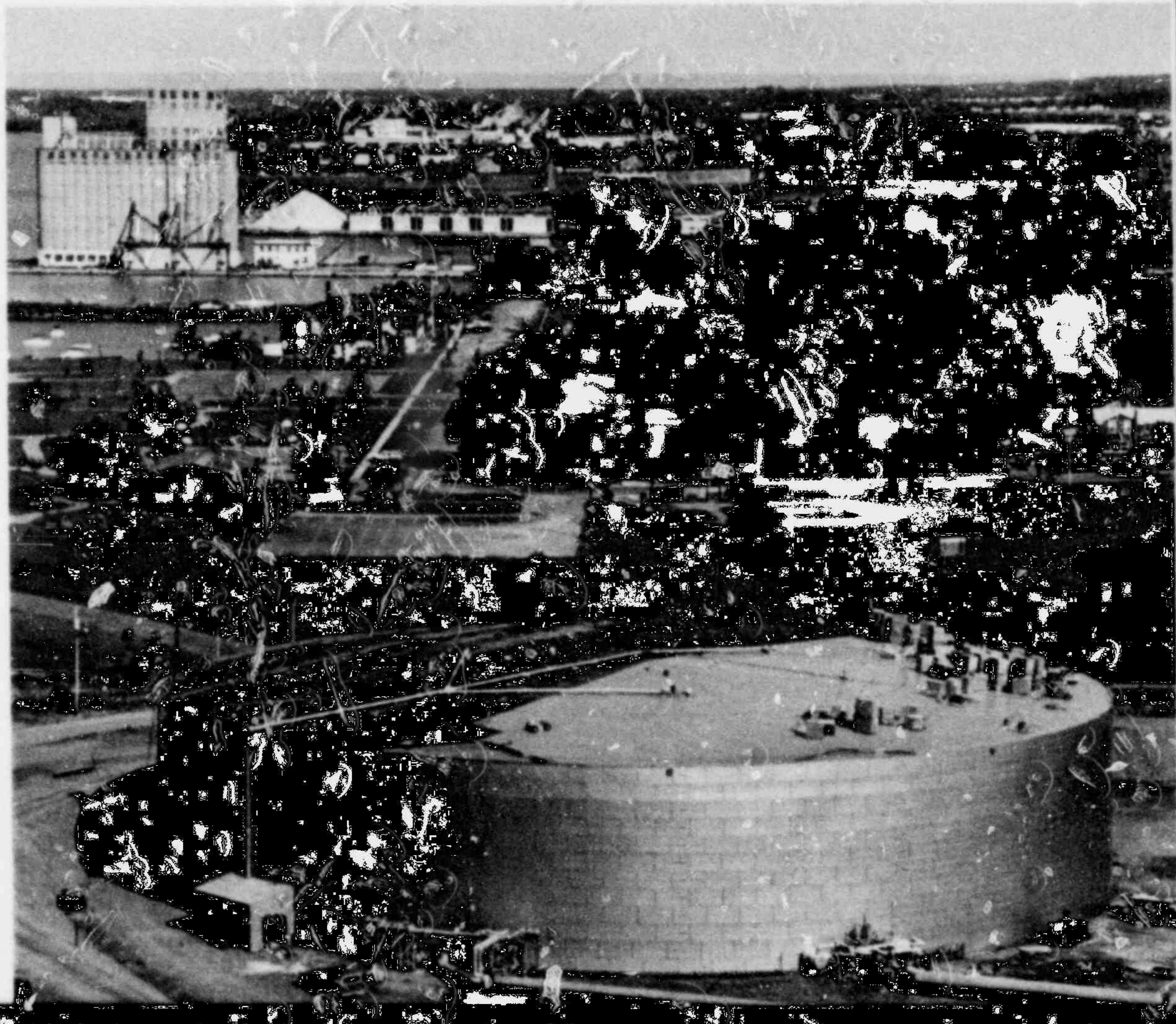
A quest for improving productivity and efficiency prevails in all Niagara Mohawk planning and work assignments. Many productivity strides were achieved in 1981, yielding cost benefits and resource-use improvements, enhancing dependability and creating manpower/time gains.

This includes continued progress on three major computer-based systems through the year. A highlight was installation of 500 terminals linking strategic customer service locations across Niagara Mohawk territory with a central customer data computer in Syracuse. Coupled with modernization of our telephone network, this advanced system is providing upgraded technical capability to respond swiftly to individual bill and service inquiries. Another computer project will refine estimating, planning, scheduling and construction of energy projects, while the third system will help simplify corporate accounting, financing and regulatory-related tasks.

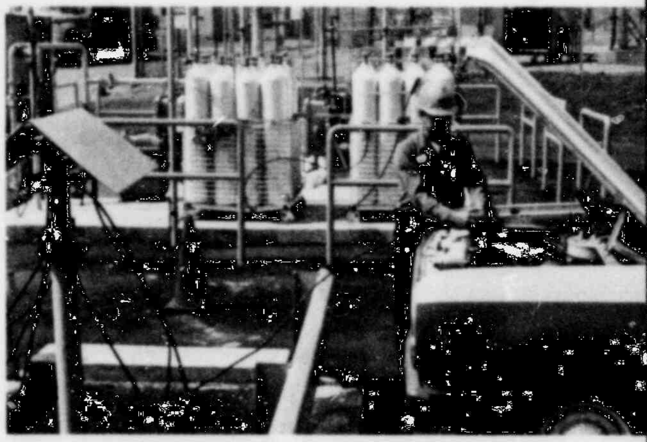
Construction of a master control center, to be the hub of an extensive system-wide Energy Management System (EMS), is expected to begin in late 1982 in Syracuse. Incorporating the latest state-of-the-art technology, EMS is now well into the design stage. It will further strengthen and modernize Niagara Mohawk's massive transmission and distribution systems to provide more economic power delivery to customers. The new master control center will be computer-linked to smaller regional control centers in Buffalo, Syracuse, Albany and Northern New York and to generating stations and substations throughout the service territory. Initial start-up and testing is anticipated in the mid-1980s, with full-scale operation targeted for 1991. Some 600 remote terminal units (sensor devices to receive and transmit data on conditions at the various facilities involved) will be installed by 1991 as a part of this far-reaching utility concept.

Computers also will be linked to remote telemonitoring instruments at the facilities of about 50 of our large, dual-fuel gas customers, and will form the heart of a new Gas Load Management (GLM) program begun in 1981. GLM controls gas usage by these customers by requiring them through a reimbursement plan to switch temporarily from gas to their secondary fuel at periods of high demand on the overall gas system, normally during severe cold spells. By reducing peak demand, not only is the cost of gas held down and the reliability of delivery maintained, but the need for additional future gas facilities, with their associated costs, is minimized. Niagara Mohawk and all of our consumers benefit from this cost-effective, productivity oriented concept, the only program of its kind conducted by a New York State utility.

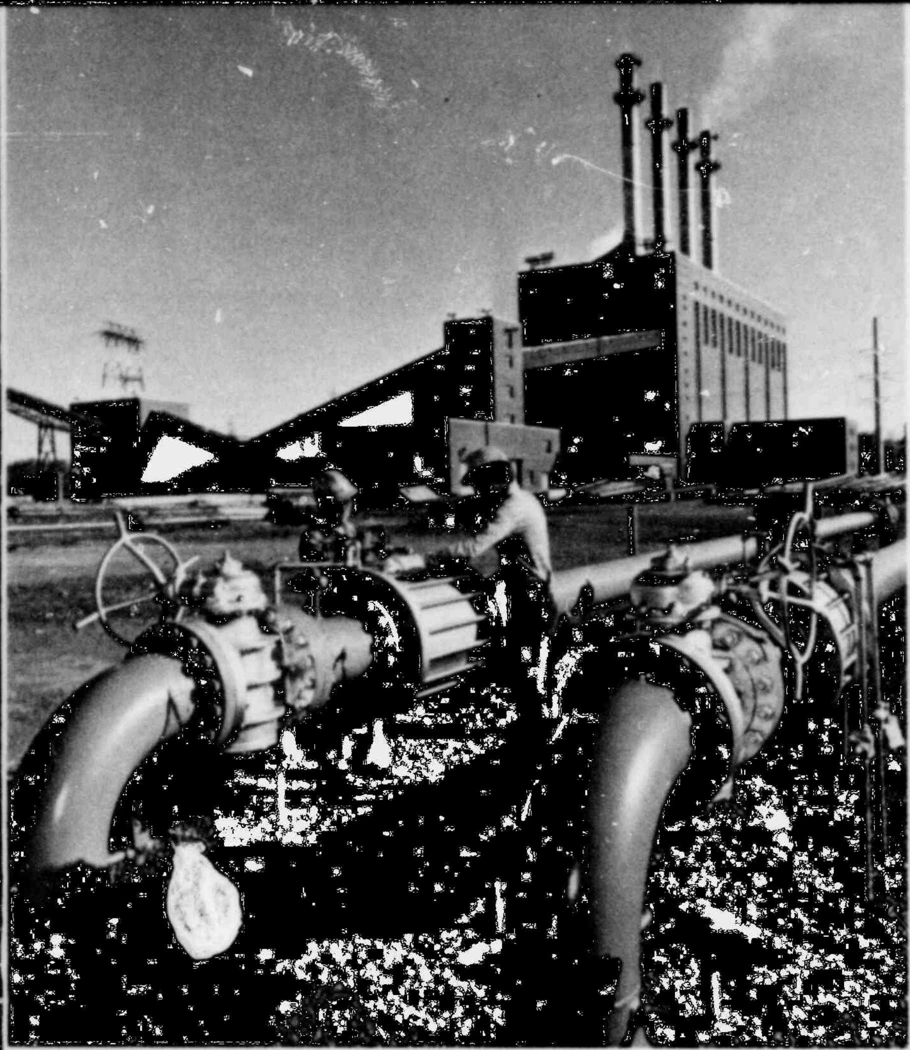
Fuel conversion to natural gas at our Albany Steam Station was accomplished by November, equipping the plant with dual-fuel capability to switch quickly back to oil when necessary during winter periods of high demand by our gas customers. The PSC ap-



View east of Oswego Harbor shows steam station fuel storage tank being sheathed with insulation to prevent heat escaping from oil stored within. This energy conservation measure reduces costs by some $3 million annually, saving more than 100,000 barrels of imported oil while also improving combustion efficiency of power plant boilers.

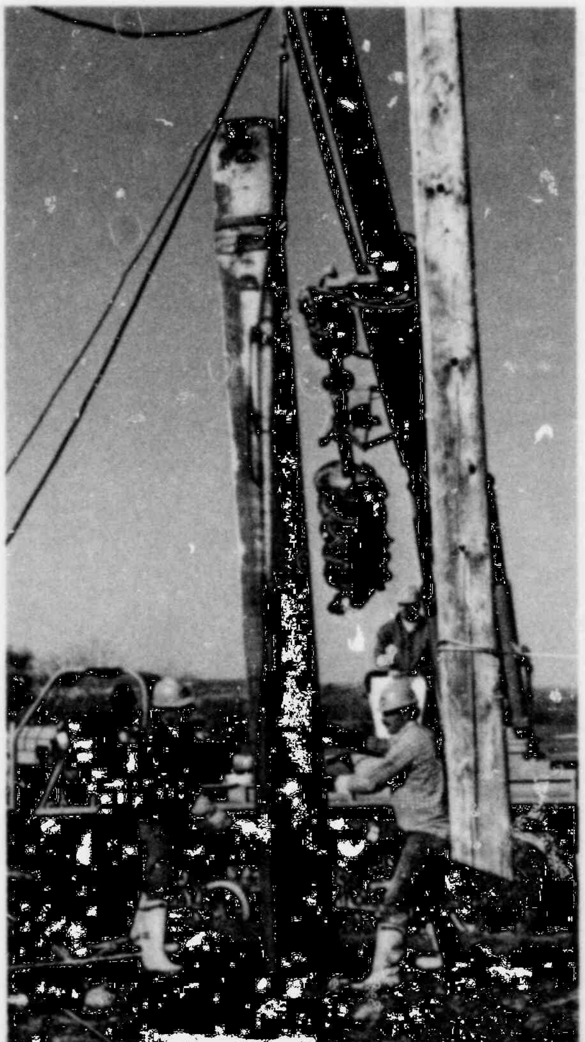


Truck equipped for compressed natural gas (CNG) operation is refueled at one of two Niagara Mohawk CNG filling stations. Eighty vehicles in our motor fleet now operate on either CNG or gasoline, while further conversions are under way.



Newly installed pipes feed natural gas to Albany Steam Station following modification of the plant to burn either oil or gas. About $21 million in savings, comparing gas and imported oil costs, are anticipated from the project for a net reduction of costs to consumers of some $13.5 million.

Mod/Pole lowered into place by line crew enables repair and use of older transmission poles, reducing labor and material costs normally required for replacement. Deteriorated portion of pole is cut off and the remaining section is lowered into sturdy concrete sleeve in this operation, initiated in 1981.



proved a proposal by the Corporation to recover through July 1982 the approximate $7.5-million cost for making the conversion. Some $21 million in savings, considering cost of gas versus imported oil, are expected in this period from the modification for a net reduction of energy costs to consumers of some $13.5 million. Regulatory approvals to extend the gas supply contract beyond July 1982 also will be sought.

The Corporation's Productivity Planning Department continues to broaden its responsibilities. Applying industrial engineering and behavioral sciences, the Department acts as an in-house "consultant" wherever needed to help increase efficiency and output. During the year, productivity planners were called upon to streamline everyday administration of natural gas operations and customer services, with positive results.

Practical technical know-how, combined with creative in-house engineering talent, will reward our consumers with previously unexpected savings of some $3 million of imported oil yearly — besides boosting plant performance — in an unusual energy conservation challenge at Oswego Steam Station. The plant's five fuel storage tanks, with capacities up to 16 million gallons of heavy residual oil, were completely covered with foam-type insulation and aluminum paneling in 1981. Costing slightly over $1 million, the project has helped to ease operation of plant boilers by stabilizing fuel temperatures in the huge tank structures, openly exposed to bitter cold and gale-force winds off Lake Ontario. Payback (in terms of energy saved) for the total insulation job costs required only four months. This measure was unique because of the size of the tanks.

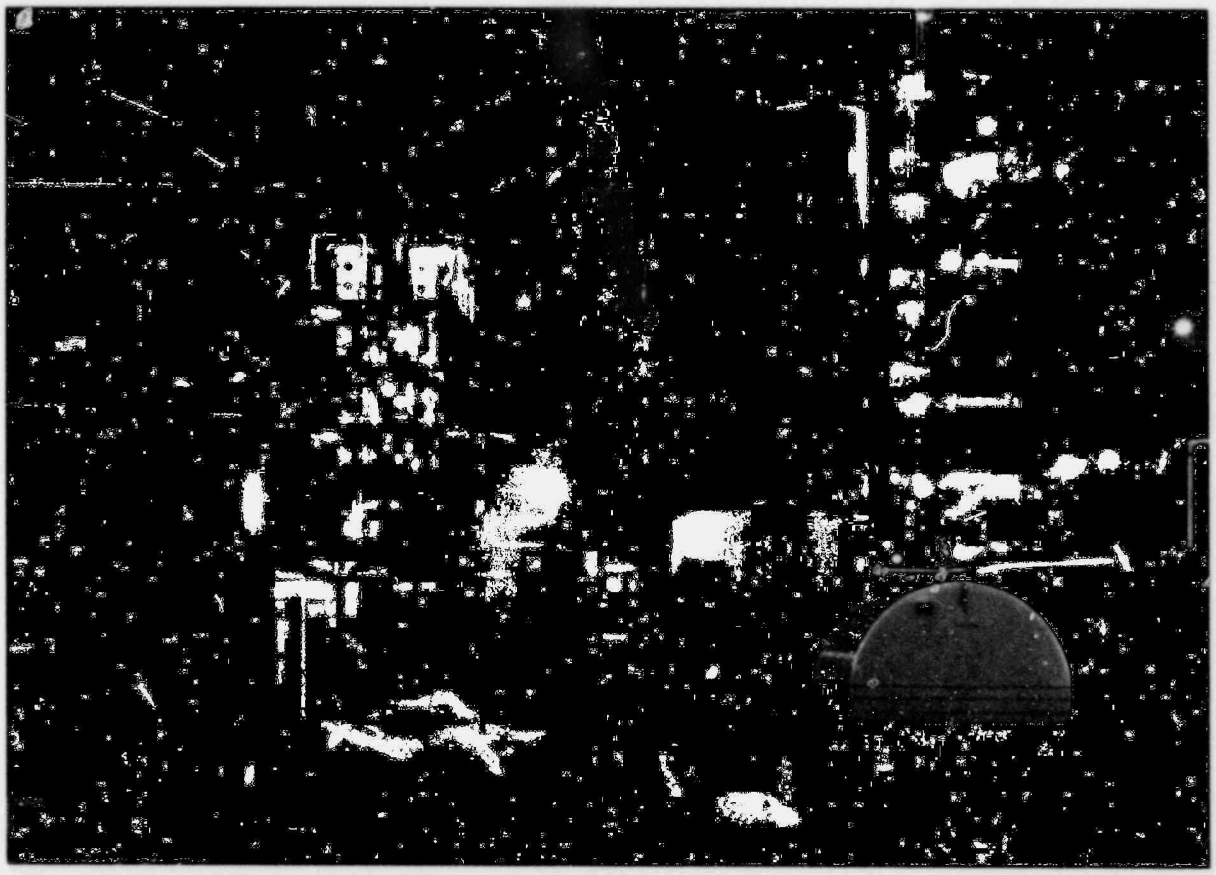
A further productivity and cost-cutting innovation entailed conversion of 80 vehicles in Niagara Mohawk's motor fleet to operate on either compressed natural gas (CNG) or gasoline. First initiated on a trial basis in 1980, this effort has provided annual savings of more than 63,500 gallons of conventional motor fuel. As an environmental measure, CNG also lowers emission levels. The Company plans major expansion of CNG throughout its fleet. ■

Research

1982 will be a threshold year in Niagara Mohawk energy research programming as select new technologies advance from laboratory testing to actual field demonstration, where their commercial potential will be tried.

At the R&D forefront is an experimental flue gas desulfurization (FGD) plant scheduled to begin prototype operation in spring 1982 at the company's Huntley Steam Station at Tonawanda, near Buffalo.

This jointly sponsored five-year experiment, costing up to $55 million, with Niagara Mohawk's share at $5 million as part of its research and development programs, involves equipment suppliers, New York State utilities and government agencies. It is designed to demonstrate a technology to enable large power generating plants to burn low-cost, high-sulfur Eastern coal to produce electricity virtually without adverse air, land or water



Night settles in at new Flue Gas Desulfurization (FGD) project readied for initial testing at Huntley Steam Station, Tonawanda. Jointly sponsored five-year research effort aims to remove 90 percent of sulfur oxides discharged from stacks of large power plants burning higher sulfur coal, promising economic and environmental benefits.

Family enjoys comforts of home in Niagara Mohawk research project seeking practical information and data on passive solar facilities now in use in our service territory. Twelve upstate New York homes are being monitored to determine how the sun's energy, coupled with electricity, meets residential and utility needs.

With help of microscope, technician splices hair-like fiber optics in research communications demonstration in Syracuse. Each fiber carries same capacity for voice messages as more than 200 copper wires in conventional telephone circuit.

impacts, most notably sulfur oxide emissions. The only significant byproduct is pure sulfur, a marketable element in sharply growing demand, in contrast with troublesome waste slurry byproducts resulting from other flue gas desulfurization processes. Both consumers and the environment will ultimately benefit from the reduced fuel costs and design advantages of this endeavor.

As part of our continuing solar research programs, a practical energy-from-the-sun study using 12 modern homes in our service area was initiated in spring 1981. With energy conservation and utilization as a goal, various solar and thermal energy storage systems in the participating dwellings are under evaluation employing computers, magnetic tape recording and remote data acquisition. The one-year study is expected to yield highly practical data of value to builders and contractors, real estate firms and lending institutions. In addition, findings in this venture are expected to be useful in long-range planning of power generating and delivery facilities, to the advantage of the Company and its consumers. A thermal storage research project has been in progress at the site of the former Olympic Village (now a correctional facility) at Lake Placid and energy conservation studies with commerical and institutional applications are planned at a modern town hall in Oswego County and a Ballston Spa school.

A near-future alternate-energy prospect, under extensive R&D for years by Niagara Mohawk with other utility participants, is the low-temperature fuel cell. Albany Steam Station has been selected as host site for an 11,000-kilowatt fuel cell demonstration unit targeted for operation in the mid-1980s. A smaller fuel cell of similar design was installed in 1981 at a generating station of Consolidated Edison Co. of New York, Inc. These devices, first employed in the U.S. manned space program, are designed to supplement conventional power production methods and operate principally on hydrogen as a fuel. Similar in appearance to large batteries but requiring no charging, fuel cells function without causing pollution, noise or vibration.

Other research activities, including fossil, nuclear, load management and supply, conservation, power delivery and environmental study projects, will amount to some $106.4 million over the next five years. Many, such as our widely recognized fiber optics/satellite communication R&D, expanded in 1981, are independent "in-house" assignments. The fiber optics/satellite experiment, the first-ever by an electric utility, could prove beneficial in reducing the Company's operating expenses, if successful.

We also are participating in ventures with other utilities, government and industry groups such as the nationwide Electric Power Research Institute, Empire State Electric Energy Research Corp. and N.Y. State Energy Research and Development Authority. ■

Consumer relations

Another year of positive programs dedicated to helping all categories of customers was recorded in 1981 by the Consumer Relations Department.

A Home Insulation and Energy Conservation Program was introduced as required by the Public Service Commission in 1981, modifying our former Home Energy Audits in effect since the 1970s. Aimed at residential consumers with up to four-family homes, the broadened program features thorough, free-of-charge inspections by trained specialists of insulation and overall weather-tightness as well as furnace, boiler and water-heating equipment. Recommendations follow the inspections, with estimates of costs for and savings resulting from the various energy conservation improvements. Consumers also receive a list of approved contractors in their area and low-cost loans with liberal repayment terms are made available through the program.

New heat pump installed at Albany area home as part of our Add-On Heat Pump Program is examined by residential customer and consumer relations representative. Program is latest in Company campaign to help consumers conserve energy and cut heating bills. More than 700 customers with oil furnaces equipped their homes with heat pumps during 1981, reducing heating costs by up to 50%.

Customer service telephone representative responds to inquiry using one of our latest computer terminals installed in 1981. This allows for instant retrieval of individual billing information, including electric and gas-use history and electronic "snapshot" of customer's most current bill.

This and other Company-sponsored home energy conservation programs were widely publicized and advertised throughout the year in all media in our service area. In 1981, promotional emphasis began on the advantages of modern heat pumps and solar-assisted water heating systems, both new energy options in upstate New York environs. Information tools consisted of a wide selection of displays and exhibits, bill enclosures, brochures and other printed materials, motion picture films and slide shows, television tapes and Speakers Bureau presentations to hundreds of organizations meeting across the service territory. Additionally, hundreds of customers attended do-it-yourself energy conservation workshops and seminars.

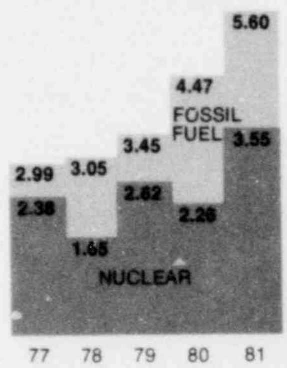
To maintain sensitivity and alertness to consumers' problems and help them with energy concerns, a number of direct customer services continue to be popular. These include Extended Due Date Plan, Budget Payment Plan, Third Party Notification, Life Support, Home Service Calls and Winter Referral Programs. Senior consumers are a special concern and the Corporation continually seeks better ways to ease their energy burdens. The Consumer Advisory Council on Energy Affairs, with 26 non-Company volunteers representing all walks of upper New York State life, continues to offer valuable insights and guidance in programming to help respond to such specialized customer groups and community needs.

At industrial and commercial customer levels, our Energy Management Action Program grows more and more popular. Consisting of five-day classroom sessions on improving lighting, load demand and energy monitoring, the classes marked another success year in 1981. Attendance totaled some 400 representatives from varied industrial and commercial firms and institutions on Niagara Mohawk lines. Of six awards for excellence granted annually by the National Electrification Council, two were presented to upstate New York EMA alumni for energy management practices learned in these Company-sponsored seminars.

Late in 1981, several customer services were realigned under one vice president. The transfer resulted from a growing number of services now available to customers and need to strengthen communications with allied rate, accounting and regulatory operations. ■

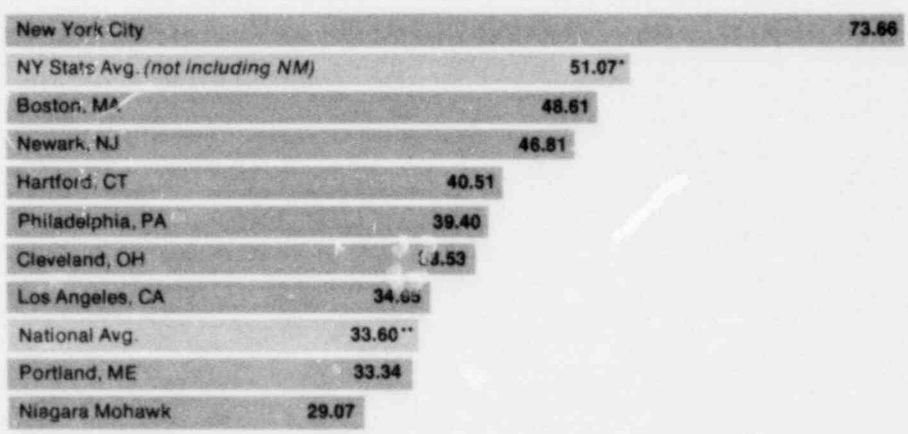
TOTAL GENERATING COSTS: FOSSIL FUEL VS. NUCLEAR

Cents per Kw-hr.



MONTHLY RESIDENTIAL ELECTRIC COST FOR 500 KILOWATT-HOURS

Dollars



Includes fuel and PASNY credit adjustments as applicable
**NM Rate Department as of 11/30/81*
***E.E.I. report with rates effective 7/1/81*

People

In ongoing efforts to keep in step with the changing times, in 1981 senior management and the Corporate Planning Department conducted a series of formal assessments of the many critical issues expected to influence the Company's direction and operations.

These evaluation sessions formed the basis for an extensive Corporate Strategic Plan in which management excellence, unity of purpose and willingness to apply new concepts and implement new actions to improve Niagara Mohawk's future were established as standards. In addition to the issues, assumptions on future trends and developments were used to formulate objectives, strategies and specific tasks. Milestone goals provide measurement guidelines to "strengthen Niagara Mohawk's ability to fulfill obligations to stockholders, customers, employees and the social communities in which it does business . . . responding to changing environments while providing direction and integration vital to meeting needs of the business environment." Under continuing development in 1982, the Plan will provide a master blueprint for Niagara Mohawk's future.

In the same spirit, following comprehensive studies, the Company is gradually implementing a regional management concept, starting late in 1981 when the Syracuse and Oswego areas were combined into the Central Region and the Watertown and St. Lawrence areas were merged into a newly established Northern Region. By early 1983, the reorganization will be accomplished in full with a total of eight regions, compared with what previously had been 13 separate areas for many years. The six other operating regions will be designated Capital, Genesee, Mohawk Valley, Frontier, Northeast and Southwest.

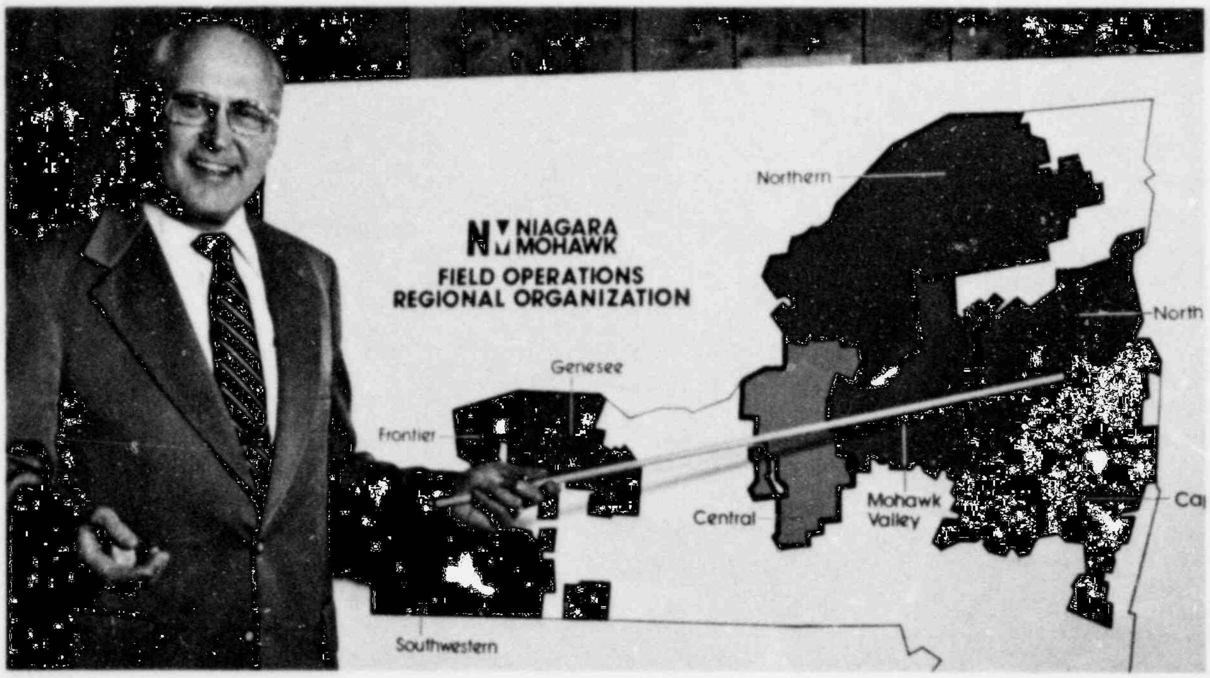
The Corporation's Training Department recorded another productive year in 1981, with emphasis on management development and skills. A program for supervisors at fossil-fired and nuclear generating stations is scheduled in 1982 in cooperation with Clarkson College Management Institute. At the same time, a formal training program — first of its kind — is planned for new customer accounting and consumer relations supervisors, with assistance from Management Systems & Services. Also, an innovative Problem Analysis and Decision-Making Process Program initiated in 1981 will be broadened in our ongoing management training curriculum.

In management and personnel developments of note, John J. Ehlinger, vice president of employee relations since 1970, retired at the year-end with 45 years of dedicated service to Niagara Mohawk. Mr. Ehlinger was active in many professional and business organizations, particularly in the fields of industrial and labor relations.

At the outset of 1982, Niagara Mohawk's total work force numbered 9,900, about the same as in the late 1950s when there were 333,000 less customers, considerably fewer utility plant facilities and electric peak load was 41 percent less than today. A two-year labor contract with 12 locals and System Council U-11, International Brotherhood of Electrical Workers, expires on May 31, 1982. Approximately 7,700 employees or 78 percent of all employees are affected by the agreement.

The Employee Savings Fund Plan is subscribed to by 6,820 or 75% of all eligible personnel. Employees allocate from 2% to 6% of their wages toward purchase of common stock or U.S. Government Bonds. The Company matched employee contributions by 50%, or $4,124,308, in 1981. The Plan holds 8,291,059 shares or 10% of the outstanding common stock. In addition, employees may make unmatched contributions of up to 4% of their wages.

Many stockholders have joined the Association of Investors in New York Utilities, Inc. (AINYU), a forceful stockholder organization formed three years ago to "protect the financial integrity of utilities to assure continued supply of power at reasonable cost to consumers and at reasonable profit to owners." AINYU's membership rolls have grown rapidly since its formation and the group is becoming increasingly influential in utility-oriented government affairs and legis-



Senior Vice President James J. Miller points out features of Niagara Mohawk's regional management plan, initiated in 1981 for 1983 completion. Concept of eight regions to replace the previous 13 separate areas is designed to improve field operations and streamline administration and communication channels.

iation. Stockholders interested in AINYU may obtain information by writing P.O. Box 12423, Albany, N.Y. 12212.

Participation in the Company's Dividend Reinvestment and Stock Purchase Plan continued to increase in 1981. Holders of both common and preferred stock are eligible. The limit on optional cash investments has been increased to \$30,000 yearly. In 1981, 42,000 participants representing 20 percent of all common stockholders, an increase of eight percent over 1980, invested \$21,153,000 in new common shares.

Dividends reinvested through the Plan qualify for tax-deferred treatment as a result of Congress enacting revisions in tax laws during the year. Effective January 1, 1982, individual taxpayers who have shares registered in their own name may exclude for federal income tax purposes up to \$750 (\$1,500 if a joint return) of dividend income reinvested in qualified shares until the shares are sold. A prospectus containing a complete description of the Plan has been mailed to all shareholders. Those desiring further copies or information on the Plan are invited to call or write NMPC Dividend Reinvestment Plan, P.O. Box 131, Syracuse, N.Y. 13201.

The number of Niagara Mohawk stockholders in 1981 totaled 210,047. New York State residents may obtain information and service related solely to stockholder account matters by calling a toll-free number established in 1982 for their convenience: 1+800 962-3236. Shareowners living elsewhere in the continental United States may call 1+800 448-5450, while Syracuse, N.Y. area security holders may dial 474-1511, extension 1983.

In the first year since its inception, Niagara Mohawk's "In-the-Know" Stockholder Information Program has met with enthusiastic response. This program, designed to supplement information provided in the quarterly and annual reports, is available to all shareholders by writing or calling our Shareholder Services Department at 300 Erie Boulevard West, Syracuse, N.Y. 13202.■

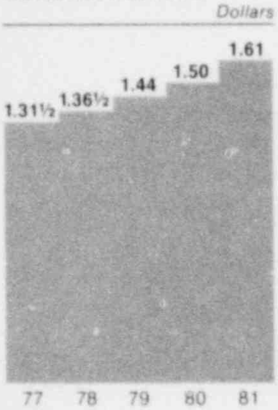
Market price of common stock and related stockholder matters

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

Preferred and common stock dividends were paid on March 31, June 30, September 30 and December 31. The Company presently estimates that 10% of the 1981 and 65% of the 1980 common stock dividends are a return of capital and therefore not taxable as dividend income for income tax purposes. The remaining percentage on common dividends and 100% of preferred stock dividends are taxable as dividend income.

The table below shows dividends per share for our common stock and quoted market prices:

DIVIDENDS PAID PER COMMON SHARE



1981	Dividend paid per share	Price range High	Price range Low
1st Quarter	$ .38	$12½	$10¾
2nd Quarter	.41	13¼	11
3rd Quarter	.41	13	10⅞
4th Quarter	.41	13¾	11
	$1.61		
1980			
1st Quarter	$ .36	$13	$10½
2nd Quarter	.38	14¼	10⅞
3rd Quarter	.38	14	12
4th Quarter	.38	12⅝	10
	$1.50		

While the Company intends to continue the practice of paying cash dividends quarterly, declarations of future dividends are necessarily dependent upon future earnings, financial requirements and other factors, including restrictions in governing instruments.

The holders of common stock are entitled to one vote per share and may accumulate their votes for the election of Directors. Whenever dividends of 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 issued 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 apart for payment, the holders of such stock can elect two members of the Board of Directors. No such dividends are now in arrears.

Upon any dissolution, liquidation or winding up of the Company's business, the holders of common stock are entitled to receive pro rata 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 surplus 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 equal 2.25% of depreciable property as defined. Such provisions have never restricted the Company's surplus.

At year end, about 210,000 stockholders own common shares of Niagara Mohawk and 10,000 hold preferred and preference stock. The chart below summarizes common stockholder ownership by size of holding:

Size of holding (Shares)	Total stockholders	Total shares held
1 to 99	58,923	1,970,520
100 to 999	142,174	33,660,850
1,000 or more	8,950	48,341,882
	210,047	83,973,252

Management's discussion and analysis of financial condition and results of operations

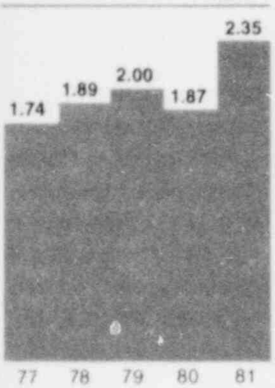
Results of operations

Niagara Mohawk's earnings in 1981 were $2.35 per share, up $.48 from 1980, $.35 above 1979, and $.46 above 1978 earnings, with fewer shares outstanding in each of the earlier years.

The substantial improvement in the Company's earnings per share for 1981 from 1980 came primarily from rate relief granted in March 1980 and 1981, and increased electric and gas sales to ultimate consumers, 0.4% and 8.6%, respectively. However, operating expenses including depreciation increased 21%, and Federal income and other taxes increased 16%, reducing the impact of the 21% increase in revenues. In addition, financing

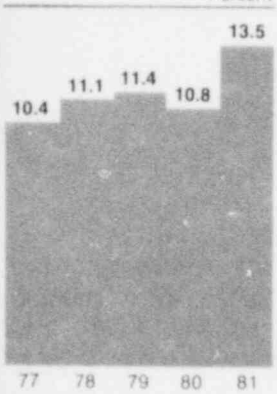
EARNINGS PER COMMON SHARE

Dollars



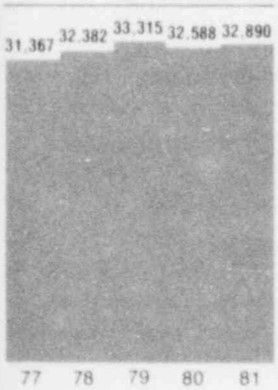
EARNED RATE OF RETURN ON COMMON EQUITY

Percent



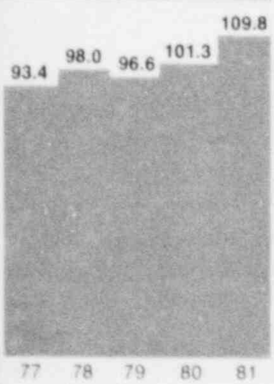
ELECTRIC SALES

Millions of Kw-hrs.



GAS SALES

Millions of dekatherms



costs were approximately 17% higher due to higher debt levels, caused by increased working capital and construction needs, at continued high interest rates.

The Company's earned rate of return on common equity rose to 13.5% for 1981 after falling to 10.8% in 1980 from the 11.4% rate achieved in 1979. The Company's 1981 return on equity remains below the 16.0% currently approved by the New York State Public Service Commission (PSC) for the rate year beginning March 1981. Recent rate awards have not provided an adequate return on equity or recovery of steadily increasing costs resulting from inflation, thus necessitating annual petitions for rate increases.

The discussion and analysis that follows highlights items that have had a significant effect on operations during the three-year period ended December 31, 1981. This discussion and analysis should be read in conjunction with the Notes to Consolidated Financial Statements and other financial and statistical information appearing elsewhere in this report and may not be indicative of future operations or earnings.

Electric revenues increased $700 million or 69% over the three-year period. This increase is largely attributable to recovery of increased fuel and purchased power costs and to a lesser extent, to rate relief, as indicated by the table below:

	Increase (decrease) from prior year *In millions of dollars*			
Electric revenues	**1981**	1980	1979	Total
Increase in base rates	**$115.2**	$ 80.8	$ 24.5	$220.5
Fuel and purchased power cost increases	**141.5**	69.9	108.8	320.2
Sales to ultimate consumers	**27.1**	1.1	20.7	48.9
Sales to other electric systems	**30.9**	23.2	23.7	77.8
Miscellaneous operating revenues	**11.8**	7.4	13.1	32.3
	$326.5	$182.4	$190.8	$699.7

Electric kilowatt-hour sales were 32.9 billion in 1981, an increase of 0.9% from 1980. However, 1981 electric kilowatt-hour sales are 1.3% below sales achieved in 1979 (see Electric and Gas Statistics—Electric Sales appearing on page 36). Details of the changes in our electric revenues and kilowatt-hour sales by customer group are highlighted in the table below:

	1981	% Increase (decrease) from prior year					
	% of electric	**1981**		1980		1979	
Class of service	revenues	Revenues	Sales	Revenues	Sales	Revenues	Sales
Residential	**28.1%**	**19.5%**	**1.5%**	13.2%	0.7%	11.9%	1.7%
Commercial	**33.6**	**24.8**	**0.6**	17.8	0.9	17.8	1.8
Industrial	**25.0**	**24.9**	**(0.6)**	10.0	(6.2)	20.9	2.3
Municipal service	**1.8**	**15.2**	**(2.6)**	13.9	(0.4)	10.8	(0.7)
Total to ultimate consumers	**88.5**	**22.9**	**0.4**	14.0	(2.1)	16.5	2.0
Other electric systems	**8.0**	**29.0**	**6.5**	27.9	(3.3)	39.9	13.0
Miscellaneous	**3.5**	**24.8**	**—**	18.4	—	48.0	—
Total	**100.0%**	**23.4%**	**0.9%**	15.1%	(2.2)%	18.7%	2.9%

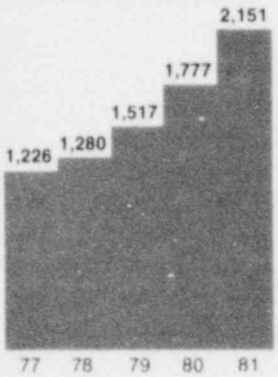
Gas revenues increased $171 million or 66% over the three-year period. As shown by the table below, this rise is primarily from increased costs of purchased gas recovered from customers through the purchased gas adjustment clause.

	Increase (decrease) from prior year *In millions of dollars*			
Gas revenues	**1981**	1980	1979	Total
Increase in base rates	**$11.0**	$ 1.2	$ 4.6	$ 16.8
Purchased gas cost increases	**4.8**	67.3	42.3	114.4
Gas sales	**31.3**	9.7	(1.4)	39.6
	$47.1	$78.2	$45.5	$170.8

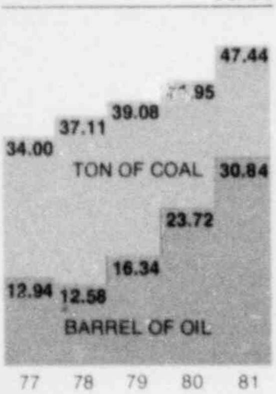
Gas sales were 109.8 million dekatherms in 1981, an 8.3% increase from 1980 and 13.6% from 1979 (see Electric and Gas Statistics—Gas Sales appearing on page 36). This increase is primarily attributable to industrial sales which increased principally as a result of boiler conversions from oil to gas. The changes in residential and commercial sales during the last three years generally follow the weather pattern, offset by customer conservation efforts. Changes in gas revenues and dekatherm sales by customer group are detailed in the table below:

Class of service	1981 % of Gas Revenues	% Increase (decrease) from prior year 1981 Revenues	1981 Sales	1980 Revenues	1980 Sales	1979 Revenues	1979 Sales
Residential	**51.6%**	**6.1%**	**1.1%**	18.6%	(1.5)%	11.3%	(5.3)%
Commercial	**23.9**	**15.3**	**10.5**	25.2	1.8	17.0	(1.3)
Industrial	**20.7**	**28.5**	**23.9**	50.3	26.5	42.7	9.5
Total to ultimate consumers	**96.2**	**12.6**	**8.6**	25.2	4.5	16.7	(1.8)
Other gas systems	**3.2**	**2.5**	**3.6**	34.4	12.4	46.0	9.2
Miscellaneous	**.6**	**21.2**	**—**	50.0	—	15.3	—
Total	**100.0%**	**12.3%**	**8.3%**	25.6%	4.9%	17.5%	(1.4)%

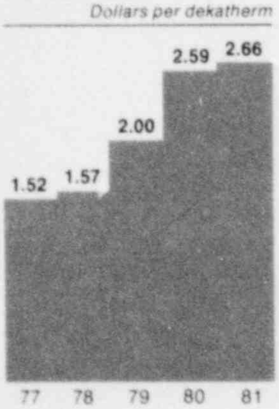
TOTAL ELECTRIC AND GAS OPERATING REVENUES
Millions of dollars



AVERAGE COST OF FUEL BURNED
Dollars



UNIT COST OF GAS PURCHASED
Dollars per dekatherm



In summary, total operating revenues increased $871 million, or 68% over the three-year period, largely representing recoveries of fuel and purchased gas costs through fuel adjustment clauses and increased rates. Through the energy 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.

On March 12, 1981, the PSC approved rate increases to provide the Company additional annual revenues of $161,286,000 (11.0%) for electric and $16,918,000 (4.1%) natural gas. These new rates became effective March 18, 1981. The PSC had approved in 1980 rate increases providing additional annual revenues of $122,577,000 (11.5%) for electric and $3,263,000 (1.0%) natural gas. The 1980 rates were effective March 7, 1980.

Further rate action, made necessary by continuing inflation, high interest rates and the need to increase cash flow, was requested on April 16, 1981 when the Company filed for an annual increase of $273.4 million, including $245.7 million (14.0%) electric and $27.7 million (5.5%) gas. In December 1981, a PSC Administrative Law Judge recommended rate increases of $209.2 million (11.4%) electric and $22.3 million (4.3%) gas or about 85% of what the Company had requested. Because of the nearly year-long regulatory process for any rate proceeding, any increase determined by the PSC will not be reflected in the Company's operations until March 1982.

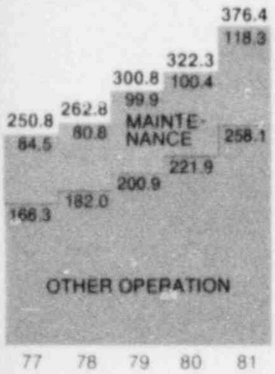
In 1981, fuel and purchased power costs continued to increase sharply, from $411 million in 1978, to $540 million in 1979, to $644 million in 1980 and to $840 million in 1981. The continued increases result primarily from higher coal, oil and purchased power costs and changes in the mix of generation resources. The Company's Nine Mile Point Nuclear Station Unit No. I was out of service for several months in 1981 and 1979 for scheduled refueling and maintenance requiring the replacement of this relatively low-cost nuclear generation with fossil fuel generation and purchased power. (See Electric and Gas Statistics—Electricity Generated and Purchased appearing on page 36.) The following table summarizes the Company's average fossil fuel and purchased power unit costs:

Average cost per:	1981	1980	1979	1978
Ton of coal burned (dollars)	**$47.44**	$41.95	$39.08	$37.11
Barrel of oil burned (dollars)	**$30.84**	$23.72	$16.34	$12.58
Kilowatt-hour purchased (mills)	**18.1**	13.6	12.1	8.8

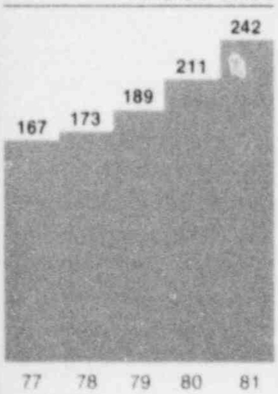
During 1981, in an effort to minimize such fuel cost increases, the Company converted its Albany Steam Station to burn natural gas as well as oil to enable utilization of lower cost fuel supplies. The cost of this conversion (about $7,500,000) is being recovered on an accelerated basis from a portion of fuel cost savings through July 1982. Fuel cost savings in excess of capital costs recovered are being passed on to customers through the fuel adjustment clause.

The total cost of gas purchased, net of re-

OTHER OPERATION AND MAINTENANCE EXPENSE
Millions of dollars



TOTAL TAXES, INCLUDING INCOME TAXES
Millions of dollars



funds from the Company's supplier, rose 6% in 1981, 41% in 1980 and 24% in 1979. These increases are primarily the result of deregulation of wellhead prices which increased the Company's cost per dekatherm purchased to $2.66 in 1981 from $2.59 in 1980, $2.00 in 1979 and $1.57 in 1978.

Other operation and maintenance expenses increased 16.8% in 1981, 7.2% in 1980 and 14.5% in 1979, as a result of increases in wages and associated benefits, higher costs charged by suppliers and increased levels of maintenance. In May 1980, the Company entered a two-year labor agreement providing for increased wages and supplementary benefits of 9.64% and 9.35% in June 1980 and 1981, respectively. The increase in other operation and maintenance expenses in 1981 and 1979 was also attributable, in part, to the refueling of Nine Mile Point Nuclear Station Unit No. I.

In July 1980, the Company placed its Oswego Steam Station Unit No. 6 in commercial operation. This oil-fired unit, of which 24% is owned by Rochester Gas and Electric Corp., was completed at a cost to Niagara Mohawk of approximately $240 million, including allowance for funds used during construction (AFC). The effect of adding this unit to our plant in service is reflected in increased depreciation expense.

Federal and foreign income taxes rose in 1981, 1980 and 1979 as a result of increased income and an increase in the amounts on which deferred taxes are provided. The increase in other taxes in these same three years is due principally to higher property taxes resulting from property additions and higher state and local gross income taxes resulting from increased revenues.

The $13.1 million increase in AFC for 1981 results from higher AFC rates (detailed in Note 1 of Notes to Consolidated Financial Statements) applied to increased overall levels of plant under construction, partially offset by the suspension of AFC associated with the Company's investment in N M Uranium, Inc. (NMU). On April 1, 1981, the Company suspended accruing AFC on the NMU investment because of the uncertainty of full recovery of the investment (see Note 3 of Notes to Consolidated Financial Statements). The impact of this suspension of AFC reduced 1981 net income by approximately $5.4 million ($.07 per share).

The Company's revenues and costs of operation over the past three years show substantial increases in several respects, due primarily to the effect of general inflation and higher fuel costs. Inflation has eroded the purchasing power of the dollar, as measured by the Consumer Price Index, to less than three-fourths of its 1978 value. The Company is especially sensitive to inflation because of the large amount of capital it must raise to finance its construction program and because its prices are regulated using a rate base that reflects the historical cost of its plant. Inflation information in Note 10 of the Notes to Consolidated Financial Statements indicates the approximate effect of inflation on certain aspects of the Company's operations and financial position.

Financial position, liquidity and capital resources

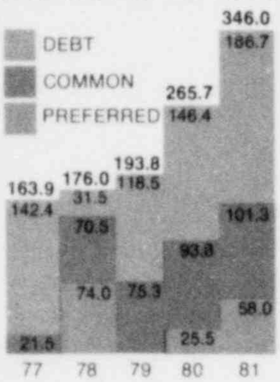
As is common in the utility industry, internal funds generated from operations are insufficient to meet the Company's capital requirements. Therefore, significant funds from external sources are required on an annual basis. External capital needs are first met through utilization of short-term borrowing arrangements, including bank lines of credit and commercial paper. These short-term borrowings are repaid through the issuance of securities, consisting of intermediate and long-term debt, preferred and preference stock and common stock.

Capital resources from internal and external sources are used to pay for the Company's construction program, working capital needs, maturing debt issues and sinking fund provisions on outstanding debt and preferred stocks. Sources and uses of funds during the past three years are reported in the Consolidated Statement of Changes in Financial Position at page 24.

The Company presently has short-term bank credit arrangements aggregating $327 million including arrangements with Oswego Facilities Trust (OFT). At December 31, 1981, $123.3 million of such arrangements were in use or being held available to support the Company's outstanding commercial paper obligations. The Company generally issues long-term debt secured by a mortgage on the Company's properties. However, in 1981, the Company continued to borrow under its unsecured revolving credit and term loan agreements and at December 31, 1981 had $86 million outstanding (of a total amount available under these agreements of $110 million). Preferred stock issues in recent years have typically been redeemable at specified dates and prices. Common stock is sold through periodic public offerings as well as under the Company's Dividend Reinvestment, Employee

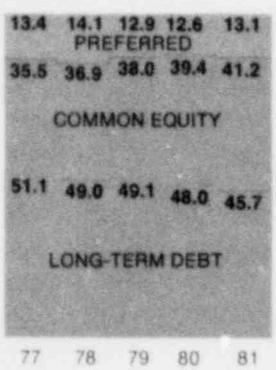
ANNUAL EXTERNAL FINANCING BY TYPE

Millions of dollars



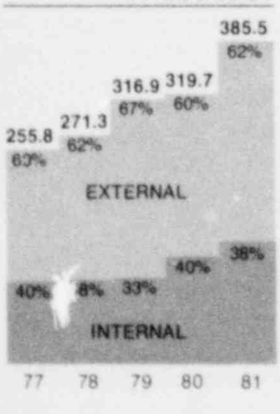
CAPITALIZATION RATIOS

Percent



SOURCE OF CAPITAL FOR CONSTRUCTION PROGRAM

Millions of dollars



Savings Fund and Employee Stock Ownership plans. At the 1981 annual meeting, the shareholders approved a 40 million share increase in the number of common shares which the Company is authorized to issue.

In addition to the $86,000,000 outstanding under the revolving credit and term loan agreements, the Company completed $339,963,000 of financing during 1981 as detailed below. Short-term debt remained at the 1980 level of $123.3 million.

First Mortgage Bonds	$113,650,000
Notes Payable	67,000,000
Preferred Stock	58,000,000
Common Stock[1]	101,313,000
	$339,963,000

(1) Includes public sale of 5 million shares at $11.50 per share and proceeds from sales through dividend reinvestment, employee savings fund and employee stock ownership plans at varying prices.

Approximately $151 million of these funds was used to pay maturing bonds and to provide for sinking fund requirements on existing obligations. Total financing for 1982 is estimated to approximate $300 million. Of this amount, requirements for maturing debt and sinking funds total approximately $16.7 million.

The Company has endeavored to strengthen its capitalization structure through the reduction of long-term debt as a percent of total capitalization. The proportion of long-term debt to total capitalization has decreased from 49.1% at the end of 1979 to 45.7% at the end of 1981 while common equity as a percent of total capitalization has increased from 38.0% at the end of 1979 to 41.2% in 1981.

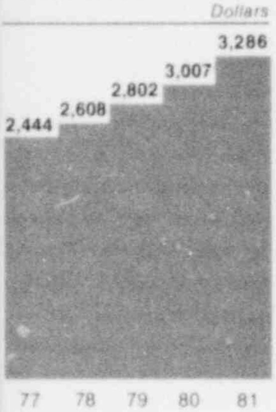
Construction and other capital requirements continue to increase. Net additions for construction and nuclear fuel, excluding financing costs, totaled $385.5 million in 1981, $319.7 million in 1980 and $316.9 million in 1979. In recent years, the largest cost component of construction programs has been the cost of new generating stations. The only new major station presently under construction is Nine Mile Point Unit No. 2, scheduled for completion in late 1986, in which the Company had invested about $546 million through December 31, 1981. Outlays associated with construction of this nuclear unit, along with other facilities requirements, are expected to increase overall construction expenditures in future years (see Notes 6 and 11 of Notes to Consolidated Financial Statements).

Financial resources provided internally from operations consist of net income, adjusted for non-cash expenses, such as depreciation, amortization of nuclear fuel and deferred income taxes, and non-cash income, such as AFC. AFC represents the financing costs of the Company's construction program and is added to the cost of construction until such time as the capital projects are completed, and is then recovered through depreciation included in rates charged to customers. As previously discussed, the Company suspended accruing AFC on its investment in NMU, based upon current regulatory restrictions on the cost of NMU uranium recovered from customers and based on currently depressed uranium market conditions. Although the investment in NMU, which approximated $84,500,000 (including inventory with a market value of $18,300,000) at December 31, 1981, is not material to the financial position of the Company, a loss could be sustained through the term of operations of this subsidiary (see Note 3 of Notes to Consolidated Financial Statements).

While financial resources from operations, as determined above, have been increasing in recent years, such increases have not kept pace with the Company's construction and other requirements, thus necessitating increasing amounts of outside financing. During 1981, the Company began funding most of its disbursement as checks are presented to the banks on which the checks are drawn. Previously these disbursements were funded on a current basis. At December 31, 1981, the amount payable on outstanding bank checks was approximately $50,000,000. The Company and other investor-owned utilities have filed testimony with the PSC to seek generic regulatory policy changes which would improve cash flow and decrease the need for outside financing. Additionally, the Company is seeking adequate overall earnings levels and cash flow improvements in its periodic rate filings. Although not significant in 1981, adoption of new tax depreciation rates prescribed under the Economic Recovery Tax Act of 1981 (ERTA), and the full normalization requirements thereunder, are expected to provide increased future cash flow.

The Company's requirement for funds may be affected by possible increases in construction costs brought on by inflation and regulatory requirements, among other factors. Continued increases in internally generated funds and their adequacy in relation to the Company's needs depend partly on the results of current and future rate cases and the extent to which increased rates can be translated into improved earnings. The cost and availa-

AVERAGE GROSS ELECTRIC UTILITY PLANT PER ELECTRIC CUSTOMER



bility of external sources of funds will be affected by the retention and maintenance of an adequate credit rating by the Company and conditions in the financial markets. Also, financial market conditions influence the timing and types of securities to be offered, repayment terms and the decision to place such offerings privately with institutional investors or publicly through underwriters. Any of these factors could have an adverse effect on the Company's ability to fully implement its intended construction and financing programs. The Company will continue to explore and utilize other methods of financing, such as the Eurodollar market, tax-exempt financing methods, leasing of equipment and similar non-traditional sources of funds. However, management believes that traditional sources of funds will provide the majority of its needs.

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 Code of Conduct which requires all employees to maintain the highest level of ethical standards and requires key management employees to formally affirm their compliance with the Code.

The financial statements have been examined by Price Waterhouse, the Company's independent accountants, in accordance with generally accepted auditing standards. As part of their examination, they made a study and evaluation of the Company's system of internal accounting control. The purpose of such study was to establish a basis for reliance thereon in determining the nature, timing and extent of other auditing procedures that were necessary for expressing an opinion as to whether the financial statements are presented fairly. Their examination resulted in the expression of their opinion which follows this report. The independent accountants' examination 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 three 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 present.

Report of independent accountants

To the Stockholders and the 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 changes in financial position present fairly the financial position of Niagara Mohawk Power Corporation and its subsidiaries at December 31, 1981 and 1980, and the results of their operations and the changes in their financial position for each of the three years in the period ended December 31, 1981, in conformity with generally accepted accounting principles consistently applied. Our examinations of these statements were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Price Waterhouse

Syracuse, New York
January 27, 1982,
except as to Note 11
which is as of
February 9, 1982

Consolidated statement of income and retained earnings

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

For the year ended December 31,	1981	1980	1979
		In thousands of dollars	
Operating revenues:			
Electric	**$1,719,933**	$1,393,467	$1,211,068
Gas	**430,785**	383,648	305,435
	2,150,718	1,777,115	1,516,503
Operating expenses:			
Operation:			
Fuel for electric generation	**582,033**	462,573	380,101
Electricity purchased	**257,788**	181,223	159,453
Gas purchased	**292,863**	276,680	196,711
Other operation expenses	**258,124**	221,879	200,917
Maintenance	**118,331**	100,470	99,857
Depreciation *(Note 2)*	**102,536**	92,210	84,212
Federal and foreign income taxes *(Note 9)*	**53,043**	43,498	34,64€
Other taxes	**214,624**	186,830	166,666
	1,879,342	1,565,363	1,322,563
Operating income	**271,376**	211,752	193,940
Other income and deductions:			
Allowance for other funds used during construction *(Note 1)*	**48,281**	38,209	39,063
Federal income tax credits *(Note 1)*	**19,548**	15,651	13,782
Other items (net)	**9,598**	5,995	524
	77,427	59,855	53,369
Income before interest charges	**348,803**	271,607	247,309
Interest charges:			
Interest on long-term debt	**131,146**	115,809	105,399
Other interest	**20,623**	13,766	4,416
Allowance for borrowed funds used during construction *(Note 1)*	**(23,609)**	(20,607)	(18,536)
	128,160	108,968	91,279
Net income	**220,643**	162,639	156,030
Dividends on preferred stock	**34,285**	29,438	27,844
Balance available for common stock	**186,358**	133,201	128,186
Dividends on common stock	**127,781**	106,967	92,136
Retained earnings for the year	**58,577**	26,234	36,050
Retained earnings at beginning of year	**430,179**	403,945	367,895
Retained earnings at end of year	**$ 488,756**	$ 430,179	$ 403,945

Average number of shares of common stock outstanding *(in thousands)*	**79,204**	71,257	63,976
Balance available per average share of common stock	**$ 2.35**	$ 1.87	$ 2.00
Dividends per average share of common stock	**$ 1.61**	$ 1.50	$ 1.44

( ) Denotes deduction.

Consolidated balance sheet

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

At December 31,	In thousands of dollars 1981	1980
ASSETS		
Utility plant, at original cost *(Notes 1 and 3)*	**$4,985,315**	$4,563,309
Less accumulated depreciation and amortization *(Note 2)*	**1,348,738**	1,232,675
Net utility plant	**3,636,577**	3,330,634
Other property and investments	**42,130**	16,451
Current assets:		
Cash, including time deposits of $500 and $1,809, respectively *(Note 4)*	**8,259**	13,829
Accounts receivable (less allowance for doubtful accounts of $2,800)	**195,957**	198,150
Materials and supplies, at average cost:		
Coal and oil for production of electricity	**149,102**	107,508
Other	**51,742**	48,175
Prepayments	**8,956**	9,187
	414,016	376,849
Deferred debits:		
Unamortized debt expense	**16,029**	14,041
Deferred recoverable energy costs	**50,477**	61,839
Other	**16,703**	9,005
	83,209	84,885
	$4,175,932	$3,808,819
CAPITALIZATION AND LIABILITIES		
Capitalization *(Note 5)*:		
Common stockholders' equity:		
Common stock	**$ 83,973**	$ 75,231
Premium on capital stock	**895,804**	802,954
Capital stock expense	**(10,599)**	(10,363)
Retained earnings	**488,756**	430,179
	1,457,934	1,298,001
Redeemable preferred stock	**254,748**	205,924
Non-redeemable preferred stock	**210,000**	210,000
Long-term debt	**1,619,369**	1,443,607
Total capitalization	**3,542,051**	3,157,532
Current liabilities:		
Short-term debt *(Note 4)*	**123,330**	123,300
Long-term debt due within one year	**9,250**	142,500
Sinking fund requirements on redeemable preferred and preference stock *(Note 5)*	**7,450**	6,950
Accounts payable	**165,354**	144,876
Payable on outstanding bank checks	**50,358**	—
Customers' deposits	**4,769**	4,952
Accrued taxes	**23,343**	27,837
Accrued interest	**36,340**	32,818
Accrued vacation pay	**18,367**	16,406
Gas supplier refunds payable to customers	**34,080**	10,436
Other	**5,814**	6,132
	478,455	516,207
Deferred credits:		
Income tax refunds *(Note 9)*	**9,943**	1,772
Mandated refunds to customers *(Note 9)*	**16,418**	25,326
Accumulated deferred Federal income taxes *(Note 9)*	**112,544**	98,918
Other	**16,521**	9,064
	155,426	135,080
Commitments and contingencies *(Note 11)*	—	—
	$4,175,932	$3,808,819

( ) Denotes deduction

Consolidated statement of changes in financial position

NIAGARA MOHAWK POWER CORPORATION AND SUBSIDIARY COMPANIES

For the year ended December 31,	1981	In thousands of dollars 1980	1979
FINANCIAL RESOURCES WERE PROVIDED BY:			
Operations:			
Net income	**$220,643**	$162,639	$156,030
Charges (credits) to income not requiring (not providing) working capital—			
Depreciation	**102,536**	92,210	84,212
Allowance for funds used during construction	**(71,890)**	(58,816)	(57,599)
Amortization of nuclear fuel	**37,427**	48,829	28,090
Provision for deferred Federal income taxes (net)	**19,734**	20,895	14,566
	308,450	265,757	225,299
Outside financing:			
Sale of common stock	**101,313**	93,823	75,266
Sale of preferred stock	**58,000**	25,500	—
Sale of mortgage bonds	**113,650**	66,350	118,500
Issuance of long-term notes payable	**67,000**	—	—
Net borrowings under revolving credit facilities *(Note 5)*	**6,000**	80,000	—
Increase in short-term debt	**30**	41,260	58,040
	345,993	306,933	251,806
Other sources:			
Deferred recoverable energy costs	**11,362**	(17,669)	(16,204)
Mandated refunds to customers *(Note 9)*	**(10,445)**	(6,758)	—
Income tax refunds	**9,943**	—	—
Other investments	**(23,349)**	—	—
Sale of uranium *(Note 3)*	**—**	13,983	35,987
(Increase) decrease in working capital other than short-term debt *(see below)*	**(74,949)**	48,346	33,660
Miscellaneous (net)	**(708)**	113	5,313
	(88,146)	38,015	58,756
Total resources provided	**$566,297**	$610,705	$535,861
FINANCIAL RESOURCES WERE USED FOR:			
Construction additions	**$439,418**	$341,237	$347,544
Nuclear fuel	**17,997**	37,266	26,986
Allowance for funds used during construction	**(71,890)**	(58,816)	(57,599)
Net additions	**385,525**	319,687	316,931
Reduction of long-term debt	**9,530**	145,387	90,000
Reduction of preferred and preference stock *(Note 5)*	**9,176**	9,226	8,950
Dividends	**162,066**	136,405	119,980
Total resources used	**$566,297**	$610,705	$535,861
(Increase) decrease in working capital other than short-term debt:			
Cash	**$ 5,570**	$ (5,302)	$ 2,259
Accounts receivable	**2,193**	(18,660)	(52,271)
Coal and oil for production of electricity	**(41,594)**	1,770	(39,046)
Other materials and supplies	**(3,567)**	(12,632)	(5,807)
Long-term debt due within one year	**(133,250)**	54,000	78,050
Accounts payable	**20,478**	26,149	31,873
Payable on outstanding bank checks	**50,358**	—	—
Accrued taxes and interest	**(972)**	4,391	5,475
Gas supplier refunds due customers	**23,644**	—	—
Other (net)	**2,191**	(1,370)	13,127
	$ (74,949)	$ 48,346	$ 33,660

Notes to consolidated financial statements

NOTE 1. Summary of Significant Accounting Policies

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

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

Utility Plant: The cost of additions to utility plant and of replacements of retirement units or property is capitalized. Cost includes direct material, labor, overhead and an allowance for funds used during construction (AFC). 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. The following table summarizes the components of Utility Plant:

At December 31,	1981 (In thousands of dollars)	%	1980
Electric plant	**$3,411,098**	**69**	$3,223,017
Nuclear fuel *(Note 3)*	**248,836**	**5**	230,780
Gas plant	**420,654**	**8**	390,237
Common plant	**71,198**	**1**	67,474
Construction work in progress	**833,529**	**17**	651,801
Total utility plant	**$4,985,315**	**100**	$4,563,309

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. As a result of rate proceedings, the Company began computing AFC at a rate which is reduced to reflect the income tax effect of the borrowed funds component of AFC for its Oswego Steam Station Unit No. 6 and Nine Mile Point Nuclear Station Unit No. 2 on December 1, 1976 and for the capitalized costs associated with its investment in NM Uranium, Inc. on July 1, 1978 (See Note 3). The AFC rates in effect during the three-year period ended December 31, 1981 were:

Period	AFC rate	Net of tax AFC rate
January 1, 1979 through October 31, 1979	9.25%	7.50%
November 1, 1979 through December 31, 1979	9.60	7.75
January 1, 1980 through February 29, 1980	10.00	7.90
March 1, 1980 through June 30, 1980	11.00	8.40
July 1, 1980 through September 30, 1980	10.00	8.20
October 1, 1980 through December 31, 1980	10.25	8.30
January 1, 1981 through March 31, 1981	11.10	8.75
April 1, 1981 through June 30, 1981	11.50	9.30
July 1, 1981 through September 30, 1981	11.75	9.60
October 1, 1981 through December 31, 1981	11.85	9.75

AFC is segregated into its two components, borrowed funds (which are reflected in the Interest Charges section of the income statement) and other funds (which are reflected in the Other Income and Deductions section of the income statement).

Depreciation and Nuclear Generating Plant Decommissioning Costs: For accounting purposes, depreciation is computed on the straight-line basis using the average service lives by classes of depreciable property. For Federal income tax purposes, the Company computes depreciation using accelerated methods and shorter allowable depreciable lives.

Estimated decommissioning costs (costs to take the plant out of service in the future) of the Company's Nine Mile Point Nuclear Station Unit No. 1 are recovered in rates and charged to operations through depreciation charges. From July 1978 through March 1981, the annual nuclear plant depreciation rate reflected an estimated service life of the plant of 30 years and an allowance for decommissioning costs at the annual rate of 1% of the plant's cost. Beginning April 1981, as a result of a PSC rate decision, the 1% decommissioning cost allowance was replaced by a gradually increasing annual allowance set initially at $2,476,000 for the twelve months ending March 1982. There is no assurance that the revenues provided by the decommissioning allowance will ultimately aggregate a sufficient amount to decommission the plant. The Company believes that decommissioning costs, if higher than currently provided, will ultimately be recovered in the rate process, although no such assurance can be given.

Amortization of Nuclear Fuel: The cost of nuclear fuel, plus a provision for disposal cost, is charged to operating expenses on the basis of the quantity of heat produced for the generation of electric energy. These costs are charged to customers through base rates or through the fuel adjustment clause. Until June 1979, the Company had assumed that spent nuclear fuel would be disposed of by reprocessing and that uranium recovered through such reprocessing would have value. At that time, because of proposed Federal action rendering the viability of disposal by means of reprocessing questionable, the Company abandoned its reprocessing plans in favor of a permanent storage assumption. The Company believes that nuclear fuel disposal costs, which may be higher than presently provided for, will continue to be recovered in the rate process, although no such assurance can be given.

Revenues: Revenues are based on cycle billings rendered to certain customers monthly and others bi-monthly. The Company does not accrue revenues for energy consumed and not billed at the end of any fiscal period. 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 changes, a portion of deferred energy costs would not be recovered under the normal operation of the electric adjustment clause. However, the Company has been permitted to amortize and bill such portions to customers, through the electric adjustment clause, over 36 months from the effective date of each change.

Federal Income Taxes: The general policy, in accordance with PSC requirements, is to flow through the tax effect of timing differences between book and taxable income, that is, to record only income taxes currently payable. However, deferred taxes are provided on benefits realized from the class life system of depreciation permitted under the Revenue Act of 1971 (shorter depreciable lives, repair allowance and cost or removal), on deferred energy and purchased gas costs, on nuclear fuel disposal costs, nuclear generating plant decommissioning costs and on certain other items, as approved by the PSC (see Notes 3 and 9). No deferred taxes are presently provided for other depreciation differences (including accelerated methods of depreciation), except under necessity certificates in prior years, or for other items (such as taxes, a portion of AFC, pensions and certain other employee benefits) which are deductions currently for tax purposes but capitalized for accounting purposes.

The benefits resulting from an increase in the investment tax credit from 4% to 10% and from the change in the limitation on the amount of credit which may be claimed in any year have been deferred and are being amortized over the book life of the property which gives rise to such credits. One-half of the 4% investment tax credits realized have been allocated to Other Income and Deductions, consistent with PSC directives. For the projects specified in the AFC section above, the imputed tax benefit of the borrowed funds component of AFC has been credited to Other Income and Deductions.

As directed by the PSC, the Company deferred a portion of the increase in Federal income taxes for the year 1978 associated with the tax gain on the sale of a portion of its interest in the Roseton Steam Station. The PSC authorized the Company to recover such increased taxes through its electric adjustment clause over a one-year period commencing July 1978.

Oswego Steam Station Unit No. 6 attained in-service status for Federal income tax purposes in 1979 and generated investment tax credits amounting to $14,400,000. During 1979, the year in which these credits would normally be recognized under the Company's previously described Federal Income Tax accounting policies, the Company deferred the full amount of these credits, subject to the final decision of the PSC in a then pending rate case where the treatment of such credits was at issue. The effect of such deferral on the 1979 results of operations was to increase tax expense and thereby decrease income by $6,500,000 ($.10 per share). In accordance with a 1980 PSC Order and consistent with the Company's 1979 deferral, the deferred investment tax credits attributable to the 4% portion are being amortized over three years and the additional 6% portion is being amortized over the book life of the plant.

During the year, the Company adopted the provisions of the Economic Recovery Tax Act of 1981 (ERTA). The most significant provisions of ERTA, as it affects the Company's Federal income tax policy, are a shortening of tax depreciable lives through use of the Accelerated Cost Recovery System (ACRS) and full normalization of book and tax depreciation timing differences and investment tax credits for 1981 property additions. Included in ERTA were certain transition rules which allowed a delay in adopting mandated normalizaton requirements for financial accounting purposes until the first rate order subsequent to enactment of ERTA. However, the Company has deferred the tax benefits associated with the difference between depreciation provided under the previously allowed class life system and ACRS. The deferral of such benefits, which are not significant, is consistent with a Statement of Policy issued by the PSC.

Amortization of Debt Issue Costs: The premium or discount on long-term debt issues is amortized ratably over the lives of the issues.

Pension Plans: The cost of pension plans is based upon current costs, amortization of unfunded past service benefits over periods ranging from 15 to 40 years and amortization over 15 years of unfunded past service benefits arising from plan amendments. The Company's policy is to fund pension costs accrued.

NOTE 2. Depreciation

The total provision for depreciation, including amounts charged to clearing accounts, was $104,084,000 for 1981, $93,848,000 for 1980 and $86,178,000 for 1979. The percentage relationship between the total provision for depreciation and average depreciable property was 2.8% in 1981 and 2.7% in 1980 and 1979. The Company makes depreciation studies on a continuing basis and, when considered appropriate, adjusts the rates of its various classes of depreciable property. Such adjustments are subject to PSC approval.

NOTE 3. N M Uranium, Inc.

During 1976, through a wholly-owned subsidiary, N M Uranium, Inc. (NMU), the Company purchased a 50 percent undivided interest in uranium deposits and associated mining equipment to be held by a jointly-owned mining venture. The venture is an operating arrangement whereby the Company pays its share of the capital and operating costs and in turn receives its proportionate share of production. Although acquisition of this interest was made primarily to provide a more assured future supply of nuclear fuel for the Nine Mile Point Nuclear Station Units No. 1 and No. 2, the Company has previously sold a portion of the output to reduce net assets. During 1981, the Company did not sell any uranium produced by NMU while in 1980 such sales totaled approximately $14,000,000. The investment in the subsidiary, which includes costs incurred since acquisition and AFC accrued through March 31, 1981, has been reduced by the proceeds from the sale of uranium, net of tax and is included in the consolidated financial statements as part of the nuclear fuel component of utility plant (See Note 1 of Notes to Consolidated Financial Statements). Such investment (including inventory with a market value of approximately $18,300,000 at December 31, 1981 and $6,100,000 at December 31, 1980) totaled $84,500,000 at December 31, 1981 and $73,800,000 at December 31, 1980.

On September 8, 1978, the PSC issued an order approving the Company's investment in NMU, its guaranty of certain NMU notes and permitting, with prior approval, such subsequent advances as may be necessary to finance the uranium project. Further, effective July 1, 1978, all benefits associated with NMU accounting-tax timing differences have been deferred. The approval was subject to the condition that rates which the PSC will approve in the future will reflect the cost of NMU uranium at the lower of cost or the market price. Subject to PSC approval, the comparison of cost to market will be on an aggregate basis over the life of the project.

Recently, because of unsettled conditions in the uranium industry, the market price of uranium has been below levels anticipated by the Company at the time of its investment. The market price of uranium has fallen to $23.50 per lb. at December 31, 1981 from $27.00 per lb. at December 31, 1980 and from approximately $43.00 per lb. during 1979. Management is continually evaluating the status of this mining operation to assure maximum recovery of the Company's investment. However, due to regulatory restrictions on the extent to which the costs of uranium produced by this mining operation will be allowed in future rates and considering the current market price level, a substantial portion of the Company's investment may not be recoverable. Accordingly, the Company suspended accruing AFC on this investment as of April 1, 1981. Due to the uncertainty of future uranium market prices and operating costs over the remaining productive life of the mine and of the period of utilization of the mine's output (through 1990) the potential loss, if any, cannot be reasonably estimated.

NOTE 4. Short-Term Debt and Compensating Balances

At December 31, 1981, the Company had available $302,250,000 of bank credit arrangements consisting of a $70,000,000 contractual commitment with several banks under a Credit Agreement, lines of credit of $107,250,000, and a Bankers Acceptance Facility Agreement of $125,000,000. All of these arrangements are renewable on an annual basis. The Credit Agreement and certain of the lines of credit require the Company to maintain compensating balances which are averaged over time. Cash representing compensating balance requirements was not significant at December 31, 1981. The Company has elected to pay fees in lieu of maintaining compensation balances on its other lines of credit. The Bankers Acceptance Facility Agreement, which is used to finance the fuel oil inventory for one of the Company's generating stations, provides for the payment of fees only upon the issuance of each acceptance.

In March 1979, the Company entered into arrangements with Oswego Facilities Trust (OFT) providing for OFT to finance the acquisition of a fuel oil storage terminal at Oswego, New York and for construction of certain railroad loading and unloading facilities associated with the terminal. OFT has a $25,000,000 Letter of Credit Facility and Revolving Credit Agreement which are used to support its commercial paper obligations. The Company is obligated to make certain payments for its use of these facilities and to purchase, or otherwise arrange for, the disposition of the facilities upon the termination of the Trust. The Letter of Credit Facility and Revolving Credit Agreement of OFT require payment of fees which are based upon the amount of commercial paper outstanding.

The following table summarizes additional information applicable to short-term debt:

	In thousands of dollars 1981	1980
At December 31:		
Short-term debt:		
Notes payable	**$ —**	$ 26,000
Commercial paper, including Oswego Facilities Trust	**73,330**	57,300
Bankers Acceptances	**50,000**	40,000
	$123,330	$123,300
Weighted average interest rate *(1)*	**13.27%**	17.53%
For year ended December 31:		
Daily average outstanding	**$116,230**	$ 93,327
Daily weighted average interest rate *(1)*	**16.29%**	13.78%
Maximum amount outstanding	**$203,430**	$175,660

(1) Excluding compensating balances and fees.

NOTE 5. Capitalization

CAPITAL STOCK

The following table summarizes the shares of capital stock authorized, issued and outstanding:

December 31,	1981	1980	1979
Common stock, $1 par value: Authorized	**125,000,000(a)**	85,000,000	85,000,000
Issued and outstanding	**83,973,252**	75,231,144	67,952,043
Preferred stock, $100 par value: Authorized	**3,400,000**	3,400,000	3,400,000
Issued and outstanding	**3,199,980**	2,985,240	3,026,000
Preferred stock, $25 par value: Authorized	**9,600,000**	9,600,000	9,600,000
Issued and outstanding	**5,008,000**	3,754,000	2,800,000
Preference stock, $25 par value: Authorized	**4,000,000**	4,000,000	4,000,000
Issued and outstanding	**1,080,000**	1,220,000	1,360,000

(a) In May 1981, an increase of 40 million shares in the authorized shares of common stock was approved by shareholders.

The table below summarizes changes in capital accounts for 1979, 1980 and 1981:

	Common stock ($1 par value)		Non-redeemable preferred stock ($100 par value)		Redeemable preferred stock ($100 par value)		Redeemable preferred stock ($25 par value)		Capital stock premium and expense (net)
	Shares	Amount*	Shares	Amount*	Shares	Amount*	Shares	Amount*	Amount*
Balance January 1, 1979:	62,180,277	$62,180	2,100,000	$210,000	964,000	$96,400	4,160,000	$104,000	$635,901
Sales in 1979	3,500,000	3,500							41,154
Issued to benefit plans in 1979	2,271,766	2,272							28,198
Redemptions					(38,000)	(3,800)			575
Balance December, 31, 1979:	67,952,043	67,952	2,100,000	210,000	926,000	92,600	4,160,000	104,000	705,828
Sales in 1980	4,000,000	4,000					1,020,000	25,500	50,134
Issued to benefit plans in 1980	3,279,101	3,279							35,998
Redemptions					(40,760)	(4,076)	(206,000)	(5,150)	631
Balance December 31, 1980:	75,231,144	75,231	2,100,000	210,000	885,240	88,524	4,974,000	124,350	792,591
Sales in 1981	5,000,000	5,000			250,000	25,000	1,320,000	33,000	51,706
Issued to benefit plans in 1981	3,742,108	3,742							40,049
Redemptions					(35,260)	(3,526)	(206,000)	(5,150)	859
Balance December 31, 1981	83,973,252	$83,973	2,100,000	$210,000	1,099,980	$109,998**	6,088,000	$152,200**	$885,205

*In thousands of dollars.

**Including sinking fund requirements due within one year.

NON-REDEEMABLE PREFERRED STOCK (Optionally Redeemable)

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

At December 31,	1981	1980	1979	Redemption price per share (Before adding accumulated dividends) December 31, 1981	Eventual minimum
	In thousands of dollars				
Preferred $100 par value:					
3.40% Series; 200,000 shares	**$ 20,000**	$ 20,000	$ 20,000	**$103.50**	$103.50
3.60% Series; 350,000 shares	**35,000**	35,000	35,000	**104.85**	104.85
3.90% Series; 240,000 shares	**24,000**	24,000	24,000	**106.00**	106.00
4.10% Series; 210,000 shares	**21,000**	21,000	21,000	**102.00**	102.00
4.85% Series; 250,000 shares	**25,000**	25,000	25,000	**102.00**	102.00
5.25% Series; 200,000 shares	**20,000**	20,000	20,000	**102.00**	102.00
6.10% Series; 250,000 shares	**25,000**	25,000	25,000	**103.00**	101.00
7.72% Series; 400,000 shares	**40,000**	40,000	40,000	**107.37**	102.36
	$210,000	$210,000	$210,000		

MANDATORILY REDEEMABLE PREFERRED STOCK

The Company has certain issues of preferred and preference stock which provide for mandatory and optional redemption as follows:

At December 31,	1981	1980	1979	Redemption price per share (Before adding accumulated dividends) December 31, 1981	Eventual minimum
	In thousands of dollars				
Preferred $100 par value:					
7.45% Series; 510,000, 528,000 and 546,000 shares	**$ 51,000**	$ 52,800	$ 54,600	**$105.53**	$100.00
10.60% Series; 339,980, 357,240 and 380,000 shares	**33,998**	35,724	38,000	**110.60**	102.65
12.75% Series; 250,000 shares	**25,000**	—	—	(a)	(a)
Preferred $25 par value:					
8.375% Series; 1,600,000 shares	**40,000**	40,000	40,000	**26.76**	25.00
9.75% Series; 1,068,000, 1,134,000 and 1,200,000 shares	**26,700**	28,350	30,000	**26.80**	25.00
9.75% Series (second); 1,020,000 shares	**25,500**	25,500	—	(b)	25.00
12.25% Series; 700,000 shares	**17,500**	—	—	**28.06**	25.00
12.50% Series; 620,000 shares	**15,500**	—	—	**28.13**	25.00
Preference $25 par value:					
7.75% Series; 1,080,000, 1,220,000 and 1,360,000 shares	**27,000**	30,500	34,000	**25.83**	25.00
	262,198	212,874	196,600		
Less sinking fund requirements	**7,450**	6,950	6,950		
	$254,748	$205,924	$189,650		

(a) Entire issue to be redeemed at par value of $100 per share June 30, 1991.
(b) Not redeemable until April 1, 1983.

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 and 300,000 shares of the 9.75% series). The option to redeem additional amounts is not cumulative.

The Company's five-year mandatory sinking fund redemption requirements for preferred and preference stock are as follows:

	No. of shares	Commencing	1982	1983	1984	1985	1986
			In thousands of dollars				
Preferred $100 par value:							
7.45% Series	18,000	6/30/77	$1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800
10.60% Series	20,000	3/31/80	(a)	1,998(a)	2,000	2,000	2,000
12.75% Series	250,000	6/30/91	—	—	—	—	—
Preferred $25 par value:							
8.375% Series	100,000	4/1/83	—	2,500	2,500	2,500	2,500
9.75% Series	66,000	10/1/80	1,650	1,650	1,650	1,650	1,650
9.75% Series (second)	204,000	4/1/86	—	—	—	—	5,100
12.25% Series	43,060	3/31/87	—	—	—	—	—
12.50% Series	38,139	3/31/87	—	—	—	—	—
Preference $25 par value:							
7.75% Series	160,000(b)	9/30/80	4,000	4,000	6,000	13,000	—
			$7,450	$11,948	$13,950	$20,950	$13,050

(a) Requirements for 1982 and a portion of 1983 requirements have been met by advance purchases.
(b) Increases to 240,000 shares at September 30, 1984; the balance of the issue is to be redeemed September 30, 1985.

LONG-TERM DEBT

Long-term debt and long-term debt due within one year consisted of the following:

At December 31,	1981 (In thousands of dollars)	1980
First Mortgage Bonds:		
12.6% Series due October 1, 1981	$ —	$ 125,000
3⅜% Series due December 1, 1981	—	15,000
3½% Series due February 1, 1983	25,000	25,000
3¼% Series due October 1, 1983	40,000	40,000
3⅛% Series due August 1, 1984	25,000	25,000
10⅝% Series due September 1, 1985	47,000	47,000
3⅝% Series due May 1, 1986	30,000	30,000
4⅞% Series due September 1, 1987	50,000	50,000
3⅞% Series due June 1, 1988	50,000	50,000
14⅞% Series due August 11, 1988	50,000	—
4¾% Series due April 1, 1990	50,000	50,000
15% Series due March 1, 1991	50,000	—
4½% Series due November 1, 1991	40,000	40,000
4⅝% Series due December 1, 1994	40,000	40,000
5⅞% Series due November 1, 1996	45,000	45,000
6¼% Series due August 1, 1997	40,000	40,000
6½% Series due August 1, 1998	60,000	60,000
9⅛% Series due December 1, 1999	75,000	75,000
12.95% Series due October 1, 2000	80,000	66,350
7⅜% Series due February 1, 2001	65,000	65,000
7⅝% Series due February 1, 2002	80,000	80,000
7¾% Series due August 1, 2002	80,000	80,000
8¼% Series due December 1, 2003	80,000	80,000
9½% Series due December 1, 2003	50,000	50,000
9.95% Series due September 1, 2004	100,000	100,000
10.2% Series due March 1, 2005	40,833	41,113
8.35% Series due August 1, 2007	75,000	75,000
8⅝% Series due December 1, 2007	50,000	50,000
Paul Smith's Electric Light & Power & Railroad Company First Mortgage Bonds:		
5½% Series due May 1, 1985	450	450
Promissory Notes:		
8% Series A due June 1, 2004	46,600	46,600
Notes Payable:		
17% Eurodollar Guaranteed Notes due September 15, 1989	50,000	—
18% Adjustable London Interbank Offered Rate due September 15, 1989	17,000	—
Prime rate plus ½% (not to exceed 7½%) due in equal quarterly installments through April 1, 1984	6,250	8,750
Revolving Credit and Term Loan Agreements	80,000	80,000
Revolving Credit Notes, floating prime rate	6,000	—
Unamortized Premium	4,486	5,844
TOTAL LONG-TERM DEBT	1,628,619	1,586,107
Less long-term debt due within one year	9,250	142,500
	$1,619,369	$1,443,607

Certain of the Company's Mortgage Bonds provide for a mandatory sinking fund for annual redemption. The Company's five-year mandatory sinking fund redemption requirements for Mortgage Bonds are as follows:

	Principal amount	Commencing	1982 (In thousands of dollars)	1983	1984	1985	1986
Mortgage bonds:							
10.20% Series due March 1, 2005	$1,500	3/1/78	$ (a)	$ 1,333(a)	$ 1,500	$ 1,500	$ 1,500
8.35% Series due August 1, 2007	750	8/1/82	750	750	750	750	750
8⅝% Series due December 1, 2007	2,000	12/1/83	—	2,000	2,000	2,000	2,000
9.95% Series due September 1, 2004	5,000	9/1/85	—	—	—	5,000	5,000
14⅞% Series due August 11, 1988	16,000(b)	8/11/86	—	—	—	—	16,000
12.95% Series due October 1, 2000	5,333	9/30/86	—	—	—	—	5,333
9½% Series due December 1, 2003	2,941	12/1/87	—	—	—	—	—
			$ 750	$ 4,083	$ 4,250	$ 9,250	$30,583

(a) Requirements for 1982 and a portion of 1983 requirements have been met by advance purchases.
(b) Increases to $17,000,000 at August 11, 1987.

The remaining series of mortgage bonds provide for a debt retirement fund whereby payment requirements may be made in lieu of cash, by the certification of additional property, the waiver of additional bonds or the retirement of outstanding bonds. The 1981 requirements for these series were satisfied by the certification of additional property. The Company anticipates that the 1982 requirements for these series will be satisfied by other than payment in cash.

Total sinking and debt retirement fund requirements of mortgage bonds aggregated $10,400,000 for the year ended December 31, 1981 and based upon the mortgage bonds then outstanding, are $9,500,000, $12,833,000, $13,000,000, $18,000,000 and $39,333,000 for the years 1982 through 1986, respectively.

Notes Payable include $50,000,000 Eurodollar Guaranteed Notes issued by the Company's subsidiary Niagara Mohawk Finance, N.V. and guaranteed by Credit Lyonnais. Annual bank guarantee and support fees totaling ½% of the notes outstanding are paid by the subsidiary. In connection with the formation and capitalization of this subsidiary, the Company also issued a $17,000,000 note payable which bears interest at the London Interbank Offered Rate, currently set at 18% through March 15, 1982.

The Company has Revolving Credit and Term Loan Agreements with seven banks aggregating $90 million. Each agreement provides for borrowings on a revolving credit basis during the first three years with the option to convert borrowings to a term basis for the last four years. Amounts converted to term loans are payable in equal installments during the remaining term of the agreements. There are no penalties for early termination or prepayment of these loans. The Company pays fees in lieu of maintaining compensating balances for the unused portion of these credit arrangements. Interest on domestic borrowings during the revolving credit period approximates the floating prime rate, or under a Eurodollar option, ½% above the London Interbank Offered Rate.

In 1981, the Company entered into agreements with the New York State Energy Research and Development Authority and a group of four commercial banks under which the Company may borrow up to $20 million on notes maturing no later than July 1984, to finance a portion of its hydro-electric construction program. The Company pays fees in lieu of compensating balances for the unused portion of this facility. Borrowings under these agreements, which aggregated $6,000,000 at December 31, 1981, are unsecured and bear interest at the floating prime rate.

NOTE 6. Jointly-Owned Generating Facilities

The following table reflects the Company's share of jointly-owned generating facilities at December 31, 1981. The Company is required to provide financing for the unit in process of construction and for any additions to the units in service. The Company's share of expenses associated with the Roseton units and Oswego Steam Station Unit No. 6 are included in the appropriate operating expenses in the consolidated statement of income.

		In thousands of dollars		
	Percentage ownership	Utility plant	Accumulated depreciation	Construction work in progress
Roseton Steam Station Units No. 1 and 2 *(a)*	30	$101,972	$19,878	$ 227
Oswego Steam Station Unit No. 6	76	249,161	10,791	3,624
Nine Mile Point Nuclear Station Unit No. 2 *(b) (c)*	41	—	—	546,414

(a) Central Hudson Gas and Electric Corporation, the operator of the plant, is obligated to acquire an additional ⅛ of the Company's original 40% interest in this unit in 1982.

(b) See Note 11.

(c) Excludes amounts spent for nuclear fuel.

NOTE 7. Pension Plans

The Company and its subsidiaries have non-contributory pension plans covering substantially all their employees. The total pension cost was $34,100,000 for 1981, $32,100,000 for 1980 and $28,900,000 for 1979 (of which $9,300,000 for 1981, $8,500,000 for 1980 and $6,800,000 for 1979 was included in construction costs).

Studies indicate that the accumulated plan benefits, as determined by consulting actuaries, and plan net assets for the Company's plans at December 31, 1981 and 1980 are as follows:

	In thousands of dollars	
	1981	1980
Actuarial present value of accumulated benefits:		
Vested	**$270,000**	$242,000
Non-vested	**16,000**	14,000
Total	**$286,000**	$256,000
Net assets available for plan benefits	**$265,000**	$250,000

The weighted average assumed rate of return used in determining the actuarial present value of accumulated plan benefits was 7% in each year.

The above table summarizes accumulated plan benefits attributable to employee wage levels and service rendered through December 31, 1981 and 1980. These amounts do not take into consideration expected future service and the associated actuarial assumptions which are considered in funding the Company's ongoing pension plans.

NOTE 8. Information Regarding the Electric and Gas Businesses

The Company is engaged in the electric and natural gas utility businesses. Certain information regarding these segments is set forth in the following table. General corporate expenses, property common to both segments and depreciation of such common property have been allocated to the segments in accordance with practice established for regulatory purposes. Identifiable assets include net utility plant, materials and supplies and deferred recoverable energy costs. Corporate assets consist of other property and investments, cash, accounts receivable, prepayments, unamortized debt expense and other deferred debits.

	In thousands of dollars		
	1981	1980	1979
Operating revenues:			
Electric	**$1,719,933**	$1,393,467	$1,211,068
Gas	**430,785**	383,648	305,435
Total	**$2,150,718**	$1,777,115	$1,516,503
Operating income before taxes:			
Electric	**$ 288,990**	$ 235,811	$ 200,718
Gas	**35,429**	19,439	27,868
Total	**$ 324,419**	$ 255,250	$ 228,586
Pretax operating income, including AFC:			
Electric	**$ 360,580**	$ 294,039	$ 257,954
Gas	**35,729**	20,027	28,231
Total	**396,309**	314,066	286,185
Income taxes	**53,043**	43,498	34,646
Other income and deductions	**29,146**	21,646	14,306
Interest charges	**151,769**	129,575	109,815
Net income	**$ 220,643**	$ 162,639	$ 156,030
Depreciation:			
Electric	**$ 91,571**	$ 82,188	$ 74,957
Gas	**10,965**	10,022	9,255
Total	**$ 102,536**	$ 92,210	$ 84,212
Construction expenditures (including nuclear fuel):			
Electric	**$ 424,596**	$ 347,182	$ 351,972
Gas	**32,819**	31,321	22,558
Total	**$ 457,415**	$ 378,503	$ 374,530
Identifiable assets:			
Electric	**$3,517,290**	$3,203,737	$2,981,005
Gas	**370,608**	344,419	315,951
Total	**3,887,898**	3,548,156	3,296,956
Corporate assets	**288,034**	260,663	231,981
Total assets	**$4,175,932**	$3,808,819	$3,528,937

NOTE 9. Federal and Foreign Income Taxes

Current Federal Tax Expense: The current Federal income tax expense for 1979 includes credits of $2,600,000 for investment tax credit generated in 1979 and carried back to 1978.

Income Tax Refunds: In 1974, 1975 and 1978, the Company received refunds resulting primarily from the adoption of the "guideline" method of depreciation. These refunds, including interest net of tax, less principally amounts representing prior tax deficiencies paid, were recorded in Deferred Credits and totaled approximately $21,600,000 at December 31, 1979. In February 1980, the PSC ordered the flow-through to customers of this amount (Electric—$13,300,000, Gas—$8,300,000). The entire amount, together with other mandated items and related tax effects, was recorded in Mandated Refunds to Customers and, commencing in March 1980, is being refunded to electric customers over three years and to gas customers over two years.

In September 1981, the Company received a refund of Federal income tax, including interest thereon, amounting to approximately $13,600,000. The refund was in settlement of a refund claim filed with the Internal Revenue Service in February 1973 relating to a deficiency assessment paid by the Company in October 1972 as a result of an audit of the tax years 1957 through 1962. The deficiency assessment arose as a result of the disallowance of certain deductions taken by the Company for the loss of water rights at Niagara Falls terminated in connection with the redevelopment of Niagara power by the Power Authority of the State of New York. In accordance with a PSC Order issued in August 1981, the Company is required to notify the PSC of certain tax refunds and propose the methodology by which such refunds will be flowed through to customers or reasons why such flow-through should not be made. The Company has notified the PSC of this refund and the reasons why a distribution of this refund to customers should not be made. Pending a determination as to the ultimate disposition of this refund by the PSC, the Company has recorded such amount, net of Federal income taxes on the interest portion of the refund, in Deferred Credits: Income tax refunds. The Company is unable to predict the ultimate disposition of this refund.

Investment Tax Credits: The Company deferred the net benefit of investment tax credits of approximately $21,500,000 ($.27 per share), $8,000,000 ($.11 per share) and $15,100,000 ($.24 per share) for the years ended December 31, 1981, 1980 and 1979, respectively, in accordance with the general policy as stated in Note 1.

The Company has unused credits at December 31, 1981 of approximately $11,600,000 which may be utilized to reduce current tax expense in subsequent years. Such credits, if unused, expire in 1996.

Components of income before income taxes:

	In thousands of dollars		
	1981	1980	1979
United States	**$247,374**	$185,026	$172,215
Foreign	**14,339**	10,769	9,527
Consolidating eliminations	**(7,411)**	(5,309)	(4,848)
Income before income taxes	**$254,302**	$190,486	$176,894

Summary Analysis:

	In thousands of dollars		
	1981	1980	1979
Components of Federal and foreign income taxes:			
Current tax expense: Federal	**$ 6,996**	$ 1,492	$ 1,618
Foreign	**6,765**	5,460	4,680
	13,761	6,952	6,298
Deferred Federal income tax expense	**39,282**	36,546	28,348
Income taxes included in Operating Expenses	**53,043**	43,498	34,646
Federal income tax credits included in Other Income and Deductions	**(19,548)**	(15,651)	(13,782)
Total	**$33,495**	$27,847	$20,864
Timing differences resulting in deferred Federal income taxes *(Note 1):*			
Depreciation	**$12,533**	$12,834	$ 8,227
Cost of removal of property	**193**	(127)	(1,010)
Investment tax credit	**21,501**	7,985	15,149
Recoverable energy and purchased gas costs	**(1,811)**	7,236	(239)
Necessity certificates	**(700)**	(700)	(700)
Nuclear fuel disposal cost	**(12,224)**	(12,383)	(5,388)
Sales and loans of nuclear fuel	**(83)**	(1,304)	(5,678)
Sterling abandonment	**2,018**	5,195	—
Gain on Roseton sale	**—**	—	3,962
Other	**(1,693)**	2,159	243
Deferred Federal income taxes (net)	**$19,734**	$20,895	$14,566
Reconciliation between Federal and foreign income taxes and the tax computed at prevailing U.S. statutory rate on income before income taxes:			
Computed tax	**$116,904**	$87,624	$81,372
Reduction attributable to flow-through of certain tax adjustments:			
Depreciation	**9,422**	8,616	13,329
Allowance for funds used during construction	**33,069**	27,056	26,496
Taxes, pensions and employee benefits capitalized for accounting purposes	**12,515**	11,429	10,202
Real estate taxes on an assessment date basis	**3,086**	3,458	2,178
Investment tax credit	**12,354**	1,289	2,775
Deferred taxes provided at other than the statutory rate	**7,424**	743	6,752
Other	**5,539**	7,186	(1,224)
	83,409	59,777	60,508
Federal and foreign income taxes	**$33,495**	$27,847	$20,864

NOTE 10. Supplementary Information to Disclose the Effects of Changing Prices (Unaudited)

Continued inflation, resulting in a decline in the purchasing power of the dollar, is one of our nation's principal concerns. Inflation has an enormous impact on all sectors of the economy, including consumers, wage earners, investors, government and industry.

The Company's consolidated financial statements are based on historical events and transactions when the purchasing power of the dollar was substantially different than at the present. The effects of inflation on most utilities, including Niagara Mohawk, are most significant in the areas of depreciation and utility plant and amounts owed on borrowed funds.

In recognition of the fact that users of financial reports need to have an understanding of the effects of inflation on a business enterprise, the following supplementary information is supplied for the purpose of providing certain information about the effects of both general inflation and changes in specific prices. It should be viewed as an estimate of the approximate effect of inflation, rather than as a precise measure.

Statement of income from continuing operations adjusted for changing prices for the year ended December 31, 1981

	In thousands of dollars		
	Conventional historical cost	Constant dollar average 1981 dollars	Current cost average 1981 dollars
Operating revenues	$2,150,718	$2,150,718	$2,150,718
Fuel for electric generation	582,033	582,033	582,033
Electricity purchased	257,788	257,788	257,788
Gas purchased	292,863	292,863	292,863
Depreciation	102,536	248,821	304,038
Other operating and maintenance expenses	591,079	591,079	591,079
Federal and foreign income taxes	53,043	53,043	53,043
Interest charges	128,160	128,160	128,160
Other income and deductions—net	(77,427)	(77,427)	(77,427)
	1,930,075	2,076,360	2,131,577
Income (loss) from continuing operations (excluding reduction to net recoverable cost)	$ 220,643	$ 74,358*	$ 19,141
Increase in specific prices (current cost) of utility plant held during year**			$ 684,866
Increase (reduction) to net recoverable cost		$ (183,291)	158,123
Effect of increase in general price level			(971,063)
Excess of increase in general price level over increase in specific prices after increase to net recoverable cost			(128,074)
Gain from decline in purchasing power of net amounts owed		172,769	172,769
Net		$ (10,522)	$ 44,695

*Including the reduction to net recoverable cost, the income (loss) from continuing operations on a constant dollar basis would have been $(108,933) for 1981.

**At December 31, 1981, current cost of utility plant, net of accumulated depreciation, was $7,767,561 while historical cost or net cost recoverable through depreciation was $3,774,127.

Constant dollar amounts attempt to adjust for general inflation and represent historical costs stated in terms of dollars of equal purchasing power, as measured by the Consumer Price Index for all Urban Consumers. Current cost amounts reflect the changes in specific prices of plant from the date the plant was acquired to the present and differ from constant dollar amounts to the extent that specific prices have increased more or less rapidly than prices in general.

The current cost of utility plant net of accumulated depreciation and amortization, represents the estimated cost of replacing existing plant assets in kind. Since existing utility plant is not expected to be replaced precisely in kind due to technological changes, current cost does not necessarily represent the replacement cost of the Company's utility plant. The portion of the accumulated amortization relating to disposal costs of nuclear fuel was not used in the calculation of current costs but rather reclassified to a monetary liability. In most cases, current costs were determined by indexing surviving plant dollars by the Handy-Whitman Index of Public Utility Construction Costs. However, when an account could not be indexed by Handy-Whitman, other appropriate indices were used. The current year's provision for depreciation and amortization on the constant dollar and current cost amounts of utility plant was determined by applying the Company's average annual depreciation rates to the indexed plant amounts.

Fuel inventories, the cost of fuel used in generation, and electricity and gas purchased have not been restated from their historical cost in nominal dollars. The recovery of energy and purchased gas costs are limited to historical costs through the operation of the Company's electric and gas adjustment clauses. For this reason fuel inventories and deferred recoverable energy costs are effectively monetary assets. Income taxes have not been adjusted.

The Company is subject to the jurisdiction of regulatory commissions in the determination of a fair rate of return on its investment. Current ratemaking policy provides for the recovery of historical costs. Therefore, any difference between the historical cost of utility plant and utility plant stated in terms of constant dollars or current cost not presently includible in rates as depreciation, is reflected as an increase (reduction) to net recoverable cost. While the ratemaking process gives no recognition to the current cost of replacing utility plant, based on past practices, the Company believes it will be allowed to earn on the increased cost of its net investment when replacement of facilities actually occurs.

To properly reflect the economics of rate regulation in the Statement of Income from Continuing Operations, the increase (reduction) of net utility plant to net recoverable cost should be adjusted by the gain from the decline in purchasing power of net amounts owed on borrowed funds. During a period of inflation, holders of monetary assets suffer a loss of general purchasing power while holders of monetary liabilities experience a gain. The gain from the decline in purchasing power of net amounts owed is primarily attributable to the substantial amount of debt which has been used to finance utility plant. Since the depreciation on this plant is limited to the recovery of historical costs, the Company does not have the opportunity to realize a holding gain on debt and is limited to recovery only of the embedded cost of debt capital.

Five year comparison of selected supplementary financial data adjusted for effects of changing prices

		In thousands of average 1981 dollars			
For the year ended December 31,	**1981**	1980	1979	1978	1977
Operating revenues	**$2,150,718**	$1,961,451	$1,900,163	$1,784,747	$1,839,761
Historical cost information adjusted for general inflation:					
Income (loss) from continuing operations (excluding reduction to net recoverable cost)	**$ 74,358**	$ 26,454	$ 67,423		
Income (loss) per common share (after dividend requirements on preferred stock and excluding reduction to net recoverable cost)	**$ 0.51**	$ (0.09)	$ 0.51		
Net assets at year-end at net recoverable cost	**$1,614,015**	$1,593,404	$1,635,063		
Current cost information:					
Income (loss) from continuing operations (excluding reduction to net recoverable cost)	**$ 19,141**	$ (34,083)	$ (2,524)		
Income (loss) per common share (after dividend requirements on preferred stock and excluding reduction to net recoverable cost)	**$ (0.19)**	$ (0.94)	$ (0.59)		
Excess of increase in general price level over increase in specific prices after reduction to net recoverable cost	**$ 187,251**	$ 221,238	$ 316,677		
Net assets at year-end at net recoverable cost	**$1,614,015**	$1,593,404	$1,635,063		
General information:					
Gain from decline in purchasing power of net amounts owed	**$ 172,769**	$ 231,282	$ 266,468		
Cash dividends declared per common share	**$ 1.61**	$ 1.66	$ 1.80	$ 1.90	$ 1.97
Market price per common share at year-end	**$ 12.38**	$ 12.28	$ 15.82	$ 19.52	$ 23.46
Average consumer price index	**272.4**	246.8	217.4	195.4	181.5

NOTE 11. Commitments and Contingencies

Construction Program: The Company presently estimates that the construction program for the years 1982 through 1986 will require approximately $1,806 million, excluding AFC and certain overheads capitalized. By years the estimates are $371 million, $412 million, $395 million, $337 million and $291 million, respectively. At December 31, 1981, substantial construction commitments existed, including those for the Company's share of Unit No. 2 at Nine Mile Point Nuclear Station.

Nine Mile Point Nuclear Station Unit No. 2: Nine Mile Point Nuclear Station Unit No. 2 (the Unit), a nuclear power plant to be constructed and operated by the Company and shared with other utilities, is the only major generating facility currently under construction by the Company. Ownership is shared by the Company (41%), Long Island Lighting Company (18%), New York State Electric & Gas Corporation (18%), Rochester Gas and Electric Corporation (14%), and Central Hudson Gas & Electric Corporation (9%). Output of the Unit, which will have a projected capability of 1,084,000 kw., will be shared in the same proportions as the co-tenants' respective ownership interests.

In early 1980, the co-tenants engaged independent engineering and management consulting firms to perform a review of the Unit's estimated cost and scheduled in-service date, together with engineering, construction and management systems at the project. Also, a reassessment was conducted by the Company and Stone & Webster (the architect-engineer and construction agent for the project). As a result of these reviews, a revised cost of $2.4 billion (exclusive of AFC and nuclear fuel) and a rescheduling of the operation date from 1984 to late 1986 were announced in September 1980. The Company's share of the construction cost, exclusive of AFC and nuclear fuel, is now estimated to be $984 million ($2,214 per kilowatt).

Also during 1980, the PSC directed Theodore Barry and Associates and Canatom Limited to perform a comprehensive management audit of the Unit. This audit covered essentially the same areas as the study commissioned by the co-tenants and a report thereon (the TB&A Report) was issued in July 1981. While stating that the planned 1986 completion date is possible, the TB&A Report states that a likely one-year slippage in schedule, new regulatory requirements, higher escalation and other factors could increase the cost of the Unit significantly beyond the current estimate. However, while recognizing that schedule slippage and cost increases in any major construction project are always possible, the co-tenant utilities believe that the current cost estimate and the anticipated construction schedule are reasonable.

In July 1981, various parties petitioned the PSC to establish a single consolidated public evidentiary proceeding involving all of the co-tenants to consider the future of the Unit. In addition, in certain co-tenants' rate proceedings, various motions were made and petitions filed by intervening parties requesting a separate examination of the project. Also, in September 1981, the Staff of the PSC issued a report on a comparative analysis of the economic and financial feasibility of the Unit and coal alternatives. This report concluded that completion of the Unit is warranted. In response to these motions and petitions and based on the TB&A Report and PSC Staff's comparative analysis, in September 1981 the PSC ordered an expedited public proceeding to inquire into the financial and economic cost implications of completing the Unit. In December 1981, public evidentiary hearings were held and briefs were submitted to the PSC. At a February 9, 1982 PSC meeting the Commissioners reached a majority consensus that completion of the Unit is warranted and that no basis exists at this time to take further action regarding abandonment of the project. The Commissioners also concurred with the PSC Staff's recommendation that the co-tenants must emphasize their attention to the project's cost and schedule to minimize its impact on ratepayers and indicated their intention to closely monitor construction activities. In addition, the Commissioners decided to explore the feasibility of instituting a yet undefined incentive program that could cause the return on the equity portion of the investment in the Unit to vary depending on a variety of items related to the project's ultimate cost and completion date. A formal PSC decision is expected upon completion of its review of the feasibility of instituting an incentive program. The Company is unable to predict what recommendations or actions may arise as a result of this review or what further actions, if any, may be brought by the intervening parties.

Long-term Contracts for the Purchase of Electric Power: At January 1, 1982 the Company had contracts to purchase electric power from the following generating facilities owned by the Power Authority of the State of New York (PASNY):

Facility	Expiration date of contract	Purchased capacity in kw	Estimated annual capacity cost
St. Lawrence—hydroelectric project	1985	115,000	$ 1,380,000
Niagara Falls—hydroelectric project	1990	1,122,432	13,469,000
Blenheim-Gilboa—pumped storage generating station	2002	550,000	12,540,000
FitzPatrick—nuclear plant	year-to-year basis	116,000*	10,456,000
		1,903,432	$37,845,000

*98,000 kw. for winter of 1982-83.

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.

Litigation: In 1978, several electric customers brought suit against the Company and PASNY requesting that certain power purchased from PASNY be allocated exclusively for their benefit and are asking monetary damages for the difference between rates charged by the Company and rates that would otherwise have been charged if this power had been furnished to them since the initiation of the suit in 1978 and for the six years prior thereto. A settlement was reached wherein these electric customers will receive an initial allocation and thereafter an increased allocation (through December 31, 1987) when their proposed plant expansion activities are completed. No monetary damages were awarded and the settlement will not affect the consolidated financial statements of the Company.

FERC Audit: During 1979, the staff of FERC conducted a compliance audit of the Company covering the years 1973 through 1978. All of the adjustments proposed by FERC have been resolved and recorded by the Company except certain adjustments concerning the base cost of nuclear fuel on which AFC should be applied. The resolution of these adjustments has been deferred pending the development of generic rulemakings by the FERC concerning accounting for nuclear fuel. If the associated recommended adjustments are sustained by FERC, the resulting reduction in retained earnings would approximate $26,000,000 through 1981. The Company believes that the adjustments are not justified and is contesting them. The recommended adjustments result from FERC staff taking exception to regulatory accounting treatment prescribed by the PSC, the Company's primary rate setting body. Although FERC has ratemaking jurisdiction over only about 10% of the Company's electric revenues, representing sales to other electric systems and revenues from transmission of energy, it has the power to prescribe books of account on which reports to stockholders are based. Due to the extensive jurisdiction which the PSC has over the Company's affairs, it is the opinion of the Company that the financial statements based on the requirements of the PSC represent the proper presentation of the financial position and the results of operations of the Company.

Sterling Nuclear Station: As a result of a January 1980 decision by the New York State Board on Electric Generation Siting and the Environment to vacate the construction permit it had previously issued because it could no longer find a public need for the proposed jointly-owned Sterling Nuclear Station generating facility, the project was discontinued. The PSC has permitted the Company to accrue AFC on the discontinued project. Through December 31, 1981, the Company's costs associated with its 22% interest in the project, when reduced for Federal income taxes, approximated $18,000,000 including AFC. The Company, together with the other co-owners, petitioned the PSC to seek recovery of these and all subsequently incurred costs associated with cancellation of this project. In January 1982, the PSC granted the Company permission to commence recovery of its costs, together with carrying charges on the unrecovered balance, over a three year period. The Company expects to commence recovery in March 1982.

NOTE 12. Quarterly Financial Data (Unaudited)

Operating revenues, operating income, net income and earnings per common share by quarters for 1981, 1980 and 1979 are shown in the following table. The Company, in its opinion, has included all adjustments (consisting only of normal recurring accruals except for giving effect to the deferral of Oswego Unit No. 6 investment tax credit during the quarter ending December 31, 1979—see Note 1) 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.

	In thousands of dollars			
Quarters ended	Operating revenues	Operating income	Net income	Earnings per common share
December 31				
1981	$529,844	$63,879	$52,063	$.52
1980	479,512	52,085	37,756	.41
1979	416,066	41,570	28,005	.31
September 30				
1981	$481,377	$60,831	$48,500	$.48
1980	379,705	37,742	26,020	.25
1979	335,944	34,764	25,511	.29
June 30				
1981	$528,216	$69,303	$55,696	$.61
1980	425,238	57,729	44,701	.54
1979	352,107	50,114	41,878	.56
March 31				
1981	$611,281	$77,363	$64,384	$.76
1980	492,660	64,196	54,162	.69
1979	412,386	67,492	60,636	.86

Selected financial data

	1981	1980	1979	1978	1977
Operations: *(000's)*					
Operating revenues	**$2,150,718**	$1,777,115	$1,516,503	$1,280,248	$1,225,832
Net income	**220,643**	162,639	156,030	141,162	123,832
Common stock data:					
Book value per share at year-end	**$17.36**	$17.25	$17.33	$17.14	$16.95
Earnings per average common share	**2.35**	1.87	2.00	1.89	1.74
Dividends paid per common share	**1.61**	1.50	1.44	1.36½	1.31½
Capitalization: *(000's)*					
Common equity	**$1,457,934**	$1,298,001	$1,177,725	$1,065,976	$ 968,236
Non-redeemable preferred stock	**210,000**	210,000	210,000	210,000	240,000
Redeemable preferred stock	**254,748**	205,924	189,650	198,600	126,400
Long-term debt	**1,619,369**	1,443,607	1,443,056	1,414,997	1,394,387
Total	**3,542,051**	3,157,532	3,020,431	2,889,573	2,729,023
First mortgage bonds maturing within one year	**—**	140,000	80,000	—	—
Total	**3,542,051**	3,297,532	3,100,431	2,889,573	2,729,023
Capitalization ratios *(including first mortgage bonds maturing within one year):*					
Common stock equity	**41.2%**	39.4%	38.0%	36.9%	35.5%
Preferred stock	**13.1**	12.6	12.9	14.1	13.4
Long-term debt	**45.7**	48.0	49.1	49.0	51.1
Financial ratios:					
Ratio of earnings to fixed charges	**2.63**	2.43	2.61	2.58	2.49
Ratio of earnings to fixed charges and preferred stock dividends	**2.10**	1.93	2.03	1.95	1.90
Other ratios-% of operating revenues:					
Fuel, purchased power and purchased gas	**52.6**	51.8	48.6	44.5	44.6
Maintenance and depreciation	**10.3**	10.8	12.1	12.6	13.2
Total taxes	**11.2**	11.9	12.4	13.5	13.6
Operating income	**12.6**	11.9	12.8	14.4	14.7
Balance available for common stock	**8.7**	7.5	8.5	8.8	8.0
Ratio of depreciation reserve to gross utility plant	**27.1**	27.0	26.3	26.2	25.6
Ratio of mortgage bonds to net utility plant	**39.0**	43.4	47.0	46.7	48.6
Miscellaneous: *(000's)*					
Gross additions to utility plant	**$ 457,415**	$ 378,503	$ 374,530	$ 316,280	$ 289,931
Total utility plant	**4,985,315**	4,563,309	4,218,528	3,905,374	3,647,274
Accumulated depreciation and amortization	**1,348,738**	1,232,675	1,110,563	1,021,417	935,212
Total assets	**4,175,932**	3,808,819	3,528,937	3,189,112	3,019,054

Electric and gas statistics

ELECTRIC CAPABILITY

At January 1,	1982	%	1981	1980
	Thousands of kilowatts			
Thermal:				
Coal fuel				
Huntley, Niagara River	705	10	785	785
Dunkirk, Lake Erie	540	7	600	585
Total coal fuel	1,245	17	1,385	1,370
Residual oil fuel				
Albany, Hudson River**	400	5	400	400
Oswego, Lake Ontario	1,736	24	1,821	1,200
Roseton, Hudson River	358	5	357	360
Middle distillate oil fuel				
20 Combustion turbine and diesel units	310	4	310	354
Total oil fuel	2,804	38	2,888	2,314
Nuclear fuel				
Nine Mile Point, Lake Ontario	610	8	610	610
Purchased—firm contract Power Authority—FitzPatrick, Lake Ontario	116	2	141	154
Total nuclear fuel	726	10	751	764
Total thermal sources	4,775	65	5,024	4,448
Hydro:				
Owned and leased hydro stations (81)	650	9	733	733
Purchased—firm contracts				
Power Authority—Niagara River	1,122	15	1,122	1,122
Power Authority—St. Lawrence River	115	2	115	115
Power Authority—Blenheim-Gilboa Pumped Storage Plant	550	8	550	550
Other	67	1	75	76
Total hydro sources	2,504	35	2,595	2,596
Total capability*	7,279	100	7,619	7,044

	1981	1980	1979
Electric peak load during year	5,616	5,543	5,641

*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.

**Converted in 1981 to burn natural gas (as well as oil) as a fuel.

ELECTRICITY GENERATED AND PURCHASED *(Millions of kw-hrs.)*

	1981	%	1980	%	1979	%
Thermal:						
Generated						
Coal	7,046	20	7,213	20	7,275	20
Oil	7,044	19	7,392	21	8,534	24
Nuclear	3,270	9	4,538	13	3,005	8
Natural gas	681	2	—	—	—	—
Purchased—						
Nuclear from Power Authority	690	2	934	2	722	2
Total thermal	18,731	52	20,077	56	19,536	54
Hydro:						
Generated	3,703	10	3,175	9	3,641	10
Purchased from Power Authority	8,522	24	8,925	25	8,263	23
Total hydro	12,225	34	12,100	34	11,904	33
Other purchased power—various sources	4,907	14	3,616	10	4,621	13
Total generated and purchased	35,863	100	35,793	100	36,061	100

ELECTRIC STATISTICS

	1981	1980	1979
Electric sales *(Millions of kw-hrs.)*			
Residential	8,459	8,330	8,269
Commercial	9,418	9,361	9,279
Industrial	11,636	11,703	12,471
Municipal service	266	273	274
Other electric systems	3,111	2,921	3,022
	32,890	32,588	33,315
Electric revenues *(Thousands of dollars)*			
Residential	$ 483,852	$ 404,899	$ 357,818
Commercial	578,186	463,315	393,173
Industrial	429,870	344,053	312,833
Municipal service	31,274	27,147	23,832
Other electric systems	137,341	106,429	83,188
Miscellaneous	59,410	47,614	40,224
	$1,719,933	$1,393,467	$1,211,068
Electric customers *(Average)*			
Residential	1,223,484	1,217,214	1,206,469
Commercial	131,119	131,210	130,119
Industrial	2,807	2,896	2,906
Other	3,232	3,222	3,189
	1,360,642	1,354,542	1,342,683
Residential *(Average)*			
Annual kw-hr. use per customer	6,914	6,843	6,854
Cost to customer per kw-hr.	5.72¢	4.86¢	4.33¢
Annual revenue per customer	$395.47	$332.64	$296.58

GAS STATISTICS

	1981	1980	1979
Gas sales *(Thousands of dekatherms)*			
Residential	51,701	51,121	51,895
Commercial	26,342	23,833	23,415
Industrial	26,826	21,647	17,109
Other gas systems	4,889	4,720	4,199
	109,758	101,321	96,618
Gas revenues *(Thousands of dollars)*			
Residential	$222,280	$209,416	$176,567
Commercial	102,727	89,088	71,139
Industrial	89,337	69,506	46,260
Other gas systems	13,795	13,455	10,014
Miscellaneous	2,646	2,183	1,455
	$430,785	$383,648	$305,435
Gas customers *(Average)*			
Residential	393,182	388,720	383,617
Commercial	30,564	29,682	29,009
Industrial	530	530	525
Other	2	2	2
	424,278	418,934	413,153
Residential *(Average)*			
Annual use per customer *(dekatherms)*	131.5	131.5	135.3
Cost to customer *(per dekatherm)*	$4.30	$4.10	$3.40
Annual revenue per customer	$565.34	$538.73	$460.27
Maximum day gas sendout *(dekatherms)*	824,777	740,594	750,666

Officers

ohn G. Haehl, Jr.
hairman of the Board and
hief Executive Officer

illiam J. Donlon
resident

mes Bartlett
xecutive Vice President

chard C. Clancy
enior Vice President

hn M. Endries
enior Vice President

hn M. Haynes
enior Vice President

mes J. Miller
enior Vice President

hn H. Terry
enior Vice President,
eneral Counsel and Secretary

chard F. Torrey
enior Vice President

onald P. Dise
ice President—Engineering

ohn J. Ehlinger*
ice President—Employee Relations

illiam C. Franklin
ice President—Purchasing

hn P. Hennessey
ice President—Management
ystems and Services

homas E. Lempges
ice President—Nuclear Generation

onald L. MacVittie
ice President—Fossil Generation

ugene J. Morel
ice President—Administrative
ervices and Risk Management

ames F. Morrell
ice President—Corporate Planning

erald K. Rhode
ice President—System Project
anagement

enneth A. Tramutola
ice President—Gas and
onsumer Services

obert M. Cleary, Jr.
ice President and General
anager—Western Division

aymond Kolarz
ice President and General
anager—Central Division

ichard H. Kukuk
ice President and General
anager—Eastern Division

nthony J. Baratta, Jr.
ontroller

ohn W. Powers
reasurer

dward P. Gueth, Jr.
ssistant General Counsel

erman B. Noll
ssistant General Counsel

icholas L. Prioletti, Jr.
ssistant Controller

dam F. Shaffer
ssistant Controller

enry B. Wightman, Jr.
ssistant Controller

arold J. Bogan
ssistant Secretary

oseph F. Cleary
ssistant Secretary

rederick C. McCall, Jr.
ssistant Secretary

ichard N. Wescott
ssistant Treasurer

*Retired Dec. 31, 1981

Directors

James Bartlett
Executive Vice President, Syracuse

Thomas J. Brosnan
Consultant (formerly Vice President—Research and Development, Environmental Matters), Syracuse

Edmund M. Davis
Partner, Hiscock, Lee, Rogers, Henley & Barclay, attorneys-at-law, Syracuse

William J. Donlon
President, Syracuse

Edward W. Duffy
Chairman of the Board and Chief Executive Officer, Marine Midland Banks, Inc., a bank holding company, Buffalo

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

Edwin F. Jaeckle
Senior Partner, Jaeckle, Fleischmann & Mugel, attorneys-at-law, Buffalo

Lauman Martin
Consultant (formerly Senior Vice President and General Counsel), Syracuse

Baldwin Maull
Director of various corporations, New York

Martha Hancock Northrup
Housewife, former President, Crouse-Irving Memorial Hospital Board, Syracuse

Frank P. Piskor
President Emeritus, St. Lawrence University, Canton

Donald B. Riefler
Chairman, Sources and Uses of Funds Committee, Morgan Guaranty Trust Company of New York, commercial bank, New York

Lewis A. Swyer
President, L. A. Swyer Company, Inc., builders and construction managers, Albany

John G. Wick
Cox, Barrell, Walsh, Roberts & Grace, attorneys-at-law, Buffalo

BOARD COMMITTEES

Executive Committee
John G. Haehl, Jr., Chairman
Edmund M. Davis
Edwin F. Jaeckle
Frank P. Piskor
Baldwin Maull
John H. Terry, Secretary

Compensation Committee
Baldwin Maull, Chairman
Edwin F. Jaeckle
Edmund M. Davis
Lewis A. Swyer

Audit Committee
Edward W. Duffy, Chairman
Lewis A. Swyer
Frank P. Piskor

Committee on Corporate Public Policy
Frank P. Piskor, Chairman
Martha H. Northrup
Lewis A. Swyer
John G. Wick

Finance Committee
Donald B. Riefler, Chairman
John G. Wick
Edmund M. Davis

Investor notes

Dividend Reinvestment Plan
Stockholders are encouraged to enroll in Niagara Mohawk's popular Dividend Reinvestment and Stock Purchase Plan, which offers new tax-deferral features. See page 15

Annual Meeting
The annual meeting of stockholders will be held on May 4, 1982 at the Company's main office in Syracuse. A formal notice of meeting, proxy statement and proxy form will be sent to holders of common stock in early April.

Transfer Agents
Preferred Stock and Preference Stock:
Marine Midland Bank, N.A.
140 Broadway, New York, N.Y. 10015

Common Stock:
Morgan Guaranty Trust Company
of New York
30 W. Broadway, New York, N.Y. 10015

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

Stock Exchanges
Common and Certain Preferred Series:
Listed on New York Stock Exchange
Common Stock:
Also traded on Amsterdam (Netherlands), Boston, Cincinnati, Midwest, Pacific and Philadelphia stock exchanges.

Ticker symbol: NMK

Form 10-K Report
A copy of the Company's Form 10-K report filed annually with the Securities and Exchange Commission is available after March 31, 1982 by writing the Treasurer at 300 Erie Boulevard West, Syracuse, N.Y. 13202.

Printed in U.S.A.

NIAGARA MOHAWK
300 ERIE BOULEVARD WEST
SYRACUSE, NEW YORK 13202

Day begins for Niagara Mohawk service representative with drive down country road on trouble call to customer's home. About 400 dedicated service personnel stand ready to respond to consumer energy emergencies any hour day or night.