NSP

Northern States Power Company

414 Nicollet Mall
Minneapolis, Minnesota 55401
Telephone (612) 330-5500

October 27, 1982

Director, Office of Nuclear
Reactor Regulation
U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Re: Monticello Nuclear Generating Plant, Docket No. 50-263
Prairie Island Nuclear Generating Plant, Docket Nos.
50-282 and 50-306

Attached is a schedule showing cash flow generated by Northern States Power Company in 1981 and projected to be generated for the year 1982. These statements are in compliance with Regulatory Guide 10.1, Revision 4, issued in October, 1981, which requests cash flow information for the most recently completed annual period and projected cash flow.

These cash flow statements comply with the suggested format with one minor exception. We have reduced net income by dividends declared, instead of dividends paid, to arrive at retained earnings on the third line of the statement. This adjustment was made to reflect the fact that Northern States Power Company normally declares dividends so that a charge is made to retained earnings during a quarter and a corresponding credit made to dividends payable. The cash disbursement is made during the first month of the following calendar quarter. Any increase in dividends declared during the year will be properly reflect in the retained earnings account as a result of treating the dividends in the manner which we have elected for this filing.

I am enclosing a copy of our 1981 Annual Report. The information for 1981 Actual Cash Flow is taken from the Statement of Changes in Financial Position on page 23 of the Annual Report.

If you have any questions regarding this letter, please feel free to write me or call me at (612)330-6622.

Sincerely

M004

E J Hall

E J Hall
Assistant Treasurer

cc R G Johnson, Manager, Insurance and Security
Northern States Power Company

Northern States Power Company (Minn & Subs)
1981 Actual Cash Flow and
1982 Projected Cash Flow
Related to Retrospective Premiums for
Monticello, Prairie Island I and Prairie Island II
Nuclear Generating Units

(Dollars In Thousands)

	Actual Total	Projected Total
Net Income After Taxes	$ 127 553	$ 157 565
Less Dividends Declared	(87 578)	(93 057)
Retained Earnings	39 975	64 508
Adjustments:		
Depreciation & Amortization	148 596	180 115
Deferred Income Taxes & Investment Tax Credits	32 226	96 529
Allowance for Funds Used During Construction	(15 186)	(19 208)
Total Adjustments	165 636	257 436
Internal Cash Flow	$ 205 611	$ 321 944
Average Quarterly Cash Flow	$ 51 403	$ 80 486

Percentage Ownership in All Operating Nuclear Units		
	Monticello	100%
	Prairie Island I	100%
	Prairie Island II	100%

Maximum Total Contingent Liability	$	$ 30 000

Cash and Banking
GAL/fkm
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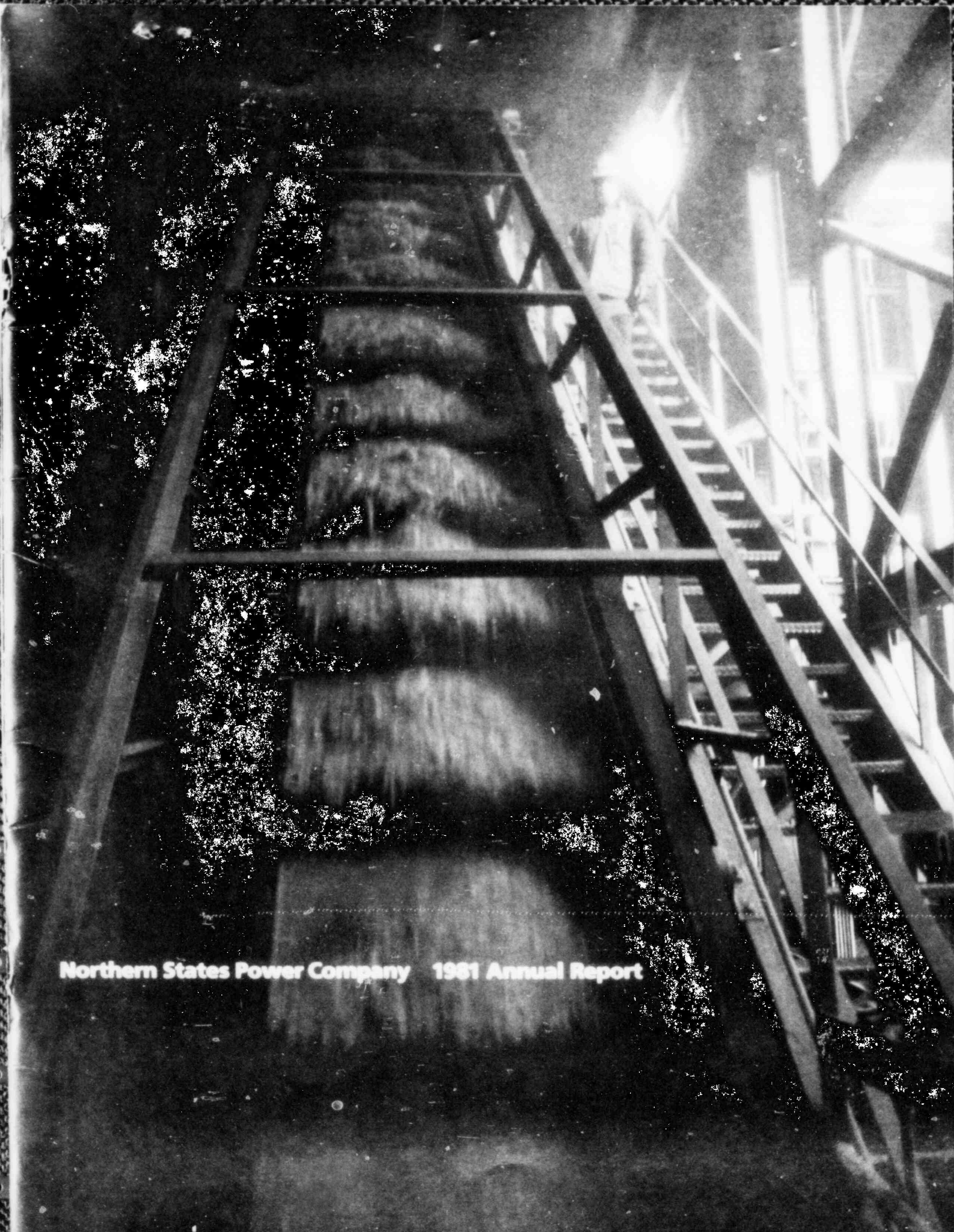
Northern States Power Company 1981 Annual Report

Northern States Power Company (Minnesota)—and its subsidiary, Northern States Power Company (Wisconsin), together known as NSP, serve a 49,000 square mile area in parts of Minnesota, Wisconsin, North and South Dakota. The company generates, transmits and distributes electric power to more than one million customers and distributes natural gas to more than 275,000 customers in 81 communities within its service area. It also supplies telephone service in Minot, North Dakota.

NSP, an Equal Opportunity employer, had 7,045 benefit employees at December 31, 1981.

Mission

Northern States Power Company will supply and distribute those essential energy requirements of customers in its service territory which it can provide more efficiently and effectively than others.

NSP will serve those requirements as an efficiently managed, investor-owned company subject to appropriate regulation. The company will operate within the limits of its resources.

NSP will strive to provide service at the lowest prices that allow customers to receive the quality of service they require, investors to earn a fair return and employees to conduct the business of the company in a socially responsible manner.

About the Cover

Renewable fuel—wood chips, sawdust and bark wastes from sawmills—moves up the conveyor at NSP's French Island facility near La Crosse, Wisconsin. The wastes burn in an innovative fluidized-bed boiler, believed to be the first in the United States to produce electricity commercially. (Photo by Greg Bissen.)

Headlines:

Earnings improve, dividends increase (page 2)
Generating plants outperform industry (page 4)
French Island facility fueled by waste wood (page 6)
Natural gas supply ample, but price rising (page 7)
NSP plans for the future (page 8)
Division Operations assists NSP load management (page 9)
Rate increases sought in all jurisdictions (page 11)
Utility industry year reviewed (page 15)
NSP financial performance ahead of industry (page 15)

Highlights:

	1981	1980	Percent Increase (Decrease)
Dividend rate at year end	**$2.56**	$2.42	5.8%
Earnings per share	**3.89**	3.23	20.4
Return on average common equity	**13.5%**	11.7%	
Earnings available for common stock (millions)	**$ 114.0**	$ 97.3	17.2
Revenues (millions)	**1 280.9**	1 159.1	10.5
Total assets (millions)	**2 860.1**	2 735.3	4.6
Peak electric demand (thousands of kilowatts)	**4 681**	4 873	(3.9)*
Electric retail use (millions of kilowatt-hours)	**21 125**	21 008	0.6
Gas heating use (millions of cubic feet)	**42 823**	45 419	(5.7)
Customers	**1 394 108**	1 371 651	1.6
Benefit employees	**7 045**	6 965	1.1

*0.8% weather normalized

Contents

Photos by Greg Bissen, Merle Morris and Paul Snodgrass.

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To Our Shareholders:

In 1981 we continued our vigorous commitment and determination to improve profitability. We are pleased that 1981 was better than we expected at this time last year.

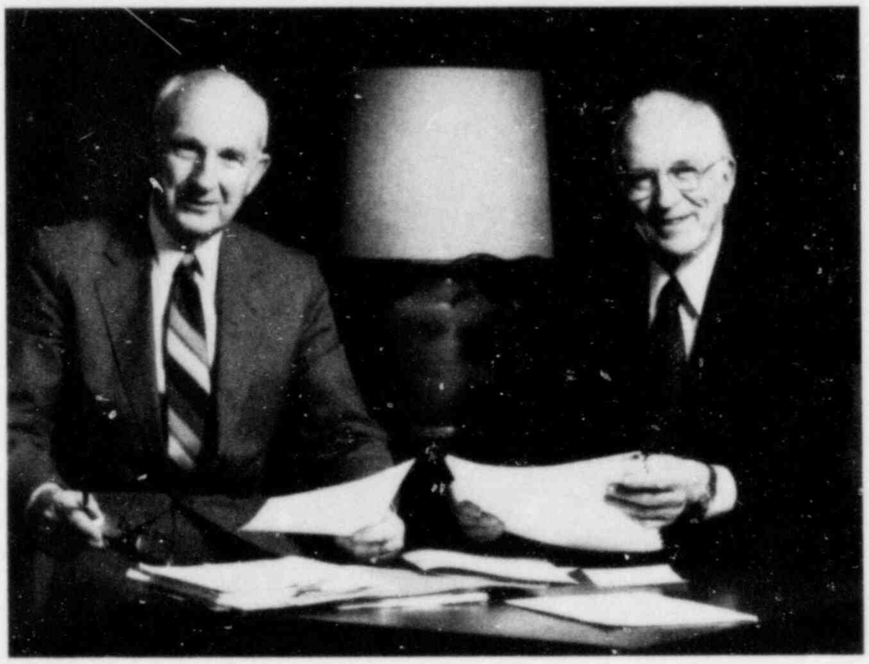
In June 1981 common stock dividends were increased for the fifth consecutive year. The increase was 3.5 cents a share per quarter, bringing the annual dividend rate to $2.56.

Our 1981 earnings were $3.89 per share, up 66 cents from the $3.23 we earned last year. The main reasons for the improvement in earnings were rate increases and adjustment of the Tyrone nuclear plant amortization. When we compare 1981 earnings, we must remember that our 1980 earnings were down from the $3.51 we earned in 1979.

We were especially pleased to achieve this earnings result because in 1981 we faced several formidable obstacles. The economy declined in our service area as well as the nation. Inflation continued, although its pace eased somewhat. New housing construction was at an unusually low level. The economic situation, new dwelling construction and customers' good efforts in conservation, along with a warm winter and a cool summer, resulted in energy sales up very little over 1980.

The entire electric industry in 1981 produced better financial results than in the recent past. NSP again outperformed industry averages. In this report you will find a more detailed explanation and comparison between NSP and the electric utility industry.

Donald W. McCarthy
and Clayton K. Larson



Our average long-term earnings per share growth rate for the five years ending in 1981 was 5.3 percent, which moves us closer to our objective of at least 6 to 7 percent. We will continue to work toward that objective and are optimistic that goal will be achieved.

NSP met these 1981 challenges with a demonstration of creativity that blended some new production technology, careful management of our energy products, expertise and some exceedingly sharp attention to expenses. And in 1982 we're continuing these efforts.

NSP Is Planning for Profitability

Our continuously polished crystal ball displays that in 1982 and the coming years an energy company will show that profitability follows dedication, close attention to all facets of the business and creativity. NSP is committed to management that will benefit its shareholders, its customers and its service area.

We remain optimistic for the future. First, we expect energy use to increase in 1982 with an improvement in the economy and the prospect of normal weather.

Next, we continue to emphasize planning and internal cost controls in management of the company.

And regulatory agencies are responding more realistically to the rate requirements of investor-owned utility companies. In 1981 we requested rate increases for both electric and natural gas service in every jurisdiction. These requests were for a total return on equity of 16 percent and came to $171 million, with $152.2 million in requested increases still under regulatory consideration.

We are determined to meet the energy demands of customers and at the same time keep the price of our energy competitive with other fuels and with other electric and gas suppliers in our area while earning a fair return for our shareholders.

Beyond 1982, our expectations also are optimistic. We have considerable financial flexibility, with a strong capital structure, adequate bond interest coverage and good internal cash generation.

Our mix of fuels for producing electricity is well balanced and our attention to the maintenance of facilities makes their availability for service well above industry averages. Our

construction and financing requirements are relatively low for the next two years. This, plus our good internal cash generation, will minimize the pressure for new financing.

The Economic Recovery Tax Act of 1981 should help the electric utility industry and NSP. Provisions of this act help to provide common equity to the company and offer a tax benefit to individual shareholders.

Sherco 3 Hearings in Progress

NSP is seeking recertification by the Minnesota Department of Energy, Planning and Development for Sherco 3. This is an 800-megawatt (Mw) coal-fired facility proposed for construction at the same site as the Sherco 1 and 2 units at Becker, Minnesota. Public hearings are under way on the joint plans of NSP, which would own 451 Mw of its capacity; Southern Minnesota Municipal Power Agency, 300 Mw; and United Minnesota Municipal Power Agency, 49 Mw. The unit is planned for service in 1986. It will reduce dependence on oil-fired electric generation, reduce over-all environmental effect of Minnesota electric generation and provide adequate future electric energy at moderate prices for the customers of each partner.

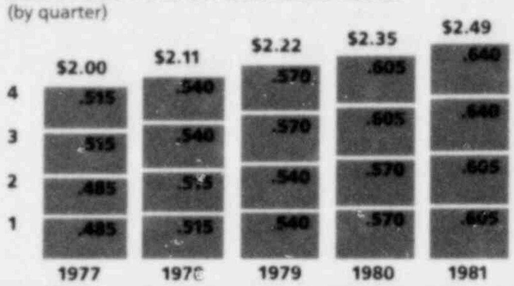
LSDP Affiliation

In January 1982, shareholders of Lake Superior District Power Company (LSDP), Ashland, Wisconsin, received a common stock exchange offer from NSP. On February 23, 1982, the affiliation was completed when more than the required number of common shares of LSDP were presented for exchange for NSP common stock. We welcome the former LSDP shareholders to NSP.

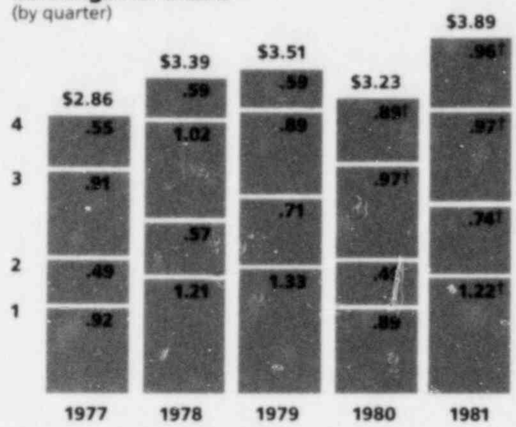
NSP Service Is Based on People

The year saw many retirements of persons who made many and varied contributions to the company's success. D.W. (Jack) Angland, executive vice president and designer of the industry's power pooling concept, retired. So did M. D. (Bud) Olson, vice president-commercial operations, and George A. Des Rosier, vice president-division operations for the Wisconsin company. Two others are examples of the employee dedication that gives NSP pride—Robert J. Roggensack, head meterman in Southern Wisconsin, and Robert O. Olson, plant

Dividends Paid on Common Stock
(by quarter)



Earnings Per Share
(by quarter)



†Includes earnings from rate increases subject to possible refunding: 1980 3rd qtr., 2¢; 4th qtr., 2¢; 1981 1st qtr., 2¢; 2nd qtr., 2¢; 3rd qtr., 3¢; 4th qtr., 33¢

administrative specialist senior at Prairie Island. Both retired after 44 years' service to NSP. We are proud to have been associated with people of such skills and caliber.

Your directors, officers and employees will carry on their work with the same dedication to service and creativity as in the past. We are grateful for their participation and guidance. We invite you to read more about our plans and achievements.

Sincerely,

Don McCarthy

Don McCarthy
Chairman and
Chief Executive Officer

Clayton Larson

Clayton Larson
President and Chief Operating Officer

February 26, 1982

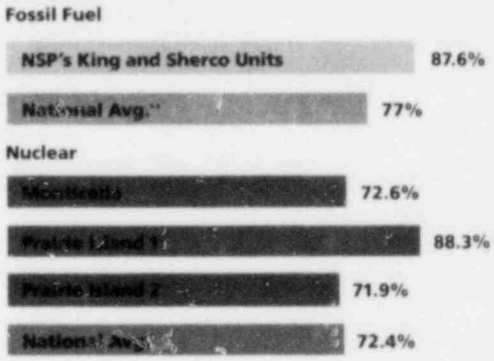
Dennis E. Gilberts
Senior Vice President
– Power Supply

NSP's electric rates are among the lowest in the nation, and some of the reasons for this performance are in the area of Power Supply. Sources of energy are primarily the lowest-cost options—uranium, coal and hydro power. Equally important, the company's nuclear and coal-fired plants performed very well in 1981.

Of the 25,784 million kilowatt-hours used by NSP customers in 1981, 48 percent came from coal-burning plants, 38 percent from nuclear and 14 percent from hydro generation. Excluding power purchased under an exchange agreement with Manitoba Hydroelectric Board, NSP's own power generation was 54 percent coal, 42 percent nuclear and 3.7 percent hydro, with oil and gas accounting for less than 0.3 percent.

A good mix of coal, nuclear and hydro plants is necessary to produce economical electricity. However, these plants also must perform well to achieve the potential savings over higher-cost generation.

Plant Availability 1981*



*Plant availability is the number of hours in a year a plant is available for service divided by the total hours in a year.
**National Electric Reliability Council 10-year average.
†Nuclear Regulatory Agency 1981 data.

In 1981, the company's major coal and nuclear units again performed very well. One commonly used measure of performance is operating availability. This is simply the percent of time during the year a plant was running or could have run if system demand required it.

NSP's three largest coal-burning units had an average availability of 87.6 percent in 1981. This compares to the most recent 10-year national average for units of this class at 77 percent.

Similarly, NSP nuclear plants had an average availability of 77.5 percent in 1981, compared to a 1981 average of 72.4 percent for similar facilities.

Nuclear Plants Evaluated

When evaluating nuclear plants, the company recognizes that safe operation of these facilities and the necessity of operating them in full compliance with federal regulations is of even greater importance than their performance as suppliers of electric energy.

The Institute of Nuclear Power Operations (INPO) is an organization set up by the industry following the accident at Three Mile Island in 1979 to help individual utilities achieve excellence in nuclear operations. One of its functions is to make in-depth evaluations of all aspects of nuclear plant operations.

The NSP Monticello plant was evaluated in 1980 and Prairie Island in 1981. Over-all, both plants received good marks in all areas.

"Within the scope of the evaluation, the team concluded the station is in superior material condition and is being operated in a safe manner by competent personnel who exhibit high morale," according to the final INPO Prairie Island report.

In another evaluation, the regional office of the Nuclear Regulatory Commission classified both plants as above average.

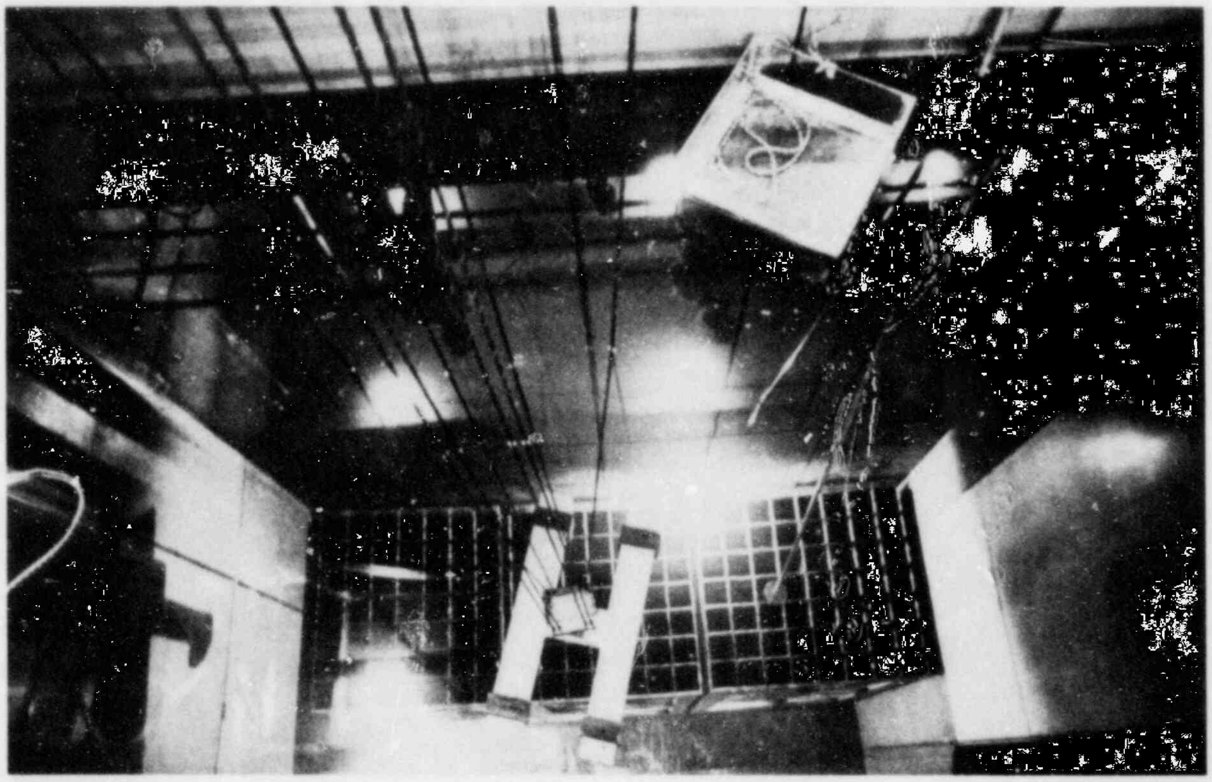
However, NSP will not become complacent about its nuclear operations. There are literally thousands of requirements and regulations which the company must follow at all times. In this area, the only appropriate goal is zero mistakes and zero defects. During 1981 there were a number of nuclear plant occurrences, all of a relatively minor nature but sufficient to remind the operators they must be unrelenting in pursuit of this goal.

Nuclear Waste Disposal Unresolved

Permanent disposal of high-level nuclear wastes continues to be an unresolved issue for the nuclear industry. The federal government is, by law, responsible for providing a safe repository for these wastes. So far, it has failed to develop such a facility.

The industry believes it has developed technical solutions to this problem. The delay is primarily a political, rather than technical, problem. Recently, however, the federal government showed signs of renewed commitment to get on with a solution.

In the interim until a repository is available, NSP must continue to store spent fuel at plant sites. The capacity of the Monticello plant storage pool



New fuel racks at Prairie Island will store more spent nuclear fuel in a 40-foot deep pool.

increased in 1981 with installation of new storage racks permitting more fuel to be stored in the pool. A similar project in progress at Prairie Island will be completed in 1982. The plants then will have sufficient capacity to store all fuel discharged until the early 1990s.

Low-level radioactive waste disposal also presents a problem which must be resolved. This waste consists of materials used in plant operation and maintenance. Currently, low-level waste goes to disposal sites in South Carolina and Washington. A 1980 federal law made each state responsible for disposing of wastes produced within its borders by 1986. This includes medical, research and industrial wastes, as well as those from nuclear plant operations. This law also permits states to form regional compacts for cooperative waste management, an option Minnesota now is studyi[illegible]

Fuel Supply Favorable but Costly

The fuel supply picture is favorable, with [illegible] fuel costs remaining stable and much of [illegible]s coa[illegible] needs under contract through the mid-1990s.

Most of NSP's coal comes from Montana in unit trains, each 105 cars long and carrying 10,500 tons of coal. The largest users are Sherco units 1 and 2, 700-megawatt generators in Sherburne County. These consume about 11 trainloads of coal each week. Moving this quantity of coal a long distance is necessarily costly. Transportation accounted for about half of NSP's 1981 coal bill. Deregulation of the railroads could have severe effects on the delivered cost of coal.

Another element of cost is the 30-percent severance tax Montana levies on the purchase of coal mined within the state. In 1981 this tax cost NSP customers $14 million. The company opposes the tax as excessive and, as a member of the National Coal Consumers Alliance, backs legislation to limit the severance tax to 12.5 percent.

Fuel Costs
(Dollars per million BTUs)

	Industry 1981 Estimate	NSP 1981	NSP 1982	NSP 1986	NSP Annual Growth 86/81
Coal	$1.48	**$1.12**	$1.23	$1.76	9.5%
Nuclear	.48	**.47**	.43	.74	9.6%
Oil	5.28	**4.33**	3.90	7.28	11.0%
All Fuels	$1.85	**$ .83**	$ .84	$1.35	10.2%

French Island Burns Waste Wood

Continuous study and testing of renewable energy sources helped transform the 15-megawatt oil-burning French Island generating Unit 2 near La Crosse, Wisconsin, to a demonstration of technical ingenuity. Retrofitting completed in 1981 converted French Island Unit 2 to burn wood through a new use of fluidized-bed technology.

Up to 300 tons of sawdust, bark and other sawmill wastes daily fuel the boiler. Potentially, the same equipment could burn a variety of other waste products, such as garbage, tires and even sewage sludge. Operating 16 hours a day, the plant uses renewable fuel that otherwise would have been wasted and posed a disposal problem in the area.

Believed to be the nation's first application of the fluidized-bed method for commercial electric generation, it's also environmentally desirable. Plant emissions go through a gravel-bed air-filtration system that emits very little air pollution.

Besides providing an economical source of electricity, the project provides NSP an opportunity to gain experience with fluidized-bed combustion, which appears to be economical to construct and to operate.

Prairie Island Cooling System Improved

A major modification is under way at the Prairie Island nuclear plant to improve the cooling water intake and discharge systems. The new arrangement will provide additional protection to fish and other aquatic organisms and also reduce the need to operate the plant's cooling towers. This will increase efficiency, saving more than $6 million annually in operating costs.

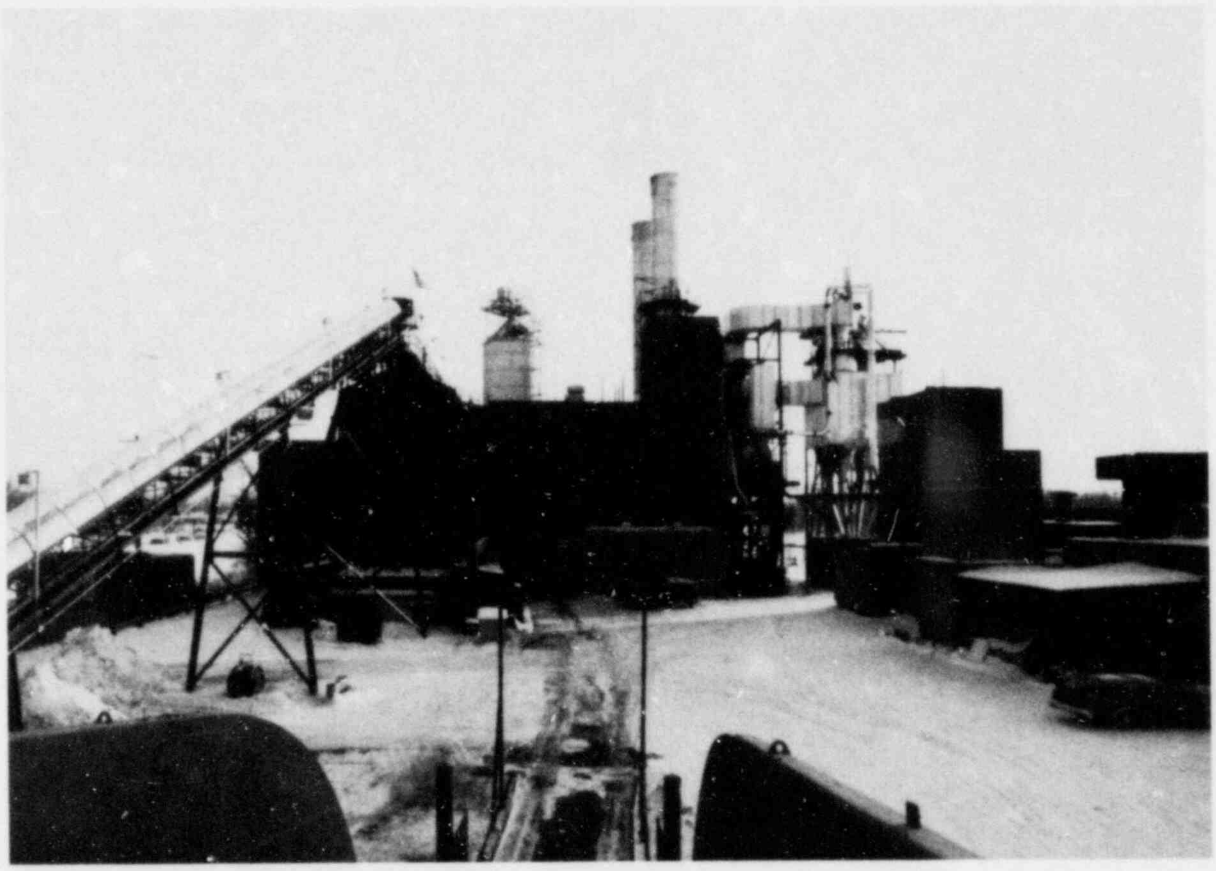
Sherco Aquaculture Swims Along

At the Sherco plant, waste heat has been used for several years to heat greenhouses where flowers and vegetables are grown commercially. Experimental work now is completed to prove that fish will grow at an accelerated rate when they live in a blend of plant cooling water and well water. The six-month growth rates of fingerling catfish and tilapia were equal to two to three years in warm-water lakes or streams.

University of Minnesota aquaculture specialists plan a pilot commercial fish facility at Sherco, where warm water will cascade through a series of stacked raceways for intensive fish culture.

1982 Power Supply Outlook Good

The outlook for Power Supply in 1982 is generally favorable. Transmission and generating facilities are in good condition to provide customers' electrical energy needs. The continuing challenge will be controlling costs to keep the product competitive.



Wood waste fuels the converted French Island generating facility.

While natural gas prices are likely to increase over the coming years, gas should maintain its competitive advantage over other heating fuels. NSP expects ample supplies for distribution, at least through the end of this century. Federal price decontrol and greater incentives for gas exploration increase potential supplies, and customers are taking conservation seriously. Reduced use makes more gas available for additional hookups on NSP systems.

The company distributes gas to customers through two separate systems. Northern Natural Gas Company supplies primarily domestic gas on the Northern system to 86 percent of the company's gas customers. Midwestern Gas Transmission Company provides 100-percent Canadian gas to the rest. The two systems serve 81 communities in Minnesota, Wisconsin and North Dakota.

Gas Transfer Plan Proposed

The price of Canadian export natural gas is tied to that country's coastal petroleum import prices, which results in a higher price than comparable U.S. domestic supplies.

As the U.S. deregulates natural gas prices as a profit incentive for new gas exploration, the price differential is narrowing between the Canadian and U.S. natural gas prices. To reduce the difference further, NSP is arranging to substitute some Northern Natural gas it purchases and distribute this to Midwestern system customers. It then would re-sell some of the Canadian natural gas it is committed to buy to the Tennessee Gas Transmission Company.

If approved by the Federal Energy Regulatory Commission (FERC), this gas transfer plan would result in a price reduction of about 12 percent to NSP customers served by the Midwestern system. The company hopes to get FERC approval by spring to begin this service.

The company's contract with Northern Natural, its primary Minnesota supplier, runs through 1991, while the contract for imported gas from Midwestern expires in 1985. The company is negotiating with both of these suppliers for contract extensions.

NSP Gas Supplies Increase

NSP obtained an additional daily 24,000 thousand cubic feet (mcf) natural gas supply from Northern in 1981—20,000 mcf for distribution by the Minnesota company and 4,000 mcf for Wisconsin company resale.

Customer conservation also makes added supplies of gas available to new customers. The typical NSP residential gas customer cut use from a weather-normalized average of 162 mcf a year in 1979 to 146 mcf in 1981 through weatherization measures and "dialing down" the thermostat. Such conservation and additional pipeline supplies made it possible for NSP to supply firm, rather than interruptible, gas service to customers who need up to 200 mcf daily in Minnesota and Wisconsin.

The number of natural gas customers continues to grow on both NSP systems. The company added 6,148 new customers for a total of 276,377 by the end of 1981. Of the total, 91.3 percent was residential and 8.7 percent was in the commercial and industrial category.

The Public Service Commission of Wisconsin (PSCW) granted NSP's March 1981 request to resume adding new natural gas customers in the Eau Claire, Chippewa Falls, Menomonie and Altoona areas.

Company Improves Facilities Use

Northern States Power Company (Minnesota) agreed with its Wisconsin subsidiary to liquefy up to 110,000 mcf of natural gas at the company's liquid natural gas (LNG) plant at Inver Grove Heights, Minnesota, for redelivery by cryogenic truck tanker to La Crosse, Wisconsin. This agreement provides the Wisconsin company lower-cost peak-shaving gas than it has had in the past.

NSP and Northern Natural extended for two years an agreement to liquefy, store and vaporize up to 1 million mcf of natural gas annually at the NSP Wescott LNG facility. This agreement provides Northern with a supply source in its principal market area and makes use of part of NSP's peak-shaving facilities that aren't now required to provide service to its firm gas customers.

New Records Established

Cold weather and additional gas supplies enabled NSP to set new records in daily gas sendout compared to previous years. The January 6, 1981, record sendout of 438,000 mcf fell to a new record January 9, 1982, when NSP supplied its customers with 502,000 mcf.

Corporate Planning and Development

Edward C. Glass
Vice President–
Planning and
Development

NSP's ability to operate in a rapidly changing business environment depends to a large extent on a thoughtfully conceived corporate strategy. The company is examining ways to fulfill its future responsibilities with activities that include examining energy trends and new supply technologies, exploring business options, and reevaluating its structure to maintain a financially strong company.

Supplementary Energy Stressed

The company encourages efficient development and use of all energy resources, including alternative energies, because of the direct relationship between energy availability and the general quality of life. NSP believes, too, that the rising cost of energy and declining available natural resources require extensive conservation efforts. Conservation, renewable energy and energy efficiency programs will fill a substantial part of future energy growth needs to the extent they are technically and economically feasible.

Research on sources that could supplement conventional electric generation includes technology to use the sun, wind and water efficiently and cost-effectively.

Rooftop solar collectors heat water at a number of NSP service centers where researchers record and compare their performance. Photovoltaic cells at an NSP laboratory will demonstrate how much electricity they can generate in NSP's service area climate. In 1981 the company gave $48,000 to continue tests of an experimental solar furnace at the University of Minnesota.

Wind potential, too, eventually will supplement conventional electric generation. NSP engineers installed a modern 10-kilowatt windmill to monitor its efficiency at the University's St. Paul campus and a second phase of this research will collect data from 15 wind-monitoring stations sited across the NSP system.

At NSP's 15 hydropower facilities, engineers are working to get the most power possible from rivers by redesigning and retrofitting generators for optimum output.

NSP is investigating the economics of providing a wholesale supply of thermal energy from the High Bridge, Riverside and Red Wing coal plants to district heating operations in St. Paul, Minneapolis and Red Wing. If selling coal-based steam proves economical, NSP could profit from the new business as well as reduce the state's dependence on oil and gas.

Project 2000 Provides Analysis

Through Project 2000, initiated in 1980, NSP analyzes alternatives that can make more effective use of its facilities, expertise and personnel. The ongoing study includes new business development, corporate structure options, management productivity, system expansion, end-use equipment and product pricing.

The first phase of study emphasized new business development and its criteria now are being applied in new business considerations.

Project 2000 also considers corporate structure options that could fit future operations better than NSP's current centralized management. If the company can deal effectively with a changing society within the centralized structure, reorganization would not necessarily be needed. However, if such issues as new competition and deregulation impede the company's ability to provide suitable services to customers or its financial viability, restructuring could be advantageous.

The study outlines areas where the company might improve its management techniques and take advantage of emerging technological advances. These efforts in productivity could make operations increasingly cost-effective.

Another area evaluated by Project 2000 is system expansion. It explores supplying long-term energy requirements with various capacity resources while balancing risks and benefits to shareholders and customers.

The feasibility of supplying end-use equipment commercially, providing conservation consultation and load management equipment is being analyzed. This relates to energy applications at the customer level for a specific purpose, primarily efficiency and economy to the customer.

Ratemaking philosophy must be considered in the light of social, political and economic developments. Project 2000 will provide corporate guidance on how rate-making and pricing strategies will help achieve business, social and economic objectives.

By initiating Project 2000, NSP created a basis to guide its corporate development into the next century.

Retail customers of electricity, natural gas and telephone service (in Minot, North Dakota) get utility service, billing advice and demonstrations of wise energy use through 17 division offices—seven in the Minneapolis-St. Paul metropolitan area and the rest in cities throughout the NSP four-state service area. More than 1.3 million retail customers rely on Division Operations not only for retail energy service, but also for expert advice on energy use through a comprehensive program of consultation, demonstration and financing assistance.

Retail electric kilowatt-hour sales for 1981 were up only 0.6 percent from the previous year. Conservation played a large part in this modest growth, and housing construction slowed to a virtual halt, limiting the number of potential new residential customers. NSP added only 13,435 residential customers in the year, 20 percent less than joined the system the previous year. Moderate weather, too, kept electric use to a slow increase.

Customers responded to energy conservation recommendations, reducing average electric use in residential, commercial and industrial categories. NSP believes rising energy cost and limited natural resources require intensive conservation efforts by the company and its customers. To make conservation attractive, divisions now provide Home Energy Audits, then follow them up with technical and, if necessary, financing assistance to eliminate energy waste.

Energy Auditors Start Inspections

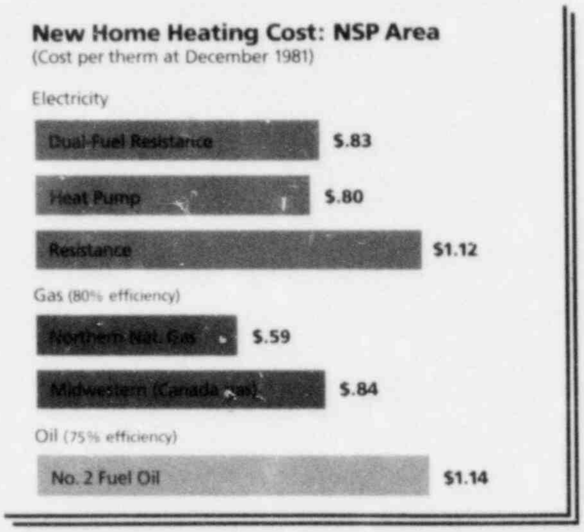
Specially trained energy auditors inspected 2,991 residences in 1981 and recommended cost-effective home improvements to increase comfort and save energy costs. Under the energy audit program mandated by federal law, home inspections cost the householder only $10; the rest of the approximately $120 cost is included in the rates paid by all customers.

Energy Is a Learning Experience

The Minneapolis Energy Learning Center—a rehabilitated 100-year-old fourplex—opened in 1981 to show the public how to weatherize older structures. NSP purchased and remodeled it, replacing heating, plumbing and electrical work to display four types of heating systems and several optional window treatments, insulation and water heating systems. The renovated building is open to visitors and educational groups to promote retrofitting of existing housing. A second Energy Learning Center opened in Eau Claire and one is under way in St. Paul to extend energy counseling to other areas where existing housing offers broad conservation opportunities at moderate initial expense. The Wisconsin Company opened an energy information center in a shopping mall where experts can field questions on conservation.

New housing, too, should provide for future energy savings. NSP cooperated in designing and building the Northstar Home in a Minneapolis suburb to show that a conventional, affordable home can be heated for only about $155 a season. Heat from occupants, lights and major appliances provide most of the home's heat, and the ventilating system includes an air-to-air heat exchanger to recapture 70 percent of the warmth from exhausted stale air. Double walls, triple-glazed windows, an air-lock entry and passive solar design help retain heat indoors. NSP's Northstar Home won a Reggie Award for building excellence from the Minnesota Home Builders Association for superior design, appearance and appeal during the Minneapolis Parade of Homes.

Ralph O. Duncanson
Senior Vice President
—Division Operations



NSP inaugurated three conservation investment programs in Minnesota as part of a demonstration project ordered by the state legislature. The first program includes rebates to NSP natural gas customers on its Midwestern (Canadian) gas system if they make qualifying weatherization improvements after a Home Energy Audit.

The second program provides deferred principal payments on loans at 7-percent interest to 200 St. Paul homeowners for weatherization installations. Rebates for part of the cost of energy-efficient appliances (based on $500 per kilowatt of expected peak demand reduction) are included in the third demonstration program.

Load Management Looks Ahead

Of all approaches to maximizing NSP energy efficiency, load management offers the best use of existing company facilities. By reducing peak demands and shifting use to off-peak hours and seasons, the company can delay building additions and use existing capacity effectively.

NSP restored service to Twin Cities customers after a record snowfall left more than 100,000 without power.

Load management is a cooperative effort between NSP and its customers. Together they can monitor electric demand and shift use to slack periods to eliminate excessive peaks.

As the price gap widens between oil and electricity as fuel for home heating, NSP anticipates a significant switch from oil or propane to electric heat by the middle of this decade. Electric demand now peaks in the summer because of air conditioning. Within a few years, the expected increase in winter heating electric demand could force NSP to use large amounts of oil-fired generation. Such costly generation would increase operating costs borne by all electric customers.

To reduce the increase of such future costs, NSP secured regulatory approval in Minnesota and the Dakotas to introduce a Dual-Fuel program for electric residential customers. It works this way: the customer would install an electric heating system but retain the existing oil or propane system as a backup. Electricity would be the primary fuel when NSP can provide it from coal, nuclear or hydro generating sources. When system demand reaches a level that requires the company to use oil, the customer's heating system would revert to the secondary fuel. In return for the interruptible electric heating service, the customer gets a rate below comparable oil heating costs.

DUAL FUEL

If the customer implements measures recommended in a Home Energy Audit, NSP will finance up to $3,500 for weatherization, including installation of the dual heating system, at 16-percent interest.

Conservation makes more gas available for new customers along gas mains to convert furnaces and appliances to gas. The price differential encouraged new customers within reach of mains to convert from oil heating.

An accelerated consultation program for commercial and industrial electric customers, planned in 1981, has begun. Effective use of the NSP low energy rates is reinforced by trained consultants who can tailor programs specifically to the needs of commercial and industrial customers.

Advisory Panels Study Concerns

Two consumer panels of community agency representatives and NSP customers meet regularly to discuss corporate policy and practices and how these relate to consumer concerns. In North Dakota, this appointed panel meets quarterly; the Minnesota panel, selected by community organizations, meets monthly. The panels' agendas cover a variety of issues, with special emphasis on problems of customers on fixed incomes.

Their resulting recommendations are intended to assist all consumers. This evaluation of corporate policy and practice helps keep the company apprised of customer problems and concerns.

Storms Leave Heavy System Damage

Division Operations efforts were divided in 1981 between initiating new programs to assist customers and maintaining traditional electric service through an unusual series of storms.

Distribution and transmission systems were heavily damaged by summer winds, a tornado that slashed through Minneapolis and St. Paul, then by a heavy snowstorm that downed lines in the NSP service area.

NSP Is a Corporate Citizen

The company's concern for the communities it serves is demonstrated by its contributions to local organizations that help improve the quality of life. In 1981 NSP distributed more than $1.4 million to a variety of charitable groups selected by two management committees that study the merits of a growing stream of requests.

Local United Way groups received 36 percent of 1981 NSP bequests, followed by 25 percent to community service groups, 20 percent to educational institutions, 8 percent each to civic and cultural groups and 3 percent to health organizations.

In addition, NSP matches its employees' gifts to higher educational institutions. In 1982 it will match educational contributions of retirees, as well, up to a corporate total of $25,000.

Bruce A. Richard
Senior Vice President
—Corporate Affairs

Public understanding and fair regulatory treatment of NSP concerns is the goal of Corporate Affairs. The company's rates for services, its production and transmission of energy and the environmental effect of its operations are monitored and controlled by several levels of government in each state it serves and by federal regulators in some operational areas. The company constantly must present its views to the public and to regulatory agencies to promote equitable government policy, legislation and regulation. These regulatory decisions should allow NSP to provide its customers with ample, low-cost energy and earn an adequate return for its investors.

Rate Increases Sought

Of NSP's total 1981 revenues (excluding non-firm sales to other utilities), 75.9 percent were within Minnesota's regulatory jurisdiction, 12.3 percent within Wisconsin's, 7.0 percent within North Dakota's, 2.5 percent within South Dakota's and 2.3 percent within the Federal Energy Regulatory Commission (FERC).

Rate increases requested in previous years were:

	Requested (Millions)	Granted
1977	$ 92.4	$56.4
1978	1.9	1.3
1979	7.4	4.8
1980	125.6	96.0

The Minnesota Public Utilities Commission (MPUC) issued an order for NSP's electric rate increase on April 30, 1981, and granted a $56.2 million revenue increase, or 72 percent of NSP's request. The MPUC granted the company a 13.5 percent return on common equity on a common equity ratio of 42.2 percent.

In its last NSP rate order in 1981, the MPUC granted $9 million, or 82 percent of the company's requested increase in natural gas rates. The order granted a 13.77 percent return on a common equity ratio of 41.46 percent.

Due to continued high inflation during 1981, NSP found it necessary to file increases in all regulatory jurisdictions for the electric and natural gas utilities. NSP requested a total revenue increase of $171 million, of which $152.2 million is pending regulatory action.

In its current Minnesota electric rate filings, NSP asked for a 16 percent return on its common equity ratio of 41.26 percent. The request is for $115.6 million in increased annual revenue, or 16.77 percent. Included in this increase is:

- $35.3 million to increase the return on common equity to 16 percent.
- $37.5 million to cover costs related to increased investment.
- $33.8 million to cover increased expenses due to inflation and other costs.
- $9.0 million for amortization of the Tyrone abandonment.

The company asked for interim rates subject to refund to provide a return on common equity of 14.5 percent. These rates, in the amount of $94.4 million, are being collected subject to refund until final determination is made.

FERC Rules on Tyrone Amortization

The Federal Energy Regulatory Commission (FERC) ruled in December 1981 that NSP (Minnesota) should pay NSP (Wisconsin) under their Coordinating

1981 Rate Increase Program

	Annual Increase			Effect On 1981	
	Requested	Allowed	Pending	Revenues	Status
	(Millions of Dollars)				
Electric—Retail					
Minnesota	$115.6		$115.6	$18.3(I)	Order Expected 6-30-82
North Dakota	11.4	$10.2(F)		1.0	Order Issued 1-11-82
South Dakota	6.2	5.2(F)		.1	Order Issued 12-15-81
Wisconsin	12.5		12.5		Order Expected 5-22-82
Electric—Wholesale					
Minnesota	4.8		4.8	1.2(I)	Order Expected in April 1982
Wisconsin	1.6		1.6	.4(I)	Order Expected 6-30-82
Gas—Retail					
Minnesota	16.6		16.6		Order Expected 9-30-82
North Dakota	1.1		1.1		Order Expected 6-1-82
Wisconsin	1.2	.9(F)			Order Issued 12-22-81
1981 Totals	$171.0	$16.3	$152.2	$21.0	

(I) Denotes Interim Rates Subject to Refund
(F) Denotes Final Rates

Agreement approximately 87 percent of the costs incurred in the cancelled Tyrone nuclear plant. These costs total about $67.1 million to be shared by the parent and subsidiary companies. Under the FERC amortization formula, the write-off period will be about nine years, rather than the five years proposed by the company. FERC's ruling termed the Tyrone cancellation a prudent decision by NSP.

Arguments are expected in the spring of 1982 before the Ramsey County (Minnesota) district court on the question of whether the federal or state government has jurisdiction in the Tyrone dispute over how ratepayers will share costs incurred before the PSCW withdrew its certificate of need and NSP cancelled construction plans. The company maintains the FERC ruling is a determination of an interstate wholesale electric rate, a matter of exclusive federal jurisdiction.

Rates Under Bond Questioned

Rates under bond are a provision of statutes in Minnesota and South Dakota and can be granted by Wisconsin and North Dakota regulators. They provide the company rate relief, subject to refund, during the long period required for a final decision in a rate case. In the $115.6 million Minnesota electric case, NSP volunteered to collect rates under bond at the $94.4 million level, delaying billing for the full amount until the final rate decision. It made a similar two-step increase proposal in its Minnesota natural gas case. NSP initiated the two-step rate plan as an indication of good faith as political pressure grew to eliminate rates under bond in spite of a record of responsible implementing of permissible price increases.

Rate Design Studied

State and federal government agencies control not only unit prices of electricity and natural gas, but also rate design—how approved total revenue requirements are allocated to different types of customers.

NSP believes in general that cost-based rates for energy supplies are the best public policy. Such rates encourage individuals to use energy wisely, take cost-effective steps to weatherize buildings and select efficient appliances. Historically, rates favored residential customers by shifting a higher share of cost to commercial and industrial users.

As living costs rise through inflation, some customers are unable to pay the full cost of their basic needs. Public welfare is not addressing the problem adequately as special programs are curtailed.

Residential Electric Bills
500 kwh/month for selected cities—Dec. 1981*

*Includes fuel and purchased power adjustments. Excludes city fees and state taxes.

To meet this growing need, NSP proposes that Minnesota regulatory and welfare agencies consider establishing a 25-percent rate break to residential electric customers with incomes below 125 percent of the federally designated poverty level. The cost of this estimated $8-million subsidy to low-income electric users would be borne by all customers. Residential customers' electric bills would increase about 1.25 percent, or 38 cents a month. The MPUC will consider NSP's proposal in its deliberation of the company's 1981 electric rate case.

Averaged Gas Prices Ruled Out

NSP buys natural gas from two different suppliers for distribution to its customers in Minnesota, North Dakota and Wisconsin. The relative cost of natural gas distributed by NSP's two systems in 1981 generated a controversy that was resolved by North Dakota's supreme court ruling in favor of the company's pricing policy. North Dakota customers (and others in the Red River Valley) use imported Canadian gas from the Midwestern Gas Transmission Company, while most Minnesota customers are on the Northern system, supplied by Northern Natural Gas Company with less-costly domestic gas. In 1981, Midwestern system natural gas cost NSP, and therefore its customers, about 81 percent more than gas on the Northern system.

North Dakota's Public Service Commission (NDPSC) ordered NSP to average gas prices between the two systems to equalize customer prices, but the MPUC refused to agree to Minnesota customers on the Northern system subsidizing the rates of Midwestern system customers. The dilemma meant a potential loss of up to $8 million annually to

the company if NSP reduced North Dakota prices without a compensating increase in Minnesota. Under Northern Natural's current tariff approved by FERC, NSP cannot supply its customers on the Midwestern system with gas from Northern Natural. NSP appealed the decision to a North Dakota district court, which upheld the NDPSC, bu' 'he supreme court, on NSP's appeal, overturned the lower court and ruled in favor of the NSP cost-based rates.

North Dakota customers could get a measure of price relief if NSP receives FERC approval to sell part of its contracted Canadian gas supply to Tennessee Gas Transmission Company and replace it on the Midwestern system with Northern Natural Gas. (See Page 7.) Contracts are complete for this gas transfer plan, but FERC approval is pending. As U.S. natural gas deregulation progresses, domestic gas prices are expected to increase, narrowing the price difference between the two NSP distribution systems.

NSP, Partners Seek Sherco 3 Permit

The company requested a modified certificate of need to build Sherco 3, an 800-megawatt (Mw) coal-fired electric generating unit to be built adjacent to its Sherco 1 and 2 units in Becker in Sherburne County, Minnesota. Modification of the need certificate is necessary to include Southern Minnesota Municipal Power Agency (SMMPA) and United Minnesota Municipal Power Agency (United Minnesota) as partners in its ownership.

NSP proposed to the Minnesota Energy Agency (MEA) that the company retain about 451 Mw of Sherco 3's capacity, with SMMPA to own 300 Mw and United Minnesota to own 49 Mw. The municipal agencies represent 19 Minnesota municipal utilities. Of its share, NSP reserves 20 Mw for use by Lake Superior District Power Company, Ashland, Wisconsin.

NSP planned the facility in 1972 and proceeded through the regulatory process, obtaining siting and environmental clearance and limited work authorization, and beginning work in 1977. The following year the company voluntarily postponed construction when the forecast of future electric demand diminished. While it was apparent NSP's customers would not need Sherco 3's full capacity as soon as expected, the municipal agency members, who depend heavily on oil for fuel, saw rapidly escalating costs as oil prices increased and decided to participate in the Sherco 3 plant. NSP continues to forecast gradually growing electric demand and expects less-reliable performance from its older generating facilities. By the time Sherco 3 would go into service in 1986, about 300 Mw of NSP's coal-fired plant capacity would be at least 33 years old—near the end of its useful life.

Public hearings on the joint application for modification of Sherco 3's need certificate began February 8, 1982, and are expected to continue for several months. When the state hearing examiner reports findings, a final decision will come from the newly merged Minnesota Department of Energy, Planning and Development.

Transmission Line Rulings Issued

The Wisconsin Public Service Commission (PSCW) denied NSP's request to build a new 345-kv transmission line from its Prairie Island nuclear power facility to Eau Claire, Wisconsin. The $30-million line would have served west-central Wisconsin. Instead, the PSCW ordered the company to upgrade its transmission capacity on five existing lines that interconnect Minnesota generating plants with Wisconsin customers. Although the PSCW conceded eventual need for the line, it said reconductoring would allow it more time to determine the line's location.

Work is under way on the Sherco-Benton 345-kv transmission line connecting the Sherburne County substation at the Sherco generating plant with the Benton County substation near St. Cloud, Minnesota. Following public information meetings, NSP applied for a construction permit, which the Minnesota Environmental Quality Board granted in February 1981.

Corporate Affairs also obtained: regulatory clearance for re-spacing spent nuclear fuel rods stored at NSP's nuclear plants; the final operating license for the Monticello plant; approval to improve the Prairie Island plant's intake and outflow systems; and permission to improve low-level radioactive waste-handling facilities at both NSP nuclear plants. In 1981 Sherco units 1 and 2 got operating permits and baghouse filter installation at the Riverside facility received regulatory approval.

LSDP Affiliation

Solicitation offers went out in January 1982 to shareholders of Lake Superior District Power Company (LSDP), Ashland, Wisconsin. The Securities and Exchange Commission approved NSP's proposal to exchange .43 share of the company's common stock for each share of LSDP common stock.

This affiliation was completed on February 23, 1982, when more than 86 percent of common shares of LSDP were presented for exchange.

The affiliation was initiated by LSDP in 1977 because NSP can raise capital at lower cost and the company's generating capacity will help maintain a reliable energy supply for LSDP customers in northern Wisconsin and part of Upper Michigan, according to K.S. Austin, LSDP president.

Harriet B. Rogge
Vice President—
Administration

Corporate Services includes human resources, information systems, buildings, purchasing supervision, stores and inventory of needed equipment. For a discussion of natural gas utility operations, also a part of Corporate Services, see Page 7.

NSP's diverse internal corporate functions include sophisticated management and information to assist shareholders and customers and encouraging optimum employee productivity through training. The company's creative approach to efficiency is not limited to energy production and distribution; it encompasses alert internal management, too.

Plan Revised for Shareholders

The federal Economic Recovery Tax Act of 1981 includes a provision that could benefit shareholders of many public utilities. The Act permits shareholders to exclude dividends of up to $750 on an individual tax return ($1,500 on a joint return) if the dividends are reinvested in newly issued common stock of the same utility through a qualified dividend reinvestment plan. The reinvestment provision of the Act was written with individual shareholders in mind. It does not apply to corporations, trusts, estates, non-resident aliens or persons holding more than five percent of the voting power or value of the stock in the corporation.

NSP revised its Dividend Reinvestment Plan before payment of its January 1982 dividends to give its holders of both common and preferred stock an opportunity to take advantage of the exclusion. The utility dividend reinvestment provisions of the tax law are effective from January 1, 1982, to December 31, 1985. For more details please see Page 36.

Information System Updated

Computers continue to play an increasing role in managing NSP's information resources, producing reports used by management and documents sent to customers and shareholders.

A new Customer Information System, installed in 1981, produces the bills customers receive and manages the account information of 1.2 million customers. The new system allows NSP to respond quickly to regulatory and customer information requirements.

Information Systems initiated a long-range planning process to define the company's future information needs. Personnel from major functional areas formed a task force to interview company officers, determine their information needs and establish information goals. The resulting plan, called "Corporate Resources-Information Systems Plan" (CRISP), provides broad guidelines for Information Systems.

NSP computers in 1981 gained the capability of developing reports, charts and graphs for rate cases, environmental and other regulatory documents and for use by management and the Board of Directors.

Employees Build Careers

More than 7,000 company employees have continuous opportunities to improve job skills and prepare for promotion through a variety of training and development programs at work or through outside educational institutions. Computerized training allows each student to expand job skills independently at work. Other employees attend company-sponsored group courses. In 1981 more than 3,300 employees completed some form of training to develop better job skills.

When an employee survey in 1980 indicated a need for broad understanding of corporate policy and programs, NSP responded in 1981 with an unusual series of employee meetings. More than 40 managers got special briefings, then visited groups of employees to discuss company plans and answer questions. More than 100 meetings brought employees up to date on corporate programs and projects.

Flex-Benefits Attract Attention

The company attracted national attention in 1981 as one of a handful of U.S. corporations offering full-time non-union employees flexible or "cafeteria" benefits. Through the flexible benefits program, eligible employees are entitled to basic "core benefits", plus the option of additional coverage in health care, medical insurance, disability insurance, vacation and retirement savings options. The employee's "core benefits" are paid by the company; higher levels of benefit coverage are available if the employee contributes to their cost. The plan allows each person a choice of benefits according to individual needs.

Such innovative programs, together with company counseling, contribute to NSP's unusual level of employee tenure; the average NSP employee has 14 years' experience with the company and 36 percent tally more than 20 years.

NSP continues its active Equal Employment Opportunity policy and seeks to purchase supplies and services from qualified minority and female contractors and vendors. In 1981, about $1.9 million in purchases and contracts were awarded minority- and female-owned firms.

Office Space Needs Changed

The company's General Office crowding was relieved temporarily in 1981 by leasing space in the nearby 100 Washington Square building in downtown Minneapolis, and reassigning offices at the headquarters building.

Industry Performance Edges Upward

After 10 years of rather dismal performance with average return on equity in the 11 percent range, the electric utility industry performed somewhat better in 1981. It is estimated that return on equity will move up to approximately 12.5 percent.

However, the industry's quality of earnings continues to be less than satisfactory. For a second year, non-cash allowance for funds used during construction (AFC) accounted for about half of utility earnings per share.

While the industry's performance was better in 1981, it is a long way from being satisfactory. The return on equity is still considerably below that for American industry in general despite the fact that electric utilities are at least as risky. The market price of utility stock is still low. It now is at 78 percent of book value. Moreover, the industry still does not have enough financial flexibility and dividend payout ratios average approximately 77 percent, which could well inhibit the growth in dividends over the next few years.

But continued improvement for the industry might well occur. Many electric utility analysts see the 1981 turn-around as something which could be lasting. Rate regulation has improved as regulators gain a better understanding of the industry, and returns granted in 1981, on average, have exceeded 15 percent, up from 14 percent a year ago. Dividends went up an estimated 7 percent in 1981 and the market price of utility stock increased marginally in spite of extraordinarily high interest rates. Furthermore, many companies are finishing large construction programs so that financing needs will be somewhat less.

By 1990, it is estimated that electric energy will supply 13 percent of U.S. energy needs, up from 11 percent in 1981. This indicates an annual increase in electric generation of about 3 percent over the next nine years, a responsibility that requires a financially healthy electric utility industry. To improve its financial health, the utility industry must obtain sufficient rate relief from regulators, improve productivity, stringently control costs and improve the industry's load factor by better management of customers' energy requirements.

NSP, over the last ten years, out-performed the electric utility industry. It did again in 1981 and expects that it will continue to out-perform the industry in the future.

NSP's 1981 financial performance was a step in the right direction. However, continued improvement is needed if the company is to treat shareholders fairly and to meet the increasing energy requirements of its service area.

One approach to measuring financial progress is to analyze the financial measures that concern shareholders and bondholders.

There are three financial measures generally used to evaluate how a company is treating its shareholders: earnings per share growth rate, dividend growth and the market price of the stock relative to its book value.

For bondholders, capital structure and bond interest coverage are two of the most important measures of NSP's ability to retain the high quality double-A bond and preferred stock ratings it has held for more than 30 years.

Earnings Per Share

Objectives:

Earnings per share growth: Average growth rate of at least 6 to 7 percent per year.

Earnings per share growth is dependent largely upon the return on common equity. (Return on common equity is the earnings available for common stock as a percentage of the average amount of common equity.)

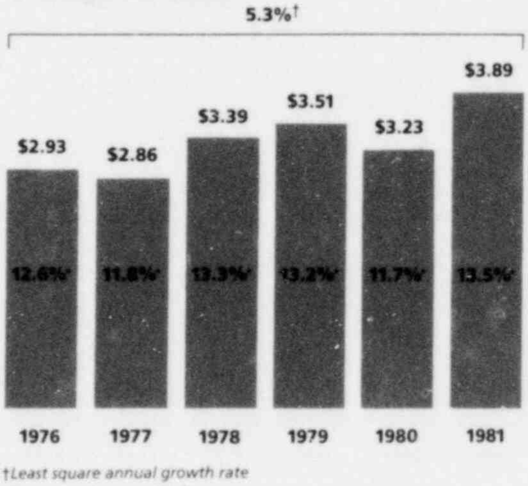
NSP did not achieve its earnings per share objective in 1981, with a five-year growth rate of 5.3 percent.

To meet the earnings objective, return on equity must show further improvement over 1981 results of 13.5 percent.

The quality of NSP's earnings, however, continued to be high in 1981. Allowance for Funds Used During Construction (AFC) was only 13 percent of earnings compared to 50 percent for the electric utility industry.

Electric utilities must earn returns comparable to U.S. industry to compete effectively for capital. Surveys indicate that most institutional investors believe that electric utilities have the same or more risk than industrials. Yet while American industry earned 15 to 16 percent during the last five years, electric utilities generally earned only about 12 percent during the same period.

Earnings Per Share



†Least square annual growth rate
**Return on Common Equity*

Harry W. Spell
Senior Vice President
– Finance

Dividend Policy

Objectives:

Payout ratio: 65 to 70 percent.
Increase dividends on a regular basis.

The NSP dividend policy is based on an earnings payout that averages 65 to 70 percent. Although it varies on a year-to-year basis, the company's average payout ratio over the last five years was 67 percent. In addition to the payout ratio, NSP considers the ratio of dividends paid to the common stock's book value when declaring dividends. The ratio of dividends ($2.56) to book value (year-end 1980) was 9.1 percent.

The NSP objective is substantially less than the 1981 national utility industry average payout ratio of about 77 percent. NSP's lower payout ratio provides better potential for future dividend growth.

In each of the past five years, the NSP directors have increased dividends at their June meeting. The company intends to continue to increase dividends on as regular a basis as possible.

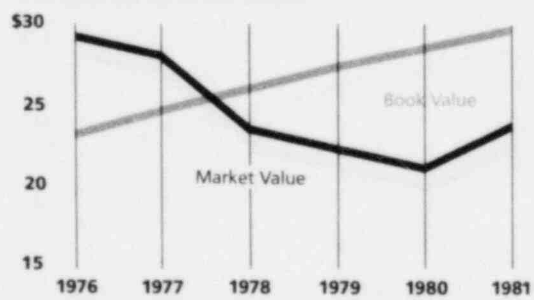
Annualized Dividends

June	From	To	Increase
1977	$1.94	$2.06	12¢
1978	$2.06	$2.16	10¢
1979	$2.16	$2.28	12¢
1980	$2.28	$2.42	14¢
1981	$2.42	$2.56	14¢

Market to Book Value

The market value of NSP stock continues at levels below book value, a clear indication that suppliers of capital are not satisfied with the returns earned by NSP. At year-end the company's market stock value was 82 percent of book value. If and when the company's returns increase to levels of alternative investments of comparable risk, the market value of NSP stock will reflect this improvement in competitive position.

NSP Market Value Compared to Book Value



Capital Structure

Objective:

Common equity 40 to 45 percent of the total capital invested in the company.

The capital structure is the total amount of money invested in the company through various securities. A large amount of total equity—particularly common equity—assures NSP greater flexibility and NSP's creditors more protection. In 1981, NSP broadened and strengthened its capital structure objectives. This table shows the old and the new objectives. The company believes the new objectives better reflect the risk of the business and the high interest rates that are forecast for the future. In addition, the objectives are more in concert with the views of the bond rating agencies. And, finally, a broader band is better because, as a practical matter the ratios do tend to change considerably from time to time, based on economic conditions and company operations.

Capital Structure Objectives

	Old	New
	(Percent)	
Common equity	40 - 42	40 - 45
Preferred stock	10 - 12	9 - 12
Long and short-term debt	48 - 50	45 - 50

The amount of common equity in the capital structure was an issue with the Minnesota Public Utilities Commission (MPUC) in a 1979 rate case. In that case the MPUC set return levels based on a common equity ratio of 40 percent. However, in the electric rate case which was settled in 1981, the company used a projected test year of 42.2 percent common equity and the MPUC approved that level.

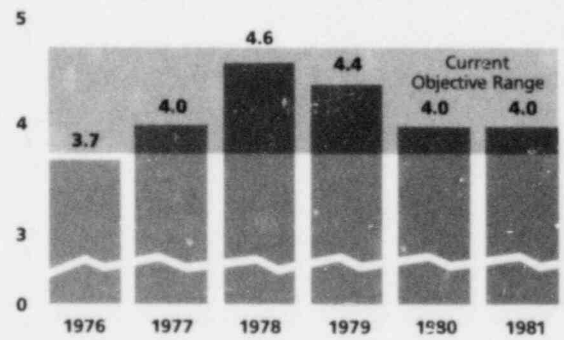
Bond Interest Coverage

Objective:

Pre-tax interest coverage of at least 3.75 to 4.75 times expected interest charges.

To maintain a solid double-A bond rating and assure financial flexibility, the company strives to

NSP Bond Interest Coverage



achieve pre-tax interest coverage of at least 3.75 to 4.75 times interest charges. In 1981 bond interest coverage was 4.0 times interest charges. This compares with an estimated 3.5 times coverage rate for comparable utilities.

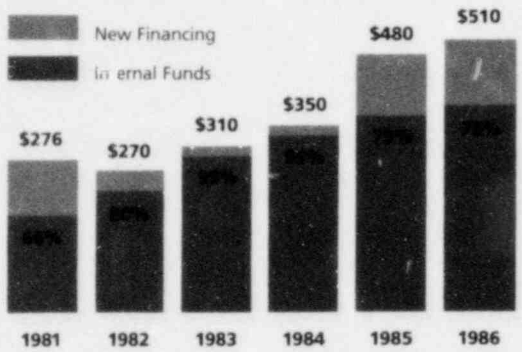
The company expects to maintain interest coverage well within objective levels in the future.

1981 Financing

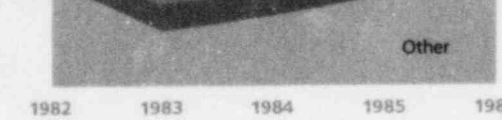
Construction expenditures for 1981 were $276 million. An additional cash requirement of $9 million resulted from the purchase of tax benefit transfers. These requirements were met primarily by internally generated funds and the sale in December of $75 million of first mortgage bonds, sold at a record high interest cost to the company of 16.05 percent.

Proceeds from sales of pollution control revenue bonds by municipalities added $12 million.

Where Construction Dollars Will Come From
(Dollars in millions)



Where Construction Dollars Will Go
(Dollars in millions)



1982 Financing

Estimated 1982 cash requirements are as follows:

	(Millions)
Construction expenditures	$270
Refund of maturing bonds	22
Purchased tax benefits (net)	38
Total	$330

The net cash requirement will be met primarily through internally generated funds and the sale of $75 to $100 million of first mortgage bonds. Proceeds from sales of tax-exempt bonds by municipalities are expected to add $5 million. In addition, $7 million of new common stock is estimated to be issued through the Dividend Reinvestment Plan.

In the 1982 to 1986 period, anticipated financing will be relatively light—about $370 million—with internal funds providing about 80 percent of the $1.9 billion in forecast construction expenditures. This compares with expected industry-average internal funds generation of about 40 percent.

Outlook for the Future

Several positive signs encourage optimism about the future for NSP. Regulatory agencies appear to be gaining a better understanding of the financial pressures on the company, as demonstrated by the granting of somewhat higher returns. Inflation is diminishing after an extended period at a double-digit pace. If inflation can be brought under control, interest rates also should ease, critical factors in the financial health of a capital-intensive industry.

Estimated cash requirements over the next five years are less than projections made just a few years ago. The Economic Recovery Tax Act of 1981 should help bring in additional capital for construction programs.

The price of electricity on the NSP system compares very favorably with the rates of other utilities across the country and within the state of Minnesota. The company's goal is to keep the price of its product competitive. NSP intends to make every effort to minimize the need for rate increases. Maintaining the competitive position of NSP's rates is a key to enhancing the company's future financial performance.

Directors and Officers (as of December 31, 1981)

Directors of the Minnesota Company

David A. Christensen (46)*
President and Chief Executive Officer,
Raven Industries, Incorporated
(Manufacturers of reinforced plastics, sportswear and electronic equipment)
Sioux Falls, South Dakota

W. John Driscoll (52)*
President, Green Valley Holding Company
(Private investment firm)
St. Paul, Minnesota

N. Bud Grossman (60)*
Chairman of the Board and Chief Executive Officer,
Gelco Corporation
(Transportation leasing, management and corporate services firm)
Eden Prairie, Minnesota

Dale L. Haakenstad (53)*
Chairman and Chief Executive Officer, Western States Life Insurance Company
(Life insurance company)
Fargo, North Dakota

Robert E. Haugan (64)*
President, The Webb Company *(Printing and publishing)*
St. Paul, Minnesota

Clayton K. Larson (63)
President and Chief Operating Officer
Northern States Power Company, Minneapolis, Minnesota

Richard H. Magnuson (56)
Senior Vice President and General Counsel,
Land O'Lakes, Incorporated
(Food processing, marketing and agricultural services cooperative)
Arden Hills, Minnesota

Donald W. McCarthy (59)
Board Chairman and Chief Executive Officer
Northern States Power Company, Minneapolis, Minnesota

M. D. McVay (63)
President, Cargill, Incorporated
(International merchant, food, milling and shipping enterprise)
Minneapolis, Minnesota

William G. Phillips (61)
Board Chairman and Chief Executive Officer
International Multifoods Corporation
(Food processing and marketing company)
Minneapolis, Minnesota

G. M. Pieschel (54)
President and Chairman, Farmers and Merchants State Bank
(Commercial bank)
Springfield, Minnesota

Margaret R. Preska (43)
President, Mankato State University
(Institution of higher education)
Mankato, Minnesota

D. B. (Rhiny) Reinhart (61)
President, Gateway Foods, Incorporated
(Wholesale food distributor)
La Crosse, Wisconsin

Dorothy J. Skwiera (45)
Vice Chairman, Minnesota Corrections Board, *(State parole board)*
St. Paul, Minnesota

Chairman Emeritus
Robert H. Engels (71)
Retired Chairman of the Board of NSP
Minneapolis, Minnesota

Principal Officers of the Minnesota Company

Roy H. Berglund (56)[1], Vice President-Commercial Operations
Arland D. Brusven (49), Secretary and Financial Counsel
Roland W. Comstock (51), Vice President-Public Affairs
James O. Cox (54), Vice President and Treasurer
Arthur V. Dienhart (61), Vice President-Plant Engineering and Construction
Ralph O. Duncanson (56)
Senior Vice President-Division Operations
Dennis E. Gilberts (50), Senior Vice President-Power Supply
Edward C. Glass (59)[1]
Vice President-Planning and Development
Clayton K. Larson (63)
President and Chief Operating Officer
Donald W. McCarthy (59)
Chairman of the Board and Chief Executive Officer
Gerald S. Pettersen (50), Controller
Robert E. Pile (59), Vice President-Gas Planning and Supply
Arthur R. Renquist (61), Vice President-Law
Bruce A. Richard (52), Senior Vice President-Corporate Affairs
Harriet B. Rogge (55), Vice President-Administration
Harry W. Spell (58), Senior Vice President-Finance
Leo J. Wachter (62), Vice President-Power System Operation and Maintenance
Rosanne Giombolini, Assistant Secretary
Shirley L. Grich, Assistant Secretary
E. J. Hall[2], Assistant Treasurer

Directors of the Wisconsin Company

John L. Carroll (65), Retired President and Chief Executive Officer, Northern States Power Company (Wisconsin), Eau Claire, Wisconsin
Chauncey J. Cooke (62)*, Farmer, Eau Claire, Wisconsin
F. Jerry Kripps (59), Executive Vice President-Operations, Northern States Power Company (Wisconsin), Eau Claire, Wisconsin
Clayton K. Larson (63), President and Chief Operating Officer, Northern States Power Company (Minnesota), Minneapolis, Minnesota
Ray A. Larson, Jr. (52),* President, Wissota Sand and Gravel Company, Eau Claire, Wisconsin
D. B. (Rhiny) Reinhart (61)*, President, Gateway Foods, Incorporated, La Crosse, Wisconsin
Richard L. Roehrich (57), Vice President-Administrative Services, Northern States Power Company (Wisconsin), Eau Claire, Wisconsin
Harry W. Spell (58), Senior Vice President-Finance, Northern States Power Company (Minnesota), Minneapolis, Minnesota
Edwin M. Theisen (51), President and Chief Executive Officer, Northern States Power Company (Wisconsin), Eau Claire, Wisconsin

Principal Officers of the Wisconsin Company

Arthur V. Dienhart (61)[3], Vice President-Plant Engineering and Construction
Roland J. Jensen (52)[4], Vice President-Commercial and Division Operations
Donald P. Jolstad (52), Secretary and Assistant Treasurer
John L. Koplin (48), Treasurer
F. Jerry Kripps (59), Executive Vice President-Operations
Richard L. Roehrich (57), Vice President-Administrative Services
Edwin M. Theisen (51), President and Chief Executive Officer
Glenn B. Thorsen (47), Vice President-Finance
Irene Shiffer, Assistant Secretary

* *Member of Finance-Audit Committee*
[1] *Elected June 1981*
[2] *Elected October 1981*
[3] *Resigned December 1981*
[4] *Elected July 1981*

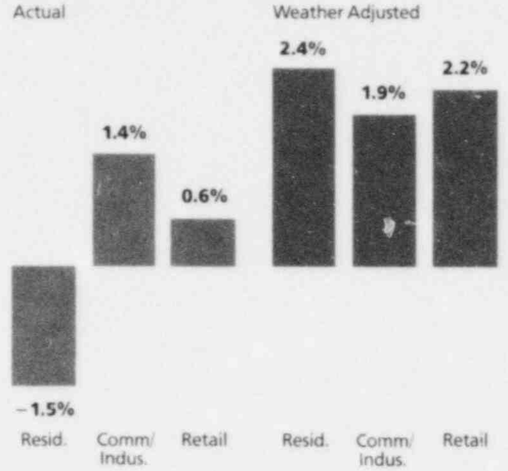
Results of Operation

NSP's 1981 earnings per share were $3.89, up 66¢ from the $3.23 per share earned in 1980 and up 38¢ from the $3.51 earned in 1979. Of the 1981 earnings, 40¢ is subject to refund: 29¢ from pending rate cases and 11¢ related to the cancelled Tyrone nuclear plant. The earnings increase in 1981 was due primarily to rate increases that were implemented during 1980 and 1981 and an adjustment of the Tyrone amortization.

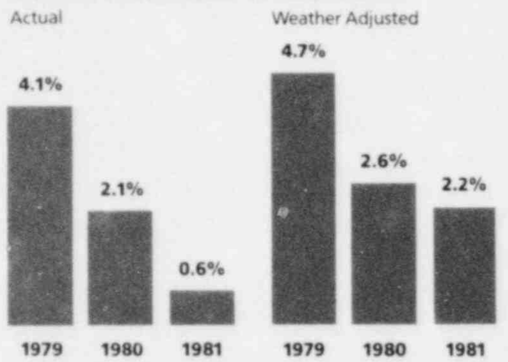
Electric Sales and Revenues

Over the past three years, electric retail sales have shown little growth. Retail sales, and especially residential and small commercial and industrial sales, are influenced by extreme weather conditions, as electric energy is used for both summer air conditioning and winter home heating. During 1981, the weather was mild during both the winter heating season and the summer cooling season.

1981 Electric Sales Growth



Electric Retail Sales Growth Rates



On a weather-adjusted basis, retail sales increased 2.2 percent in 1981 over 1980. This gain can be attributed primarily to a 1.6 percent increase in average retail customers. However, even the rate of increase in new customers declined from previous years (2.3 percent in 1980 and 2.6 percent in 1979) due to the decline of the new housing market and continued recession. Electric sales to customers who heat their homes with electricity increased 6 percent (weather-adjusted) during 1981 due to an 11 percent increase in the number of these residential customers.

Commercial and industrial sales, which increased 1.9 percent (weather-adjusted) in 1981, have been affected by weather and, to a large degree, by the current recession. Megawatt-hour sales to small commercial customers increased 2.6 percent, while sales to large industrial customers increased 1.7 percent, which is the lowest rate of increase for this category since 1974.

The 0.6 percent increase in retail electric sales in 1981 added only $4 million to the electric revenue increase of $83 million, with the balance due to price increases. During 1980, NSP requested annual electric rate increases totaling $110.4 million, of which $83.8 million ultimately was approved by the various regulatory bodies. The 1980 rate increase program increased 1981 revenues, compared to the amounts collected in 1980, $59 million. During 1981, NSP filed electric retail and wholesale rate increases in each jurisdiction, totaling $152.1 million. Of this amount, approximately $21 million was collected during 1981 on an interim basis, subject to refund.

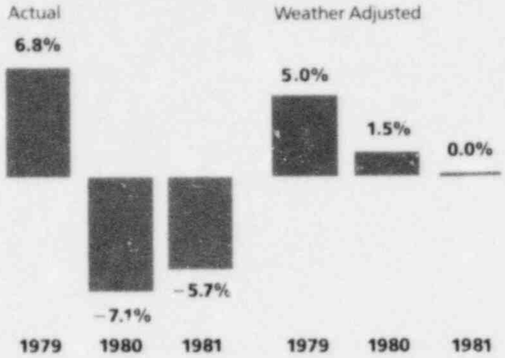
Summary of Electric Revenue Increase

	1980/79	**1981/80**
	(Dollars in millions)	
Sales Increase	$ 7	**$ 4**
Rate Increases	33	**80**
Fuel Clause & Other	42	**(1)**
	$82	**$83**

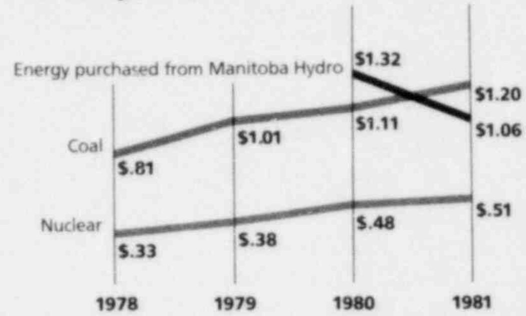
Gas Sales and Revenues

Gas sales are categorized as firm sales (primarily to heating customers) and interruptible sales (to customers with an alternate energy supply). The decline in firm gas sales of 5.7 percent was due in large part to milder weather during the heating season (8 percent warmer than 1980). On a weather-adjusted basis, firm gas sales were the same as 1980. Gas sales to residential heating customers declined 1.0 percent (weather-adjusted) in spite of the addition of 10,000 new residential gas heating customers in 1981. Residential heating use per customer declined 5.3 percent in 1981 as rapidly escalating prices continued to encourage customer conservation efforts.

Firm Gas Sales Growth Rates



Fuel Cost per Kwh



The increase of $38 million in gas revenue was due entirely to rate increases and increases in the cost of purchased gas. The increased cost of purchased gas recovered from our customers amounted to $44 million, while the full-year effect of 1980 rate increases raised revenues $6 million over 1980. Annual rate increases of $18.9 million were requested in 1981; however, none of these were implemented during the year. Partially offsetting the revenue gain from price increases was a reduction of $12 million due to lower firm and interruptible gas sales.

Summary of Gas Revenue Increase

	1980/79	1981/80
	(Dollars in millions)	
Sales Increase	$ (7)	**$(12)**
Rate Increases	2	**6**
Gas Purchased for resale recovery	33	**44**
	$28	**$ 38**

Electric Production Exper se

Electric production expense, which includes fuel for electric generation and purchased and interchange power, increased only 3.2 percent in 1981, compared to increases of 19.6 percent in 1980 and 8.7 percent in 1979. The fuel cost per kilowatt-hour (kwh) of energy from coal increased 8 percent in 1981 and the cost of nuclear fuel increased 5 percent. The cost per kwh of energy purchased from Manitoba Hydro decreased 19 percent from 1980. While the cost of fuel itself reflected increases, total electric production expense was held to a 3.2 percent increase because more lower-fuel-cost generation and purchases were available in 1981.

An additional 161 gigawatt-hours (gwh) of nuclear output was available in 1981 and 279 gwh more was generated from our lowest-cost coal units —Sherburne County units 1 and 2. Purchases from Manitoba Hydro more than doubled in 1981. The Manitoba Hydro interconnection was completed in May 1980 but 1980 purchases were below expected amounts due to a severe drought in the Manitoba Hydro Nelson River area.

Gas Purchased for Resale

Increases in the cost of gas from our suppliers, Northern Natural Gas Co. and Midwestern Gas Transmission Co. accounted for the entire increase in gas supply expense.

The increase in the cost of gas purchased is recovered from retail customers through a purchased-gas adjustment clause. These increases, plus NSP rate increases, continue to encourage customer energy conservation efforts.

Administrative and General, Other Operation and Maintenance

These expenses, in total, increased 11.9 percent in 1981, 20.9 percent in 1980 and 8.7 percent in 1979. Expenses in each of these years were affected by high rates of inflation and increased regulatory-related expenses, especially in 1980. Maintenance expenses increased at a relatively low rate (3.4 percent) in 1981. The Nuclear Regulatory Commission (NRC) required a large number of plant maintenance projects in 1980 and work continued on these in 1981, but many were capital, rather than operating expenses.

Depreciation and Amortization

Depreciation and amortization costs decreased $11.3 million, or 9.9 percent, during 1981. The decrease was due entirely to the adjustment for the Tyrone nuclear plant cancellation. NSP had been amortizing the loss from Tyrone based on a five-year amortization period. The Federal Energy Regulatory Commission (FERC) on December 3, 1981, issued an order requiring amortization of the loss at a rate of $7.5 million per year over approximately a nine-

year period. This adjustment of the Tyrone cancellation reduced amortization by $17.4 million.

Tyrone Amortization

As indicated above, the amortization of costs associated with the Tyrone nuclear plant cancellation was adjusted in 1981 pursuant to a FERC order. In addition to the change in amortization and related deferred taxes, refunds to customers and the associated current income tax effect were recorded in 1981. The net effect of these adjustments was to increase net income by $5.4 million, or 19 cents a share, in 1981.

Impact of Inflation

See Note 13 to the financial statements for a discussion on the impact of inflation on NSP.

Capital Resources

NSP has a continuing need for capital to finance its construction program. In 1981 construction expenditures were $276 million, of which 66 percent was provided by internally generated funds. The 1982 estimated construction expenditures are $270 million and the estimated expenditures for the five-year period 1982-1986 are $1.9 billion. It is estimated that 80 percent of the 1982 expenditures and 80 percent of the 1982-1986 expenditures will be met by internally generated funds.

In addition to the construction program, $61 million will be required during the five-year period 1982-1986 to retire maturing first mortgage bonds and to meet sinking fund requirements of the preferred stock and Wisconsin Company first mortgage bonds.

For the affiliation with Lake Superior District Power Company (LSDP) common stock held in treasury will be exchanged for the common stock of LSDP.

For the five-year period 1982-1986, it is estimated that NSP will need $370 million of external financing. In 1982 NSP plans to issue $75 to $100 million of first mortgage bonds and approximately $18 million of tax-exempt financing. Also, NSP will issue new common stock for its dividend reinvestment program instead of purchasing shares on the open market.

During 1981, the company issued two series of bonds. In July, $13.7 million of bonds were used as collateral for pollution control revenue bonds issued by municipalities. These bonds had a 20-year maturity and a cost to NSP of 11.30 percent. In December, $75 million of first mortgage bonds were issued with a 30-year maturity and a cost to NSP of 16.05 percent.

Liquidity

An electric utility's liquidity is a function of internal funds generation, access to the long-term securities market and the availability of short-term credit facilities.

At the end of 1981, approximately 49 percent of NSP's total capital structure was debt, which is relatively low for the utility industry. Compared to the electric utility industry, NSP has a relatively low debt ratio, adequate interest coverage and favorable internal cash generation. Consequently, NSP expects to have access to long-term debt markets on terms better than the electric utility industry in general.

Notes payable of $76 million at the end of 1981 represent about 4 percent of total capitalization. At the end of 1981, NSP had $161 million of credit lines with commercial banks.

Report of Management to Shareholders

Management is responsible for the financial statements and representations in the annual report. Management believes the financial statements have been prepared in conformance with generally accepted accounting principles. In preparing such statements, management makes informed judgements and estimates of the expected effects of events and transactions that are currently being reported.

Management depends on the Company's internal accounting control system to assure reliability in financial reporting. This system is designed to reasonably assure the assets are safeguarded and transactions are executed in accordance with management's authorization and recorded properly for the preparation of financial statements in accordance with generally accepted accounting principles. Management believes the Company's accounting controls provide reasonable assurance that potentially material errors or irregularities would be prevented or would be detected within a timely period by employees in the normal course of their duties. The Audit Committee of the Board of Directors, composed solely of directors who are not officers or employees, meets regularly with management, internal auditors and the Company's independent certified public accountants to discuss their evaluation of internal accounting controls and financial reporting. Internal and independent auditors have free access to the Audit Committee, without management's presence, to discuss the results of their audits. The Audit Committee recommends for shareholder ratification the selection of the independent auditors to perform an audit in accordance with generally accepted auditing standards and express an opinion on NSP's financial statements.

Statement of Income

Northern States Power Company, Minnesota and Subsidiaries

	Year Ended December 31		
	1981	1980	1979
	(Thousands of dollars)		
Operating Revenues			
Electric (Note 2)	**$ 998 034**	$ 914 704	$ 832 663
Gas	**271 995**	233 809	205 623
Telephone and heating	**10 860**	10 539	9 890
Total	**1 280 889**	1 159 052	1 048 176
Operating Expenses			
Fuel for electric generation	**207 966**	203 924	178 972
Purchased and interchange power	**40 084**	36 451	22 096
Gas purchased for resale	**206 681**	172 893	142 606
Administrative and general	**86 342**	72 716	59 422
Other operation	**131 330**	115 139	95 628
Maintenance	**91 819**	88 838	73 842
Depreciation and amortization (Notes 1 and 8)	**102 887**	114 151	107 161
Property and general taxes	**97 549**	92 535	87 497
Income taxes (Notes 1 and 5)	**118 242**	100 105	109 362
Total	**1 082 900**	996 752	876 586
Operating Income	**197 989**	162 300	171 590
Other Income			
Allowance for funds used during construction—equity (Note 1)	**10 448**	9 950	9 944
Miscellaneous	**2 090**	4 192	3 270
Total	**12 538**	14 142	13 214
Total Income	**210 527**	176 442	184 804
Income Deductions and Non-Operating Taxes	**6 833**	(690)	1 527
Income Before Interest Charges	**203 694**	177 132	183 277
Interest Charges			
Interest on long-term debt	**62 924**	61 352	61 726
Other interest and amortization	**17 955**	7 209	3 704
Allowance for funds used during construction—debt (Note 1)	**(4 738)**	(2 712)	(2 831)
Total	**76 141**	65 849	62 599
Net Income (Note 2)	**127 553**	111 283	120 678
Preferred Stock Dividends	**13 516**	14 030	14 406
Earnings Available for Common Stock (Note 2)	**$ 114 037**	$ 97 253	$ 106 272
Average Shares of Common Stock Outstanding (000's)	**29 334**	30 087	30 270
Earnings per Share on Average Shares (Note 2)	**$3.89**	$3.23	$3.51
Common Dividends Declared per Share	**$2.525**	$2.385	$2.25

See Notes to Financial Statements on pages 27 to 32

	Year Ended December 31		
	1981	1980	1979
	(Thousands of dollars)		
Balance at Beginning of Year	**$368 052**	$342 479	$304 534
Net income	**127 553**	111 283	120 678
Capital stock expense and other	**(23)**	(85)	(36)
Net additions	**127 530**	111 198	120 642
Dividends declared			
Cumulative preferred stock at required annual rates	**13 516**	14 030	14 406
Common stock—per share: 1981, $2.525; 1980, $2.385; 1979, $2.25	**74 062**	71 595	68 291
Total dividends declared	**87 578**	85 625	82 697
Balance at End of Year (Note 3)	**$408 004**	$368 052	$342 479

Statement of Changes in Financial Position

	1981	1980	1979
Source of Funds			
Funds from operations			
Net income	**$127 553**	$111 283	$120 678
Depreciation and other amortization	**107 417**	118 422	111 941
Nuclear fuel amortization	**41 179**	38 316	31 868
Deferred income taxes	**14 978**	14 532	61 229
Investment tax credit adjustment—net	**17 248**	8 726	18 615
Allowance for funds used during construction	**(15 186)**	(12 662)	(12 775)
Total	**293 189**	278 617	331 556
Proceeds from sale of notes and securities			
Notes payable		63 079	20 999
Long-term debt	**89 257**	509	157
Common stock		3 920	15 365
Total	**89 257**	67 508	36 521
Total Source of Funds	**$382 446**	$346 125	$368 077
Application of Funds			
Construction expenditures	**$275 522**	$222 343	$231 336
Transfer of Tyrone to abandoned projects			(40 000)
Allowance for funds used during construction	**(15 186)**	(12 662)	(12 775)
Tyrone abandonment	**(7 900)**	(5 000)	80 000
Repayment of notes payable	**8 336**		
Reductions of long-term debt and preferred stock with mandatory redemption	**22 568**	1 044	4 184
Purchase of tax benefits	**8 602**		
Acquisition of common stock		36 774	
Acquisition of preferred stock with mandatory redemption	**678**	4 291	
Preferred and common dividends	**87 578**	85 625	82 697
Increase (decrease) in working capital (excluding notes payable)	**(3 255)**	10 230	22 773
Other—net	**5 503**	3 480	(138)
Total Application of Funds	**$382 446**	$346 125	$368 077
Increase (Decrease) in Working Capital (excluding notes payable)			
Cash and temporary cash investments	**$ (11 096)**	$ (498)	$ (37 291)
Accounts receivable—net	**14 760**	23 035	42 029
Materials and supplies	**(13 121)**	23 068	35 884
Long-term debt and preferred stock with mandatory redemption due within one year	**(21 500)**	2 527	21 979
Accounts payable, Tyrone charges accrued and salaries, wages, etc.	**26 683**	(3 669)	(56 234)
Revenue refunds due customers	**(8 788)**	3 151	(3 151)
Income and other taxes accrued	**11 569**	(40 478)	20 787
Other current assets and liabilities—net	**(1 762)**	3 094	(1 230)
Total	**$ (3 255)**	$ 10 230	$ 22 773

See Notes to Financial Statement on pages 27 to 32

Balance Sheet Northern States Power Company, Minnesota and Subsidiaries

	December 31 1981	1980
	(Thousands of dollars)	
ASSETS		
Utility Plant (Notes 1 and 6)		
Electric—including construction work in progress: 1981, $266,786,000; 1980, $217,673,000	**$3 138 595**	$2 949 850
Gas	**247 330**	227 648
Other	**85 679**	86 817
Total	**3 471 604**	3 264 315
Accumulated provision for depreciation	**(955 358)**	(871 877)
Nuclear Fuel—including in process: 1981, $27,277,000; 1980, $19,183,000	**203 702**	163 611
Accumulated provision for amortization	**(203 390)**	(162 211)
Net utility plant	**2 516 558**	2 393 838
Other Property and Investments	**15 439**	5 961
Current Assets		
Cash (Note 7)	**2 886**	5 604
Temporary cash investments		8 378
Accounts receivable	**130 756**	116 350
Accumulated provision for uncollectible accounts	**(1 019)**	(1 373)
Materials and supplies—at average cost		
Fuel	**80 504**	99 364
Other	**36 197**	30 458
Prepayments and other	**15 629**	14 445
Total current assets	**264 953**	273 226
Deferred Debits		
Extraordinary property losses (Note 8)	**43 769**	47 601
Other	**19 357**	14 641
Total deferred debits	**63 126**	62 242
Total	**$2 860 076**	$2 735 267

See Notes to Financial Statements on pages 27 to 32.

	December 31 1981	December 31 1980
	(Thousands of dollars)	
LIABILITIES		
Capitalization (Page 26) (Note 3)		
Common stock—authorized 40,000,000 shares of $5 par value; issued shares: 1981 and 1980, 30,834,075	$ 154 170	$ 154 170
Premium on common stock	339 426	339 426
Retained earnings	408 004	368 052
Treasury stock: 1,500,000 shares at cost	(36 774)	(36 774)
Total common stock equity	864 826	824 874
Cumulative preferred stock—authorized 3,500,000 shares of $100 par value; outstanding shares: 1981, 2,200,274; 1980, 2,207,304 (Note 4)		
Without mandatory redemption	205 000	205 000
With mandatory redemption (net of treasury shares at cost)	15 040	15 709
Premium on preferred stock	715	729
Long-term debt (Note 6)	956 769	890 900
Total capitalization	2 042 350	1 937 212
Current Liabilities		
Notes payable (Note 7)	75 742	84 078
Long-term debt due within one year	21 500	
Accounts payable	81 107	75 597
Tyrone cancellation charges accrued (Note 8)	1 735	32 000
Salaries, wages, and vacation pay accrued	12 655	14 583
Revenue refunds due customers	8 788	
Federal income taxes accrued	16 168	37 808
Other taxes accrued	81 219	71 148
Interest accrued	22 462	20 643
Dividends declared on preferred and common stocks	22 143	21 152
Other	418	282
Total current liabilities	343 937	357 291
Deferred Credits		
Accumulated deferred income taxes (Note 1)	345 289	330 311
Accumulated deferred investment tax credits (Note 1)	120 802	103 554
Other	7 698	6 899
Total deferred credits	473 789	440 764
Commitments and Contingent Liabilities (Notes 2, 8 and 9)		
Total	$2 860 076	$2 735 267

Statement of Capitalization

Northern States Power Company, Minnesota and Subsidiaries

				December 31, 1981 (Thousands of dollars)	%	December 31, 1980 (Thousands of dollars)	%
Common Stock Equity (Note 3)				$ 864 826	42%	$ 824 874	43%
Cumulative Preferred Stock							
Without mandatory redemption (Note 4)							
$3.60 series, 275,000 shares	$27 500	4.56 series, 150,000 shares	15 000				
4.08 series, 150,000 shares	15 000	6.80 series, 200,000 shares	20 000				
4.10 series, 175,000 shares	17 500	7.00 series, 200,000 shares	20 000				
4.11 series, 200,000 shares	20 000	8.80 series, 250,000 shares	25 000				
4.16 series, 100,000 shares	10 000	7.84 series, 350,000 shares	35 000				
		Total	$205 000	205 000	10	205 000	10
With mandatory redemption (Note 4)		1981	1980				
$10.36 series, 1981, 187,500 shares; 1980, 200,000 shares		$18 750	$20 000				
Less treasury stock (1981, 37,226 shares; 1980, 42,696 shares)		3 710	4 291				
Net		$15 040	$15 709	15 040	1	15 709	1
Premium on Preferred Stock				715		729	
Long-Term Debt (Note 6)							
First Mortgage Bonds Minnesota Company—Series due:							
June 1, 1982, 3¼%	$21 500	Mar. 1, 2001, 8%	50 000				
Oct. 1, 1984, 3⅛%	20 000	June 1, 2001, 8¼%	50 000				
Sep. 1, 1986, 4¼%	15 000	Mar. 1, 2002, 7⅜%	50 000				
July 1, 1988, 4%	30 000	Feb. 1, 2003, 7½%	50 000				
Dec. 1, 1990, 5%	35 000	Jan. 1, 2004, 8⅜%	75 000				
Aug. 1, 1991, 4⅞%	20 000	Oct. 1, 1989-2004, 7.97%	35 000*				
June 1, 1992, 4⅜%	15 000	May 1, 1996-2005, 7⅝%	25 000*				
Sep. 1, 1993, 4⅜%	15 000	May 1, 2005, 9½%	80 000				
June 1, 1995, 6⅛%	30 000	Total	790 300			790 300	
Mar. 1, 1996, 6.2%	8 800*	July 1, 2001, 11%	13 745*				
Aug. 1, 1996, 5⅞%	45 000	Dec. 1, 2011, 15¾%	75 000				
Oct. 1, 1997, 6½%	30 000	Less current maturities	21 500				
May 1, 1998, 6¾%	45 000						
Oct. 1, 1999, 8%	45 000	Net	$857 545	857 545			
First Mortgage Bonds Wisconsin Company—Series due:							
(less reacquired bonds of $976,000 and $924,000 at December 31, 1981 and 1980, respectively)							
	Annual Sinking Fund Requirement	1981	1980				
June 1, 1987, 4⅝%	$100	$ 7 502	$ 7 660				
Aug. 1, 1994, 4½%	150	12 347	12 562				
Dec. 1, 1999, 9¼%	100	8 717	8 758				
Oct. 1, 2003, 7¾%	300	27 558	27 846				
Total	$650	$56 124	$56 826	56 124		56 826	
Guaranty Agreements Minnesota Company—Series due:*							
Feb. 1, 1989-2003, 5.39%		$ 7 600	$ 7 600				
May 1, 1987-2003, 5.66%		28 750	28 750				
Feb. 1, 2003, 7.40%		3 500	3 500				
Total		$39 850	$39 850	39 850		39 850	
Miscellaneous Long-Term Debt				3 259		3 114	
Unamortized Premium and (Discount) on Long-Term Debt				(9)		810	
Total Long-Term Debt				956 769	47	890 900	46
Total Capitalization				$2 042 350	100%	$1 937 212	100%

*Pollution control financing at average interest rates.

See Notes to Financial Statements on pages 27 to 32.

1. Summary of Accounting Policies

System of Accounts—The accounting records of the Company and the Wisconsin Company are maintained in accordance with either the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) or those prescribed by the state commissions, which systems are the same in all material respects.

Principles of Consolidation—All significant subsidiary companies have been included in the consolidated financial statements.

Utility Plant and Retirements—Utility plant is stated at original cost. The cost of additions to utility plant includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The cost (actual or estimated) of units of property retired, sold, or otherwise disposed of, plus removal costs less salvage, is charged to the accumulated provision for depreciation and amortization. Maintenance and repair costs and replacement and renewal of items determined to be less than units of property are charged to operating expenses.

Allowance for Funds Used During Construction (AFC)—AFC, a non-cash item, is included in construction work in progress and credited to income using composite rates which assumes that funds used for construction were provided by debt and equity. The AFC so included in construction work in progress will ultimately be included in the rate base in establishing rates for utility service. The composite AFC rate for the Company was 8% in 1981, 7.75% in 1980, and 7.5% in 1979. The AFC rate approximates a net of tax rate which because of rate treatment in Minnesota yields the same result as would be obtained if a gross rate were used and the tax effect recorded as a deferred item. The determination of this rate is pursuant to an order of the Minnesota Public Utilities Commission in rate proceedings. The composite AFC rate for the Wisconsin Company was 7%.

Depreciation—For financial reporting purposes, depreciation is computed on the straight-line method based on estimated useful lives of the various classes of property. Such provisions as a percentage of the average balance of depreciable property in service were 3.47% in 1981, 3.46% in 1980, and 3.44% in 1979. Prior to August 1, 1981, depreciation expense included a provision for decommissioning costs equal to 10% of the installed cost of nuclear plants. As of August 1, 1981, and with the approval of the Minnesota Public Utilities Commission, the provision for decommissioning costs was increased according to an internal sinking fund method which will provide for full recovery of the disposal cost of the nuclear plants.

Nuclear Fuel Amortization—Nuclear fuel amortization includes recovery amounts for the original cost of nuclear fuel and also amounts to provide for the ultimate disposal of spent nuclear fuel. The original cost of the fuel is amortized to fuel expense based on the energy expended. Prior to August 1, 1981, future disposal cost estimates were recovered using a straight line recovery approach. As of August 1, 1981, estimated disposal costs are recovered using an internal sinking fund method with cost estimates based on information prepared by the Department of Energy. This process is the result of an order obtained from the Minnesota Public Utilities Commission and is subject to continuing review.

Income Taxes—Income taxes are now deferred for substantially all differences between book and tax basis. However, income tax expense is still currently affected by the reversal of amounts accounted for on the flow-through method in prior years.

Investment Tax Credits—Investment tax credits are deferred and amortized to income over the estimated lives of the related property. Additional investment credits of 1½% related to the Employee Stock Ownership Plan do not affect net income because the reduction in Federal income taxes charged to operations is offset by a charge to deferred investment tax credit adjustment. Such amounts are included in accounts payable until the common stock is purchased.

Revenues—Customers' meters are read and bills rendered on a cycle basis. Revenues of the Company are recorded in the accounting period during which the meters are read. The Wisconsin Company, pursuant to an order of the Public Service Commission of Wisconsin, accrues estimated unbilled revenues for services provided from the monthly meter reading date to month-end.

2. Revenues Subject to Refund

For the years ended December 31, 1981 and 1980 electric revenues included $24,500,000 and $2,300,000 respectively, which are subject to refund from rate orders. These revenues increased net income by $11,800,000 (40¢ per share) and $1,100,000 (4¢ per share), respectively.

	Twelve Months Ended December 31, 1981		
	Revenues	Net Income	Per Share
	(Thousands of dollars except per share amounts)		
Electric Rate Cases			
1981 Rate Cases			
Tyrone	$ 2 100 000	$ 1 000 000	$.04
Other	17 700 000	8 600 000	.29
Total	19 800 000	9 600 000	.33
1980 Minnesota Rate Case			
Tyrone	4 700 000	2 200 000	.07
Total Subject to Refund	$24 500 000	$11 800 000	$.40

All of the revenue subject to refund in 1980 and $6,800,000 of the 1981 revenue subject to refund relate to amortization charges of the Tyrone Nuclear Plant Abandonment, (see Note 8). The Minnesota Public Utilities Commission rejected the recovery of the amortization charges for the Tyrone project in its April 30, 1981 electric rate order. The Company appealed this decision on the Tyrone issue and was granted a stay order by the Minnesota District Court. This order stays the refund of revenues collected for the Tyrone amortization and allows the Company to continue to collect revenues for Tyrone, pending a final decision.

3. Common Stock

	Common Stock			Treasury Stock	
	Shares	Par Value	Premium	Shares	Cost
			(Thousands of dollars)		
Balance at January 1, 1979	29 970 108	$149 851	$324 417		
Dividend Reinvestment and Stock Purchase Plan	564 169	2 821	9 891		
Employee Stock Ownership Plan	106 540	532	2 122		
Balance at December 31, 1979	30 640 817	153 204	336 430		
Dividend Reinvestment and Stock Purchase Plan	190 093	950	2 948		
Employee Stock Ownership Plan	3 165	16	48		
Purchase of Treasury Stock				1 500 000	$(36 774)
Balance at December 31, 1980 and 1981	30 834 075	$154 170	$339 426	1 500 000	$(36 774)

The Company's Articles of Incorporation and Trust Indenture provide for certain restrictions on the payment of cash dividends on common stock. Retained earnings were not restricted as to payment of cash dividends on common stock.

4. Cumulative Preferred Stock

All Issues—The preferred stock may be called at the option of the Company at prices per share at December 31, 1981, ranging from $102.00 to $115.00 plus accrued dividends.

Mandatory Redemption Issue—The $10.36 series is subject to a mandatory annual sinking fund requirement for the retirement of a minimum of 12,500 shares and a maximum of 25,000 shares at $101.10 per share, the original purchase price.

5. Income Tax Expense

The total income tax expense differs from the amount computed by applying the Federal income tax statutory rate (46%) to net income before income tax expense. The reasons for the difference are as follows:

	1981	1980	1979
		(Thousands of dollars)	
Tax computed at statutory rate	**$114 036**	$ 97 273	$106 637
Increases (decreases) in tax from:			
State income taxes, net of Federal income tax benefit	**13 505**	9 472	12 823
Allowance for funds used during construction	**(6 986)**	(5 825)	(5 877)
Investment tax credit on plant additions	**(25 423)**	(14 987)	(25 725)
Investment tax credit adjustments—net	**20 135**	10 605	22 152
Reduced tax depreciation resulting from use of the flow-through method in prior years	**5 185**	6 555	6 070
Other—net	**(101)**	(2 914)	(4 938)
Total income tax expense	**$120 351**	$100 179	$111 142
Effective income tax rate	**48.5%**	47.4%	47.9%
Composite statutory tax rate	**51.7%**	51.7%	51.7%
Income tax expense is comprised of the following:			
Included in income taxes:			
Current Federal tax expense	**$ 65 078**	$ 60 938	$ 13 471
Current state tax expense	**22 074**	14 033	12 480
Deferred Federal tax expense	**8 502**	11 042	50 375
Deferred state tax expense	**2 453**	3 487	10 884
Investment tax credit adjustments—net	**20 135**	10 605	22 152
Total	**118 242**	100 105	109 362
Included in depreciation expense:			
Deferred Federal tax expense	**639**	2 059	2 174
Deferred state tax expense	**119**	353	373
Included in income deductions:			
Current Federal tax expense	**(2 224)**	(2 008)	(747)
Current state tax expense	**(448)**	(333)	10
Deferred Federal tax expense	**3 211**	3	(30)
Deferred state tax expense	**812**		
Total income tax expense	**$120 351**	$100 179	$111 142
Deferred income tax expense is comprised of the following:			
Tyrone abandonment	**$ (1 663)**	$ (9 523)	$ 31 250
Excess of tax over book depreciation—net	**28 620**	18 665	23 296
ADR repair allowance	**(17 786)**	4 506	5 807
Overhead costs	**4 984**	4 031	4 611
Other	**1 581**	(735)	(1 188)
Total	**$ 15 736**	$ 16 944	$ 63 776

6. Long-Term Debt

The annual sinking fund requirements of the Company are the amounts necessary to redeem 1% of the highest principal amount of each series of first mortgage bonds (other than pollution control financing) at any time outstanding. Property additions have been applied in lieu of cash as permitted by the Company's Trust Indenture.

All utility property, except for minor exclusions, is subject to the lien of the indentures relating to the first mortgage bonds.

Maturities and sinking fund requirements on long-term debt are as follows: 1982, $21,500,000; 1983, $324,000; 1984, $20,650,000; 1985, $650,000; and 1986, $15,650,000.

7. Short-Term Borrowings and Compensating Balances

At December 31, 1981 there were bank lines of credit aggregating $161,209,000. There are compensating balance arrangements in support of such lines of credit and substantially all cash is considered compensating balances. These credit lines make short-term financing available by providing bank loans and back-up for commercial paper.

8. Tyrone Nuclear Plant Abandonment

The Wisconsin Company was a participant in a jointly-owned project for the construction of a 1,100 megawatt nuclear generating plant called the Tyrone Energy Park, in which it had a 67.6% undivided interest. During 1979, the Public Service Commission of Wisconsin issued an order denying the application for authority to construct the proposed plant and the co-owners subsequently reached an agreement to terminate the project.

At December 31, 1981, settlements had been reached with substantially all of the vendors involved with the Tyrone Nuclear Plant. The present estimate for the Wisconsin Company's share of the project abandonment cost is $67,100,000.

The total cost has been recorded as a deferred extraordinary property loss and was initially being amortized over a sixty-month period which started in March 1979 with deferred taxes recorded to reflect the timing difference between the tax write-off and the book amortization. The Company and the Wisconsin Company had filed an application with FERC to provide for the sharing of the loss between the two Companies over the sixty-month period under the terms of an existing Coordinating Agreement. On December 3, 1981, FERC issued an order stating that the loss is to be shared between the two Companies and also requires that the loss be amortized at the rate of $7,500,000 per year over approximately a nine year period commencing March 1979. The results of operations prior to the date of this order have not been restated as the effect on the consolidated financial statements would not be material.

The Wisconsin Company has received an order from the Public Service Commission of Wisconsin granting it the right to recover its portion of the amortization in rates. The Minnesota Public Utilities Commission has disallowed the recovery of Tyrone in rates in an order received April 30, 1981. This order is being contested because it is felt that FERC has jurisdiction over the determination of whether these costs are allowed under the Coordinating Agreement. To the extent that amortization were to be denied in rate proceedings, the remaining appropriate unamortized costs would be written-off at the time a final determination is made. The unamortized costs, net of deferred income taxes, at December 31, 1981 and 1980 were $23,370,000 and $24,937,000, respectively. Management has assessed the potential impact of the termination of the Tyrone Energy Park project and has concluded that the effect of a write-off, if any, would not be material to the financial position of the Company.

9. Commitments and Contingent Liabilities

At December 31, 1981 there were commitments in connection with construction programs aggregating about $401 million including $293 million relating to nuclear fuel purchases.

There are also contracts for the purchase of coal, natural gas, and oil, and a contract for delivery of BTUs of energy for the operation of its Monticello nuclear power plant. The nuclear fuel lease payments are charged to fuel for electric generation based on the BTUs of energy expended.

Rentals (including nuclear fuel of $10,594,000, $10,590,000, and $11,856,000) were approximately $18,282,000, $19,200,000, and $18,400,000 for 1981, 1980, and 1979, respectively.

Minimum lease commitments as of December 31, 1981, under all non-cancellable leases (principally lease of nuclear fuel) are about: 1982, $14,693,000; 1983, $33,372,000; 1984, $479,000; 1985, $474,000; 1986, $157,000; and 1987-1991, $42,000. The minimum lease commitments for nuclear fuel are based on the estimated use through 1983, a final payment of $31,200,000 in 1983, and the escalation of the contract price using the latest wholesale commodities price index.

The Price-Anderson liability provisions of the Atomic Energy Act of 1954 provides for a limit of $560 million on each nuclear generating unit in the United States for public liability claims that could arise from a nuclear incident. In the event of any such incident, all owners of nuclear generating units licensed to operate would be required to contribute toward satisfaction of such claims. The owners insure against this exposure by purchasing the maximum available private insurance of $160 million, and the remainder is provided by indemnity agreements with the Nuclear Regulatory Commission. In the event of such an incident, the Company, to the extent of its ownership participation, could be assessed up to $5 million for each licensed reactor owned, with a maximum assessment of $10 million per reactor in a year. The Company now owns three reactors.

10. Pension Plans

The noncontributory funded pension plans cover substantially all employees. Pension costs are determined under the aggregate cost method using market value of assets of the trust fund. Contributions, equal to the pension costs accrued, made to the trust fund were $23,131,400 for 1981, $20,522,400 for 1980, and $18,070,500 for 1979. The weighted average assumed rate of return used in determining the actuarial present value of accumulated plan benefits was 7% for 1981 and 1980. A comparison of accumulated plan benefits and plan net assets for the defined benefit plans is presented below:

	December 31	
	1981	1980
	(Thousands of dollars)	
Actuarial present value of accumulated plan benefits:		
Vested	**$239 371**	$212 315
Nonvested	**15 806**	13 477
Total	**$255 177**	$225 792
Net assets available for benefits	**$231 089**	$236 605

11. Segment Information

	Year Ended December 31, 1981			
	Electric	Gas	Other	Total
	(Thousands of dollars)			
Operating revenues	$ 998 034	$271 995	$10 860	$1 280 889
Operating income before income taxes	300 609	13 087	2 535	316 231
Depreciation and amortization	92 576	8 672	1 639	102 887
Construction expenditures	253 075	24 367	(1 920)	275 522
	December 31, 1981			
Net utility plant	$2 316 667	$180 348	$19 543	$2 516 558
Other corporate assets				343 518
Total assets				$2 860 076

	Year Ended December 31, 1980			
	Electric	Gas	Other	Total
	(Thousands of dollars)			
Operating revenues	$ 914 704	$233 809	$10 539	$1 159 052
Operating income before income taxes	246 072	4 158	2 175	262 405
Depreciation and amortization	104 659	7 760	1 732	114 151
Construction expenditures	190 656	28 412	3 275	222 343
	December 31, 1980			
Net utility plant	$2 205 046	$165 391	$23 401	$2 393 838
Other corporate assets				341 429
Total assets				$2 735 267

	Year Ended December 31, 1979			
	Electric	Gas	Other	Total
	(Thousands of dollars)			
Operating revenues	$ 832 663	$205 623	$ 9 890	$1 048 176
Operating income before income taxes	257 897	20 640	2 415	280 952
Depreciation and amortization	98 281	7 233	1 647	107 161
Construction expenditures	213 577	16 202	1 557	231 336
	December 31, 1979			
Net utility plant	$2 144 739	$145 101	$21 935	$2 311 775
Other corporate assets				308 033
Total assets				$2 619 858

12. Summarized Quarterly Financial Data (Not Certified)

	Quarter Ended			
	March 31, 1981	June 30, 1981	September 30, 1981	December 31, 1981
	(Thousands of dollars)			
Operating revenues	$357 132	$283 274	$300 770	$339 714
Operating income	54 115	38 667	51 791	53 416
Net income	39 093	25 144	31 781	31 536
Earnings available for common stock	35 704	21 768	28 405	28 160
Earnings per share	1.22*	.74*	.97*	.96*

	Quarter Ended			
	March 31, 1980	June 30, 1980	September 30, 1980	December 31, 1980
	(Thousands of dollars)			
Operating revenues	$322 288	$250 415	$279 389	$306 960
Operating income	40 562	30 404	46 438	44 897
Net income	31 004	18 725	32 127	29 426
Earnings available for common stock	27 435	15 165	28 632	26 021
Earnings per share	.89	.49	.97*	.89*

**Includes earnings for rate increases subject to possible refund for the quarter ended: September 30, 1980, 2¢; December 31, 1980, 2¢; March 31, 1981, 2¢; June 30, 1981, 2¢; September 30, 1981, 3¢ and December 31, 1981, 33¢. (See Note 2.)*

13. Financial Reporting of Changing Prices (Not Certified)

The following information is supplied in accordance with the requirements of the Financial Accounting Standards Board (FASB) Statement No. 33, Financial Reporting and Changing Prices, for the purpose of providing certain information about the effects of changing prices. This information is not intended as a substitute for earnings reported on a historical cost basis. It offers some perspective of the approximate effects of inflation rather than a precise measurement of these effects.

Constant dollar amounts represent historical cost stated in terms of dollars of equal purchasing power, as measured by the Consumer Price Index for All Urban Consumers (CPI-U). 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.

Property, Plant, and Equipment — The current cost of all depreciable property is the estimated cost of replacing existing depreciable property and was determined by indexing the original cost of the property by the Handy-Whitman Index of Public Utility Construction Costs. The unrecovered portion of the original cost of the capitalized nuclear fuel is restated in terms of constant dollar and current cost by applying the CPI-U. Spent nuclear fuel is not reflected in either of the supplementary calculations.

Accumulated Depreciation — The net assets at year-end were determined by reducing the respective constant dollar and

current costs by the corresponding theoretical accumulated provision for depreciation. This provision for accumulated depreciation was calculated by the appropriate survivor curve reserve ratios, by FERC account, to the respective vintaged indexed amounts.

Depreciation Expense—The current year's provision for depreciation for each method was determined by applying depreciation rates, by FERC account, to the year's average indexed plant amounts.

Reduction to Net Recoverable Cost—Under the rate-making prescribed by the regulatory commissions, only the historical cost of plant is recoverable in revenues as depreciation. Therefore, the excess of the cost of plant stated in terms of constant dollars or current cost over the historical cost of plant is not presently recoverable in rates as depreciation, and is reflected as a reduction to net recoverable cost. While the rate-making process gives no recognition to the current cost of property, management believes, based on past practices, it will be allowed to earn on the increased cost of its net investment when replacement of facilities actually occurs.

Gain from Decline in Purchasing Power of Net Amounts Owed—By holding monetary assets, a loss of purchasing power is suffered during periods of inflation because the amount of cash received in the future for these items will purchase less. Conversely, by holding monetary liabilities, primarily long-term debt, there is a benefit because the payment in the future will be made with dollars having less purchasing power. Significant amounts of long-term debt are outstanding which will be paid back in dollars having less purchasing power and, therefore, for purposes of these calculations, shows a net gain from holding monetary liabilities in excess of monetary assets. However, the Company and the Wisconsin Company do not have the opportunity to realize a holding gain on debt and preferred stock because they are limited to the recovery of only the historical embedded cost.

Other Items—Fuel inventories, the cost of fuel used in generation, and gas purchased for resale have not been restated. Regulation permits the recovery of actual fuel and purchased gas costs through the operation of adjustment clauses in basic rate schedules. For this reason, fuel inventories are effectively monetary assets.

Since present tax laws do not allow deductions for higher depreciation rates to reflect the effects of inflation, income taxes included in the data adjusted for general inflation were not adjusted from those amounts presented in the primary financial statements. Therefore, the Company's effective Federal income tax rate, when adjusted for inflation, is 89.9 percent under constant dollar and 107.8 percent under current cost for 1981, each of which exceeds its reported effective tax rate of 48.5 percent.

As can be seen from the accompanying information in the five-year comparison of supplementary financial data, inflation has had a significant impact. Although operating revenues over the last five years has increased significantly as reported, they have remained relatively constant in real terms. Also, even though cash dividends have increased every year, they have decreased every year in price level adjusted dollars. Market price per share in adjusted dollars has also had a significant decline.

Statement of Income from Continuing Operations Adjusted for Changing Prices for the Year Ended December 31, 1981 (Thousands of dollars)

	Historical Cost	Constant Dollar Average 1981 Dollars	Current Cost Average 1981 Dollars
Operating revenues	$1 280 889	$1 280 889	$1 280 889
Electric fuel and purchased power	248 050	248 050	248 050
Gas purchased for resale expense	206 681	206 681	206 681
Depreciation	107 222	221 182	243 432
Amortization	(4 335)	(4 335)	(4 335)
Other operating and maintenance expense	407 040	407 040	407 040
Income tax expense	118 242	118 242	118 242
Interest charges	76 141	76 141	76 141
Other income and deductions—net	(5 705)	(5 705)	(5 705)
Total	1 153 336	1 267 296	1 289 546
Income (Loss) from continuing operations (excluding reduction to net recoverable cost)	$ 127 553	$ 13 593*	$ (8 657)
Reduction to net recoverable cost		$ (96 733)	$ (209 780)
Gain from decline in purchasing power of net amounts owed		$ 138 177	$ 138 177
Effect of increase in general price level			401 964
Increase in specific prices (current cost) of property held during the year**			$ 537 261
Excess of increase in general price level over increase in specific prices			$ (135 297)

*Including the reduction to net recoverable cost, the income (loss) from continuing operations on a constant dollar basis would have been ($83,140) for 1981.

**At December 31, 1981, current cost of property, net of accumulated depreciation was $4,968,979, while historical cost or net cost recoverable through depreciation was $2,516,558.

Financial Data of Changing Prices (Not Certified) (Continued)

Five-Year Comparison of Selected Supplementary Financial Data Adjusted for Effects of Changing Prices (In Thousands of Mid-Year 1981 Dollars)

	Years Ended December 31,				
	1981	1980	1979	1978	1977
Operating revenues					
As reported	**$1 280 889**	$1 159 052	$1 048 176	$ 979 251	$ 881 510
Adjusted	**1 280 889**	1 270 321	1 313 365	1 360 180	1 315 213
Income (Loss) from continuing operations (excluding reduction to net recoverable cost)					
As reported	**$ 127 553**	$ 111 283	$ 120 678		
Constant dollar adjusted	**13 593**	21 657	63 972		
Current cost adjusted	**(8 657)**	(4 364)	29 776		
Income (Loss) per common share (after dividend requirements on preferred stock)					
As reported	**$ 3.89**	$3.23	$3.51		
Constant dollar adjusted	**.00**	.21	1.52		
Current cost adjusted	**(.76)**	(.57)	.39		
Net assets at year-end at net recoverable cost					
As reported	**$1 085 581**	$1 046 312	$1 057 884		
Constant dollar adjusted	**1 046 246**	1 098 829	1 263 795		
Current cost adjusted	**1 046 246**	1 098 829	1 263 795		
Excess of increase in general price level over increase in specific prices	**$ (135 297)**	$ 88 136	$ 104 158		
Gain from decline in purchasing power of net amounts owed	**$ 138 177**	$ 196 723	$ 231 734		
Cash dividends declared per common share					
As reported	**$ 2.525**	$2.385	$2.25	$2.135	$2.03
Adjusted	**2.525**	2.61	2.82	2.97	3.03
Market price per common share at year-end					
As reported	**$ 24.125**	$21.50	$22.375	$23.50	$28.25
Adjusted	**24.125**	23.56	28.04	32.64	42.15
Mid-Year consumer price index	**271.3**	247.6	216.6	195.3	181.8

Accountants' Opinion

To the Shareholders of Northern States Power Company:

We have examined the balance sheets and statements of capitalization of Northern States Power Company (Minnesota) and its subsidiaries as of December 31, 1981 and 1980 and the related statements of income, retained earnings, and changes in financial position for each of the three years in the period ended December 31, 1981. Our examinations 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.

In our report dated February 17, 1981, our opinion on the 1980 financial statements of Northern States Power Company was qualified as being subject to the effects of such adjustments, if any, as might have been required had the outcome of the rate increases being collected subject to refund been known. As a result of an order issued by the Minnesota Public Utilities Commission on April 30, 1981, the amounts now subject to possible refund would not have a material impact on the financial statements. Accordingly, our present opinion on the 1980 financial statements, as expressed herein, is different from that expressed in our previous report.

As discussed in Note 2 to the financial statements, 1981 revenues include amounts which are subject to refund pending the outcome of various rate proceedings. The ultimate outcome of these proceedings cannot presently be determined.

In our opinion, subject to the effects on the 1981 financial statements of such adjustments, if any, as might have been required had the outcome of the uncertainty referred to in the preceding paragraph been known, such financial statements present fairly the financial position of the Companies 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 applied on a consistent basis.

DELOITTE HASKINS & SELLS
Minneapolis, Minnesota
February 17, 1982

Selected Financial Data

	1981	1980	1979	1978	1977
			(Millions of Dollars)		
Operating revenues	**$1 280.9**	$1 159.1	$1 048.2	$ 979.3	$ 881.5
Operating expenses	**$1 082.9**	$ 996.8	$ 876.6	$ 807.3	$ 725.9
Net income	**$ 127.5**	$ 111.3	$ 120.7	$ 115.2	$ 98.6
Earnings available for common stock	**$ 114.0**	$ 97.3	$ 106.3	$ 100.7	$ 84.1
Average shares of common stock outstanding (000's)	**29 334**	30 087	30 270	29 712	29 389
Earnings per share on average shares	**$ 3.89**	$ 3.23	$ 3.51	$ 3.39	$ 2.86
Dividends declared per share	**$ 2.525**	$ 2.385	$ 2.25	$ 2.135	$ 2.03
Total assets	**$2 860.1**	$2 735.3	$2 619.9	$2 [illegible]31.5	$2 407.4
Long-term debt	**$ 956.8**	$ 890.9	$ 891.5	$ 893.1	$ 916.0
Mandatory redemption preferred stock (net of treasury shares)	**$ 15.0**	$ 15.7	$ 20.0	$ 22.5	$ 25.0
Ratio of earnings to fixed charges	**4.0**	4.0	4.4	4.6	4.0

Financial Statistics

	1981	1980	1979	1978	1977
Earnings per share on average shares	**$ 3.89**	$ 3.23	$ 3.51	$ 3.39	$ 2.86
Return on average common equity	**13.5%**	11.7%	13.2%	13.3%	11.8%
Dividends in percent of earnings	**64.9%**	73.6%	64.3%	63.1%	71.0%
Dividends in percent of book value	**9.1%**	8.9%	8.8%	8.7%	8.6%
Five year growth rates in earnings per share (1)	**5.3%**	3.4%	6.8%	5.4%	2.2%
Construction expenditures (Millions)	**$ 275.5**	$ 222.3	$ 231.3	$ 213.4	$ 159.3
Percent of construction expenditures financed by internally generated funds (excluding AFC)	**66.4%**	88.7%	76.8%	98.0%	100.0%
Cash dividend coverage	**3.8**	3.7	4.6	4.1	4.1
AFC percent of earnings per share	**13.3%**	13.0%	12.0%	9.2%	8.4%
Effective tax rate	**48.5%**	47.4%	47.9%	53.3%	51.5%
Capitalization (2)					
Common	**40.4%**	40.8%	42.2%	40.5%	38.7%
Preferred	**10.3%**	11.0%	11.6%	12.0%	12.2%
Debt	**49.3%**	48.2%	46.2%	47.5%	49.1%
Total	**100.0%**	100.0%	100.0%	100.0%	100.0%
Embedded cost of long-term debt	**7.76%**	7.00%	7.00%	6.90%	6.85%
Average plant investment per dollar of revenue	**$ 2.77**	$ 2.87	$ 2.99	$ 3.02	$ 3.16
Depreciation reserve in percent of depreciable plant	**30.2%**	29.1%	27.9%	26.4%	24.3%
Depreciation provision in percent of average depreciable plant	**3.47%**	3.46%	3.44%	3.41%	3.43%
Benefit employees (at December 31)	**7 045**	6 965	6 700	6 580	6 694

AFC—Allowance for Funds Used During Construction
(1) Least squares method.
(2) Includes notes payable and long-term debt and preferred stocks with mandatory redemption due within one year.

	1981	1980	1979	1978	1977
ELECTRIC					
Revenues (thousands)					
Residential					
With space heating	$ 32 098	$ 28 017	$ 23 607	$ 17 921	$ 12 739
Without space heating	312 258	290 225	260 567	252 914	233 942
Small commercial and industrial	162 848	149 878	131 872	122 992	112 435
Large commercial and industrial	363 332	330 276	289 202	266 804	234 480
Street lighting and other	25 569	22 216	20 061	19 193	18 944
Total retail	896 105	820 612	725 309	679 824	612 540
Sales for resale	90 055	87 220	102 378	125 592	118 018
Miscellaneous	11 874	6 872	4 976	4 252	1 702
Total	$ 998 034	$ 914 704	$ 832 663	$ 809 668	$ 732 260
Sales (millions of kwh)					
Residential					
With space heating	764	763	721	575	445
Without space heating	6 178	6 283	6 177	6 118	5 976
Small commercial and industrial	3 403	3 380	3 284	3 172	3 027
Large commercial and industrial	10 202	10 033	9 854	9 374	8 875
Street lighting and other	578	549	539	526	543
Total retail	21 125	21 008	20 575	19 765	18 866
Sales for resale	4 659	4 346	5 041	6 795	7 500
Total	25 784	25 354	25 616	26 560	26 366
Customer Accounts (at December 31)					
Residential					
With space heating	49 027	44 711	39 393	32 846	25 878
Without space heating	930 664	921 545	910 106	892 127	875 892
Small commercial and industrial	109 603	105 888	103 831	102 049	99 556
Large commercial and industrial	5 387	5 335	5 107	4 861	4 634
Street lighting and other	5 049	6 792	6 641	6 504	6 262
Total retail	1 099 730	1 084 271	1 065 078	1 038 387	1 012 222
Sales for resale	76	77	76	84	83
Total	1 099 806	1 084 348	1 065 154	1 038 471	1 012 305
Residential With Space Heating					
Annual kwh per customer	16 255	18 016	19 986	19 637	19 654
Annual revenue per customer	$ 683.14	$ 661.77	$ 654.90	$ 612.20	$ 561.83
Annual revenue per kwh	4.20¢	3.67¢	3.28¢	3.12¢	2.86¢
Residential Without Space Heating					
Annual kwh per customer	6 672	6 862	6 858	6 923	6 858
Annual revenue per customer	$ 337.23	$ 316.94	$ 289.27	$ 286.19	$ 268.48
Annual revenue per kwh	5.05¢	4.62¢	4.22¢	4.13¢	3.91¢
Kilowatt-hour Output (millions)					
Thermal	23 041	23 706	24 381	25 866	26 428
Hydro	875	827	924	945	771
Purchased and interchange	3 711	2 561	1 856	1 499	828
Total	27 627	27 094	27 161	28 310	28 027
Capability at Time of Maximum Demand (megawatts)					
Company owned	6 032	6 110	6 108	6 257	6 209
Purchases and sales—net	496	504	(264)	(306)	(644)
Total	6 528	6 614	5 844	5 951	5 565
Maximum Demand (megawatts)	4 681	4 873	4 247	4 625	4 503
Date of Maximum Demand	July 8	July 14	Aug 7	Sept 7	July 19

	1981	1980	1979	1978	1977
GAS					
Revenues (thousands)					
Residential					
With space heating	**$ 120 834**	$ 108 939	$ 100 810	$ 80 394	$ 68 756
Without space heating	**3 465**	2 921	3 434	2 993	2 890
Commercial and industrial	**144 907**	119 157	98 224	74 437	67 654
Miscellaneous	**2 789**	2 792	3 155	2 657	2 566
Total	**$ 271 995**	$ 233 809	$ 205 623	$ 160 481	$ 141 866
Sales (thousands of mcf)					
Residential					
With space heating	**28 342**	30 558	33 616	31 533	30 044
Without space heating	**590**	716	807	801	856
Commercial and industrial	**38 747**	39 798	38 737	36 108	37 112
Miscellaneous	**55**	51	54	40	85
Total	**67 734**	71 123	73 214	68 482	68 097
Customer Accounts (at December 31)					
Residential					
With space heating	**224 832**	216 602	206 195	198 977	193 581
Without space heating	**27 574**	30 246	33 488	35 124	36 356
Commercial and industrial	**23 971**	23 381	22 762	22 222	21 848
Total	**276 377**	270 229	262 445	256 323	251 785
Residential With Space Heating					
Annual mcf per customer	**128**	145	167	161	157
Annual revenue per customer	**$ 546.22**	$ 515.40	$ 499.53	$ 409.87	$ 360.22
Average revenue per mcf	**$ 4.26**	$ 3.57	$ 3.00	$ 2.55	$ 2.29

Common Stock Data

	1981	1980	1979	1978	1977
Shareholders at year-end	**94 453**	98 821	100 857	101 389	100 253
Book value	**$29.48**	$28.12	$27.16	$25.99	$24.74
Market prices					
High	**27**	25⅜	25⅞	28¼	30½
Low	**20**	18	21⅜	23¼	26½
Year-end	**24⅛**	21½	22⅜	23½	28¼

Quarterly Stock Data

Following are the reported high and low sales prices based on the NYSE Composite Transactions for the quarters of 1981 and 1980 and the dividends declared per share during those quarters:

1981	High	Low	Dividends
First Quarter	**22¾**	**20**	**.605**
Second Quarter	**27**	**20⅜**	**.64**
Third Quarter	**26⅜**	**22⅜**	**.64**
Fourth Quarter	**26¾**	**23**	**.64**

1980	High	Low	Dividends
First Quarter	23½	18	.57
Second Quarter	25⅜	19⅝	.605
Third Quarter	25⅛	23⅛	.605
Fourth Quarter	23¾	20¼	.605

Shareholders' Calendar

Schedule of Dividend Payment Dates

Common Stock	Preferred Stock
April 20, 1982	April 15, 1982
July 20, 1982	July 15, 1982
October 20, 1982	October 15, 1982
January 20, 1983	January 15, 1983

NSP's Dividend Reinvestment and Stock Purchase Plan

NSP's Dividend Reinvestment and Stock Purchase Plan permits individual shareholders to reinvest common and preferred stock dividends in newly issued shares of NSP common stock, thereby qualifying for special tax treatment under the Economic Recovery Tax Act of 1981.

Individual shareholders may elect to exclude qualified reinvested dividends, including NSP's, from income on their federal income tax return up to $750 ($1,500 on a joint return) for each year beginning in 1982 through 1985. Common and preferred stock dividends are reinvested automatically each quarter for participating shareholders.

In addition, individual shareholders may elect to make optional cash payments either on a regular basis or from time to time. Cash payments are invested monthly for the purchase of common stock in market transactions at a weighted average price.

NSP sends participating shareholders a statement after each purchase, detailing the purchase and the shares held for the participant. Any costs, commissions or fees for reinvesting dividends or investing optional cash payments are paid by NSP.

Shareholders may join the plan at any time by completing an authorization form and returning it to NSP. The prospectus and authorization form can be obtained from Shareholder Relations, as indicated on the following page. Shareholders may terminate their participation in the plan at any time by written notice to NSP Shareholder Relations.

Information on NSP Stock

Information about your stock is available from [illegible], Administrator, Shareholder Relations, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401, or by calling toll-free at (800) 328-8226. (From within the Minneapolis-St. Paul area, call 330-5560. Other Minnesota residents may call toll-free at (800) 292-4140.)

A statistical supplement to this report is available from the Securities Issuance and Financial Reports Section, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401, as is a copy of NSP's Form 10-K annual report to the Securities and Exchange Commission.

Information on NSP

More information on NSP's operations and special publications issued by the company are available by writing to: Communications Department, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401. Company publications cover energy conservation, coal and nuclear generation, natural gas and NSP's research efforts.

Stock Exchange Listings

Common stock is listed for trading on the New York Stock Exchange and the Midwest Stock Exchange. The ticker symbol is NSP. Preferred stock is listed for trading on the New York Stock Exchange.

Annual Meeting of Shareholders

The annual meeting of shareholders will be held at 10 a.m. Wednesday, May 26, 1982, at the Prom Center, 1190 University Avenue (near Lexington), St. Paul, Minnesota.

Fiscal Agents

Northern States Power Company, Minnesota

Registrar
Common and Preferred Stocks
Northwestern National Bank
Minneapolis, Minnesota 55479

Transfer Agent
Common and Preferred Stocks
Northern States Power Company
414 Nicollet Mall, Minneapolis, Minnesota 55401

Forwarding Agent
Northwestern Trust Company
40 Wall Street, New York, New York 10005

Trustee—Bonds
Harris Trust and Savings Bank
111 West Monroe, Chicago, Illinois 60690

Coupon Paying Agents—Bonds
Harris Trust and Savings Bank
111 West Monroe, Chicago, Illinois 60690
Irving Trust Company
1 Wall Street, New York, New York 10015

Northern States Power Company, Wisconsin

Trustee—Bonds
First Wisconsin Trust Company
777 East Wisconsin Avenue,
Milwaukee, Wisconsin 53202

Coupon Paying Agents—Bonds
First Wisconsin Trust Company
777 East Wisconsin Avenue,
Milwaukee, Wisconsin 53202
Harris Trust and Savings Bank
111 West Monroe, Chicago, Illinois 60690
Irving Trust Company
1 Wall Street, New York, New York 10015

Northern States Power Company

414 Nicollet Mall
Minneapolis, Minnesota 55401
(612) 330-5500