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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)
/X/ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 1994

OR

/ / TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______________ to _______________

Commission File No. 1-3548

MINNESOTA POWER & LIGHT COMPANY
(Exact name of registrant as specified in its charter)

Minnesota	41-0418150
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
30 West Superior Street Duluth, Minnesota	55802
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (218) 722-2641

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Stock Exchange on Which Registered
Common Stock, without par value	New York Stock Exchange
5% Cumulative Preferred Stock, par value $100 per share	American Stock Exchange
Serial Preferred Stock, $7.36 Series, cumulative, without par value	American Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
Preferred Stock, without par value

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes /X/ No / /

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. /X/

The aggregate market value of voting stock held by nonaffiliates on March 1, 1995, was $839,981,386.

As of March 1, 1995, there were 31,251,068 shares of Minnesota Power & Light Company Common Stock, without par value, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Minnesota Power 1994 Annual Report are incorporated by reference in Part II, Items 7 and 8, and portions of the Proxy Statement for the 1995 Annual Meeting of Shareholders are incorporated by reference in Part III.

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DEFINITIONS

The following abbreviations or acronyms are used in the text.

Abbreviations or Acronyms	Term
ADESA	ADESA Corporation
BNI Coal	BNI Coal, Ltd.
Boise	Boise Cascade Corp.
Boswell	Boswell Energy Center
Btu	British thermal units
Capital Re	Capital Re Corporation
CIP	Conservation Improvement Programs
Company	Minnesota Power & Light Company and its Subsidiaries
Duluth	City of Duluth, Minnesota
Energy Policy Act	National Energy Policy Act of 1992
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FPSC	Florida Public Service Commission
Heater	Heater Utilities, Inc.
Hibbard	M. L. Hibbard Station
Hibbing Taconite	Hibbing Taconite Co.
Inland	Inland Steel Mining Co.
Laskin	Laskin Energy Center
Lehigh	Lehigh Acquisition Corporation
LSPI	Lake Superior Paper Industries
Manitoba Hydro	Manitoba Hydro Electric Board
MBtu	Million British thermal units
Minnesota Paper	Minnesota Paper, Incorporated
Minnesota Power	Minnesota Power & Light Company and its Subsidiaries
Minnkota	Minnkota Power Cooperative, Inc.
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MW	Megawatt(s)
MWh	Megawatt-hour
National	National Steel Pellet Co.
NCUC	North Carolina Utilities Commission
Note __	Note __ to the consolidated financial statements in the Minnesota Power 1994 Annual Report
PSCW	Public Service Commission of Wisconsin
Rainy River	Rainy River Energy Corporation
Reach All	Reach All Partnership
SCPSC	South Carolina Public Service Commission
Square Butte	Square Butte Electric Cooperative
SRFI	Superior Recycled Fiber Industries Joint Venture
SSU	Southern States Utilities, Inc.
SWL&P	Superior Water, Light and Power Company
Synertec	Synertec, Incorporated
Topeka	Topeka Group Incorporated
UtilEquip	UtilEquip, Incorporated
WPPI	Wisconsin Public Power, Inc. SYSTEM

PART I

Item 1. Business.

Minnesota Power is an operating public utility incorporated under the laws of the State of Minnesota in 1906. Its principal executive office is at 30 West Superior Street, Duluth, Minnesota, 55802; and its telephone number is (218) 722-2641. Minnesota Power has operations in three business areas: (1) electric utility operations, which include electric, gas and coal mining operations; (2) water utility operations, which include water, wastewater and sanitation operations; and (3) investments and corporate services, which include investments in securities, equity ownership in a financial guaranty reinsurance company, real estate, paper and pulp production and manufacturing of truck-mounted lifting equipment. As of December 31, 1994, the Company and its subsidiaries had approximately 2,500 employees.

Summary of Consolidated Earnings Per Share

	1994	1993	1992
Total Earnings Per Share	$2.06	$2.20	$2.47
Business Area		Percentage	
Electric Utility Operations	62%	64%	56%
Water Utility Operations	23	4	(2)
Investments and Corporate Services	15	32	46
	100%	100%	100%

Since 1983 Minnesota Power has been diversifying to reduce its reliance on electricity sales to Minnesota's taconite industry and to gain additional earnings growth potential. Acquisitions have been a primary means of diversification, and this is expected to continue as the Company reinvests funds from its securities investment portfolio in additional businesses.

For a detailed discussion of results of operations and trends, see Management's Discussion and Analysis of Financial Condition and Results of Operations in the Minnesota Power 1994 Annual Report. For business segment information, see Note 1.

The information contained or incorporated by reference in this annual report on Form 10-K reflects a categorization of the Company's business which is different from the categorization used in the annual report on Form 10-K for 1993. Financial data from prior years has been reclassified in this annual report on Form 10-K to present comparable data in all periods.

Electric Utility Operations

Minnesota Power's electric utility operations generate, distribute and sell electricity in a 26,000 square mile electric service territory located in northern Minnesota. On December 31, 1994, the Company was supplying retail electric service to 119,100 customers in 135 cities, towns and communities, and outlying rural areas. The largest city served is Duluth with a population of 85,000 based on the 1990 census. Wholesale electric service for resale is supplied to 13 municipal distribution systems, a private utility and to SWL&P. Transmission service (wheeling) is provided to 7 customers.

Minnesota Power has three wholly owned subsidiary companies within its electric utility operations - SWL&P, BNI Coal and Rainy River. SWL&P provides electric, water and natural gas service in Superior, Wisconsin, and adjacent areas. As of December 31, 1994, SWL&P was supplying electric service to 13,700 customers, water service to 9,800 customers and gas service to 10,400 customers. BNI Coal owns and operates a lignite mine in North Dakota. Two electric generating cooperatives, Minnkota and Square Butte, presently consume virtually all of BNI Coal's production of lignite coal under coal supply agreements extending to 2027. Minnkota has an option to extend its coal supply agreement to 2042. (See - Fuel.) Rainy River is exploring possibilities for participation in cogeneration projects.

Electric Sales

The Company expects that kilowatt-hour sales will remain relatively stable over the next five years. (See Regulatory Issues - Minnesota Public Utilities Commission.)

Summary of Electric Revenue and Income

	1994	1993	1992
		In thousands	
Total Electric Revenue and Income	$453,182	$457,719	$449,803
Type of Sales and Income		Percentage	
Retail Sales			
Industrial			
Taconite and Iron Mining	35%	34%	37%
Paper and Other Wood Products	14	14	14
Other Industrial	6	8	8
Total Industrial	55	56	59
Residential	12	11	11
Commercial	12	11	11
Other Retail	3	4	3
Sales for Resale	8	7	6
Other Sales and Income	10	11	10
	100%	100%	100%

The Company's largest customers, Minntac and Hibbing Taconite, represented 13 percent and 10 percent, respectively, of total electric revenue and income in 1994, 1993 and 1992.

The Company sold 171 MW of firm energy to sales for resale customers in 1994. (See Regulatory Issues - Federal Energy Regulatory Commission.)

In the last five years, more than 70 percent of all iron ore consumed by iron and steel plants in the United States has originated from within the Company's Minnesota electric service territory. Taconite, an iron-bearing rock of relatively low iron content which is abundantly available in Minnesota, is an important domestic source of raw material for the steel industry. Taconite processing plants use large quantities of electric power to grind the ore-bearing rock and agglomerate and pelletize the iron particles into taconite pellets. The taconite industry in Minnesota has had relatively stable production levels over the past five years. Annual production from the Minnesota taconite companies was 43 million tons in 1994, 41 million tons in 1993, 40 million tons in 1992, 41 million tons in 1991, and 44 million tons in 1990. The Company estimates that 1995 taconite production will be about 48 million tons.

Firm Large Power Customer Contracts

The Company has power contracts which require the Company to have a certain amount of capacity available at all times (Firm Power) with five large taconite and five paper producing customers, each requiring 10 MW or more (Firm Large Power Customers). Contracts with these ten Firm Large Power Customers require payment of minimum monthly demand charges that cover most of the fixed costs associated with having capacity available to serve them, including a return on common equity. Such contracts minimize the impact on earnings that otherwise would result from significant reductions in kilowatt-hour sales to such customers. These contracts, which are subject to MPUC approval, have a minimum contract term of ten years initially, with a four-year cancellation notice required for termination of the contract at or beyond the end of the tenth year. The rates and corresponding revenue associated with capacity and energy provided under these contracts are subject to change through the same regulatory process governing all retail electric rates. As of March 17, 1995, the minimum annual revenue the Company would collect under contracts with these Firm Large Power Customers, assuming no electric energy use by these customers, is estimated to be $113.6, $95.7, $92.8, $80.2 and $61.1 million during the years 1995, 1996, 1997, 1998 and 1999, respectively. The Company believes actual revenue received from these Firm Large Power Customers will be substantially in excess of the minimum contract amounts.

Contract Status for Minnesota Power Firm Large Power Customers
as of March 17, 1995

Plant and Location	Operating Agent	Ownership	Firm Contracted MW	Earliest Termination Date
Eveleth Mines Eveleth, MN	Oglebay Norton Co.	41.7% Rouge Steel Co. 17.8% Oglebay Norton Co. 28.5% Armco Steel 12.0% Steel Co. of Canada	67.0	October 31, 1999
Hibbing Taconite Co. Hibbing, MN	Cliffs Mining Company	50% Bethlehem Hibbing Corporation 10% Cliffs Mining Company 6.67% Ontario Hibbing Company 33.33% Hibbing Development Company	162.2	December 31, 2000
Inland Steel Mining Co. Virginia, MN	Inland Steel Mining Co.	100% Inland Steel Co.	45.0	October 31, 1997
Minntac (USX) Mt. Iron, MN	U.S. Steel Co.	100% USX Corp.	201.0	April 30, 1999
National Steel Pellet Co. Keewatin, MN	National Steel Corp.	100% National Steel Corp.	85.0	October 31, 2004
Blandin Paper Co. Grand Rapids, MN	Blandin Paper Co.	100% Fletcher Challenge Canada Ltd.	50.6	December 31, 2003
Boise Cascade Corp. International Falls, MN	Boise Cascade Corp.	100% Boise Cascade Corp.	32.0	December 31, 1998
Lake Superior Paper Industries Duluth, MN	Lake Superior Paper Industries	50% Minnesota Paper 50% Pentair Duluth Corp.	48.0	December 31, 2005
Potlatch Corp. Cloquet, MN	Potlatch Corp.	100% Potlatch Corp.	14.7	April 30, 1997
Potlatch Corp. Brainerd, MN	Potlatch Corp.	100% Potlatch Corp.	10.0	November 30, 1999

The following terms are used in the contract descriptions footnoted below.

Firm demand is a take-or-pay obligation which is the sum of contract demand plus incremental demand.

Incremental production service is billed on an energy only basis for energy used above a customer's specific demand threshold. This service does not include a take-or-pay obligation.

Interruptible service is electrical service for a customer that may be interrupted by the Company under certain conditions. In return for this service, customers receive a reduced demand charge, but are obligated to the Company for future service requirements. In June 1993 the MPUC approved 100 MW of interruptible service. In October 1994 the MPUC approved an additional 100 MW of interruptible service to become effective May 1, 1995.

Firm contracted MW represents take-or-pay obligation for March 1995.

Eveleth Mines has firm demand through October 1999. Service requirements through October 1995 are between 58 and 67 MW, from November 1995 through October 1998 are at 51 MW, and from November 1998 through October 1999 are at 37.8 MW. This contract also provides $2.15 million of CIP funding commitments and allows Eveleth to use incremental production service as well as interruptible service. Beginning May 1, 1995, 10 MW of Eveleth's firm demand will be interruptible service.

Hibbing Taconite has contract demand of 120.6 MW through December 2000 and incremental demand of approximately 40 MW through December 1997. Hibbing Taconite's firm demand includes 53 MW of interruptible service. This contract also includes a CIP funding commitment of $2.1 million and incremental production service for loads above 162.7 MW. Beginning May 1, 1995, Hibbing Taconite's firm demand will include another 28 MW of interruptible service.

Inland has contract demand of 34 MW and incremental demand of between 9 and 11 MW through October 1997. Inland's firm demand includes 18 MW of interruptible service.

Minntac (USX) has contract demand of 150.4 MW through December 1995, incremental demand of between 50.6 and 52.6 MW through April 1995, and contract demand of 95 MW from January 1996 through April 1999. This contract also includes a CIP funding commitment of $1.85 million and provides for incremental production service for loads in excess of 203 MW. Beginning May 1, 1995, 21 MW of Minntac's firm demand will be interruptible service.

National has firm demand of 85 MW (63 MW of contract demand and 22 MW of incremental demand) through October 2004. An amendment incorporating incremental production service over 85 MW and updating the interruptible service provision is subject to MPUC approval. Beginning May 1, 1995, 39 MW of National's firm demand will be interruptible service.

Blandin Paper has contract demand of 37.5 MW and incremental demand of 13.1 MW through December 2003.

LSPI has contract demand of 38 MW, incremental demand of 10 MW, and incremental production service above 52 MW through December 2005. LSPI's firm demand includes 29 MW of interruptible service and beginning May 1, 1995, will include another 2 MW of interruptible service.

Purchased Power

Minnesota Power has contracts to purchase capacity from various entities.

Contract Status of Minnesota Power Purchased Power Contracts

Entity	Contract MW	Contract Period
Participation Power Purchases		
Square Butte	323	May 6, 1977, through December 31, 2007
LTV Steel Mining Company	75	November 1, 1991, through April 30, 1995
City of Aitkin	2	May 1, 1993, through April 30, 1998
City of Two Harbors	2	May 1, 1993, through April 30, 1998
Silver Bay Power Company	10	May 1, 1995, through October 31, 1995

Participation power purchase contracts require the Company to pay the demand charges for MW under contract and an energy charge for each MWh purchased. The selling entity is obligated to provide energy as scheduled by the Company from the generating unit specified in the contract as energy is available from that unit.

The Company has a contract which extends through 2007 to purchase 71 percent of the output of a generating plant owned by Square Butte which is capable of generating up to 455 MW. Reductions to about 49 percent of the output are provided for in the contract and, at the option of Square Butte, could begin after a five-year advance notice to the Company. The cost of the power and energy purchased is a proportionate share of Square Butte's fixed obligations and operating costs based on the percentage of the total output purchased by the Company. The annual fixed lease obligations of the Company to Square Butte are $19.4 million from 1995 through 1999. The variable obligation consists of operating costs which are not incurred unless production takes place. The Company is responsible for paying all costs and expenses of Square Butte (including leasing, operating and any debt service costs) if not paid by Square Butte when due. These obligations and responsibilities of the Company are absolute and unconditional, whether or not any power is actually delivered to the Company. (See Note 10.)

Capacity Sales

Minnesota Power has contracts to sell capacity to nonaffiliated utility companies.

Contract Status of Minnesota Power Capacity Sales Contracts

Utility	Contract MW	Contract Period
Participation Power Sales		
Interstate Power Company	55	May 1 through October 31 of each year from 1994 through 2000
	20	November 1, 1997, through April 30, 1998
	35	November 1, 1998, through April 30, 1999
	50	November 1, 1999, through April 30, 2000
Firm Power Sales		
Wisconsin Power & Light Company	30	November 1, 1993, through December 31, 1997
	75	January 1, 1998, through December 31, 2007
Northern States Power Company	150	May 1 through October 31 of each year from 1994 through 1996
Cooperative Power Association	25	April 1, 1995, through September 30, 1995
	10	April 1, 1997, through September 30, 1997
Minnkota Power Cooperative	10	May 1 through October 31 of each year for 1995 and 1996

Participation power sales contracts require the purchasing utility to pay the demand charges for MW under contract and an energy charge for each MWh purchased. The Company is obligated to provide energy as scheduled by the purchasing utility from the generating unit specified in the contract as energy is available from that unit.

Firm power sales contracts require the purchasing utility to pay the demand charges for MW under contract and an energy charge for each MWh purchased. The Company is obligated to provide energy as scheduled by the purchasing utility.

Fuel

The Company has experienced no difficulty in obtaining an adequate fuel supply. The Company purchases low-sulfur, sub-bituminous coal from the Powder River Basin coal field located in Montana and Wyoming to meet substantially all of its coal supply requirements. Coal consumption for electric generation at the Company's Minnesota coal-fired generating stations in 1994 was about 3.4 million tons. As of December 31, 1994, the Company had a coal inventory of about 410,000 tons. During 1994, the Company obtained its coal through both long- and short-term agreements. A long-term agreement (January 1993 through May 1997) with Big Sky Coal Company enables the Company to purchase up to 2.5 million tons of coal on an annualized basis from the Big Sky Mine. The Company also obtained coal under one-year agreements from Kennecott Energy Company's Spring Creek Mine, Western Energy Company's Rosebud Mine, and additional coal from Big Sky Coal Company's Big Sky Mine. In August 1994 the Company entered into a separate agreement (November 1994 through May 1997) with Big Sky Coal Company to purchase an additional 600,000 tons of coal on an annualized basis from the Big Sky Mine. The Company will obtain coal in 1995 under similar one-year agreements with Kennecott Energy Company and Western Energy Company and will continue to obtain coal under its long-term agreements with Big Sky Coal Company. This mix of coal supply options allows the Company to reduce market risk and to take advantage of favorable spot market prices.

The Company is exploring future coal supply options and believes that adequate supplies of low-sulfur, sub-bituminous coal will continue to be available.

Burlington Northern Railroad transports the coal by unit train from Montana or Wyoming to the Company's generating stations. The Company and Burlington Northern Railroad have two long-term coal freight-rate contracts that have been in effect since January 1, 1993. These contracts substantially lowered the delivered price of coal to Minnesota Power. The contracts provide for coal deliveries through 2002 to Laskin and through 2003 to Boswell. The Company also has a contract with the Duluth Missabe & Iron Range Railway which is the final destination short-hauler to Laskin. This contract, which has been in effect since October 15, 1992, also substantially lowered the delivered price of coal and provides for deliveries through 2002. The delivered price of coal is subject to periodic adjustments in freight rates.

Summary of Coal Delivered to Minnesota Power

	Average Delivery Price	
Year Ended December 31	Per Ton	Per MBtu
1994	$19.27	$1.08
1993	$19.31	$1.07
1992	$21.30	$1.18

The generating unit operated by Square Butte, which is capable of generating up to 455 MW, burns North Dakota lignite that is being supplied by BNI Coal, a wholly owned subsidiary of the Company, pursuant to the terms of a contract expiring in 2027. Square Butte's cost of lignite burned in 1994 was approximately 56 cents per million Btu. The lignite acreage that has been dedicated to Square Butte by BNI Coal is located on lands essentially all of which are under private control and presently leased by BNI Coal. This lignite supply is sufficient to provide the fuel for the anticipated useful life of the generating unit. Under the various agreements with Square Butte, the Company is unconditionally obligated to pay all costs not paid by Square Butte when due. These costs include the price of lignite purchased under a cost-plus contract from BNI Coal. (See Item 2. Properties and Note 10.) BNI Coal has experienced no difficulty in supplying all of Square Butte's lignite requirements.

Regulatory Issues

The Company and its subsidiaries are exempt from regulation under the Public Utility Holding Company Act of 1935, except as to Section 9(a)(2) which relates to acquisition of securities of public utility companies.

The Company and its subsidiaries are subject to the jurisdiction of various regulatory authorities. The MPUC has regulatory authority over Minnesota Power's retail rates, issuance of securities and other matters. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates and charges for the sale of electricity for resale, and certain accounting and record keeping practices. The PSCW has regulatory authority over the retail sales of electricity, water and gas by SWL&P. The MPUC, FERC and PSCW had regulatory authority over 55 percent, 6 percent, and 5 percent, respectively, of the Company's 1994 total operating revenue and income.

Electric Rates

The Company has historically designed its electric service rates based on cost of service studies under which allocations are made to the various classes of customers. Nearly all retail sales include billing adjustment clauses which adjust electric service rates for changes in the cost of fuel and purchased energy, and recovery of current and deferred CIP expenditures.

The Company's current policy for all contracts with Firm Large Power Customers is to require a minimum initial contract term of ten years with the term perpetuated thereafter (continuous term) subject to a minimum cancellation notice of four years. The Company's Firm Power rate schedules are designed to recover the fixed costs of providing Firm Power to Firm Large Power Customers, including a return on common equity, regardless of the amount of power or energy actually used. A Firm Large Power Customer's monthly demand charge obligation in any particular month is determined based upon the greater of its actual demand for electricity or the firm demand amount. Contract and rate schedule provisions provide for adjustment if the customer's firm demand amount is set significantly below the customer's actual electric requirements. The rates and corresponding revenue associated with capacity and energy provided under these contracts are subject to change through the regulatory process governing all retail electric rates. Contracts with eight of the ten Firm Large Power Customers provide for deferral without interest or diminishment of one-half of demand charge obligations incurred during the first three months of a strike or illegal walkout at a customer's facilities, with repayment required over the 12-month period following resolution of the work stoppage.

The Company also has contracts with large industrial customers who require less than 10 MW of capacity (Large Light and Power Customers). The terms of these contracts vary depending upon the customers' demand for power and the cost of extending the Company's facilities to provide electric service. Generally, the contracts for less than 3 MW have one-year terms and the contracts ranging from 3 to 10 MW have initial five-year terms. The Company's rate schedule for Large Light and Power Customers is designed to minimize fluctuations in revenue and to recover a significant portion of the fixed costs of providing service to such customers.

The Company requires that all large industrial and commercial customers under contract specify the date when power is first required, and thereafter the customer is billed for at least the minimum power for which it contracted. These conditions are part of all contracts covering power to be supplied to new large industrial and commercial customers and to current contract customers as their contracts expire or are amended. All contracts provide that new rates which have been approved by appropriate regulatory authorities will be substituted immediately for obsolete rates, without regard to any unexpired term of the existing contract. All rate schedules are subject to approval by appropriate regulatory authorities.

Federal Energy Regulatory Commission

Twelve Minnesota municipalities have contracts with the Company through at least 2007 and three additional municipalities have contracts through 1999. Thirteen of these contracts have caps of about 2 percent per year (including fuel costs) on rate increases. The other two municipal customers signed amendments under which the Company will provide exclusive brokering service for the municipalities' purchases of economy energy and will supply emergency, scheduled outage and firm energy as required through 1999. In 1994, 11 municipal customers purchased 76 MW of Firm Power.

In September 1988 the FERC approved a contract between Minnesota Power and SWL&P which provides for SWL&P to purchase its power from the Company through at least 1999 and incorporates the same cap on future rate increases as discussed above. The Company also has a contract, approved by the FERC, to supply electricity to Dahlberg Light and Power Company (Dahlberg) through December 2004. SWL&P purchased 87 MW and Dahlberg purchased 8 MW of Firm Power in 1994.

The Company's hydroelectric facilities which are located in Minnesota are licensed by the FERC. The FERC issued an annual operating license for the St. Louis River hydroelectric project (88.2 MW generation capability) in January 1994, which is effective until a final 30-year license is issued. As a part of the relicensing process, the FERC issued an environmental impact statement for the St. Louis River project in February 1995. A new license is expected in late 1995. The Company filed a draft relicensing application for the Pillager hydroelectric project (1.6 MW) in January 1995 and will file a final application in May 1995. (See Environmental Matters - Water.)

Minnesota Public Utilities Commission

In January 1994 the Company filed with the MPUC a request for a final annual rate increase for all retail electric customers aggregating $34 million, or 11.8 percent, with a 12.5 percent return on equity. In August 1994 the Company reduced its requested annual increase of $34 million to $27 million for 1994 and $23 million for 1995 because of reductions in the projected cost of service and the addition of long-term contract commitments by a taconite customer. On February 17, 1994, the MPUC voted to approve the Company's requested annual interim rate increase of $20 million, or 7 percent. This interim rate increase was implemented on March 1, 1994, subject to refund with interest, and will continue until final rates are effective.

In November 1994 the MPUC issued an order granting the Company an increase in annual electric operating revenue of $19 million, or 6.4 percent, with an 11.6 percent return on equity. Rates for large industrial customers will increase less than 4 percent, while the rate for small businesses will increase 6.5 percent. The rate increase for residential customers will be phased in over three years: 13.5 percent beginning in 1995, an additional 3.75 percent beginning January 1996 and another 3.75 percent beginning January 1997. The increase for large industrial users will be more than offset by savings in coal purchase and transportation costs. These savings are passed on to all customers and are the result of contracts negotiated with suppliers in recent years.

In December 1994 intervenors, including the Company, filed with the MPUC for reconsideration of its November 1994 order. In a March 15, 1995 order, the MPUC denied all material aspects of the requests for reconsideration and upheld the increase granted in November 1994. This order is subject to appeal for a 30 day period ending April 14, 1995. However, no appeals have been filed to date. Final rates are expected to be implemented in the second quarter of 1995.

In 1994 the Company collected $17.2 million of interim revenue, subject to refund with interest. As of December 31, 1994, the Company had reserved $6.1 million of the interim rate revenue for anticipated refunds.

In 1991 the Minnesota State Legislature passed legislation that mandates Minnesota electric utilities to spend a minimum of 1.5 percent of gross annual electric revenue by 1995, on CIP. In 1994, 1993 and 1992, the Company spent $8, $4.1 and $1.8 million, respectively, on CIP and expects to spend a total of $8.5 million during 1995. The MPUC allows such conservation expenditures to be accumulated in a deferred account for recovery through future rates.

In January 1994 the Company began recovering ongoing 1994 CIP expenditures and $8.2 million of deferred CIP expenditures incurred prior to December 31, 1993, through an annual billing adjustment mechanism approved by the MPUC. Through the adjustment the Company is allowed to recover current and deferred CIP expenditures and a lost margin associated with power saved as a result of these programs. The adjustment is revised annually to reflect CIP expenditures that differ from the base level included in the rate schedules. The Company collected $7.8 million of CIP related revenue in 1994.

In 1993 the MPUC approved 100 MW of interruptible service for Firm Large Power Customers. As a condition to taking advantage of the interruptible service, the customers agreed that, to the extent they have electric service requirements (other than requirements served by the customer's ownership share of electric generating facilities at the customer's site) in the period 1997 through 2008, such customers will purchase from the Company not less than the initially certified interruptible load allocation. Also, if the interruptible customer is permitted in the future to obtain electric service from another supplier, the Company shall have the right of first refusal to provide an additional amount of electric service equal to the customer's allocated interruptible load during the eleven-year period, 1997 through 2008. New contract amendments negotiated and approved in 1993 for Hibbing Taconite, Inland, and LSPI extended the contract demand terms to at least October 31, 1997. Of the initial 100 MW available for the interruptible service, Hibbing Taconite was allocated 53 MW, Inland 18 MW and LSPI 29 MW.

In 1994 the MPUC approved an additional 100 MW of interruptible service to become effective May 1, 1995. Conditions for service are similar to those with respect to the initial 100 MW offered, however, the period extends from 1999 through 2010. Of the second 100 MW of interruptible service, Eveleth Mines was allocated 10 MW, Hibbing Taconite 28 MW, Minntac 21 MW, National 39 MW, and LSPI 2 MW.

Minnesota law enables the Company to offer retail customers special rates to meet competition from unregulated energy suppliers or cogenerators. The Company implemented a generation deferral rate in November 1990 for Boise. In March 1994 the MPUC approved an amendment to Boise's contract which includes extension of the generation deferral rate until December 1998. While this rate is lower than the normal retail rate, it provides for recovery of approximately $20 million over the next five years of the Company's fixed costs which would not have been recovered had Boise installed its own generating facilities. In addition, special rates were implemented to attract a new commercial customer that has a 1 MW load. (See Competition.)

In 1994 the Company asked the MPUC to approve two additional rates for retail customers. First, an economic development rate, if approved, would give discounts to customers who invest in new capital improvements or equipment and increase electrical load on the Company's system. Second, an incremental sales rider has been approved which allows more flexibility for some customers to operate above their specified demand levels in certain months and pay only energy charges for the incremental load. (See Competition.)

Public Service Commission of Wisconsin

During 1993 and 1994 SWL&P received approval from the PSCW to expand its gas service territory to serve eight additional rural communities adjacent to its existing service territory. The expansion projects were completed in 1994 at a total cost of $2.4 million.

Capital Expenditure Program

Capital expenditures for the electric utility operations totaled $45 million during 1994, of which $2 million was for coal operations. Internally generated funds were used to fund these capital expenditures.

The Company's electric generating stations have the capacity to meet customer needs through the 1990s without major capacity additions or environmental modifications. Electric utility operations capital expenditures are expected to be $37 million in 1995, of which $7 million is related to coal operations. A total of approximately $158 million of electric utility operations capital expenditures is expected during the period 1996 through 1999, of which $10 million is related to coal operations. The Company's estimates of such capital expenditures and the sources of financing are subject to continuing review and adjustment.

Competition

The enactment of the Energy Policy Act resulted in an increase in the competitive forces that affect two of the three key elements of the electric utility industry, namely generation and transmission. The third element, distribution, remains unaffected. This legislation has resulted in a more competitive market for electricity in both the retail and wholesale markets.

Minnesota Power is well-positioned to meet both retail and wholesale competitive forces. The Company's rates are very competitive even with the retail rate increase approved by the MPUC in November 1994. Many of the Company's wholesale and Firm Large Power Customers have extended the terms of their electric service agreements with the Company. As such agreements are extended, the Company's competitive position is enhanced. In addition to providing electricity to its customers, the Company offers its customers a wide variety of value-added services, including conservation improvement services, to meet their energy needs. The Company has also obtained MPUC approval to offer interruptible rates to Firm Large Power Customers and may offer competitive rates within its service territory to serve customers that could otherwise obtain their energy needs from an unregulated energy supplier or by generating their own electricity with MPUC approval.

Retail

Large industrial and commercial customers that have the ability to own and operate their own generation facilities may compete directly with the Company to supply their own electric needs. If these facilities are Qualifying Facilities (QFs), the customers that own them may require that the Company purchase the output from them at the Company's "avoided cost" pursuant to the Public Utility Regulatory Policies Act. Additionally, these customers, as well as the balance of the Company's customers, may elect to substitute other sources of energy, such as natural gas, oil or wood, for various end uses rather than continuing to use electric energy. Municipalities may elect to serve customers of the Company lying within municipal boundaries, but must fully compensate the Company for its loss of property and revenue associated with this load. Finally, the prospect that large industrial customers might seek state authorization of retail wheeling in the future would have the effect of substantially increasing competition in the retail segment of the market for electricity.

Wholesale

The Energy Policy Act increased competition in the wholesale market by eliminating existing legal barriers with respect to entry into the generation market and with respect to the provision of transmission services. First, the Energy Policy Act created a new class of power producers, known as Exempt Wholesale Generators (EWGs). EWGs are exempt from regulation under the Public Utility Holding Company Act of 1935 and EWG sales are generally subject to less regulation than sales by traditional utilities. The fact that EWGs may include independent power producers as well as affiliates of electric utilities marks a further diminution of the role of electric utilities as the exclusive generators of electric energy. Second, the Energy Policy Act authorized the FERC to order utilities which own or operate transmission facilities to provide wholesale transmission services to or from other utilities or entities generating electric energy for sale or resale, provided that the rates charged for transmission services are recovered from the entity seeking the transmission service and not from the transmitting utility's existing wholesale, retail or transmission customers. The Energy Policy Act expressly prohibits the FERC from ordering a utility to provide retail wheeling services to any of its customers.

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 93 cities and towns located within its service territory. SWL&P holds franchises in 11 cities and towns within its service territory. The remaining cities and towns served will not grant a franchise or do not require a franchise to operate within their boundaries.

Environmental Matters

The Company's electric utility operations are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, solid wastes, and other environmental matters. The Company considers its electric utility operations to be in substantial compliance with those environmental regulations currently applicable to its operations and believes all necessary permits to conduct such operations have been obtained. Except as noted below, the Company does not currently anticipate that its potential capital expenditures for environmental control purposes will be material. However, because environmental laws and regulations are constantly evolving, the character, scope and ultimate costs of environmental compliance cannot be estimated.

Air

The Federal Clean Air Act Amendments of 1990 (Clean Air Act) require that specified fossil-fueled generating plants meet new sulfur dioxide and nitrogen oxide emission standards beginning January 1, 1995 (Phase I) and that virtually all generating plants meet more strict emission standards beginning January 1, 2000 (Phase II). None of Minnesota Power's generating facilities are covered by the Phase I requirements of the Clean Air Act.

The Clean Air Act creates emission allowances for sulfur dioxide based on formulas relating to the permitted 1985 emissions rate and a baseline of average fossil fuel consumed in the years 1985, 1986 and 1987. Each allowance is an authorization to emit one ton of sulfur dioxide, and each utility must have sufficient allowances to cover its annual emissions. Minnesota Power's generating facilities in Minnesota burn mainly low-sulfur western coal and Square Butte, located in North Dakota, burns lignite coal. All of these facilities are equipped with pollution control equipment such as scrubbers, baghouses or electrostatic precipitators. Phase II sulfur dioxide emission requirements are currently being met by Boswell Unit 4. Some moderate reductions in emissions may be necessary from Boswell Units 1, 2, and 3, Laskin Units 1 and 2, and Square Butte to meet the Phase II sulfur dioxide emission requirements. The Company believes it is in a good position to comply with the sulfur dioxide standards without extensive modifications. Any required reductions at the Minnesota generating facilities are expected to be achieved through the use of lower sulfur coal. Square Butte anticipates meeting any required reductions through increased use of existing scrubbers.

The Clean Air Act requires the EPA to set the nitrogen oxide limitations by January 1, 1997, for Phase II generating units. To meet anticipated Phase II nitrogen oxide limitations, the Company expects to install low-nitrogen oxide burner technology by the year 2000. Square Butte will be able to determine the costs of complying with the nitrogen oxide limitations when regulations applicable to this plant are promulgated by the EPA. Based on preliminary estimates, the costs of complying with the nitrogen oxide limitations for Boswell, Laskin and Hibbard are not expected to exceed $10 million.

Installation of continuous emission monitoring equipment by January 1, 1995, is also required by the Clean Air Act for Phase II units. Boswell, Laskin and Hibbard installed $2.8 million of continuous emission monitoring (CEM) equipment, and Square Butte installed over $400,000 of CEM equipment in 1994.

In August 1993 the Company indicated its intent to work with the U.S. Department of Energy to identify appropriate activities that the Company has taken and additional measures that the Company may undertake on a voluntary basis that will result in limitations, reductions or sequestrations of greenhouse gas emissions by the year 2000. Section 1605 of the Energy Policy Act mandates timely and acceptable definitions of greenhouse gas accounting guidelines and greenhouse gas crediting guidelines. The Company has agreed to participate in this voluntary program provided that such participation is consistent with the Company's integrated resource planning process, does not have a material adverse effect on the Company's competitive position with respect to rates and costs, and continues to be acceptable to the Company's regulators.

Water

The Federal Water Pollution Control Act of 1972 (FWPCA), as amended by the Clean Water Act of 1977 and the Water Quality Act of 1987, established the National Pollutant Discharge Elimination System (NPDES) permit program. The FWPCA requires that NPDES permits be obtained from the EPA (or, when delegated, from individual state pollution control agencies) for any wastewater discharged into navigable waters.

The MPCA reissued the Laskin NPDES permit on December 22, 1993. This permit will remain in effect until October 31, 1998. The permit contained a schedule of compliance which required a 57 percent reduction in the size of the ash disposal ponds by November 1, 1994. This work was completed in August 1994 at a total cost of $1.1 million. Additional work is currently planned to begin in the second quarter of 1995 at an estimated cost of $150,000. No further actions are anticipated during the remainder of the permit term.

Federal Energy Regulatory Commission (FERC) operating licenses for several of the Company's hydroelectric facilities have been received or are currently undergoing relicensing by the FERC. Thirty (30) year licenses for Little Falls, Sylvan and Prairie River Hydroelectric Projects were issued by FERC in 1993 effective on January 1, 1994. The St. Louis River Project is currently operating under an annual license until the FERC has completed its environmental review of the project. Since the final environmental impact statement for the project was released by FERC dated February 1995, the Company expects that the final license will be issued sometime in late 1995. A final application to relicense the Pillager Project will be filed with the FERC by May 11, 1995. The FERC will perform an engineering, environmental and economic analysis of that application over a two year period prior to the current Pillager FERC license expiration on May 11, 1997. A new license is expected to be issued for this project by the FERC before the current expiration date. The Company believes, that although environmental considerations may require additional studies or higher minimum flow releases for fish habitat, recreation and water quality enhancement, that the economics of each project will not be compromised.

Solid Waste

The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid wastes. As a result of this legislation, the EPA has promulgated various hazardous waste rules. The Company is required to notify the EPA of hazardous waste activity and routinely submits the necessary annual reports to the EPA.

In 1990 the Company was notified by the EPA and the MPCA that it had been named as a potentially responsible party under the Comprehensive Environmental Response, Compensation and Liability Act pertaining to the cleanup of pollution at a northern Minnesota oil refinery site (Arrowhead Site). In 1994 a settlement proposal was reached regarding cleanup at the Arrowhead Site. State and federal officials have agreed cleanup should begin in 1995. The total costs to remediate the Arrowhead Site are currently estimated at $37 million. Funding under the proposal is shared by several governmental entities and about 130 companies. The formal request for approval of the settlement has been filed with the appropriate agencies. Under the terms of the settlement, Minnesota Power's share of remediation costs is approximately $314,000, which has been paid. In addition, the Company has spent about $600,000 to date on legal and other costs since the suit was initiated.

Mining Control and Reclamation

BNI Coal's mining operations are governed by the Federal Surface Mining Control and Reclamation Act of 1977. This Act, together with the rules and regulations adopted thereunder by the Department of the Interior, Office of Surface Mining Reclamation and Enforcement (OSM), governs the approval or disapproval of all mining permits on federally owned land and also governs the actions of the OSM in approving or disapproving state regulatory programs regulating mining activities. The North Dakota Reclamation of Strip Mined Lands Act and rules and regulations enacted thereunder in 1969, as subsequently amended by the North Dakota Mining and Reclamation Act and rules and regulations enacted thereunder in 1977, govern the reclamation of surface mined lands and are generally as stringent or more stringent than the federal rules and regulations. Compliance is monitored by the North Dakota Public Service Commission. The federal and state laws and regulations require a wide range of procedures including water management, topsoil and subsoil segregation, stockpiling and revegetation, and the posting of performance bonds to assure compliance. In general, these laws and regulations require the reclaiming of mined lands to a level of usefulness equal to or greater than that available before active mining.

Water Utility Operations

Topeka, a wholly owned subsidiary of the Company, owns 100 percent of the companies described below which sell water and provide wastewater treatment services. These water utilities have been upgrading existing operations, building new facilities, acquiring new systems and seeking rate increases.

- SSU owns and operates water and wastewater treatment facilities in many communities in Florida. SSU is the largest private water supplier in Florida. At December 31, 1994, SSU served 104,000 water customers and 44,100 wastewater treatment customers. SSU also provides sanitation services to one franchise area serving 11,800 customers.

- Heater owns and operates 4 companies which provide water and wastewater treatment services in North Carolina and South Carolina. At December 31, 1994, these companies served 24,800 water customers and 2,600 wastewater treatment customers.

In October 1994 SSU and Sarasota County signed a purchase agreement regarding the threatened condemnation of the Venice Gardens water and wastewater facilities owned by SSU and located in Sarasota County, Florida. The sale for $37.6 million was completed in December 1994 adding $11.8 million or 42 cents per share to 1994 earnings.

In September 1994 SSU signed a purchase agreement to acquire the assets of Orange Osceola Utilities, Inc. located near Kissimmee, Florida, for approximately $13 million. The purchase is subject to various regulatory approvals prior to closing which the Company believes will be received in due course. In October 1994 SSU filed with the FPSC for approval of the purchase. The 17,450 water and wastewater connections which will be gained as a result of the purchase will approximate the number of connections SSU sold in the Venice Gardens transaction.

In October 1994 Seabrook Island, South Carolina, residents voted to allow the town to purchase or acquire through eminent domain powers the town's current water and wastewater treatment facilities owned by Heater of Seabrook, a wholly owned subsidiary of Heater. Heater of Seabrook currently serves 3,300 customers. In January 1995 the town of Seabrook Island initiated an eminent domain action to take the assets of Heater of Seabrook from Heater. The price will be determined through court proceedings.

Regulatory Issues

The FPSC and certain county commissions in Florida have regulatory authority over water and wastewater treatment services sold by SSU. The NCUC and the SCPSC have regulatory authority over water and wastewater treatment services sold by Heater and its subsidiaries. The Florida commissions had regulatory authority over 9 percent of the Company's 1994 total operating revenue and income, and the North Carolina and South Carolina commissions had regulatory authority over 1 percent.

Florida Public Service Commission

The following is a summary of SSU's rate filings with the FPSC and three county commissions during 1993 and 1994.

- Under provisions of a Florida state statute, water and wastewater utilities may file with the FPSC an annual index and pass-through filing designed to recover inflation costs associated with operation and maintenance expenses. The intent of the statute is to provide inflationary relief to utilities thus delaying or avoiding the costs associated with full rate case filings. In May 1994 SSU made an index and pass-through filing for its FPSC regulated systems. The annual increase requested was $711,000 or a rate increase of approximately 1.6 percent. In June 1994 SSU withdrew the portion of the request relating to Hernando County at the request of the FPSC. The FPSC approved $550,000 of the filing on an annual basis and the rates became effective in July 1994.

- In September 1994 SSU filed a pass-through filing with the Hillsborough Board of County Commissioners for a $500,000 increase in wastewater rates for the Seaboard facilities. The increase was effective in October 1994 and recovers costs SSU pays to the City of Tampa for wastewater treatment.

- In December 1994 SSU filed a pass-through filing with the FPSC for a $714,000 increase in water and wastewater rates for the Deep Creek facilities. The increase became effective in February 1995 and is expected to recover costs SSU pays to Charlotte County for bulk water and wastewater treatment.

- The FPSC ordered statewide uniform rates for 90 water and 37 wastewater service areas in SSU's 1992 consolidated rate filing. In September 1993 the FPSC initiated a separate investigation into the appropriate rate structure for SSU. The investigation was initiated for the purpose of determining if, as a matter of policy, uniform statewide rates are appropriate for SSU. In June 1994 the FPSC issued an order declining to issue a declaratory statement which would have acknowledged FPSC jurisdiction over SSU service areas in Hillsborough and Polk Counties. Instead the FPSC opened an investigation to determine if SSU is a single system pursuant to Florida statutes. If SSU is classified as a single system, all SSU facilities operated in Florida will be subject to FPSC jurisdiction. Hearings were held in January 1995, with a final decision expected in June 1995.

- In April 1994 the Hernando County Board of County Commissioners issued an order rescinding FPSC jurisdiction in Hernando County. In June 1994 the FPSC issued an order acknowledging that Hernando County has jurisdiction over privately-owned water and wastewater facilities located in the County as of April 5, 1994. In April 1994 SSU filed a court action before the Florida Circuit Court for Hernando County to stay the change in jurisdiction. This action remains pending. In April 1994 SSU also requested the FPSC to retain interim jurisdiction over SSU's facilities in Hernando County until jurisdictional determinations are made by the courts. In June 1994 the FPSC issued an order denying SSU's request. SSU has appealed this order to Florida's First District Court of Appeals. SSU believes that a jurisdictional change should not be made at this time because of the FPSC investigation to determine if SSU's facilities in all counties within Florida constitute a single system subject to the sole jurisdiction of the FPSC.

- In September 1994 the Charlotte County Board of County Commissioners declared that as of September 27, 1994, all water and wastewater utilities in Charlotte County were subject to the jurisdiction of the FPSC. The FPSC acknowledged the County action in a November 1994 order and is expected to issue in 1995 a Certificate of Authority to SSU for facilities located in Charlotte County.

SSU plans to file a general rate increase application with the FPSC in 1995. New facilities added since 1992 (SSU's last general rate increase) are not yet included in rate base for earnings purposes. Additionally, mandated regulatory compliance cost increases during the same period, particularly for environmental protection, have increased operating expenses and should also be recovered in rates. The filing is expected to include water conservation incentives and request approval of a consistent policy on charges for service availability.

North Carolina Utilities Commission and South Carolina Public Service Commission

The following is a summary of Heater's pending rate filings with the NCUC and the SCPSC.

- In July 1992 Heater filed with the SCPSC for a $233,000 rate increase for operations near Columbia, South Carolina. In January 1993 the SCPSC denied the rate increase request. In March 1993 Heater filed with the Circuit Court of South Carolina an appeal of the SCPSC's denial of the request. In September 1993 the requested rates were implemented, under surety bond, pending the decision on the appeal. As a condition to the SCPSC's grant to Heater of a $110,000 annual increase in May 1994, Heater was required to cease charging the increased rates under surety bond. The final decision on the appeal is expected in 1995 and will determine the amount of the refund with interest, if any.

- In January 1994 Heater of Seabrook, a wholly owned subsidiary of Heater, filed with the SCPSC for a $263,000 annual rate increase for operations near Charleston, South Carolina. In July 1994 the SCPSC denied the request for an annual rate increase. The SCPSC treated $64,000 in availability fees as revenue. Previously, the SCPSC treated these fees as a reduction to rate base. This treatment resulted in an 8.6 percent operating margin which the SCPSC found to be adequate. Heater of Seabrook filed a motion for reconsideration in July 1994 maintaining that the resulting 3.98 percent return on equity is inadequate. In August 1994 the SCPSC denied reconsideration. In September 1994 Heater of Seabrook filed an appeal in the Circuit Court of South Carolina and subsequently provided notice to the customers and implemented the requested rates under surety bond in January 1995, pending the final decision on the appeal.

- In July 1994 Upstate Heater Utilities (Upstate), a wholly owned subsidiary of Heater, filed for a $71,000 annual rate increase with the SCPSC. In December 1994 the SCPSC denied the request for an annual rate increase primarily due to customer opposition. In January 1995 Upstate filed for reconsideration and the SCPSC denied the request. In February 1995 Upstate filed an appeal in the Circuit Court of South Carolina.

- In February 1995 Heater filed for a $314,000 annual rate increase with the NCUC. A hearing is scheduled for July 18, 1995.

- In March 1995 Brookwood Water Corporation, a wholly owned subsidiary of Heater, filed with the NCUC for a $120,000 annual rate increase.

Capital Expenditure Program

Capital expenditures for the water and wastewater utility operations totaled $28 million during 1994. Expenditures were funded with the proceeds from long-term bonds issued by SSU and internally generated funds. Water utility capital expenditures are expected to be $26 million in 1995 for upgrades, water reuse projects and new water facilities, and to total approximately $99 million during the period 1996 through 1999.

Franchises

SSU provides water and wastewater treatment services in 22 counties regulated by the FPSC and holds franchises in three counties which to date have retained authority to regulate such operations. SSU is contesting in a Florida circuit court and a Florida appellate court the authority of one of these three counties, Hernando County, to regulate SSU's operations. (See Regulatory Issues - Florida Public Service Commission.)

All of the water and wastewater services of Heater are under the jurisdiction of regulatory commissions. These commissions grant franchises for Heater's service territory when the rates are authorized.

In March 1995 East LA Services Corporation, a wholly owned subsidiary of Topeka, was notified by Lee County, Florida that it would not be awarded any sanitation service area franchises requested as part of a proposal procedure. As a result, East LA Services Corporation expects to discontinue operations on or about September 30, 1995, the existing franchise agreement's expiration date. Discontinuation of this business will not be material.

Environmental Matters

The Company's water utility operations are subject to regulation by various federal, state and local authorities in the areas of water quality, solid wastes, and other environmental matters. The Company considers its water utility operations to generally be in compliance with those environmental regulations currently applicable to its operations and have the permits necessary to conduct such operations. Except as noted below, the Company does not currently anticipate that its potential capital expenditures for environmental control purposes will be material. However, because environmental laws and regulations are constantly evolving, the character, scope and ultimate costs of environmental compliance cannot be estimated.

In July 1992 the EPA issued a Request for Information to SSU regarding operations of SSU's wastewater facilities in the Seaboard service area in Hillsborough County, Florida. The request was made to obtain more details concerning exceedances of the NPDES permit for effluent quality. Requested information was compiled and sent to the EPA in September 1992. In 1993 SSU complied with an additional Request for Information issued by the EPA. In 1993, the EPA issued an Administrative Order regarding the violations. The Order required SSU to select a method to consistently meet all NPDES permit requirements or cease all discharges to the surface waters of the United States. In March 1994 SSU connected the Seaboard facilities with the City of Tampa's facilities and ceased discharges from the facilities to surface waters. SSU has received no further communication from the EPA regarding this matter and is unable to determine what further action, if any, may be required.

In October 1992 the EPA issued an Information Request to SSU regarding operations of SSU's facilities in the University Shores service area in Orange County, Florida. The request was made to obtain more details concerning exceedances of the NPDES permit for effluent quality. The requested information was compiled and sent to the EPA in late 1992 and supplemented in February 1993. In February 1993 the EPA issued a Notice to Show Cause letter to request SSU representatives to meet in Atlanta, Georgia, to discuss the exceedances. SSU met with the EPA in March 1993 and received an additional Information Request from the EPA in April 1993. The requested information was supplied to the EPA in June 1993. At that time, SSU was attempting to determine a feasible method to eliminate surface water discharges allowed by the NPDES permit. After months of design and environmental permitting problems, SSU signed an agreement with Orange County Utilities (OCU) to construct an interconnect between the two collection systems so that a portion of the sewage flow at University Shores could be sent to OCU. The construction of the interconnect was completed in September 1994 thereby allowing SSU to eliminate effluent discharges by the University Shores facilities to surface waters. Additional information on the project was requested by EPA in November 1994 and SSU supplied the requested information to the EPA in December 1994.

In September 1993 the EPA issued an Administrative Order to SSU regarding operations of SSU's facilities in the Woodmere service area in Duval County, Florida (Woodmere facilities). The Order requires monthly toxicity testing of the effluent for at least one year because of toxicity test failures during 1992 and 1993. In September 1994, because of additional 1993 and 1994 toxicity test failures at the Woodmere facilities, the EPA required implementation of a Toxicity Reduction Evaluation (TRE) plan to determine the cause of the toxicity. The TRE plan is expected to take approximately 15 months to complete.

In August 1994 the EPA issued an Administrative Order to SSU regarding operations of SSU's facilities in the Beacon Hills service area in Duval County. The Order requires monthly toxicity testing of the effluent because of toxicity test failures during 1993 and 1994.

SSU and the Florida Department of Environmental Protection (FDEP) completed negotiations in 1994 on five consent orders involving water and wastewater facilities within SSU's system resulting in penalties and reimbursement totaling approximately $27,000. Three additional consent orders with proposed penalties of approximately $25,000 are being negotiated with the FDEP.

In 1994 SSU invested approximately $11.2 million of a $23.6 million annual capital expenditure budget (or approximately 47.5 percent) in facilities necessary to comply with environmental requirements. In 1995 SSU expects that approximately $9.4 million of the $20.8 million annual capital expenditure budget (or approximately 45 percent) will be necessary to comply with environmental requirements.

Investments and Corporate Services

Non-regulated investments supplement Minnesota Power's earnings and, in some cases, perform an economic development function in Minnesota Power's electric utility service area. These investments include a portfolio of securities investments managed by Minnesota Power which are intended to provide funds for reinvestment and business acquisitions. Considered a part of the portfolio, the Company owns a 22.1 percent equity investment in a financial guaranty reinsurance company. Additionally, the Company owns an 80 percent interest in a real estate company in Florida, a 50 percent interest in a Duluth paper making mill, an 88 percent interest in a Duluth plant which produces recycled pulp and an 82.5 percent interest in a Duluth manufacturer of specialized truck-mounted lifting equipment.

- As of December 31, 1994, the Company had approximately $202 million in a portfolio of securities investments. The majority of the securities investments are investment grade stocks of other utility companies and are considered by the Company to be conservative investments. Additionally, the Company sells common stock securities short and enters into short sales of treasury futures contracts as part of an overall investment portfolio hedge strategy. Selling common stock securities short and entering into treasury futures contracts create off-balance-sheet market risk to the Company. At December 31, 1994, the Company had approximately $61.5 million of short stock sales outstanding and $31.7 million of treasury futures contracts. (See Note 4.)

- At December 31, 1994, Minnesota Power had a $72.1 million equity investment which represented a 21.4 percent ownership interest in Capital Re, a Delaware holding company engaged in financial and mortgage guaranty reinsurance through its wholly owned subsidiaries, Capital Reinsurance Company and Capital Mortgage Reinsurance Company. Capital Reinsurance Company is a reinsurer of financial guarantees of municipal and non-municipal debt obligations. Capital Mortgage Reinsurance Company is a reinsurer of residential mortgage guaranty insurance. In 1994 the Company purchased an additional 417,100 shares of Capital Re common stock for $8.8 million. (See Note 5.) In March 1995 the Company purchased another 100,000 shares of Capital Re common stock for $2.2 million increasing the Company's ownership interest to 22.1 percent.

- The Company, through Topeka, acquired a two-thirds ownership interest in Lehigh, a real estate company which owns various real estate properties and operations in Florida, for $6 million in July 1991. In June 1993 the Company issued 140,648 shares of common stock, with a market value at the time of issuance of approximately $4.9 million, in exchange for an additional 13.4 percent ownership in Lehigh bringing the Company's total ownership interest in Lehigh to 80 percent. Real estate properties and operations are being sold over the next several years. The acquisition was accounted for under the purchase method and has been consolidated with the Company since July 1991.

- Minnesota Paper, a wholly owned subsidiary of the Company, is a 50 percent participant in LSPI, a joint venture with Pentair Duluth Corp., a subsidiary of

St. Paul based Pentair, Inc. LSPI operates a paper mill in Duluth which produces supercalendered paper. (See Note 5.)

- UtilEquip, a wholly owned subsidiary of the Company, has an 82.5 percent ownership interest in Reach All. Located in Duluth, Reach All manufactures specialized truck-mounted lifting equipment used by utilities and governmental entities.

- Synertec, a wholly owned subsidiary of the Company, is pursuing opportunities in ventures relating to energy efficiency, resource conservation such as recycling and solid waste management, and pollution prevention.

- SRFI, a joint venture owned 88 percent by subsidiaries of the Company and 12 percent by a subsidiary of Pentair, Inc., built a $78 million plant in Duluth that produces pulp from recycled office scrap paper. Commercial operations began at SRFI in November 1993. The plant has the capacity to produce 90,000 tons of recycled pulp annually and has commitments from paper producers to purchase up to 82 percent of its output under multi-year contracts.

In January 1995 the Company and ADESA jointly announced that they had entered into a letter of intent outlining terms of a merger under which ADESA will become an 80 percent-owned subsidiary of Minnesota Power in return for payment of $167 million. ADESA, headquartered in Indianapolis, owns and operates auto redistribution facilities and performs related services through which used cars and other vehicles are sold by automobile manufacturers, franchised automobile dealers, fleet/lease companies, and licensed used car dealers. Pursuant to the proposed merger, all shareholders of ADESA, other than certain officers with respect to a portion of their shares, will receive $17.00 in cash for each share of their ADESA common stock. In February 1995 a merger agreement was signed along with employment agreements with ADESA's four top managers, and put and call agreements. The put and call agreements provide ADESA management the right to sell to Minnesota Power, and Minnesota Power the right to purchase, ADESA management's 20 percent retained ownership interest in ADESA, in increments during the years 1997, 1998 and 1999, at a price based on ADESA's financial performance. The transaction is scheduled to be completed during the second quarter of 1995 subject to, among other things, approval of the transaction by ADESA's shareholders and satisfaction of other customary conditions. It is anticipated that a portion of the Company's securities portfolio will be used to fund the ADESA purchase.

In September 1994 Pentair, Inc., the Company's joint-venture partner in LSPI, announced its desire to exit the paper business, which would likely include selling LSPI. The Company would participate in a sale under the right conditions. If LSPI is sold, it may be logical to also consider a simultaneous sale of SRFI, whose paper recycling/pulp production plant is adjacent to and operated by LSPI.

In March 1995 based on the results of a project which analyzed the economic feasibility of realizing future tax benefits available to the Company, the board of directors of Lehigh directed Lehigh Corporation, a subsidiary of Lehigh, to dispose of its assets in a manner that would maximize utilization of the tax benefits. As a result of the project findings and the board's directive, Lehigh will reduce a $26.2 million valuation allowance against its deferred tax assets to $7.8 million and recognize $18.4 million in income. The Company's portion will be $14.7 million or 52 cents per share in income in the first quarter of 1995.

The Company anticipates exiting the specialized truck-mounted lifting equipment business in 1995 and is reviewing its alternatives to accomplish this objective. In anticipation of that action, a loss, estimated to range from $3 to $5 million, after tax, will be reflected in the Company's first quarter 1995 earnings.

Capital Expenditure Program

Capital expenditures for investments and corporate services businesses totaled approximately $8 million during 1994. These expenditures included approximately $3 million for construction of the pulp production plant and approximately $5 million for affordable housing. Capital expenditures for the investments and corporate services businesses are expected to be $1.5 million in 1995 and total approximately $8.7 million during the period 1996 through 1999.

Environmental Matters

Certain of the Company's investments and corporate services businesses are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, solid wastes, and other environmental matters. The Company considers these businesses to be in substantial compliance with those environmental regulations currently applicable to its operations and believes all necessary permits to conduct such operations have been obtained. The Company does not currently anticipate that its potential capital expenditures for environmental control purposes will be material. However, because environmental laws and regulations are constantly evolving, the character, scope and ultimate costs of environmental compliance cannot be estimated.

Executive Officers of the Registrant

Executive Officers	Initial Effective Date
Arend J. Sandbulte, Age 61	
Chairman, President and Chief Executive Officer	May 9, 1989
Robert D. Edwards, Age 50	
Executive Vice President and Chief Operating Officer	March 1, 1993
Group Vice President-Corporate Services and Chief Financial Officer	January 1, 1991
Group Vice President-Finance and Chief Financial Officer	May 10, 1988
Jack R. McDonald, Age 57	
Executive Vice President-Finance and Corporate Development	March 1, 1993
Group Vice President-Corporate Development	January 1, 1991
Group Vice President-Power Systems	February 1, 1990
Group Vice President-Topeka Group	May 10, 1988
Donnie R. Crandell, Age 51	
Senior Vice President-Corporate Development	December 1, 1994
Retired	February 28, 1994
Vice President-Corporate Development	March 1, 1993
David G. Gartzke, Age 51	
Senior Vice President-Finance and Chief Financial Officer	December 1, 1994
Vice President-Finance and Chief Financial Officer	March 1, 1993
Vice President-Finance and Treasurer	January 1, 1991
Vice President and Treasurer	May 9, 1989
Warren L. Candy, Age 45	
Vice President-Boswell Energy Center	May 10, 1994
Roger P. Engle, Age 46	
Vice President-Customer Operations	June 1, 1993
General Manager-Central Division	June 1, 1992
Corporate Controller	January 1, 1991
Controller	May 8, 1984
Philip R. Halverson, Age 46	
General Counsel and Corporate Secretary	March 1, 1993
General Counsel and Assistant Secretary	January 23, 1991
Allen D. Harmon, Age 43	
Resigned from office	March 17, 1995
Group Vice President-Electric Utility Operations	January 1, 1991
Group Vice President-Customer Service	May 10, 1988
Eugene G. McGillis, Age 60	
Vice President	June 1, 1992
Vice President-Customer Operations	April 17, 1989
Gerald B. Ostroski, Age 54	
Vice President	January 1, 1991
Vice President-Information and Environmental Services	May 10, 1988
Bert T. Phillips, Age 54	
Resigned from office due to health reasons	December 31, 1994
Group Vice President-Water Resource Operations	January 1, 1991
Group Vice President-Topeka Group	February 1, 1990
Group Vice President-Power Systems	May 10, 1988
Charles M. Reichert, Age 57	
Vice President	July 21, 1993
Kevin G. Robb, Age 48	
Vice President-Generation	June 1, 1993

Executive Officers	Initial Effective Date
Mark A. Schober, Age 39	
Corporate Controller	March 1, 1993
Stephen D. Sherner, Age 44	
Vice President-Power Marketing and Delivery	March 1, 1993
Vice President-Strategic Resource Management	May 10, 1988
Geraldine R. VanTassel, Age 53	
Vice President-Corporate Resource Planning	March 1, 1993
Corporate Controller	June 1, 1992
James K. Vizanko, Age 41	
Corporate Treasurer	March 1, 1993

All of the executive officers above, except Mr. Crandell, Mr. Reichert and Mr. McGillis, had been employed by the Company for more than five years in executive or management positions. Mr. Crandell was director of business development, vice president of Topeka and vice president of business development for Topeka prior to March 1, 1993. Mr. Reichert is also president of BNI Coal, a position which he held before being elected to the above position. Mr. McGillis is also president and chief operating officer of SWL&P, a position which he held before being elected to the above position. Prior to election to the positions shown above, the following executive officers held other positions with the Company after January 1, 1990: Mr. Candy was director of Boswell, assistant plant manager and leader of the organizational development team; Mr. Halverson was director of legal services and assistant general counsel, and assistant secretary; Mr. Robb was director of independent power projects and director of engineering administration; Mr. Schober was director of internal audit; Ms. VanTassel was director of internal audit and leader of the organizational development team; and Mr. Vizanko was director of investments and analysis, and manager of financial planning and analysis. There are no family relationships between any executive officers of the Company. All officers and directors are elected or appointed annually.

The present term of office of the above executive officers extends to the first meeting of the Company's Board of Directors after the next annual meeting of shareholders. Both meetings are scheduled for May 9, 1995.

Item 2. Properties.

The Company had a net peak load during 1994 of 1,338 MW on December 19, 1994. At the time of the peak the Company's capacity margin based on installed capacity and scheduled firm purchases and sales was approximately 16 percent. Information with respect to existing power supply sources is shown below.

Power Supply	Unit No.	Year Installed	Net Winter Capability (MW)	Net Electric Requirements (MWh)	(%)
Steam					
Coal-Fired					
Boswell Energy Center					
near Grand Rapids, MN	1	1958	69		
	2	1960	69		
	3	1973	350		
	4	1980	428		
			916	5,363,634	50.4%
Laskin Energy Center					
Hoyt Lakes, MN	1	1953	55		
	2	1953	55	193,772	1.8
			110		
Total Steam			1,026	5,557,406	52.2
Hydro					
Group consisting of ten stations in MN		Various	121	693,752	6.5
Purchased Power					
Square Butte burns lignite in Center, ND			322	2,300,795	21.6
All other - net			-	2,095,211	19.7
Total Purchased Power			322	4,396,006	41.3
For the Year Ended December 31, 1994			1,469	10,647,164	100.0%

The Company has electric transmission and distribution lines of 500 kilovolts (kV) (7.8 miles), 230 kV (606.4 miles), 161 kV (42.8 miles), 138 kV (5.8 miles), 115 kV (1,239.6 miles) and less than 115 kV (6,001.3 miles). The Company owns and operates 180 substations with a total capacity of 8,545.7 megavoltamperes. Some of the transmission and distribution lines interconnect with other utilities.

The Company owns and has a substantial investment in offices and service buildings, area headquarters, an energy control center, repair shops, motor vehicles, construction equipment and tools, office furniture and equipment, and leases offices and storerooms in various localities within the Company's service territory. It also owns miscellaneous parcels of real estate not presently used in utility operations.

Substantially all of the electric utility plant of the Company is subject to the lien of its Mortgage and Deed of Trust which secures first mortgage bonds issued by the Company. The Company's properties are held by it in fee and are free from other encumbrances, subject to minor exceptions, none of which are of such a nature as to substantially impair the usefulness to the Company of such properties. Other property, including certain offices and equipment, is utilized under leases. In general, some of the electric lines are located on land not owned in fee, but are covered by necessary consents of various governmental authorities or by appropriate rights obtained from owners of private property. These consents and rights are deemed adequate for the purposes for which the properties are being used. In September 1990 the Company sold a portion of Boswell Unit 4 to WPPI. WPPI has the right to use the Company's transmission line facilities to transport its share of generation.

Substantially all of the utility plant of SWL&P is subject to the lien of its Mortgage and Deed of Trust which secures first mortgage bonds issued by SWL&P. Substantially all of SSU's properties used in the operation of its respective water utility businesses are encumbered by mortgages. Approximately one-half of BNI Coal's equipment is leased under a leveraged lease agreement which expires in 2002. The remaining property and equipment are owned by BNI Coal.

The Mid-Continent Area Power Pool (MAPP) consists of nine investor-owned utilities including the Company, eight rural electric generation and transmission cooperatives, three public power districts, four municipal electric systems, four municipal organizations, and the Western Area Power Administration - Billings, Montana. MAPP operates pursuant to an agreement, dated March 31, 1972, as amended, among its members. This agreement provides for the members to coordinate the installation and operation of generating plants and transmission line facilities.

Manitoba Hydro has export licenses from the National Energy Board in Calgary until November 1, 2005, to export up to 16.7 billion kilowatt-hours a year of energy and short-term firm hydroelectric power to other Canadian utilities and four utility companies in the United States, including the Company. Manitoba Hydro presently exports approximately 12 billion kilowatt-hours a year. When it is available and economical, the Company purchases energy and power from Manitoba Hydro that can be delivered through Minnesota Power's transmission lines.

Item 3. Legal Proceedings.

Material legal and regulatory proceedings are included in the discussion of the Company's business in Item 1 and are incorporated by reference herein.

Item 4. Submission of Matters to a Vote of Security Holders.

No matters were submitted to a vote of security holders during the fourth quarter of 1994.

PART II

Item 5. Market for the Registrant's Common Equity and Related Stockholder Matters.

The Company has paid dividends without interruption on its common stock since 1948. A quarterly dividend of $.51 per share on the common stock was paid on March 1, 1995, to the holders of record on February 15, 1995. The Company's common stock is listed on The New York Stock Exchange. Dividends paid per share and the high and low prices for the Company's common stock for the periods indicated as reported by The Wall Street Journal, Midwest Edition, were as follows:

		Price Range		Dividends Paid Per Share	
Quarter		High	Low	Quarterly	Annual
1994 -	First	$33	$28	$.505	
	Second	30 1/8	25	.505	
	Third	28 1/8	25	.505	
	Fourth	26 5/8	24 3/4	.505	$2.02
1993 -	First	$36 1/2	$32 5/8	$.495	
	Second	36 3/8	34	.495	
	Third	36 1/2	35 1/4	.495	
	Fourth	35 1/2	30	.495	$1.98

The Company's Articles of Incorporation, Mortgage and Deed of Trust and preferred stock purchase agreements contain provisions which under certain circumstances would restrict the payment of common stock dividends. As of December 31, 1994, no retained earnings were restricted as a result of these provisions. At March 1, 1995, there were 26,882 common stock shareholders of record.

Item 6. Selected Financial Data.

	1994	1993	1992	1991	1990
Operating Revenue and Income (000)	$ 637,782	$ 589,607	$ 576,197	$ 588,015	$ 556,318
Income Before Extraordinary Item (000)	61,333	62,621	68,457	75,481	74,570
Extraordinary Gain (000)	-	-	4,831	-	-
Net Income (000)	61,333	62,621	73,288	75,481	74,570
Earnings per Share					
Before Extraordinary Item	2.06	2.20	2.31	2.46	2.37
Extraordinary Item	-	-	0.16	-	-
Total	2.06	2.20	2.47	2.46	2.37
Dividends per Share	2.02	1.98	1.94	1.90	1.86
Total Assets (000)	1,807,798	1,760,526	1,625,504	1,586,519	1,572,389
Long-Term Debt (000)	601,317	611,144	541,960	533,989	520,278
Redeemable Preferred Stock (000)	20,000	20,000	21,000	24,000	28,000

Includes $0.42 per share from the sale of water utility plant. (See Note 12.)

Includes $0.16 per share from the early extinguishment of debt.

Includes $0.20 per share from a favorable court decision.

Includes $0.31 per share from the Boswell Unit 4 transactions. (See Note 11.)

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The management's discussion and analysis of financial condition and results of operations appearing on pages 6 through 23 of the Minnesota Power 1994 Annual Report are incorporated by reference in this Form 10-K Annual Report.

On March 16, 1995, Duff & Phelps lowered its ratings on the Company's first mortgage bonds from A to A-.

Item 8. Financial Statements and Supplementary Data.

The financial statements appearing on pages 25 through 39, together with the report thereon of Price Waterhouse LLP dated January 24, 1995, on page 24, of the Minnesota Power 1994 Annual Report are incorporated by reference in this Form 10-K Annual Report.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

PART III

Item 10. Directors and Executive Officers of the Registrant.

The information required for this Item is incorporated by reference herein from the "Election of Directors" section in the Company's Proxy Statement for the 1995 Annual Meeting of Shareholders, except for information with respect to executive officers which is set forth in Part I hereof.

Item 11. Executive Compensation.

The information required for this Item is incorporated by reference herein from the "Compensation of Executive Officers" section in the Company's Proxy Statement for the 1995 Annual Meeting of Shareholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management.

The information required for this Item is incorporated by reference herein from the "Security Ownership of Certain Beneficial Owners and Management" section in the Company's Proxy Statement for the 1995 Annual Meeting of Shareholders.

Item 13. Certain Relationships and Related Transactions.

The information required for this Item is incorporated by reference herein from the "Certain Relationships and Related Transactions" section in the Company's Proxy Statement for the 1995 Annual Meeting of Shareholders.

PART IV

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K.

(a) Certain Documents Filed as Part of Form 10-K.

(1) Financial Statements

	Pages in Annual Report*
Minnesota Power	
Report of Independent Accountants	24
Consolidated Balance Sheet at December 31, 1994 and 1993	25
For the three years ended December 31, 1994	
Consolidated Statement of Income	26
Consolidated Statement of Retained Earnings	26
Consolidated Statement of Cash Flows	27
Notes to Consolidated Financial Statements	28-39

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* Incorporated by reference herein from the Minnesota Power 1994 Annual Report.

(2) Financial Statement Schedules

	Page
Report of Independent Accountants on Financial Statement Schedule	31
Minnesota Power and Subsidiaries Schedule:	
II - Valuation and Qualifying Accounts and Reserves	32

All other schedules have been omitted either because the information is not required to be reported by the Company or because the information is included in the consolidated financial statements or the notes thereto.

(3) Exhibits including those incorporated by reference

Exhibit Number		
*2	-	Agreement and Plan of Merger by and among Minnesota Power & Light Company, AC Acquisition Sub, Inc., ADESA Corporation and Certain ADESA Management Shareholders dated February 23, 1995 (filed as Exhibit 2 to Form 8-K dated March 3, 1995, File No. 1-3548).
*3(a)1	-	Articles of Incorporation, restated as of July 27, 1988 (filed as Exhibit 3(a), File No. 33-24936).
*3(a)2	-	Certificate Fixing Terms of Serial Preferred Stock A, $7.125 Series (filed as Exhibit 3(a)2, File No. 33-50143).
*3(a)3	-	Certificate Fixing Term of Serial Preferred Stock A, $6.70 Series (filed as Exhibit 3(a)3, File No. 33-50143).
*3(b)	-	Bylaws as amended January 23, 1991 (filed as Exhibit 3(b), File No. 33-45549).
*4(a)1	-	Mortgage and Deed of Trust, dated as of September 1, 1945, between the Company and Irving Trust Company (now The Bank of New York) and Richard H. West (W. T. Cunningham, successor), Trustees (filed as Exhibit 7(c), File No. 2-5865).
*4(a)2	-	Supplemental Indentures to Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1949	2-7826	7(b)
Second	July 1, 1951	2-9036	7(c)
Third	March 1, 1957	2-13075	2(c)
Fourth	January 1, 1968	2-27794	2(c)
Fifth	April 1, 1971	2-39537	2(c)
Sixth	August 1, 1975	2-54116	2(c)
Seventh	September 1, 1976	2-57014	2(c)
Eighth	September 1, 1977	2-59690	2(c)
Ninth	April 1, 1978	2-60866	2(c)
Tenth	August 1, 1978	2-62852	2(d)2
Eleventh	December 1, 1982	2-56649	4(a)3
Twelfth	April 1, 1987	33-30224	4(a)3
Thirteenth	March 1, 1992	33-47438	4(b)
Fourteenth	June 1, 1992	33-55240	4(b)
Fifteenth	July 1, 1992	33-55240	4(c)
Sixteenth	July 1, 1992	33-55240	4(d)
Seventeenth	February 1, 1993	33-50143	4(b)
Eighteenth	July 1, 1993	33-50143	4(c)

Exhibit Number		
*4(b)	-	Mortgage and Deed of Trust, dated as of March 1, 1943, between Superior Water, Light and Power Company and Chemical Bank & Trust Company (Chemical Bank, successor) and Howard B. Smith (Steven F. Lasher, successor), as Trustees (filed as Exhibit 7(c), File No. 2-8668), as supplemented and modified by First Supplemental Indenture thereto dated as of March 1, 1951 (filed as Exhibit 2(d)(1), File No. 2-59690), Second Supplemental Indenture thereto dated as of March 1, 1962 (filed as Exhibit 2(d)1, File No. 2-27794), Third Supplemental Indenture thereto dated July 1, 1976 (filed as Exhibit 2(e)1, File No. 2-57478) and Fourth Supplemental Indenture thereto dated as of March 1, 1985 (filed as Exhibit 4(b), File No. 2-78641), Fifth Supplemental Indenture thereto dated as of December 1, 1992 (filed as Exhibit 4(b)1 to Form 10-K for the year ended December 31, 1992, File No. 1-3548).
*4(c)	-	Indenture, dated as of March 1, 1993, between Southern States Utilities, Inc. and Nationsbank of Georgia, National Association, as Trustee (filed as Exhibit 4(d) to Form 10-K for the year ended December 31, 1992, File No. 1-3548).
+*10(a)	-	Incentive Compensation Plan, as amended and restated, effective January 1, 1994 (filed as Exhibit 10(a) to Form 10-K for the year ended December 31, 1993, File No. 1-3548).
+*10(b)	-	Supplemental Executive Retirement Plan, as amended and restated, effective January 1, 1990 (filed as Exhibit 10(b) to Form 10-K for the year ended December 31, 1992, File No. 1-3548).
+*10(c)	-	Executive Investment Plan-I, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(c) to Form 10-K for the year ended December 31, 1988, File No. 1-3548).
+*10(d)	-	Executive Investment Plan-II, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(d) to Form 10-K for the year ended December 31, 1988, File No. 1-3548).
+10(e)	-	Executive Long-Term Incentive Plan, as amended and restated, effective January 1, 1994.
+10(f)	-	Directors' Long-Term Incentive Plan, as amended and restated, effective January 1, 1994.
+*10(g)	-	Deferred Compensation Trust Agreement, as amended and restated, effective January 1, 1989 (filed as Exhibit 10(f) to Form 10-K for the year ended December 31, 1988, File No. 1-3548).
+10(h)	-	Minnesota Power Electric Utility Operations Annual Incentive Plan, effective January 1, 1995.
+10(i)	-	Minnesota Power Corporate Annual Incentive Plan, effective January 1, 1995.
12	-	Computation of Ratios of Earnings to Fixed Charges and Supplemental Ratios of Earnings to Fixed Charges.

Exhibit
Number

13	-	Minnesota Power 1994 Annual Report.
*21	-	Subsidiaries of the Registrant (reference is made to the Company's Form U-3A-2 for the year ended December 31, 1994, File No. 69-78).
23(a)	-	Consent of Independent Accountants.
23(b)	-	Consent of General Counsel.
*27	-	Financial Data Schedule (filed as Exhibit 27 to Form 8-K dated February 27, 1995, File No. 1-3548).

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* Incorporated herein by reference as indicated.

\+ Management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

(b) Reports on Form 8-K

Report on Form 8-K dated and filed on January 5, 1995, with respect to Item 5. Other Events.
Report on Form 8-K dated and filed on February 23, 1995, with respect to Item 5. Other Events.
Report on Form 8-K dated and filed on February 27, 1995, with respect to Item 7. Financial Statements and Exhibits.
Report on Form 8-K dated and filed on March 3, 1995, with respect to Item 5. Other Events and Item 7. Financial Statements and Exhibits.

REPORT OF INDEPENDENT ACCOUNTANTS ON FINANCIAL STATEMENT SCHEDULE

To the Board of Directors
of Minnesota Power

Our audits of the consolidated financial statements referred to in our report dated January 24, 1995, appearing on page 24 of the 1994 Annual Report to Shareholders of Minnesota Power (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the Financial Statement Schedule listed in Item 14(a) of this Form 10-K. In our opinion, the Financial Statement Schedule presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

PRICE WATERHOUSE LLP
Minneapolis, Minnesota
January 24, 1995

SCHEDULE II

MINNESOTA POWER AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended December 31, 1994, 1993 and 1992
In thousands

			Additions			
		Balance at Beginning of Year	Charged to Income	Charged to Other Accounts	Deductions from Reserves	Balance at End of Period
Reserve deducted from related assets						
Provision for uncollectible accounts						
1994	Trade accounts receivable	$ 1,565	$ 722	$116	$ 1,362	$1,041
	Other accounts receivable	1,135	1,845	-	207	2,773
1993	Trade accounts receivable	1,538	492	151	616	1,565
	Other accounts receivable	1,490	494	-	849	1,135
1992	Trade accounts receivable	1,787	326	150	725	1,538
	Other accounts receivable	620	1,091	4	225	1,490
Deferred asset valuation allowance						
1994	Deferred tax assets	31,475	-	-	4,597	26,878
1993	Deferred tax assets	-	-	31,475	-	31,475

Provision for uncollectible accounts include bad debts recovered, transfers from customers' deposits, etc.
Provision for uncollectible accounts include bad debts written off.
The Company adopted Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" on a prospective basis in January 1993.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MINNESOTA POWER & LIGHT COMPANY
(Registrant)

Dated: March 24, 1995

By A. J. SANDBULTE

A. J. Sandbulte
Chairman, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
A. J. SANDBULTE ----------------------------- A. J. Sandbulte	Chairman, President, Chief Executive Officer and Director	March 24, 1995
D. G. GARTZKE ----------------------------- D. G. Gartzke	Senior Vice President-Finance and Chief Financial Officer	March 24, 1995
MARK A. SCHOBER ----------------------------- Mark A. Schober	Corporate Controller	March 24, 1995

Signature	Title	Date
M. K. CRAGUN ----------------------------- M. K. Cragun	Director	March 24, 1995
D. E. EVANS ----------------------------- D. E. Evans	Director	March 24, 1995
SR. KATHLEEN HOFER ----------------------------- Sr. Kathleen Hofer	Director	March 24, 1995
PETER J. JOHNSON ----------------------------- Peter J. Johnson	Director	March 24, 1995
MARY E. JUNCK ----------------------------- Mary E. Junck	Director	March 24, 1995
R. S. MARS, JR. ----------------------------- R. S. Mars, Jr.	Director	March 24, 1995
PAULA F. McQUEEN ----------------------------- Paula F. McQueen	Director	March 24, 1995
ROBERT S. NICKOLOFF ----------------------------- Robert S. Nickoloff	Director	March 24, 1995
JACK I. RAJALA ----------------------------- Jack I. Rajala	Director	March 24, 1995
C. A. RUSSELL ----------------------------- C. A. Russell	Director	March 24, 1995
DONALD C. WEGMILLER ----------------------------- Donald C. Wegmiller	Director	March 24, 1995

MINNESOTA POWER
EXECUTIVE LONG-TERM
INCENTIVE PLAN

(Amended and Restated Effective as of January 1, 1994)

MINNESOTA POWER
EXECUTIVE LONG-TERM INCENTIVE PLAN
(Amended and Restated Effective as of January 1, 1994)

I. EFFECTIVE DATE

This amended and restated Minnesota Power & Light Company (Company) Executive Long-Term Incentive Plan (Plan) for a select group of management or highly compensated executive employees is made effective as of January 1, 1994. Effective January 1, 1994, participation in the Plan was extended to the responsibility level of Salary Grade V. This Plan supersedes and replaces the Minnesota Power Long-Term Incentive Plan dated January 1, 1992.

II. PURPOSES OF THE PLAN

The purposes of the Plan are:

1. To reward focusing on long-term planning and results.

2. To link compensation with enhancement of shareholder value.

III. CONCEPT

At the beginning of each new Performance Period, eligible key executives will be granted a maximum Performance Award Opportunity expressed as a number of shares of the Company's common stock, not to exceed the designated maximum for that position. The extent to which the Award Opportunity is earned (e.g., the number of shares earned) depends on the Company's performance in terms of stock price appreciation plus dividends in relation to the comparator groups during the Performance Period. The Performance Period will be four calendar years and the actual value of the shares earned will depend upon the price of the Company's common stock at the end of the fourth calendar year.

Illustrated below, Performance Period 1 began January 1, 1991, and will end December 31, 1994. A new Performance Period will begin every year as shown.

	1991	1992	1993	1994	1995	1996	1997
Performance Period 1	------	------	------	------			
Performance Period 2		------	------	------	------		
Performance Period 3			------	------	------	------	
Performance Period 4, etc.				------	------	------	------

IV. ELIGIBILITY

Participation is restricted to certain key executives. Participants are divided into five groups (Participant Categories) to reflect varying responsibility levels as follows:

Participant Category	Salary Grade
I	XI
II	IX
III	VIII
IV	VI-VII
V	V

V. AWARD OPPORTUNITY

A maximum Performance Award Opportunity has been established for each Participant Category. The Performance Award Opportunity is stated as a maximum number of shares of common stock of the Company. If a Participant's Responsibility Level changes during the Performance Period, or if a participant first becomes eligible during a Performance Period, the Award Opportunity will be prorated or adjusted as determined by the Executive Compensation Committee. For Performance Periods 1, 2 and 3 illustrated in Section III, Performance Award Opportunities will be based on the following schedule:

Participant Category	Award Opportunity Maximum Number of Common Shares	
I	6,000	
II	5,000	
III	4,000	
IV	2,000	
V	0	(Not Eligible)

Based on shares outstanding as of January 1, 1991; to be adjusted in the event of ensuing stock splits.

For Performance Period 4 and later, Performance Award Opportunities will be based on the following schedule:

Participant Category	Award Opportunity Maximum Number of Common Shares
I	6,000
II	5,000
III	4,000
IV	2,000
V	1,500

Based on shares outstanding as of January 1, 1994; to be adjusted in the event of ensuing stock splits.

VI. PERFORMANCE MEASURE

The Company's long-term performance will be measured by its Total Shareholder Return (TSR) Ranking over each four-year Performance Period. TSR is defined as:

$$TSR = \frac{\text{Stock Price Appreciation + Reinvested Dividends}}{\text{Initial Stock Price}}$$

The TSR is determined by means of combining the change in stock price over the entire Performance Period with dividends which are assumed to be reinvested on each ex-dividend date. Key assumptions to be followed in calculation of TSR are:

1) Stock prices used with respect to a performance Period are the closing prices on the New York Stock Exchange on the last day before the beginning of the Performance Period and the last day of the Performance Period.

2) Dividends are assumed to be reinvested on the ex-dividend date at the closing stock prices on that date.

3) Calculation of TSR for the S&P 500 group is based on the companies included in the S&P 500 as of the end of Performance Period.

The current performance measure will be reviewed at the beginning of each new Performance Period to determine that it remains applicable and effective. A new performance measure may be adopted at any time by amending this Plan.

VII. COMPARATOR GROUPS

The TSR performance measure discussed above will be used to rank the Company's performance relative to two comparator groups on a 60/40 weighted basis. The first comparator group (weighted 60% in the award computation) will consist of the 10 regional utility companies that are used in the Minnesota Power and Affiliated Companies Incentive Compensation Plan. At the end of each Performance Period, all companies, including the Company, will be ranked from 1 to 11, according to TSR.

The second comparator group (weighted at 40% in the award computation) will include a broader group of companies comprising the S&P 500. Comparison against this group will be based on the TSR percentile ranking of the Company among the S&P 500, at the end of each Performance Period.

VIII. AWARD DETERMINATION

After calculation of the Company's TSR ranking within the utility industry comparator group and the S&P 500, the schedule below will prescribe the percent of the Participant's Performance Award Opportunity actually earned. The Performance Award Opportunity shall be as specified in Section V above.

Industry TSR Ranking	Percent of Award Opportunity Earned					
1-2	60	68	76	84	92	100
3	48	56	64	72	80	88
4	36	44	52	60	68	76
5	24	32	40	48	56	64
6	12	20	28	36	44	52
7-11	0	8	16	24	32	40
	0-40	50	60	70	80	90

TSR Percentile Ranking in S&P 500

Straight line interpolation will be used for TSR Percentile Ranking results between those discrete values specified in the table (no interpolation is necessary regarding the Industry TSR Ranking).

Final awards will be reviewed and approved by the Executive Compensation Committee. Each Participant's award amount will be the product obtained by multiplying the Participant's Performance Award Opportunity shares as determined at the beginning of the Performance Period by the appropriate weighted percentages.

IX. EXAMPLE CALCULATION OF AWARDS

Assume a Participant's Performance Award Opportunity is 4,000 shares at the beginning of the Performance Period. Assume further, that at the end of the four-year Performance Period, the Company ranks fifth in its Industry TSR Ranking and is at the 75th percentile among the S&P 500 comparator group. The award would be computed as follows:

Opportunity Shares		Industry Ranking		S&P 500 Ranking		Final Shares Awarded
4,000	x	(24%	+	28%)	=	2,080.

X. PAYMENT OPTIONS

As soon as practicable following the end of the last year of the Performance Period and upon approval of the Executive Compensation Committee, awards will be paid totally in stock or in a combination of stock and cash (up to a maximum of fifty percent cash) at the election of the Participant. At the time awards are determined and approved, a Participant may elect on a form provided by the Company to receive payment of up to fifty percent of the approved award in cash.

XI. TERMINATION OF EMPLOYMENT

Awards to the CEO and COO will continue to run after their retirement without any proration or reduction for the fact that retirement occurs before a performance period has ended.

In the event of death, disability or retirement of any Participant prior to the end of a four-year Performance Period, the provisions in the paragraphs below will apply unless the Executive Compensation Committee makes an exception and elects in its discretion to continue the award.

If termination of employment due to death, disability, or retirement occurs (except as noted above for the CEO and COO in the event of retirement) prior to the end of a Performance Period, the Participant's performance award will be paid as soon as practicable after the end of the year of such termination. The final award determination will be calculated as provided in Section VIII above, after the end of such year (as if it were the end of the four-year Performance Period). The award will then be multiplied by a prorated adjustment factor, the numerator of which is the number of months the Participant was employed by the Company during the Performance Period rounded up to whole months and the denominator of which is 48. The result thus obtained will be the actual final award to be provided by the Company to a Participant or his/her beneficiary or estate if no beneficiary is named. Notwithstanding any provisions in this Plan to the contrary, any payment to any beneficiary may be withheld until it is determined if any generation-skipping tax is due. Any amounts necessary to pay such tax may be subtracted from any benefits otherwise due.

Termination of employment for reasons other than death, disability, or retirement before the end of a Performance Period will result in forfeiture of the associated award opportunity unless an exception is made by the Executive Compensation Committee.

XII. ADMINISTRATION

The administration of the Plan will be under the overall responsibility of the Executive Compensation Committee of the Board of Directors. The Chief Executive Officer will be responsible for administering the Plan (computing awards, measuring performance of the comparator group, etc.). Any revisions to the Plan will require review by the Executive Compensation Committee and approval of the Board of Directors. The Chief Executive Officer will involve other individuals and departments as required for the full and complete administration of the Plan, in accordance with its terms.

XIII. NON-TRANSFERABILITY

In no event shall the Company make any payment under the Plan to any assignee or creditor of a Participant or of a Participant's beneficiary. Prior to the time of payment hereunder, a Participant or beneficiary shall have no rights by way of anticipation or otherwise to assign or otherwise dispose of any interest under the Plan nor shall such rights be assigned or transferred by operation of law.

XIV. CLAIMS PROCEDURE

A) Filing a Claim

Any Participant or beneficiary, or his/her authorized representative, may make a claim for benefits due under the Plan by making a written request therefor to the Executive Compensation Committee, setting forth with specificity the facts and events which give rise to the claim.

b) Denial of Claim

The Executive Compensation Committee shall notify in writing any Participant or beneficiary whose claim for benefits hereunder is denied. Said notice shall be furnished within ninety days after the Executive Compensation Committee receives the claim, unless special circumstances require an extension of time for processing the claim. If such an extension of time for processing is required, written notice of the extension shall be furnished to the Participant or beneficiary prior to the termination of the initial ninety-day period. In no event shall such extension exceed a period of ninety days from the end of such initial period. The notice of extension shall indicate the special circumstances requiring an extension of time and the date by which the Executive Compensation Committee expects to render the final decision. The notice of claim denial shall set forth the specific reasons for the denial, including specific reference to pertinent Plan provisions. If appropriate, said notice shall set forth any additional information the Participant or beneficiary needs to supply in order to perfect his/her claim. The notice shall also inform the Participant or beneficiary of the review procedure available pursuant to this Section, and of his/her right to inspect pertinent documents.

c) Review Of Claim Denial

A Participant or beneficiary who desires further consideration of his/her position, or a duly authorized representative, shall, within sixty days of receipt of the notice above referred to, make written request to the Executive Compensation Committee for review of such denial. Such request shall include a statement of the Participant's or beneficiary's position. The Executive Compensation Committee shall make a full and fair review of the decision denying the claim, and shall deliver to the Participant or beneficiary a written statement setting forth its decision and the specific reasons therefor, including specific reference to pertinent Plan provisions, within sixty days after receiving the request for review (unless special circumstances require an extension of time for processing, in which case written notice of the extension shall be furnished to the Participant or beneficiary prior to the commencement of the extension and a decision shall be rendered as soon as possible, but not later than 120 days after receiving the request for review).

XV. EXPENSES

The cost of payments from the Plan and the expense of administering the Plan shall be borne by the Company.

XVI. TAX WITHHOLDING

The Company shall have the right to deduct from all payments to be made under the Plan, any federal, state or local taxes or other charges required by law to be withheld with respect to such payments.

XVII. AMENDMENT AND TERMINATION

The Company expects the Plan to continue, but since future conditions affecting the Company cannot be anticipated or foreseen, the Company must and does hereby reserve the right to amend, modify, terminate or partially terminate the Plan at any time and in any manner whatsoever by recommendation of the Executive Compensation Committee and by action of the Board of Directors. No amendment or termination may divest a Participant of amounts accrued or credited to the Participant at the time of such amendment.

XVIII. APPLICABLE LAW

The Plan shall be governed and construed in accordance with the laws of the State of Minnesota. The invalidity of any portion of the Plan shall not invalidate the remainder hereof and said remainder shall continue in full force. The captions and other titles herein are designed for convenience only and are not to be resorted to for the purpose of interpreting any provision of the Plan.

XIX. NO EMPLOYMENT RIGHTS

The Plan and elections hereto shall not be deemed or construed to be a written contract of employment between any Participant and the Company, nor shall any provision of the Plan (i) restrict the right of the Company to discharge any Participant or (ii) in any way whatsoever grant to any Participant the right to receive any guaranteed salary, bonus, incentive compensation award or any other payments of any nature whatsoever.

XX. BINDING AGREEMENT

The provisions of the plan shall be binding upon the Participant, his or her heirs, personal representatives and beneficiaries, and subject to the rights granted to amend or terminate the Plan, the provisions of the Plan shall also be binding upon the Company, its successors and assigns.

XXI. CONTRACTUAL OBLIGATIONS

It is intended that the Company is under a contractual obligation to make payments to Participants or their beneficiaries from the general funds and assets of the Company in accordance with the terms and conditions of the Plan. A Participant or his/her beneficiary shall have no rights to such payments, other than as a general, unsecured creditor of the Company.

MINNESOTA POWER

By Arend J. Sandbulte

Its Chief Executive Officer

Attest:

By Philip R. Halverson

Its Secretary

MINNESOTA POWER
DIRECTORS' LONG TERM
INCENTIVE PLAN
(Amended and Restated Effective as of January 1, 1994)

MINNESOTA POWER
DIRECTORS' LONG-TERM INCENTIVE PLAN
(Amended and restated effective January 1, 1994)

I. EFFECTIVE DATE

The Minnesota Power Directors' Long-Term Incentive Plan (Plan) for members of the Board of Directors of Minnesota Power & Light Company (Company) is made effective as of January 1, 1994. This Plan supersedes and replaces the Minnesota Power Directors' Long Term Incentive Plan dated January 1, 1992.

II. PURPOSES OF THE PLAN

The purposes of the Plan are:

1. To reward focusing on long-term planning and results.

2. To link compensation with enhancement of shareholder value.

III. CONCEPT

At the beginning of each new Performance Period, Directors will be granted a maximum Performance Award Opportunity of up to 600 shares of the Company's common stock. The extent to which the Award Opportunity is earned (e.g., the number of shares earned) depends on the Company's performance in terms of stock price appreciation plus dividends in relation to the comparator groups during the Performance Period. The Performance Period will be four calendar years and the actual value of the shares earned will depend upon the price of the Company's common stock at the end of the fourth calendar year.

Performance Periods will begin every other year as illustrated below.

	1992	1993	1994	1995	1996	1997	1998	1999
Performance Period 1	------	------	------	------				
Performance Period 2			------	------	------	------		
Performance Period 3					------	------	------	------
Performance Period 4, etc.							------	------

IV. PERFORMANCE MEASURE

The Company's long-term performance will be measured by its Total Shareholder Return (TSR) Ranking over each four-year Performance Period. TSR is defined as:

$$TSR = \frac{\text{Stock Price Appreciation + Reinvested Dividends}}{\text{Initial Stock Price}}$$

The TSR is determined by means of combining the change in stock price over the entire Performance Period with dividends which are assumed to be reinvested on each ex-dividend date. Key assumptions to be followed in calculation of TSR are:

1) Stock prices used with respect to a performance Period are the closing prices on the New York Stock Exchange on the last day before the beginning of the Performance Period and the last day of the Performance Period.

2) Dividends are assumed to be reinvested on the ex-dividend date at the closing stock prices on that date.

3) Calculation of TSR for the S&P 500 group is based on the companies included in the S&P 500 as of the end of Performance Period.

The current performance measure will be reviewed at the beginning of each new Performance Period to determine that it remains applicable and effective. A new performance measure may be adopted at any time by amending this Plan.

V. COMPARATOR GROUPS

The TSR performance measure discussed above will be used to rank the Company's performance relative to two comparator groups on a 60/40 weighted basis. The first comparator group (weighted 60% in the award computation) will consist of the 10 regional utility companies that are used in the Minnesota Power and Affiliated Companies Incentive Compensation Plan. At the end of each Performance Period, all companies, including the Company, will be ranked from 1 to 11, according to TSR.

The second comparator group (weighted at 40% in the award computation) will include a broader group of companies comprising the S&P 500. Comparison against this group will be based on the TSR percentile ranking of the Company among the S&P 500, at the end of each Performance Period.

VI. AWARD DETERMINATION

After calculation of the Company's TSR ranking within the utility industry comparator group and the S&P 500, the schedule below will prescribe the percent of the Director's Performance Award Opportunity actually earned. The Performance Award Opportunity shall be as specified in Section III above.

Industry TSR Ranking	Percent of Award Opportunity Earned					
1-2	60	68	76	84	92	100
3	48	56	64	72	80	88
4	36	44	52	60	68	76
5	24	32	40	48	56	64
6	12	20	28	36	44	52
7-11	0	8	16	24	32	40
	0-40	50	60	70	80	90

TSR Percentile Ranking in S&P 500

Straight line interpolation will be used for TSR Percentile Ranking results between those discrete values specified in the table (no interpolation is necessary regarding the Industry TSR Ranking).

Final awards will be reviewed and approved by the Executive Compensation Committee. Each Director's award amount will be the product obtained by multiplying the Director's Performance Award Opportunity shares as determined at the beginning of the Performance Period by the appropriate weighted percentages.

VII. EXAMPLE CALCULATION OF AWARDS

The Director's Performance Award Opportunity is 600 shares at the beginning of the Performance Period. Assume that at the end of the four-year Performance Period, the Company ranks fifth in its Industry TSR Ranking and is at the 75th percentile among the S&P 500 comparator group. The award would be computed as follows:

Opportunity Shares		Industry Ranking		S&P 500 Ranking		Final SharesAwarded
600	x	(24%	+	28%)	=	312

VIII. PAYMENT OPTIONS

As soon as practicable following the end of the last year of the Performance Period and upon approval of the Executive Compensation Committee, awards will be paid totally in stock or in a combination of stock and cash (up to a maximum of fifty percent cash) at the election of the Director. At the time awards are determined and approved, a Director may elect on a form provided by the Company to receive payment of up to fifty percent of the approved award in cash.

IX. PRORATION OF AWARDS FOR INCOMPLETE PERFORMANCE PERIODS

Awards will be prorated for any Performance Period that a Director did not serve during the full four year period, due to joining the board or retiring from the board during a performance period(s). The Director's performance award will be calculated as provided in Section VI above, after the end of the last year of service (as if it were a full four-year Performance Period). The award will then be multiplied by a prorated adjustment factor, the numerator of which is the number of months the Director served as a Director during the Performance Period rounded up to whole months and the denominator of which is 48. The result thus obtained will be the actual award to be provided by the Company to a Director or his/her beneficiary or estate if no beneficiary is named. Notwithstanding any provisions in this Plan to the contrary, any payment to any beneficiary may be withheld until it is determined if any generation-skipping tax is due. Any amounts necessary to pay such tax may be subtracted from any benefits otherwise due.

X. ADMINISTRATION

The administration of the Plan will be under the overall responsibility of the Executive Compensation Committee of the Board of Directors. The Chief Executive Officer will be responsible for administering the Plan (computing awards, measuring performance of the comparator group, etc.). Any revisions to the Plan will require review by the Executive Compensation Committee and approval of the Board of Directors. The Chief Executive Officer will involve other individuals and departments as required for the full and complete administration of the Plan, in accordance with its terms.

XI. NON-TRANSFERABILITY

In no event shall the Company make any payment under the Plan to any assignee or creditor of a Director or of a Director's beneficiary. Prior to the time of payment hereunder, a Director or beneficiary shall have no rights by way of anticipation or otherwise to assign or otherwise dispose of any interest under the Plan nor shall such rights be assigned or transferred by operation of law.

XII. CLAIMS PROCEDURE

A) Filing a Claim

Any Director or beneficiary, or his/her authorized representative, may make a claim for benefits due under the Plan by making a written request therefor to the Executive Compensation

Committee, setting forth with specificity the facts and events which give rise to the claim.

b) Denial of Claim

The Executive Compensation Committee shall notify in writing any Director or beneficiary whose claim for benefits hereunder is denied. Said notice shall be furnished within ninety days after the Executive Compensation Committee receives the claim, unless special circumstances require an extension of time for processing the claim. If such an extension of time for processing is required, written notice of the extension shall be furnished to the Director or beneficiary prior to the termination of the initial ninety-day period. In no event shall such extension exceed a period of ninety days from the end of such initial period. The notice of extension shall indicate the special circumstances requiring an extension of time and the date by which the Executive Compensation Committee expects to render the final decision. The notice of claim denial shall set forth the specific reasons for the denial, including specific reference to pertinent Plan provisions. If appropriate, said notice shall set forth any additional information the Director or beneficiary needs to supply in order to perfect his/her claim. The notice shall also inform the Director or beneficiary of the review procedure available pursuant to this Section, and of his/her right to inspect pertinent documents.

c) Review Of Claim Denial

A Director or beneficiary who desires further consideration of his/her position, or a duly authorized representative, shall, within sixty days of receipt of the notice above referred to, make written request to the Executive Compensation Committee for review of such denial. Such request shall include a statement of the Director's or beneficiary's position. The Executive Compensation Committee shall make a full and fair review of the decision denying the claim, and shall deliver to the Director or beneficiary a written statement setting forth its decision and the specific reasons therefor, including specific reference to pertinent Plan provisions, within sixty days after receiving the request for review (unless special circumstances require an extension of time for processing, in which case written notice of the extension shall be furnished to the Director or beneficiary prior to the commencement of the extension and a decision shall be rendered as soon as possible, but not later than 120 days after receiving the request for review).

XIII. EXPENSES

The cost of payments from the Plan and the expense of administering the Plan shall be borne by the Company.

XIV. TAX WITHHOLDING

The Company shall have the right to deduct from all payments to be made under the Plan, any federal, state or local taxes or other charges required by law to be withheld with respect to such payments.

XV. AMENDMENT AND TERMINATION

This Plan maybe amended, modified, terminated or partially terminated at any time by action of the Board of Directors. No amendment or termination may divest a Director of amounts accrued or credited to the Director at the time of such amendment.

XVI. APPLICABLE LAW

The Plan shall be governed and construed in accordance with the laws of the State of Minnesota. The invalidity of any portion of the Plan shall not invalidate the remainder hereof and said remainder shall continue in full force. The captions and other titles herein are designed for convenience only and are not to be resorted to for the purpose of interpreting any provision of the Plan.

XVII. NO EMPLOYMENT RIGHTS

The Plan and elections hereto shall not be deemed or construed to be a promise of or right to continued service on the Board of Directors.

XVIII. BINDING AGREEMENT

The provisions of the plan shall be binding upon the Director, his or her heirs, personal representatives and beneficiaries, and subject to the rights granted to amend or terminate the Plan, the provisions of the Plan shall also be binding upon the Company, its successors and assigns.

XIX. CONTRACTUAL OBLIGATIONS

It is intended that the Company is under a contractual obligation to make payments to Directors or their beneficiaries from the general funds and assets of the Company in accordance with the terms and conditions of the Plan. A Director or his/her beneficiary shall have no rights to such payments, other than as a general, unsecured creditor of the Company.

MINNESOTA POWER

By Arend J. Sandbulte

Its Chief Executive Officer

Attest:

By Philip R. Halverson

Its Secretary

MINNESOTA POWER ELECTRIC UTILITY
OPERATIONS
ANNUAL INCENTIVE PLAN

EFFECTIVE JANUARY 1, 1995

TABLE OF CONTENTS

I. INTRODUCTION

This amended and restated Minnesota Power & Light Company (Company) Annual Incentive Plan (Plan) for a select group of Electric Utility Operations (EUO) management employees is made effective as of January 1, 1995. This Plan supersedes and replaces the Minnesota Power and Affiliated Company Amended and Restated Incentive Compensation Plan dated January 1, 1994.

II. PLAN PURPOSES

- Provide a meaningful and competitive incentive opportunity geared to the achievement of specified internal and external corporate, business unit, and strategic goals.

- Vary performance criteria/goals and incentive award amounts to reflect differences in business unit and individual participant challenges and accomplishments.

III. CONCEPT

An annual incentive plan for key management employees where the award opportunity is set at the beginning of each year. Actual payments are based on the achievement of corporate (both internal and external), business unit, and strategic goals.

IV. PARTICIPATION

Participation will be limited to those Key individuals whose actions can have a substantial impact on Minnesota Power's success. This group will consist of the officer group, directors, and management employees in salary grades I and above.

V. INCENTIVE OPPORTUNITIES

A threshold, target, and maximum award opportunity will be established for each salary range grouping. The "target" award will be earned for achievement of above average performance (60th percentile) as compared to the specified peer groups and for achievement of budgeted performance of the electric utility group. "Threshold" and "maximum" performance award levels then will be developed in relation to the target performance award levels.

The following table states the base award opportunity, as a percent of base salary, for each management group and is exclusive of the strategic award opportunity available for participants in salary grades VIII and above. Actual participant awards can vary from 0 to 120 percent of the base award opportunity depending upon actual corporate and business unit performance.

Salary Grade	Base Award Opportunities
VIII-IX	40%
VI-VII	30%
IV-V	25%
I-III	15%

As a percent of base salary.

The Chief Executive Officer will suggest, and the Compensation Committee will determine, the treatment of "extraordinary" gains or losses and their impact on earnings per share (EPS) and operating income in the Plan. Where possible, this determination will be made prior to establishing the annual targets for EPS and operating income.

VI. PERFORMANCE APPORTIONMENT

Performance will be assessed at two levels - corporate and business unit. Corporate performance will be divided into internal and external measures. The Chief Executive Officer will recommend, and the Compensation Committee will approve, the weighting of incentive opportunity. This apportionment will be determined by salary grade and will be the same for each participant within that salary grade. A participant's total incentive award will be equal to the sum of the amounts earned from each portion of the incentive opportunity. The weighting is illustrated below.

Salary Grade	Corporate Performance Internal	Corporate Performance External	Business Unit Performance
VIII-IX	25.0%	25.0%	50.0%
I-VII	12.5%	12.5%	75.0%

VII. INTERNAL CORPORATE PERFORMANCE

Internal corporate performance will be measured based on earnings per share (EPS). At the beginning of each plan year, a "target" EPS goal will be established for the Company. "Threshold" and "maximum" performance levels, for incentive award determination purposes, will be set up in relation to this performance target.

EPS for the plan year must equal or exceed the "threshold" level of performance before any incentive award is earned from this performance measure. The "maximum" performance level, when achieved, will produce the maximum incentive award opportunity achievable from the EPS portion, as illustrated below.

Performance	EPS	Percent of Corporate Internal Performance Award Earned
Maximum	$ -----	120%
Target	$ -----	60%
Threshold	$ -----	25%
Below Threshold		0%

Straight line interpolation will be used for determining results between those specified in the table.

VIII. EXTERNAL CORPORATE PERFORMANCE

External corporate performance will be based upon Minnesota Power's total shareholder return (TSR), as measured against both a diversified electric utility peer group consisting of the ten companies identified in Appendix B (60% weighting) and the S&P 500 (40%

weighting). TSR is defined in Appendix B. Minnesota Power's TSR performance will be determined relative to the two peer groups based on a ranking illustrated in the following table.

Peer Group
Percentile Ranking

TSR to S&P 500 (40% Weighting)	Percent of External Corporate Performance Award Earned			
> or = 90th percentile	48%	63%	84%	120%
60th percentile	24%	39%	60%	96%
40th percentile	10%	25%	46%	82%
< 40th percentile	0%	15%	36%	72%
	<4 companies	> or = 4 companies	> or = 6 companies	> or = 9 companies

TSR to Diversified
Utility Peer Group
(60% weighting)

Straight-line interpolation will be used for determining results between those specified in the table. No payouts will be made if TSR performance is below the 40th percentile in the S&P 500 and TSR performance is less than that of 4 companies in the utility peer group.

IX. BUSINESS UNIT PERFORMANCE

Business unit goals will be based equally upon internal operating income and annual percentage change in cost/kwh measured against the electric utility peer group identified in Appendix B. At the beginning of each plan year, a target operating income goal will be established. Threshold and maximum performance levels also will be determined. A matrix will then be established to define award opportunities based on various levels of achievement as illustrated in the following table.

Annual % Change in Cost/kwh (50% weighting)	Percent of Business Unit Performance Award Earned			
> or = 9 companies	60%	73%	90%	120%
> or = 6 companies	30%	43%	60%	90%
> or = 4 companies	13%	25%	43%	73%
< 4 companies	0%	13%	30%	60%
		$(Threshold)	$(Target)	$(Maximum)
	Operating Income (50% weighting)			

Straight-line interpolation will be used for determining results between those specified in the table. No payouts will be made if performance is below threshold and performance is less than that of 4 companies in the utility peer group.

X. STRATEGIC AWARD

The purpose of including a strategic award opportunity is to recognize individual performance and to reward those contributions that may not be adequately reflected by financial measures. The strategic award will be available to participants in salary grade VIII and above only and will consist of an additional opportunity of up to 10 percent of base salary at the end of the Plan year in which the award is earned.

At the beginning of the plan year, the specific strategic goals will be set forth by the Chief Executive Officer. Following year end, the Chief Executive Officer, with the approval of the Compensation Committee, shall determine the extent to which the strategic goals have been accomplished.

XI. FINAL AWARD DETERMINATION

See Appendix A for an illustrative award calculation.

XII. FORM AND TIMING OF PAYMENT

Cash awards will be paid as soon as practical following approval of award amounts by the Compensation Committee. No portion of the award shall be paid in employer stock.

XIII. AWARD DEFERRAL

Each participant may elect to defer receipt of all or a portion of his or her earned award. The election must be made prior to the beginning of the year in which the award is earned. The terms related to such deferrals will correspond to those provisions specified in Appendix C.

XIV. TERMINATION OF EMPLOYMENT DUE TO RETIREMENT, DEATH, OR DISABILITY

If a participant's employment is terminated due to retirement, death, or active employment is terminated due to disability during a plan year, the award earned shall be prorated based on the number of months of participation within the plan year and be based upon performance determined at year end.

XV. TERMINATION FOR ANY OTHER REASON

Termination of employment for reasons other than retirement, death, or disability before the end of a plan year will result in forfeiture of any associated award opportunity. However, the Chief Executive Officer, with the approval of the Compensation Committee, may waive such forfeiture provision.

XVI. TAX TREATMENT

Award payments are taxable to the participant in the year of receipt.

XVII. WITHHOLDING TAXES

The Company will have the right to deduct any Federal, state, or local taxes required by law to be withheld.

XVIII. BENEFICIARY DESIGNATION

A participant may name a beneficiary or beneficiaries to whom any benefit under this Plan is to be paid in the event of death.

XIX. EFFECT ON EMPLOYEE BENEFIT PLANS

Payments from this Plan shall not be included in calculating the amount of employee benefits to be paid under the terms of any of the Company's qualified employee benefit plans. Payments will be included for calculating benefits under the Supplemental Executive Retirement Plan (SERP).

XX. PARTICIPANT RIGHTS

Participation in this Plan shall not interfere with the Company's right to terminate any participant's employment at any time. Rights or interests of any participants in this Plan are nontransferable.

XXI. PLAN ADMINISTRATION

The Executive Compensation Committee of the Board of Directors will have responsibility for administration of the Plan in accordance with the provisions of the Plan, as specified in this Plan document and these administrative plan specifications.

XXII. PLAN AMENDMENTS

The Compensation Committee may, in its sole discretion, modify, amend, suspend, or terminate, in whole or in part, any or all of the provisions of the Plan. However, no modification, amendment, suspension, or termination may adversely affect a payment or distribution accrued or credited to a participant.

XXIII. BINDING AGREEMENT

The provisions of the Plan shall be binding upon the Participant, his or her heirs, personal representatives and beneficiaries, and subject to the rights granted to amend or terminate the Plan, the provisions of the Plan shall also be binding upon the Company, its successors and assigns.

XXIV. CONTRACTUAL OBLIGATIONS

It is intended that the Company is under a contractual obligation to make payments to Participants or their beneficiaries from the general funds and assets of the Company in accordance with the terms and conditions of the Plan. A Participant or his/her beneficiary shall have no rights to such payments, other than as a general, unsecured creditor of the Company.

This Minnesota Power Electric Utility Operations Annual Incentive Plan has been approved, and is effective, as of January 1, 1995.

MINNESOTA POWER

By Arend J. Sandbulte

Its Chief Executive Officer

Attest:

By Philip R. Halverson

Its Secretary

Appendix A - EUO Plan Illustration

The following illustrates application of the Plan.

Assumptions

.	Participant (salary grade VI-VII)	Vice President
.	Salary for 1995	$100,000
.	Base award opportunity	30%
.	Internal corporate performance (12.5%)	Maximum - 120% (EPS at $2.60)
.	External corporate performance (12.5%)	Target - 60% (both peer groups at 60th percentile)
.	Overall business unit performance (75%)	Threshold - 25% (threshold level for both goals)

Calculation of Award

	Base Salary		Base Award		Performance Apportionment		Performance Achievement		Award
Internal corporate portion	$100,000	x	30%	x	12.5%	x	120%	=	$4,500
External corporate portion	$100,000	x	30%	x	12.5%	x	60%	=	$2,250
EUO portion	$100,000	x	30%	x	75%	x	25%	=	$5,625
									$12,375
									=======

Appendix B - Definition of Plan Measurements

The diversified electric utility peer group used to compare TSR (60% weighting) in the external corporate performance measure and to compare annual percentage change in cost/kwh in the business unit performance measure is:

IES Industries, Inc.
Interstate Power Company
Iowa-Illinois Gas & Electric
Madison Gas & Electric Company
Midwest Resources
Northern States Power Company
Otter Tail Power Company
Wisconsin Energy Corporation
Wisconsin Public Service Corporation
WPL Holdings, Inc.

Performance Measures Definition

- TSR is defined as:

$$TSR = \frac{\text{Stock price appreciation + reinvested dividends}}{\text{Initial stock price}}$$

The TSR is determined by means of combining the change in stock price over the plan year with dividends which are assumed to be reinvested on each dividend date.

- Stock prices for the beginning and end of the one-year period are the closing prices on the New York Stock Exchange on the last business day of the period (last business day prior to the start of the period for the beginning prices).

- Dividends are assumed to be reinvested on the ex-dividend date at the closing stock prices on that date.

- Calculation of TSR for the S&P 500 group is based on the companies included in the S&P 500 Index as of the end of the period.

- Annual percentage change in cost/kwh is defined as:

  The dollar amount of O&M expense (adjusted as discussed below) incurred by the Company for each kwh sold

This performance measure reflects the change in operating and maintenance expenses incurred by the Company expressed in cents per kwh. O&M expenses exclude fuel, P&I power, taxes, and depreciation, but include an amount equal to the O&M component (the current MAPP rate) of net purchased and interchanged power.

```
Cost/kwh =          O&M expenses, as defined above
               +     (___ mills x net purchased
                     and interchanged power in)
                    ---------------------------
                         Total kwh sales
```

Performance based on this measure is calculated on an annual percentage rate of change. The lowest percentage change rate, when compared to other companies in the group, indicates the best performance.

In computing these performance measures, the most recent data published by each utility in the comparator group applicable to the plan year will be used for purposes of determining results. If the most recent data are different data from data used previously (due to restatement, etc), the latest data will be used for the current plan year in determining such year's awards, but no retroactive adjustments will be made relative to awards made previously.

Appendix C - Payment/Deferral Options

Except as hereinafter specifically provided, participants will be given the following options to receive their award:

a) current payment of all or a portion of the award

b) payment deferred to a date specified by the participant (at which time such award shall be paid in full), with the latest deferral date to be the earlier of (i) six months after the participant's seventieth birthday or (ii) such date selected by the participant up to five years after the date of the participant's retirement; or

c) payment deferred to the earlier to occur of the following events:

(i) The retirement of the participant or, if elected up to five years after retirement, but in no event later than age 70 1/2 (in which case the participant may also elect to receive the award in equal monthly installments commencing on the first day of the month following the date of the participant's retirement or anniversary thereof if so elected, and continuing thereafter for a period of fifteen (15), ten (10) or five (5) years, as is elected by the participant).

(ii) the death of the participant,

(iii) the termination of the participant's employment.

The foregoing Elections must be made in writing to the Executive Compensation Committee prior to the end of the calendar year preceding the year in which the award is earned. Such election shall be irrevocable.

Participants who elect to receive their awards currently will be paid the amount of their awards plus interest from January 1 following the Plan year to the payment date, at the rate of 8 percent per annum.

Participants who elect to defer their awards will have the following three options available under which their awards can be deferred (with the irrevocable election of an option being made contemporaneously with the election to defer):

a) Deferral in accordance with the participant's commitment under the Company's Executive Investment Plan I or Executive Investment Plan II. Amounts will be credited to the participant's account under such Plan(s) effective January 1 following the Plan year.

b) Deferral with interest paid on all amounts deferred effective January 1 following the Plan year at a fixed rate of 8 percent per annum.

c) Deferral with interest paid on all amounts deferred effective January 1 following the Plan year to the award payment date at the rate of 8 percent per annum and thereafter for the deferral period on all amounts at a rate equivalent to the overall percentage return achieved as if the deferred amounts had been invested in any of the following Mutual Funds, which shall serve as a performance reference only:

(i) Nicholas Fund, Inc.

(ii) Fidelity Magellan Fund (Amounts deferred into this Fund are subject to a 3% upfront sales charge)

(iii) Investment Advisors Incorporated (IAI) Emerging Growth Fund

(iv) Investment Advisors Incorporated (IAI) International Developed Market Fund

(v) Fidelity Balanced Fund

(vi) Vanguard Index Trust 500 Portfolio

(vii) Templeton International Emerging Market

Participants who choose deferral under either b) or c) above are permitted annually to continue the accrual of interest on deferred awards using the interest rate alternative chosen one year earlier, or to switch to an alternate method of computing interest on all deferred awards during the succeeding year. This does not in any way affect the period of the deferral chosen by the participant.

If payments to a participant are to be made in installments, then the unpaid amounts due to the participant shall continue to be credited based on the participant's annual elections.

Notwithstanding anything to the contrary herein, if a participant dies while employed by the Company, or if a participant who has terminated employment dies before receiving all payments which such participant is entitled to receive pursuant to an election hereunder, the amount then standing to the credit of such participant under this Plan shall be paid in a single sum within the first 30 days of the calendar year following the date of the participant's death to the participant's beneficiary.

In the event of a participant's financial hardship or unforeseen financial emergency, the Executive Compensation Committee, in its sole and absolute discretion may alter the timing or manner of payment of any benefits or deferred amounts to be paid pursuant to the Plan, (provided, however, any such alteration shall only occur with respect to these amounts reasonably required to alleviate the participant's financial hardship or unforeseen emergency). Financial hardship shall be deemed to have occurred in the event of the participant's impending bankruptcy, a participant's or defendant's long and serious illness or other events of similar magnitude. An unforeseeable financial emergency shall mean an unexpected need for cash arising from illness, casualty loss, sudden financial reversal or other such unforeseeable occurrence. Normal expenditures for the vocational or college education of a dependent, the purchase of a house or any similar expense, shall not be considered a financial hardship or an unforeseeable financial emergency. The Benefit Plans Committee's decision in passing upon the financial hardship or unforeseeable financial emergency of the participant, and the manner in which, if at all, the payment of any amounts pursuant to the Plan shall be altered or modified, shall be final, conclusive and not subject to appeal. The participant, the participant's spouse, if any, and the participant's beneficiary waive all claims against the Benefit Plans Committee for determinations made by the Benefit Plans Committee under this Section, and the participant shall have no claim or right to make up any amount distributed or transferred as a result of a determination of financial hardship or unforeseeable financial emergency by the Benefit Plans Committee pursuant to this Section. Any participant for whom the Benefit Plans Committee grants relief under this Section may not re-enter the Plan, or make any deferral of compensation under the Plan, until the Plan Year following the second anniversary of the date on which such relief is granted to such participant.

If a participant's employment with the Company terminates for any reason other than retirement, death or disability, the balance then standing to the credit of such participant under this Plan, as of the end of the month immediately preceding or coincident with the date of termination of employment, shall be paid to the participant in a single sum upon the date of separation from service, or within 30 days thereafter. If a participant entitled to a benefit under this paragraph dies prior to receiving payment, then such payment shall be made to the participant's beneficiary.

In years where deferred compensation elections are made available under Executive Investment Plans I & II, each participant shall be entitled to transfer unpaid awards under this plan as a Rollover Amount to the Minnesota Power and Affiliated Companies Executive Investment Plan I or the Minnesota Power and Affiliated Companies Executive Investment Plan II, all subject to the specific terms and restrictions in said Plans. Provided, however, the transfer of an unpaid award as a Rollover Amount shall not result in a deferral or acceleration of the date or dates on which such Rollover Amount would have been received had no transfer occurred.

"Retire" and "retirement" as used in this Plan shall mean a termination of employment after attaining "Early Retirement Age" as defined in the Supplemental Retirement Plan.

The administration of the Annual Incentive Plan will be under the overall responsibility of the Executive Compensation Committee of the Board of Directors. The Chief Executive Officer will be responsible for administering the Plan on a routine basis (computing awards, measuring performance of the comparator group, etc). Any revisions to the Plan will require review by the Executive Compensation Committee and approval of the Board of Directors. The Chief Executive Officer will involve those other individuals and departments as required in the full and complete administration of the Plan, in accordance with its terms.

In administering the Plan, the Executive Compensation Committee will apply uniform rules to all participants similarly situated. If any claim for benefits under the Plan is wholly or partially denied, the claimant shall be given notice in writing, within a reasonable period of time after receipt of the claim by the Plan, by registered or certified mail, of such denial, written in a manner calculated to be understood by the claimant, setting forth the specific reasons for such denial, specific reference to pertinent Plan provisions on which the denial is based, a description of any additional material or information necessary for the claimant to perfect the claim and an explanation of why such material or information is necessary, and an explanation of the Plan's claim review procedure. The claimant also shall be advised that the claimant's duly authorized representative may request a review, by the Executive Compensation Committee, of the decision denying the claim by filing with the Executive Compensation Committee, within 65 days after such notice has been received by the claimant, a written request for such review, and that the claimant's duly authorized representative may review pertinent documents, and submit issues and comments in writing within the same 65-day period. If such request is so filed, such review shall be made by the Executive Compensation Committee within 60 days after receipt of such request; and the claimant shall be given written notice of the decision resulting from such review, and shall include specific reasons for the decision, written in a manner calculated to be understood by the claimant, and specific references to the pertinent Plan provisions on which the decision is based.

The Executive Compensation Committee may make payment to any participant or any beneficiary of a participant, of any benefits or deferred amounts to be paid under the Plan, in advance of the date when otherwise due, if, based on a change in federal tax law or regulation, published rulings or similar announcements by the Internal Revenue Service, decision by a court of competent jurisdiction involving the Plan, or a closing agreement made under Section 7121 of the Internal Revenue Code of 1986 that involves the Plan, it determines that a participant or beneficiary will recognize income for federal income tax purposes with respect to amounts that are otherwise not then payable under the Plan. The Executive Compensation Committee may also make such payments to any participant, or beneficiary of a participant, in advance of the date when otherwise due, if it shall be determined that the Plan is subject to the requirements of Parts 2 and 3 of Subtitle B of Title I of the Employee Retirement Income Security Act of 1974, because such Plan is not maintained primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees.

All payments to be made by the Company under the Plan shall be made to the participant, if living. Except as otherwise provided herein, in the event of a participant's death prior to the receipt of all payments hereunder, all subsequent payments to be made under the Plan shall be made to the beneficiary designated by the participant, and, unless otherwise specified in the participant's beneficiary designation, in the event a beneficiary dies before receiving all payments due to such beneficiary pursuant to this Plan, the then remaining payments shall be paid to the legal representatives of the beneficiary's estate. The participant shall designate a beneficiary, or during the participant's lifetime change such designation, by filing a written notice of such designation with the Company in such form and subject to such rules and regulations as the Executive Compensation Committee may prescribe. If the participant's payments constitute community property, then any beneficiary designation made by the participant other than a designation of such participant's spouse shall not be effective if any such beneficiary or beneficiaries are to receive more than fifty percent (50%) of the aggregate benefits payable hereunder, unless such spouse shall approve such designation in writing. If no beneficiary designation shall be in effect at the time when any benefits payable under this Plan shall become due, the benefit payments shall be made to the legal representative of the participant's estate.

Notwithstanding any provisions in this Plan to the contrary, the Executive Compensation Committee may withhold any benefits payable to a beneficiary as a result of the death of the participant (or the death of any beneficiary designated by the participant) until such time as (i) the Committee is able to determine whether a generation-skipping transfer tax, as defined in Chapter 13 of the Internal Revenue Code of 1986, or any substitute provision therefor, is payable by the Company; and (ii) the Committee has determined the amount of generation-skipping transfer tax that is due, including interest thereon. If any such tax is payable, the Executive Compensation Committee shall reduce the benefits otherwise payable hereunder to such beneficiary by an amount equal to the generation-skipping transfer tax and any interest thereon that is payable as a result of the death in question.

Benefits payable under the Plan are not in any way subject to the debts or other obligations of the persons entitled to those payments, whether the person is a participant or a beneficiary. Benefits under the Plan may not voluntarily or involuntarily be sold, transferred, or assigned.

MINNESOTA POWER CORPORATE
ANNUAL INCENTIVE PLAN

EFFECTIVE JANUARY 1, 1995

TABLE OF CONTENTS

I. INTRODUCTION

This amended and restated Minnesota Power & Light Company (Company) Annual Incentive Plan (Plan) for a select group of management employees is made effective as of January 1, 1995. This Plan supersedes and replaces the Minnesota Power and Affiliated Company Amended and Restated Incentive Compensation Plan dated January 1, 1994.

II. PLAN PURPOSES

- Provide a meaningful and competitive incentive opportunity geared to the achievement of specified internal and external corporate, business unit, and strategic goals.

- Vary performance criteria/goals and incentive award amounts to reflect differences in business unit and individual participant challenges and accomplishments.

III. CONCEPT

An annual incentive plan for key management employees where the award opportunity is set at the beginning of each year. Actual payments are based on the achievement of corporate (both internal and external), business unit, and strategic goals.

IV. PARTICIPATION

Participation will be limited to those Key individuals whose actions can have a substantial impact on Minnesota Power's success. This group will consist of the officer group, directors, and management employees in salary grades I and above.

V. INCENTIVE OPPORTUNITIES

A threshold, target, and maximum award opportunity will be established for each salary range grouping. The "target" award will be earned for achievement of above average performance (60th percentile) as compared to the specified peer groups and for achievement of budgeted performance of the electric utility group. "Threshold" and "maximum" performance award levels then will be developed in relation to the target performance award levels.

The following table states the base award opportunity, as a percent of base salary, for each management group and is exclusive of the strategic award opportunity available for participants in salary grades VIII and above. Actual participant awards can vary from 0 to 120 percent of the base award opportunity depending upon actual corporate and business unit performance.

Salary Grade	Base Award Opportunities
XI	60%
VIII-IX	40%
VI-VII	30%
IV-V	25%
I-III	15%

As a percent of base salary.

The Chief Executive Officer will suggest, and the Compensation Committee will determine, the treatment of "extraordinary" gains or losses and their impact on earnings per share (EPS) and operating income in the Plan. Where possible, this determination will be made prior to establishing the annual targets for EPS and operating income.

VI. PERFORMANCE APPORTIONMENT

Performance will be assessed at two levels - corporate and business unit. Corporate performance will be divided into internal and external measures. The Chief Executive Officer will recommend, and the Compensation Committee will approve, the weighting of incentive opportunity. This apportionment will be determined by salary grade and will be the same for each participant within that salary grade. A participant's total incentive award will be equal to the sum of the amounts earned from each portion of the incentive opportunity. The weighting is illustrated below.

Salary Grade	Corporate Performance Internal	External	Business Unit EUO	SSU	Corporate Development*
I-XI	40%	30%	20%	10%	
Corporate Development Participants					
IV-VIII	40%	30%			30%

----

*Those participants in the corporate development area will have individual acquisition-oriented goals, rather than business unit goals relating to EUO and SSU.

VII. INTERNAL CORPORATE PERFORMANCE

Internal corporate performance will be measured based on earnings per share (EPS). At the beginning of each plan year, a "target" EPS goal will be established for the Company. "Threshold" and "maximum" performance levels, for incentive award determination purposes, will be set up in relation to this performance target.

EPS for the plan year must equal or exceed the "threshold" level of performance before any incentive award is earned from this performance measure. The "maximum" performance level, when achieved, will produce the maximum incentive award opportunity achievable from the EPS portion, as illustrated below.

Performance	EPS	Percent of Corporate Internal Performance Award Earned
Maximum	$ -----	120%
Target	$ -----	60%
Threshold	$ -----	25%
Below Threshold		0%

Straight line interpolation will be used for determining results between those specified in the table.

VIII. EXTERNAL CORPORATE PERFORMANCE

External corporate performance will be based upon Minnesota Power's total shareholder return (TSR), as measured against both a diversified electric utility peer group consisting of the ten companies identified in Appendix B (60% weighting) and the S&P 500 (40% weighting). TSR is defined in Appendix B. Minnesota Power's TSR performance will be determined relative to the two peer groups based on a ranking illustrated in the following table.

Peer Group
Percentile Ranking

TSR to S&P 500 (40% Weighting)	Percent of External Corporate Performance Award Earned			
> or = 90th percentile	48%	63%	84%	120%
60th percentile	24%	39%	60%	96%
40th percentile	10%	25%	46%	82%
<40th percentile	0%	15%	36%	72%
	<4 companies	> or = 4 companies	> or = 6 companies	> or = 9 companies
	TSR to Diversified Utility Peer Group (60% weighting)			

Straight-line interpolation will be used for determining results between those specified in the table. No payouts will be made if TSR performance is below the 40th percentile in the S&P 500 and TSR performance is less than that of 4 companies in the utility peer group.

IX. BUSINESS UNIT/CORPORATE DEVELOPMENT

Business unit goals will be based one-third on operating income for the water resource operations group and two-thirds on operating income for the electric utility operations group. For those participants in the corporate development area, business unit performance goals will instead be acquisition-oriented goals related to the participants' area of responsibility.

A matrix has been established to determine award opportunities based on various levels of achievement for the electric utility and water resource operations groups, as illustrated in the following table.

SSU Operating Income (1/3 weighting)		Percent of Business Unit Performance Award Earned		
$(Maximum)	40%	57%	80%	120%
$(Target)	20%	37%	60%	100%
$(Threshold)	8%	25%	48%	88%
	0%	17%	40%	80%
		$(Threshold)	$(Target)	$(Maximum)
		EUO Operating Income (2/3 weighting)		

Straight-line interpolation will be used for determining results between those specified in the table. No payouts will be made for performance below threshold in each performance measure.

X. STRATEGIC AWARD

The purpose of including a strategic award is to recognize individual performance and to reward those contributions that may not be adequately reflected by financial measures. The strategic award will be available to participants in salary grade VIII and above only and will consist of an additional opportunity of up to 10 percent of base salary for participants in salary grades VIII-IX and 15 percent of base salary for participants in salary grade XI. Base salary in place at the end of the Plan year in which the award is earned will be used to calculate the strategic award.

At the beginning of the plan year, the specific strategic goals will be set forth by the Chief Executive Officer (and by the Compensation Committee for the Chief Executive Officer). Following year end, the Chief Executive Officer, with the approval of the Compensation Committee, shall determine the extent to which the strategic goals have been accomplished. The Compensation Committee shall make this determination for the Chief Executive Officer.

XI. AWARD DETERMINATION

See Appendix A for an illustrative award calculation.

XII. FORM AND TIMING OF PAYMENT

Cash awards will be paid as soon as practical following approval of award amounts by the Compensation Committee. No portion of the award shall be paid in employer stock.

XIII. AWARD DEFERRAL

Each participant may elect to defer receipt of all or a portion of his or her earned award. The election must be made prior to the beginning of the year in which the award is earned. The terms related to such deferrals will correspond to those provisions specified in Appendix C.

XIV. TERMINATION OF EMPLOYMENT DUE TO RETIREMENT, DEATH, OR DISABILITY

If a participant's employment is terminated due to retirement, death, or active employment is terminated due to disability during a plan year, the award earned shall be prorated based on the number of months of participation within the plan year and be based upon performance determined at year end.

XV. TERMINATION FOR ANY OTHER REASON

Termination of employment for reasons other than retirement, death, or disability before the end of a plan year will result in forfeiture of any associated award opportunity. However, the Chief Executive Officer, with the approval of the Compensation Committee, may waive such forfeiture provision.

XVI. TAX TREATMENT

Award payments are taxable to the participant in the year of receipt.

XVII. WITHHOLDING TAXES

The Company will have the right to deduct any Federal, state, or local taxes required by law to be withheld.

XVIII. BENEFICIARY DESIGNATION

A participant may name a beneficiary or beneficiaries to whom any benefit under this Plan is to be paid in the event of death.

XIX. EFFECT ON EMPLOYEE BENEFIT PLANS

Payments from this Plan shall not be included in calculating the amount of employee benefits to be paid under the terms of any of the Company's qualified employee benefit plans. Payments will be included for calculating benefits under the Supplemental Executive Retirement Plan (SERP).

XX. PARTICIPANT RIGHTS

Participation in this Plan shall not interfere with the Company's right to terminate any participant's employment at any time. Rights or interests of any participants in this Plan are nontransferable.

XXI. PLAN ADMINISTRATION

The Executive Compensation Committee of the Board of Directors will have responsibility for administration of the Plan in accordance with the provisions of the Plan, as specified in this Plan document and these administrative plan specifications.

XXII. PLAN AMENDMENTS

The Compensation Committee may, in its sole discretion, modify, amend, suspend, or terminate, in whole or in part, any or all of the provisions of the Plan. However, no modification, amendment, suspension, or termination may adversely affect a payment or distribution accrued or credited to a participant.

XXIII. BINDING AGREEMENT

The provisions of the Plan shall be binding upon the Participant, his or her heirs, personal representatives and beneficiaries, and subject to the rights granted to amend or terminate the Plan, the provisions of the Plan shall also be binding upon the Company, its successors and assigns.

XXIV. CONTRACTUAL OBLIGATIONS

It is intended that the Company is under a contractual obligation to make payments to Participants or their beneficiaries from the general funds and assets of the Company in accordance with the terms and conditions of the Plan. A Participant or his/her beneficiary shall have no rights to such payments, other than as a general, unsecured creditor of the Company.

This Minnesota Power Corporate Annual Incentive Plan has been approved, and is effective, as of January 1, 1995.

MINNESOTA POWER

By Arend J. Sandbulte

Its Chief Executive Officer

Attest:

By Philip R. Halverson

Its Secretary

Appendix A - Corporate Plan Illustration

The following illustrates application of the Plan.

Assumptions

. Participant (salary grade VI-VII)	Vice President
. Salary for 1995	$100,000
. Base award level	30%
. Internal corporate performance (40%)	Maximum - 120% (EPS at $2.60)
. External corporate performance (30%)	Target - 60% (both peer groups at 60th percentile)
. Overall business unit performance (30%)	Threshold - 25%
EUO (20%)	(EUO at $)
SSU (10%)	(SSU at $)

Calculation of Award

	Base Salary		Base Award		Performance Apportionment		Performance Achievement		Award
Internal corporate portion	$100,000	x	30%	x	40%	x	120%	=	$14,400
External corporate portion	$100,000	x	30%	x	30%	x	60%	=	$5,400
Business Unit portion	$100,000	x	30%	x	30%	x	25%	=	$2,250
									$22,050

Appendix B - Definition of Plan Measurements

The diversified electric utility peer group used to compare TSR (60% weighting) in the external corporate performance measure and to compare annual percentage change in cost/kwh in the business unit performance measure is:

IES Industries, Inc.
Interstate Power Company
Iowa-Illinois Gas & Electric
Madison Gas & Electric Company
Midwest Resources
Northern States Power Company
Otter Tail Power Company
Wisconsin Energy Corporation
WPL Holdings, Inc.

Performance Measures Definition

. TSR is defined as:

$$\text{TSR} = \frac{\text{Stock price appreciation} + \text{reinvested dividends}}{\text{Initial stock price}}$$

The TSR is determined by means of combining the change in stock price over the plan year with dividends which are assumed to be reinvested on each dividend date.

- Stock prices for the beginning and end of the one-year period are the closing prices on the New York Stock Exchange on the last business day of the period (last business day prior to the start of the period for the beginning prices).

- Dividends are assumed to be reinvested on the ex-dividend date at the closing stock prices on that date.

- Calculation of TSR for the S&P 500 group is based on the companies included in the S&P 500 Index as of the end of the period.

Appendix C - Payment/Deferral Options

Except as hereinafter specifically provided, participants will be given the following options to receive their award:

a) current payment of all or a portion of the award

b) payment deferred to a date specified by the participant (at which time such award shall be paid in full), with the latest deferral date to be the earlier of (i) six months after the participant's seventieth birthday or (ii) such date selected by the participant up to five years after the date of the participant's retirement; or

c) payment deferred to the earlier to occur of the following events:

(i) The retirement of the participant or, if elected up to five years after retirement, but in no event later than age 70 1/2 (in which case the participant may also elect to receive the award in equal monthly installments commencing on the first day of the month following the date of the participant's retirement or anniversary thereof if so elected, and continuing thereafter for a period of fifteen (15), ten (10) or five (5) years, as is elected by the participant).

(ii) the death of the participant,

(iii) the termination of the participant's employment.

The foregoing Elections must be made in writing to the Executive Compensation Committee prior to the end of the calendar year preceding the year in which the award is earned. Such election shall be irrevocable.

Participants who elect to receive their awards currently will be paid the amount of their awards plus interest from January 1 following the Plan year to the payment date, at the rate of 8 percent per annum.

Participants who elect to defer their awards will have the following three options available under which their awards can be deferred (with the irrevocable election of an option being made contemporaneously with the election to defer):

a) Deferral in accordance with the participant's commitment under the Company's Executive Investment Plan I or Executive Investment Plan II. Amounts will be credited to the participant's account under such Plan(s) effective January 1 following the Plan year.

b) Deferral with interest paid on all amounts deferred effective January 1 following the Plan year at a fixed rate of 8 percent per annum.

c) Deferral with interest paid on all amounts deferred effective January 1 following the Plan year to the award payment date at the rate of 8 percent per annum and thereafter for the deferral period on all amounts at a rate equivalent to the overall percentage return achieved as if the deferred amounts had been invested in any of the following Mutual Funds, which shall serve as a performance reference only:

(i) Nicholas Fund, Inc.

(ii) Fidelity Magellan Fund (Amounts deferred into this Fund are subject to a 3% upfront sales charge)

(iii) Investment Advisors Incorporated (IAI) Emerging Growth Fund

(iv) Investment Advisors Incorporated (IAI) International Developed Market Fund

(v) Fidelity Balanced Fund

(vi) Vanguard Index Trust 500 Portfolio

(vii) Templeton International Emerging Market

Participants who choose deferral under either b) or c) above are permitted annually to continue the accrual of interest on deferred awards using the interest rate alternative chosen one year earlier, or to switch to an alternate method of computing interest on all deferred awards during the succeeding year. This does not in any way affect the period of the deferral chosen by the participant.

If payments to a participant are to be made in installments, then the unpaid amounts due to the participant shall continue to be credited based on the participant's annual elections.

Notwithstanding anything to the contrary herein, if a participant dies while employed by the Company, or if a participant who has terminated employment dies before receiving all payments which such participant is entitled to receive pursuant to an election hereunder, the amount then standing to the credit of such participant under this Plan shall be paid in a single sum within the first 30 days of the calendar year following the date of the participant's death to the participant's beneficiary.

In the event of a participant's financial hardship or unforeseen financial emergency, the Executive Compensation Committee, in its sole and absolute discretion may alter the timing or manner of payment of any benefits or deferred amounts to be paid pursuant to the Plan, (provided, however, any such alteration shall only occur with respect to these amounts reasonably required to alleviate the participant's financial hardship or unforeseen emergency). Financial hardship shall be deemed to have occurred in the event of the participant's impending bankruptcy, a participant's or defendant's long and serious illness or other events of similar magnitude. An unforeseeable financial emergency shall mean an unexpected need for cash arising from illness, casualty loss, sudden financial reversal or other such unforeseeable occurrence. Normal expenditures for the vocational or college education of a dependent, the purchase of a house or any similar expense, shall not be considered a financial hardship or an unforeseeable financial emergency. The Benefit Plans Committee's decision in passing upon the financial hardship or unforeseeable financial emergency of the participant, and the manner in which, if at all, the payment of any amounts pursuant to the Plan shall be altered or modified, shall be final, conclusive and not subject to appeal. The participant, the participant's spouse, if any, and the participant's beneficiary waive all claims against the Benefit Plans Committee for determinations made by the Benefit Plans Committee under this Section, and the participant shall have no claim or right to make up any amount distributed or transferred as a result of a determination of financial hardship or unforeseeable financial emergency by the Benefit Plans Committee pursuant to this Section. Any participant for whom the Benefit Plans Committee grants relief under this Section may not re-enter the Plan, or make any deferral of compensation under the Plan, until the Plan Year following the second anniversary of the date on which such relief is granted to such participant.

If a participant's employment with the Company terminates for any reason other than retirement, death or disability, the balance then standing to the credit of such participant under this Plan, as of the end of the month immediately preceding or coincident with the date of termination of employment, shall be paid to the participant in a single sum upon the date of separation from service, or within 30 days thereafter. If a participant entitled to a benefit under this paragraph dies prior to receiving payment, then such payment shall be made to the participant's beneficiary.

In years where deferred compensation elections are made available under Executive Investment Plans I & II, each participant shall be entitled to transfer unpaid awards under this plan as a Rollover Amount to the Minnesota Power and Affiliated Companies Executive Investment Plan I or the Minnesota Power and Affiliated Companies Executive Investment Plan II, all subject to the specific terms and restrictions in said Plans. Provided, however, the transfer of an unpaid award as a Rollover Amount shall not result in a deferral or acceleration of the date or dates on which such Rollover Amount would have been received had no transfer occurred.

"Retire" and "retirement" as used in this Plan shall mean a termination of employment after attaining "Early Retirement Age" as defined in the Supplemental Retirement Plan.

The administration of the Annual Incentive Plan will be under the overall responsibility of the Executive Compensation Committee of the Board of Directors. The Chief Executive Officer will be responsible for administering the Plan on a routine basis (computing awards, measuring performance of the comparator group, etc). Any revisions to the Plan will require review by the Executive Compensation Committee and approval of the Board of Directors. The Chief Executive Officer will involve those other individuals and departments as required in the full and complete administration of the Plan, in accordance with its terms.

In administering the Plan, the Executive Compensation Committee will apply uniform rules to all participants similarly situated. If any claim for benefits under the Plan is wholly or partially denied, the claimant shall be given notice in writing, within a reasonable period of time after receipt of the claim by the Plan, by registered or certified mail, of such denial, written in a manner calculated to be understood by the claimant, setting forth the specific reasons for such denial, specific reference to pertinent Plan provisions on which the denial is based, a description of any additional material or information necessary for the claimant to perfect the claim and an explanation of why such material or information is necessary, and an explanation of the Plan's claim review procedure. The claimant also shall be advised that the claimant's duly authorized representative may request a review, by the Executive Compensation Committee, of the decision denying the claim by filing with the Executive Compensation Committee, within 65 days after such notice has been received by the claimant, a written request for such review, and that the claimant's duly authorized representative may review pertinent documents, and submit issues and comments in writing within the same 65-day period. If such request is so filed, such review shall be made by the Executive Compensation Committee within 60 days after receipt of such request; and the claimant shall be given written notice of the decision resulting from such review, and shall include specific reasons for the decision, written in a manner calculated to be understood by the claimant, and specific references to the pertinent Plan provisions on which the decision is based.

The Executive Compensation Committee may make payment to any participant or any beneficiary of a participant, of any benefits or deferred amounts to be paid under the Plan, in advance of the date when otherwise due, if, based on a change in federal tax law or regulation, published rulings or similar announcements by the Internal Revenue Service, decision by a court of competent jurisdiction involving the Plan, or a closing agreement made under Section 7121 of the Internal Revenue Code of 1986 that involves the Plan, it determines that a participant or beneficiary will recognize income for federal income tax purposes with respect to amounts that are otherwise not then payable under the Plan. The Executive Compensation Committee may also make such payments to any participant, or beneficiary of a participant, in advance of the date when otherwise due, if it shall be determined that the Plan is subject to the requirements of Parts 2 and 3 of Subtitle B of Title I of the Employee Retirement Income Security Act of 1974, because such Plan is not maintained primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees.

All payments to be made by the Company under the Plan shall be made to the participant, if living. Except as otherwise provided herein, in the event of a participant's death prior to the receipt of all payments hereunder, all subsequent payments to be made under the Plan shall be made to the beneficiary designated by the participant, and, unless otherwise specified in the participant's beneficiary designation, in the event a beneficiary dies before receiving all payments due to such beneficiary pursuant to this Plan, the then remaining payments shall be paid to the legal representatives of the beneficiary's estate. The participant shall designate a beneficiary, or during the participant's lifetime change such designation, by filing a written notice of such designation with the Company in such form and subject to such rules and regulations as the Executive Compensation Committee may prescribe. If the participant's payments constitute community property, then any beneficiary designation made by the participant other than a designation of such participant's spouse shall not be effective if any such beneficiary or beneficiaries are to receive more than fifty percent (50%) of the aggregate benefits payable hereunder, unless such spouse shall approve such designation in writing. If no beneficiary designation shall be in effect at the time when any benefits payable under this Plan shall become due, the benefit payments shall be made to the legal representative of the participant's estate.

Notwithstanding any provisions in this Plan to the contrary, the Executive Compensation Committee may withhold any benefits payable to a beneficiary as a result of the death of the participant (or the death of any beneficiary designated by the participant) until such time as (i) the Committee is able to determine whether a generation-skipping transfer tax, as defined in Chapter 13 of the Internal Revenue Code of 1986, or any substitute provision therefor, is payable by the Company; and (ii) the Committee has determined the amount of generation-skipping transfer tax that is due, including interest thereon. If any such tax is payable, the Executive Compensation Committee shall reduce the benefits otherwise payable hereunder to such beneficiary by an amount equal to the generation-skipping transfer tax and any interest thereon that is payable as a result of the death in question.

Benefits payable under the Plan are not in any way subject to the debts or other obligations of the persons entitled to those payments, whether the person is a participant or a beneficiary. Benefits under the Plan may not voluntarily or involuntarily be sold, transferred, or assigned.

EXHIBIT 12

MINNESOTA POWER AND SUBSIDIARIES
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES AND
SUPPLEMENTAL RATIOS OF EARNINGS TO FIXED CHARGES

	For the Year Ended December 31,		
	1990	1991	1992
	(In Thousands Except Ratios)		
Net income per consolidated statement of income	$ 74,570	$ 75,481	$ 73,288
Add (deduct)			
Current income tax expense	26,951	15,970	26,617
Deferred income tax expense (benefit)	(2,893)	12,635	1,940
Deferred investment tax credits	(6,341)	(1,615)	(1,568)
Extraordinary item	-	-	(4,831)
Undistributed income from less than 50% owned equity investment	(3,558)	(5,155)	(5,733)
Minority interest	-	(129)	2,684
	88,729	97,187	92,397
Fixed charges			
Interest on long-term debt	43,698	43,748	44,008
Capitalized interest	803	-	422
Other interest charges - net	4,797	8,776	6,455
Interest component of all rentals	5,908	5,694	5,725
Total fixed charges	55,206	58,218	56,610
Earnings before income taxes and fixed charges (excluding capitalized interest)	$143,132	$155,405	$148,585
Ratio of earnings to fixed charges	2.59	2.67	2.62
Earnings before income taxes and fixed charges (excluding capitalized interest)	$143,132	$155,405	$148,585
Supplemental charges	16,767	16,846	16,017
Earnings before income taxes and fixed and supplemental charges (excluding capitalized interest)	$159,899	$172,251	$164,602
Total fixed charges	$ 55,206	$ 58,218	$ 56,610
Supplemental charges	16,767	16,846	16,017
Fixed and supplemental charges	$ 71,973	$ 75,064	$ 72,627
Supplemental ratio of earnings to fixed charges	2.22	2.29	2.27

	For the Year Ended December 31,	
	1993	1994
	(In Thousands Except Ratios)	
Net income per consolidated statement of income	$ 62,621	$ 61,333
Add (deduct)		
Current income tax expense	23,465	17,743
Deferred income tax expense (benefit)	5,517	6,201

Deferred investment tax credits	(2,035)	(2,478)
Extraordinary item	-	-
Undistributed income from less than 50% owned equity investment	(6,559)	(8,138)
Minority interest	(83)	(879)
	82,926	73,782
Fixed charges		
Interest on long-term debt	42,579	48,137
Capitalized interest	3,010	-
Other interest charges - net	3,570	7,382
Interest component of all rentals	5,736	5,737
Total fixed charges	54,895	61,256
Earnings before income taxes and fixed charges (excluding capitalized interest)	$134,811	$135,038
Ratio of earnings to fixed charges	2.46	2.20
Earnings before income taxes and fixed charges (excluding capitalized interest)	$134,811	$135,038
Supplemental charges	15,149	14,370
Earnings before income taxes and fixed and supplemental charges (excluding capitalized interest)	$149,960	$149,408
Total fixed charges	$ 54,895	$ 61,256
Supplemental charges	15,149	14,370
Fixed and supplemental charges	$ 70,044	$ 75,626
Supplemental ratio of earnings to fixed charges	2.14	1.98

The supplemental ratio of earnings to fixed charges includes the Company's obligations under a contract with Square Butte Electric Cooperative ("Square Butte") which extends through 2007, pursuant to which the Company is purchasing 71% of the output of a generating unit capable of generating up to 455 megawatts. The Company is obligated to pay all of Square Butte's leasing, operating and debt service costs, less any amounts collected from the sale of power or energy to others, which shall not have been paid by Square Butte when due. (See Note 10.)

MINNESOTA POWER 1994 ANNUAL REPORT

[PHOTO OF MARK PINNEY, ED MACKEY, TOM GEISELMAN, AND JOE REIS]

[PHOTO OF CINDY MCLEAN AND DEBBIE BULLOCH]

[PHOTO OF JACK HOKKANEN]

[PHOTO OF JIM JORDAN, SKIP VANDAMME, BOB FONGER, RON CLARK, RANDY BURKHART AND BRIAN DENSTON]

[PHOTO OF SHARON ALECK]

[PHOTO OF MIKE COCHRAN, MARY SCHOENROCK, JOLYNN NILSON, KARLA STROMBECK, RUSS SCHUMACHER, AND DIANE STUART]

[PHOTO OF STEVE HOVEY]

DIVIDENDS OF CHANGE

[LOGO OF MINNESOTA POWER]

Electric Utility Operations

Minnesota Power is a diversified utility company headquartered in Duluth, Minn. We provide electric service to 133,000 customers in northern Minnesota and northwestern Wisconsin. Large industrial customers, which account for about half our electric revenue, include paper mills and Minnesota's taconite industry, which supplies most of the pelletized iron used in U.S. steel-making. Wisconsin electric customers are served by our Superior Water, Light and Power Company subsidiary. SWL&P also supplies water and natural gas to about 10,000 customers in the city of Superior and nearby areas. Another subsidiary, BNI Coal, mines and sells lignite coal to two North Dakota mine-mouth generating units, one of which supplies Minnesota Power with 71% of its output under a long-term contract.

Water Utility Operations

Our Southern States Utilities subsidiary is the largest independent supplier of water and wastewater utility service in Florida, serving more than 100 communities. Our Heater Utilities subsidiary provides water and wastewater services in North Carolina and South Carolina. SSU and Heater serve a total of 139,000 water customers and 47,000 wastewater treatment customers. In addition, a subsidiary of SSU supplies sanitation service to 12,000 customers in Lehigh Acres, a community in southwest Florida.

Investments and Corporate Services

While electric and water utilities are our core businesses, non-regulated investments supplement our earnings and, in some cases, perform an economic development function in our electric utility service area. These investments - and our ownership stake in them - include a securities portfolio that provides funds for reinvestment and business acquisitions (100%); Capital Re Corporation, a financial guaranty reinsurance company (21%); Lehigh Acquisition Corp., southwest Florida real estate sales (80%); Lake Superior Paper Industries, a Duluth paper mill (50%); and Superior Recycled Fiber Industries, a Duluth recycled pulp production plant (88%).

[PHOTO OF M.L. HIBBARD POWER PLANT, WITH TRANSMISSION TOWERS.]

[PHOTO OF TWO COMPANY LINEMEN AND A ROLL OF ELECTRICAL CONDUCTOR.]

[PHOTO OF AN AERIAL SHOT OF A BNI COAL MINING AREA, SHOWING THE DRAGLINE.]

[PHOTO OF A HEATER UTILITIES' WATER TOWER.]

[PHOTO OF A SOUTHERN STATES UTILITIES WASTEWATER TREATMENT FACILITY.]

[PHOTO OF STACKED WOOD AT THE LAKE SUPERIOR PAPER INDUSTRIES MILL IN DULUTH.]

[PHOTO OF A COMPUTER MONITOR WITH A DISPLAY OF FINANCIAL LISTINGS.]

Contents

[RECYCLING LOGO] This report is printed on paper that contains a total of 50% recycled fiber, including 10% de-inked post-consumer fiber produced by our Superior Recycled Fiber Industries plant in Duluth.

Dividends of Change

Change has been a friend to Minnesota Power. In the early 1980s, when we recognized we could no longer stake our future mainly on selling electricity to the iron mining industry, we began to diversify. We invested in water utilities, coal mining, papermaking and other fields.

In all our businesses, old and new, we're dedicated to continuous improvement. We're adapting to a changing regulatory climate, streamlining and becoming more efficient in the way we work, and increasing reliance on team dynamics and participatory management.

In the hands of motivated, goal-oriented men and women, change pays important dividends. Some are intangible yet valuable, others have dramatic financial impact such as the example below. Change has strengthened our company. This report highlights 11 representative Dividends of Change.

[PHOTO OF ERIC NORBERG AND DAVE MCMILLAN.]

The Rewards of 'Partnering'

Most companies have both customers and suppliers. But not all have discovered the economic advantage in building cooperative relationships with both groups. As an example of "partnering" with a supplier, we've signed a new, more flexible contract with our coal hauler, the Burlington Northern Railroad. It's based on the assumption that we'll sell more power and buy more coal if we can keep our costs down, benefiting our company, the BN, and our customers. Our combined savings on the cost of coal and rail transportation is more than $20 million annually. Eric Norberg, left, and Dave McMillan represent the many people of Minnesota Power who presented our case in this landmark negotiation.

Financial Highlights

	1994	1993	Change
Operating Revenue and Income	$637,782,000	$589,607,000	8%
Net Income	$61,333,000	$62,621,000	(2%)
Earnings Per Share	$2.06	$2.20	(6%)
Average Shares of Common Stock	28,239,000	26,987,000	5%
Dividends Per Share	$2.02	$1.98	2%
Total Assets	$1,807,798,000	$1,760,526,000	3%
Return on Common Equity	10.5%	11.5%	(9%)

Average Annual Shareholder Return Over Last 10 Years
(Graphic material omitted)

	Percentage
Minnesota Power	12.9
U.S. Electric Utilities	12.6
S&P 500	14.3

Minnesota Power common stock bought in January 1985 and sold at year-end 1994 would have earned an average return of 12.9% per year - including dividends paid and appreciation in value.

Earnings and Dividends Per Share
(Graphic material omitted)

	1985	1986	1987	1988	1989	1990	1991	1992	1993
Earnings	2.34	2.77	2.34	2.35	2.90	2.37	2.46	2.47	2.20
Dividends	1.38	1.52	1.66	1.72	1.78	1.86	1.90	1.94	1.98

	1994
Earnings	2.06
Dividends	2.02

While earnings declined in 1994, dividends rose to 98% of earnings. The Company's earnings goal is $3.25 per share by the year 2000, with electric utilities, water utilities and non-regulated investments each contributing about a third.

Assets
Millions of Dollars
(Graphic material omitted)

	1983	1984	1985	1986	1987	1988	1989	1990
Electric Utility	1,259	1,273	1,192	1,149	1,157	1,172	1,155	1,133
Water Utility	5	12	24	34	57	104	228	269
Investments and Corporate Services	150	255	325	533	666	664	630	674

	1991	1992	1993	1994
Electric Utility	1,121	1,129	1,170	1,181
Water Utility	292	322	329	326
Investments and Corporate Services	639	639	727	778

Increasing investments in water utilities and nonutility business activities have steadily diversified Minnesota Power since 1983. This graph includes shared/leased assets not shown on our balance sheet.

We've changed our financial statements this year to reflect changes in the way we look at our business. Financial data from prior years has been reclassified in this annual report to present comparable data in all periods.

A CONVERSATION WITH THE CEO

. . . .

Arend Sandbulte

[PHOTO OF AREND SANDBULTE.]

How would you assess 1994's financial and operating results?

Earnings of $2.06 per share were disappointing, a 6% decrease from the previous year and the lowest in a decade. The largest single reason for the lower earnings was our securities portfolio. A consistent and substantial contributor to our earnings for 10 years, the portfolio was hurt by lower market returns, declines in the value of some of its holdings, and a 21-cent-per-share write-off of one investment early in the year. Despite that rocky start, it finished the year with an after-tax return of 3.8%, but compared with the previous year, its income declined 55 cents per share.

Despite the lower earnings per share, 1994 also brought important, positive developments for Minnesota Power that should help future earnings. Northeast Minnesota's taconite plants and paper mills had a good year, and this spurred our electric utility business to its second-highest kilowatt-hour sales ever. Six of our nine largest power customers extended their contracts with us. We received a rate increase, the first since 1981, and our rates remain well below national and regional utility averages. BNI Coal broke records, and Superior Recycled Fiber Industries was profitable its first year out of the gate. Lake Superior Paper, with help from price increases, turned the corner in the fourth quarter and is positioned for higher profits this year. Water utility earnings were hurt by abnormally high rainfall; we continue upgrading water facilities, improving customer service, and laying the groundwork for returns that more fairly reflect our investment in the water business. Finally, we signed an agreement to acquire 80% ownership in ADESA Corporation, a business we believe will give us the growth we need to achieve our financial goals in the coming years.

What are the Company's financial goals?

Our goal is to increase earnings to a minimum of $3.25 per share by the year 2000. We expect the earnings to come, approximately one-third each, from electric utility operations, water utility operations, and other investments, the largest of which would be ADESA. That may look like a stretch, but I'm confident we can do it.

Minnesota Power's stock price has dropped roughly 30% from the highs it hit in autumn 1993. Why?

The rising interest rates of the last year and a half have hurt most utility stocks and probably account for much of our price decline. Beyond that, three things happened. One was the National Steel taconite plant shutdown in late 1993 and, although the plant restarted last August, the stock market has not yet given back to us the price drop that hit when the closing was announced. Second, our first-quarter securities portfolio loss dashed expectations for earnings growth in 1994. Finally, the announcement of our planned ADESA acquisition in January 1995 created additional uncertainty that seemed to keep our stock from sharing in some gains that other utility stocks enjoyed early this year.

What is the Company doing to improve its stock price?

In the long run, of course, the most important thing will be performance: We intend to increase our earnings by providing exceptional customer service at competitive prices. In the shorter term, perception is also important, and I think the stock price reflects some uneasiness analysts are currently feeling about our Company. One problem is that diversification, which has benefited us significantly for the past decade, has also made us more complex to understand. That's where communication can help. We'll work hard in 1995 to help investors understand our business prospects, and then hopefully they'll appraise our future the way we do. As a diversified utility, Minnesota Power offers investors an attractive combination - solid utility businesses coupled with non-regulated investments that give us more growth potential than a "plain vanilla" utility. That's the message we're carrying to Wall Street.

Are you concerned about the Company's high dividend payout?

In 1994 we paid out in dividends 98% of our earnings. That's high, but given our cash resources and our lack of major utility construction needs, it should not be detrimental. Longer-term, our goal is to reduce dividend payout to 70% of earnings; unlike some utilities, however, we don't plan to do it by reducing dividends but rather by increasing earnings. We're confident we can increase earnings, and this is the message I believe our board of directors was sending when we raised the dividend in January 1995.

Do you think market concerns about electric utility deregulation and competition are hurting us?

It's possible. There's a perception in the market that retail electric competition, if it comes, is going to be somewhat more difficult for us than for the typical utility because we have large industrial customers who theoretically might be courted by other power suppliers if there were full retail competition. I don't agree. In 1994 six of our nine largest industrial power customers extended their long-term contracts; this doubled the amount of revenue under contract between now and 2005, and the average contract duration is now between six and seven years. Our customers aren't signing with us just because we're nice folks (although we are). They're doing it because our retail rates are the lowest in the region and among the lowest in the country. Our customers are voting with their contract-signing pens, and not with their feet.

How will you keep electric rates competitive?

Smart cost control is the answer. We'll be spending somewhat less on construction over the next several years, compared with prior years. We're being more aggressive in seeing if we can't use existing facilities longer than we might have in the past. We're focusing expenditures in areas where there are good possibilities for either substantial savings or revenue growth. A new customer information system we put in place in 1994 will help us serve customers better and more efficiently. A new energy management system, beginning in 1995, will help us compete for regional electric sales and provide new power-related services in the future.

Do you see growth opportunities for the electric utility?

If we serve our customers well, we'll do well. We will pursue any growth initiatives, traditional or not, that have a reasonable chance of being profitable. There are some growth constraints, however, such as demand-side management, the conservation ethic, and the lack of customer growth in our service area. On the other hand, there are processes in the steel and paper industries that can be done electrically that are now being done less efficiently with other energy forms. New electrotechnologies can mean sales growth for us and solve problems for customers by removing production bottlenecks and helping them remain competitive in their markets.

What's your assessment of utility competition/deregulation scenarios?

Generally, I feel fewer electric utility CEOs now believe there will be wide-open retail competition than, say, a year ago. The shock wave from California's deregulation proposal has subsided. Ironically, one factor tending to slow retail competition is that utilities, including us, have been acting more and more as if full competition and deregulation had already occurred. We've been trimming costs and offering large industrial customers rate flexibility for years. The gates of competition may open further, but many issues need to be addressed first. Besides utilities themselves and their customers, myriad federal and state regulatory bodies have stakes in the outcome and roles to play. Sorting out the complexities and resolving the issues will not be easy, and there will be reluctance to jeopardize the benefits traditional regulation has given us. Hopefully, rationality and logic will prevail, as well as a sense of fairness in how to handle utility investments made in good faith under the present system of regulation.

What are the growth prospects for water utilities?

Customer growth in our water utility businesses has been running 3% to 4% per year, not counting acquisitions or asset sales. There will probably be more opportunities for water utility acquisitions because the industry is still fragmented. Nationally, there's a trend toward privatization of smaller municipal systems,

This ad ran in regional newspapers following the January 1995 announcement of our dividend increase.

Minnesota Power's 25th Consecutive Dividend Increase

On the occasion of our 25th consecutive annual dividend increase*, we'd like to tell you about our course for the future.

Some utilities have cut dividends. Not Minnesota Power. Our policy is to maintain our dividend, and to keep raising it as earnings grow. It yields 8% based on our current stock price of about $25.

In the mid-80s, we realized we should no longer rely exclusively on our electric business. We have the financial strength to diversify, and we're doing it with ingenuity and success. The new Minnesota Power has three main parts:

[CLIPART OF ELECTRICAL PLUG]
Our traditional electric utility base, including secure long-term contracts with large industrial customers, and 11.6% authorized return.

[CLIPART OF WATER FAUCET]
Water utilities, growing and providing an increasingly valuable commodity in Florida and the Carolinas.

[CLIPART OF THREE ARROWS]
Nonregulated affiliates, with potential growth and returns higher than utilities.

* On January 25, Minnesota Power (NYSE:MPL) increased the dividend on its common stock, equivalent to an annual rate of $2.04, compared with $2.02 paid in 1994. This higher quarterly dividend is payable March 1 to shareholders of record on February 15.

For more information about Minnesota Power, please write or call our Shareholder Services Department.

[LOGO OF MINNESOTA POWER]
30 West Superior Street
Duluth, Minnesota 55802
1-800-535-3056
FAX: 218-720-2502

and we may be able to either buy them or manage them for a fee. Beyond actual utility operations, there are other water-related services and products we could offer.

Does the pending ADESA acquisition signal a shift in diversification strategy, in that it is so different from any of our other businesses?

Certainly, the type of service ADESA performs is a departure, but ADESA is more like other businesses we have than you might think - and in some very key ways. Since 1983, financial services have been an important component of our Company; our securities portfolio and Capital Re, the reinsurance firm of which we own 21%, are both examples. ADESA, too, provides a corporate service: It brings auto buyers and sellers together, similar to a stock or commodity exchange. ADESA does not own the vehicles it auctions, but rather provides services for both buyers and sellers. It's a niche service business for the automotive industry, which is huge. And ADESA is a large player in this niche.
This acquisition may have little to do with utilities, but it has a lot to do with our profit strategy. I recently reviewed a Wall Street Journal article from September of 1993 that talks about Cox Broadcasting, a private firm that owns Manheim, the largest auto auction company. Cox is considered an astute company. The article, in sum, said that auto auctions had nothing to do with Cox's broadcasting business, but had a lot to do with its profits.

Headquartered in Indianapolis, ADESA operates auto auctions at Indianapolis, Boston, Buffalo, Cleveland, Cincinnati/Dayton, Knoxville, Lexington, Memphis, Charlotte, Birmingham, Sarasota/Bradenton, Miami and Austin. In Canada ADESA auctions are at Montreal, Ottawa and Halifax, Nova Scotia.

[MAP INDICATING LOCATIONS OF ADESA'S AUTO AUCTIONS]

The ADESA File

Merger Proposal

Agreement is for us to buy an 80% stake in ADESA Corporation for $167 million ($162 million upon completing merger plus $5 million for stock owned prior to merger agreement). The companies' boards have approved a definitive merger agreement, and ADESA shareholders will vote on it by mid-1995.

The Business

North America's third-largest auto auction company, ADESA owns and operates 16 facilities in the U.S. and Canada. Auction buyers are car dealers; sellers include domestic auto manufacturers, import auto makers, car dealers, fleet/lease companies, banks and finance companies. Revenue comprises auction fees paid by sellers and buyers and charges for auxiliary services that include auto reconditioning, body and paint work, remarketing, dealer financing and transportation services.

The Numbers

ADESA sold 410,000 vehicles in 1994, generating net income of $7.8 million on revenue of $94 million. In 1992 it sold 184,000 cars, with net income of $3.6 million and revenue of $46 million.

Growth Strategy

To acquire and consolidate independent auto auctions and begin new ones.

Customer Philosophy

To have "a servant's attitude," ready to do whatever is necessary to serve those who use ADESA auctions.

[PHOTO OF ADESA IN MEMPHIS]
ADESA's five-year-old Memphis auction: 145 acres, six auction lanes, 1,000 vehicles per week.

[PHOTO OF ADESA EMPLOYEE AND CAR ENGINE]
Auxiliary services include auto reconditioning, body and paint work, dealer financing, remarketing and vehicle transport.

But other utilities are not out buying car auctions.

The fact that a host of other utilities aren't following the same strategy we are doesn't worry me, actually. I'm not a contrarian by nature, but I don't think following the same path every other utility follows will necessarily lead to success. A crowded path may mean there isn't that much revenue and earnings growth available, and the competition will be intense. We've looked at a lot of businesses in the 12 years since we decided to diversify, we've studied ADESA in detail, and that's why we're confident it's a good buy for us and at a fair price.

What was the process used to find ADESA?

First we worked through a firm that finds potential buys for companies that are looking to expand through acquisition. We wanted a business with manageable risk and the potential for growth and returns higher than those of a typical utility business. We looked at firms in 25 to 30 different industries, beginning with utility-related businesses and then gradually broadening our scope. We considered international electric utility operations, but ruled them out because we felt they were too risky. We looked at oil and gas exploration, finally rejecting this business because it's too cyclical. We considered title insurance, but that business, too, is cyclical and linked to interest rates. Manufacturing was too capital-intensive. ADESA surfaced as a potential acquisition in mid-1994 and appeared to meet most of our criteria. We studied it thoroughly, involving our own corporate development people as well as outside investment advisors. Our first impression, like many people's, was colored by stereotypes about used car salesmen. A closer look dispelled the stereotypes, however. And the closer we looked, the more we were impressed with ADESA's business prospects and the better the financial fit we saw between the two companies.

What do you like about ADESA?

Its business fundamentals are solid. It's not cyclical. It has good cash flow, and its revenue and income growth have been in the range of 30% a year for the past three years. Growth in the auto redistribution industry overall has averaged about 10% a year for the past decade, reflecting a growing supply of rental cars, a boom in leasing as well as the increasing price of new vehicles. We also like that this business is not as capital-intensive as our utility businesses. For example, our electric utility had over $3 invested in facilities to earn $1 of revenue in 1994. In contrast, ADESA generated about $1.25 in revenue for every $1 of capital it had invested in facilities. That's an advantage when you're planning on expanding. Another thing we liked about ADESA is that its values were compatible with ours.

What values do you mean?

I mean basic values: Ethics. Honesty. Being customer-oriented. Its auction facilities are huge, modern, spotless. It reconditions the cars and does repainting and body work. It delivers vehicles to and from customers, using its own fleet of modern transport trailers. It provides remarketing services and makes short-term loans to dealers until they sell the vehicles. It handles all the paperwork, using computerized equipment to expedite the process at every point. ADESA provides one-stop shopping for car dealers.

What does Minnesota Power bring to the merger?

Our primary role is to provide expansion capital in accordance with approved business plans. We're not going to try to reculturize ADESA or make a utility out of them. We want them to continue to do what they've been doing, only more of it and even better. That's why we're retaining ADESA's key top managers; they will run the business and direct its growth.

How will the company expand?

We believe the auto redistribution business, like the water utility business since the mid-1980s, is in a period of consolidation. There are three large players in the industry, of which ADESA is the third-largest. But over half the 13 million vehicles a year that go through auctions are handled by independent companies that typically don't offer the breadth of service ADESA does. ADESA will expand by acquiring independent auctions and starting up large, new facilities. Its existing auctions can also become more profitable by handling more cars.

Even if ADESA does well, how can you earn a good return when you pay such a premium for the business?

It's true that if you divide the company's past-year income by the $167 million we are paying to acquire 80% ownership, it works out to a single-digit return. Believe me, we do not part with that much money easily. But we learned early in our diversification efforts that you have to pay a premium for a good business. The way you increase the return is through growth and expansion.

What do you look for in 1995 in terms of Minnesota Power's overall performance?

I look to 1995 for a better financial year for our paper and recycled fiber businesses, better results in our water businesses, and continued good earnings for the electric utility. We expect to close the ADESA deal and tell our story effectively to investors so they fully understand our Company's strengths and so our stock is fully valued in the market. And, of course, we'll prove that value through performance.

I would like to take this opportunity to thank all Company employees for their hard work over the past year. The 11 accomplishments featured in this report are representative of the kind of work our employees do whether they live in Minnesota, Wisconsin, Florida, the Carolinas or North Dakota. I would also like to thank shareholders and ask for your continuing support as we try to increase the value of your investment and make you proud to own part of Minnesota Power.

Arend Sandbulte

Arend Sandbulte
Chairman, President and Chief Executive Officer

February 24, 1995

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

Once exclusively an electric utility, Minnesota Power has in the past decade invested in a variety of non-electric businesses.

Our purpose in diversifying was threefold: First, we wanted to reduce the Company's heavy dependence on electric sales to a small number of large customers in taconite mining, an industry whose fate is tied to steel manufacturing. Second, we wanted to increase our growth potential beyond what we projected for our electric business. Third, in the case of investments such as our Duluth paper and recycled pulp plants, we also wanted to create jobs and boost the economy in our electric utility service area.

We feel diversification has served us well and is a valid strategy for meeting our future goals:

- To increase earnings to a minimum of $3.25 per share by the year 2000;
- To maintain our financial strength and increase the value of our shareholders' investment; and
- To nurture a customer-driven, quality-oriented corporate culture that is both internally cooperative and externally competitive.

To hit our earnings target, we will need to sustain the good financial performance of our electric utility, achieving our authorized rate of return. We will need earnings growth from our water utilities through customer growth, additional acquisitions, and rates that reflect our investment in facilities to meet increasing water demand and government-mandated environmental standards.

This won't be enough, however. We will need to supplement the regulated income from our electric and water utilities with income growth and higher returns from non-regulated businesses.

Our goal is that by the year 2000 each of our core businesses, electric and water utilities, would provide about one-third of Minnesota Power's income. The remaining third would come from non-regulated investments, including a proposed acquisition we announced recently.In February 1995 Minnesota Power and ADESA Corporation signed a merger agreement in which ADESA, an auto auction firm with 16 outlets in the United States and Canada, would become our 80%-owned subsidiary.

[PHOTO OF CINDY MCLEAN AND DEBBIE BULLOCH]

The Paper Goes 'Round and Round'

In 1994 Minnesota Power's electric utility operations collected and recycled 98,362 lbs. of white paper, 99,079 lbs. of mixed paper plus mountains of magazines, phone books, cardboard, newsprint, aluminum, glass and plastic - all because Cindy McLean decided one day in 1989 that "somebody should get us organized." Most collected materials are sold. (Paper goes to our Superior Recycled Fiber Industries operation.) The reduced cost of trash hauling is a valuable bonus. In the photo, Cindy is pictured on the right with Debbie Bulloch, who recently took over the leadership of the recycling program.

The $167 million transaction is scheduled for completion by mid-1995 following approval by ADESA shareholders.

ADESA's management will retain 20% ownership. Under the agreement, they have the right to sell, and Minnesota Power has the right to buy, their 20% in increments during the 1997-99 period at a price linked to ADESA's financial performance.

The money for buying and expanding ADESA and the possible acquisition of more water companies will come mainly from our securities portfolio. We expect to retain our investment in Capital Re Corporation. We will continue selling our southwest Florida real estate and expect to sell all or nearly all the property by 2000.

Another shift in resources is possible in 1995. Pentair, Inc. - our joint-venture partner in Lake Superior Paper Industries - has announced its desire to exit the paper business, which would likely entail selling LSPI. We believe a sale could improve the chances for expanding the Duluth mill, which was originally designed for more than one paper machine. Our position as half-owner is that we would join in a sale under the right conditions. If LSPI is sold, it may be logical to also consider a simultaneous sale of Superior Recycled Fiber Industries (SRFI), whose paper recycled fiber plant is adjacent to and operated by LSPI.

1994 Performance

Earnings per share of common stock for 1994 were $2.06, compared with $2.20 in 1993 and $2.47 in 1992.

The largest single factor in the lower earnings was a decline in the performance of the Company's securities investment portfolio.

Though the portfolio was profitable for the year, its income was reduced 55 cents per share from the previous year due to lower returns, including declines in the value of some securities, and the 21-cent-per-share write-off of one investment. Also contributing to lower 1994 earnings was an 11-cent-per-share loss from our investment in Reach All Partnership, a Duluth manufacturer of truck-mounted lifting equipment in which the Company has an 82.5% interest.

Kilowatt-hour sales increased 4% in 1994, reflecting an increase in sales to large industrial customers and resale customers. Despite this and higher retail electric rates that went into effect on an interim basis March 1, 1994, income from electric utility operations was down from the previous year.

The Company's water utility operations were helped by higher rates, but that benefit was offset by heavy summer rains that reduced water consumption. A $19.1 million gain from the sale of water plant facilities increased water utility operations income over 1993, contributing 42 cents per share to income.

Minnesota Power's coal mining business and sales of Florida real estate turned in solid performances in 1994,surpassing their 1993 income. Our Duluth paper mill, helped by a rebound in paper prices last fall, went from a $3.7 million pre-tax loss in 1993 to a $3.1 million pre-tax profit for 1994; the Company recognizes 50% of the mill's pre-tax earnings. SRFI, which began operating in late 1993, contributed $906,000 to corporate earnings in 1994.

Where 1994 Earnings Came From

Earnings Per Share	1994	1993	1992
Electric Utility Operations			
Electric	$1.17	$1.32	$1.30
Coal Mining	.11	.10	.09
	1.28	1.42	1.39
Water Utility Operations	.48	.08	(.05)
Investments and Corporate Services			
Portfolio and Reinsurance	.08	.63	.92
Real Estate	.36	.24	.35
Paper and Pulp	.05	(.08)	.01
Other Operations	(.19)	(.09)	(.15)
	.30	.70	1.13
Total Earnings Per Share	$2.06	$2.20	$2.47
Average Shares of Common Stock - 000s	28,239	26,987	29,442

Return on Common Equity
(Graphic material omitted)

Year	Percentage
1990	13.6
1991	15.4
1992	15.3
1993	11.5
1994	10.5

In 1994 the Company earned 10.5% on common shareholders' equity, which averaged $562 million during the year.

Operating Revenue and Income
Millions of Dollars
(Graphic material omitted)

	1992	1993	1994
Electric	449.8	457.7	453.2
Water	53.6	65.5	91.2
Investments and Corporate Services	72.8	66.4	93.4
	576.2	589.6	637.8

A sale of water facilities and revenue from SRFI's recycled fiber plant, which started up in fall 1993, accounted for most of the increase in 1994 operating revenue and income.

COMPARING FINANCIAL RESULTS FROM 1994, 1993 AND 1992

Operating Revenue and Income

Electric utility operations revenue was lower in 1994 than 1993, because the Company recognized $5.1 million of unbilled revenue and recovered $14.6 million more of coal contract termination costs in 1993. Also, National Steel Pellet Co., a taconite producer that purchases its electricity from the Company, operated for seven months in 1993 compared with four months in 1994. Additional revenue in 1994 of $11.1 million from the interim rate increase partially offset the decreases in revenue. Revenue was higher in 1993 than 1992, because 1993 included $4 million more of the coal contract termination cost recovery, $2.5 million more in unbilled revenue, and increased sales to resale customers.

Water utility operations revenue was higher in 1994 than 1993 because of higher water rates and a $19.1 million gain from the sale of water plant assets. However, 1994 revenue from ongoing operations was less than expected because abnormally high rainfall reduced consumption 8%. Revenue was higher in 1993 than 1992 because of higher water rates.

Investments and corporate services revenue was higher in 1994 than 1993 because SRFI, which began operating in November 1993, had $47.2 million more revenue in 1994. The $10.1 million write-off of an investment, lower returns and the decline in value of some securities due to higher interest rates lowered 1994 income. 1993 income was increased by a $2.7 million gain on a leveraged preferred stock investment but reduced by $8.1 million to reflect new accounting rules for employee stock ownership plans. 1992 income includes a $5.1 million gain from the redemption by the issuer of a preferred stock investment.

Operating Expenses

Fuel and purchased power expenses were lower in 1994 than 1993 because the monthly amortization of coal contract termination costs was completed in March 1994; 1993 included $14.6 million more of these costs than 1994. 1994 expenses included additional purchased power to provide for unscheduled outages at our Boswell power plant and to meet unexpected demand from three taconite customers. Expenses were higher in 1993 than 1992 because additional purchased power was used during scheduled maintenance at Company power plants.

Operations expenses were higher in 1994 than 1993, reflecting the fact that SRFI began full operations in November 1993. Expenses were higher in 1993 than 1992 due to scheduled power plant maintenance and higher property taxes.

Administrative and general expenses were higher in 1994 than 1993 and 1992 due to salary and benefit increases.

Interest expense was higher in 1994 than 1993, reflecting $45 million of new debt financing obtained for SRFI at the end of 1993. Expense was lower in 1993 than 1992 because of refinancings at lower interest rates.

Income from equity investments was higher in 1994 than 1993 because of additional income from our increased ownership in Capital Re and improved earnings from LSPI due to higher paper prices. Income was lower in 1993 than 1992 because of LSPI's loss. The Company recognized losses from its investment in Reach All in all three years.

Income tax expense was lower in 1994 than 1993. Effective tax rates were 25.9% in 1994, 30.1% in 1993, and 26.9% in 1992. The effective tax rate was lower in 1994 than 1993, due primarily to tax credits generated by affordable housing investments and the recognition of income from escrow funds that had been previously taxed. The effective tax rate was higher in 1993 than 1992, reflecting a 1% increase in the federal income tax rate in 1993 and fewer tax benefits generated by the investment portfolio.

[REPRODUCTION OF CONSOLIDATED STATEMENT OF INCOME AS ON PAGE 26 OF THIS REPORT.]

. . . .

Electric utilities are undergoing a transformation as efforts to stimulate competition begin to take effect. How far open competition will go and whether it will apply to retail customers, however, is not clear.

Federal Energy Regulatory Commission proposals have altered the competitive landscape, affecting transmission access and pricing. Under FERC's transmission access policies, competitors can gain access to a utility's transmission system, at rates set by FERC, to compete for sales to the utility's wholesale customers. While utilities have commonly allowed use of their lines for wholesale power transactions, most object to being required to transmit or "wheel" a competing electric supplier's power to the utility's own retail customers.

With our low rates, Minnesota Power is well positioned to meet competition. However, we remain opposed to retail wheeling. We believe it would benefit only a few large customers while causing smaller users' rates to rise dramatically and shareholder returns to fail to pay for capacity built on the strength of future promises of cost recovery. At present there are no proposals that, in our view, adequately address this stranded investment issue.

Recent developments suggest that retail wheeling, if it comes, is not expected for some time. Though Minnesota and other states are studying it - the most publicized proposal has been in California - retail wheeling is in use only in rare locations in this country. One disincentive is that states like Minnesota require utilities to invest in social and environmental programs that could be jeopardized if their electric utilities had to compete head-to-head with outside energy suppliers. Moreover, Minnesota's generally low electric rates, half those of California, provide little incentive to change a system that has been working well.

Despite uncertainty about the ultimate outcome of change in our industry, Minnesota Power is preparing for a more competive future.

Our methods include cost cutting, pursuing legislative and regulatory reforms to assure we compete with other power suppliers on a level playing field, realigning our business functions to make it easier to price and market "unbundled" products and services, and cementing relationships with customers through innovative pricing and excellent service. We will learn more about our customers as well as our competitors and use that information strategically. We expect to expand our product offerings and build our customer base through economic development and other initiatives. We will continue working to extend electric service contracts with our largest customers, a strategy that achieved good results in 1994.

We see ourselves increasingly as energy service providers. We look at our customers' objectives as joint challenges. By finding ways to help them conserve energy and cut costs, we help them become more productive. And that increased productivity, we have found, can result in increased electric power use longer-term for industrial customers as they compete with other operations.

We also encourage energy-saving electrotechnologies. We are promoting ground-source heat pumps in residential and commercial markets. More efficient than conventional

[PHOTO OF HEIDI JAGODZINSKI AND JACK HOKKANEN]
Ashes to Ashes

The northern Minnesota community of Hibbing, a Minnesota Power wholesale electric customer, had a problem. The city, which operates a power plant of its own, was running out of landfill space for its 7,000 tons of ash per year. We offered to dispose of it at the Boswell Energy Center ash pond. Trucks that carry the ash away make the trip pay by back-hauling coal, which fuels Hibbing's power plant. It's a creative, economical, environmentally sound solution. Pictured: Heidi Jagodzinski, Boswell environmental engineer, submitted the ash disposal plan to the state. Jack Hokkanen is a customer representative for our large municipal accounts. Both credit others for making the idea work.

Our Competitive Picture

Customer Favorability
(Graphic material omitted)

	Percentage
Minnesota Power	91
Typical U.S. Electric Utility	71

Our 1994 rate increase had no appreciable effect on our electric customers' overall impression of us. In a 500-person telephone survey, 91% rated the Company positively. A full 82% said they'd choose us in a competitive situation. Only one in 25 said they'd switch suppliers if given the option; nationally, five in 25 would.

Average Price of Electricity - Residential
(Graphic material omitted)

	Cents per Kilowatt-hour
Minnesota Power	5.55
Northern States Power	7.40
Otter Tail Power	6.42
Interstate Power	8.01
National Average	8.85
Average Cooperatives	8.24

On average, our residential customers paid 37% less for electricity in 1994 than customers of other U.S. utilities.

Average Price of Electricity - Overall
Cents per Kilowatt-hour
(Graphic material omitted)

	Minnesota Power	National Average
Residential	5.55	8.85
Commercial	5.58	7.90
Industrial	3.66	5.14
Overall	4.08	7.25

Averaging rates for all service classes, our customers paid 44% less for their power than utility customers elsewhere in the country.

electric heating and cooling systems, ground-source heat pumps are especially cost-effective where the user wants both air conditioning and heating. With normal usage, energy savings will offset installation costs in three to five years.

The continued financial health of Minnesota Power's electric utility business depends on the financial viability of our large industrial customers, particularly taconite producers and paper manufacturers.

Both industries compete in global markets and, therefore, need to control costs and increase their productivity. Through energy audits, we have helped our large industrial customers identify cost-effective conservation measures as well as projects that will improve production efficiencies. These improvements are funded through state-mandated Conservation Improvement Program grants.

In many ways, we have always competed to serve our large industrial customers. Because of their size, they have had the option to generate their own power if they felt they could do it more economically than buying from us. Paper mills, which require steam for their manufacturing process, are ideal candidates for building their own cogeneration facilities, which operate efficiently by burning a fuel to make steam for papermaking as well as electric generation. Federal law says that when cogenerators meet certain conditions, utilities must purchase their surplus power.

In recent years, the Company has offered customers a wider choice of electric service options. For example, interruptible rates for large industrial customers offer a price discount in return for agreeing to have service interrupted on occasion. Another example: state law allows us, with Minnesota Public Utilities Commission approval, to offer lower rates to service area customers who could otherwise obtain energy from an unregulated supplier or generate their own electricity. The Company is exploring the joint development of cogeneration facilities with some of its key customers to meet future energy needs.

1994 Performance

The Company's electric utility business performed well in 1994. Kilowatt-hour sales rose 4% to their second-highest level ever despite the idling of one of our largest customers for seven months of the year.

Revenue was boosted by a 7% interim retail rate increase. Customers also saw the full impact of savings from new coal purchase and transportation contracts, which more than offset the final electric rate increase for our largest customers and reduced it for others. In the second half of the year, six of our nine largest industrial customers extended their electric service contracts, more than doubling the amount of revenue committed to us in the 1995-2005 period.

We sharpened our focus on customer service, streamlining operations in some areas while emphasizing others where there is the greatest potential for growth and likelihood of competition. We also realigned the functions in our electric utility business to address the more competitive future many are predicting for our industry.

Two industries - taconite production and the manufacture of paper and wood products - accounted for 49% of the Company's electric operating revenue in 1994, versus 48% in 1993 and 51% in 1992.

An encouraging development during 1994 was the dramatic turnaround in the market for pulp and paper. Electric sales to paper and other wood-products customers in 1994 were up 5% over 1993 and 3% over 1992. Paper and wood-products firms provided 14% of electric operating revenue each of the last three years.

The paper industry is in better condition than it has been in many years. Its additional energy use benefited us, as we provide power to all four of northern Minnesota's largest paper mills. During the year we extended power contracts with Blandin Paper Co., Boise Cascade, and Lake Superior Paper Industries. One existing customer, Potlatch Corporation's paper division in Brainerd, signed a four-year contract as a Large Power customer for 10 megawatts through November 1999; MPUC approval has been requested.

Taconite production provided 35% of electric operating revenue in 1994, 34% in 1993 and 37% in 1992. An important raw material for steelmaking, taconite pellets are made from iron-bearing rock. In an energy-intensive process, the rock is blasted from the earth, crushed and ground into powder. The iron is magnetically separated, concentrated and rolled into a pellet with a uniform 65% iron content for shipping to steel mills on the lower Great Lakes.

In 1994 the taconite industry recorded its best year since 1981, producing more than 43 million tons of pellets, and it is expecting to produce approximately 48 million tons in 1995. In August 1994 we resumed providing power to National after a lapse of 12 months while the plant was idled. The Keewatin, Minn., plant is now fully operational and is expected to produce 5 million tons of taconite pellets in 1995, more than 10% of Minnesota's total projected shipments. Though we had largely compensated for the loss of this business through tight cost controls and the sale of power to other utilities, National's return is a boon to the region and sounds an encouraging note for 1995.

In addition to signing a 10-year contract with National, we renewed contracts with USX's Minntac plant and Hibbing Taconite. In January 1995, we extended our contract to supply power to Eveleth Mines through 1999.

In November the Minnesota Public Utilities Commission granted us a retail rate increase, our first since 1981.

The new rates will increase annual revenue by about $19 million, beginning in 1995. Our initial request, filed in January 1994, had been for a $34 million increase, but we reduced it to $27 million for 1994 and $23 million for

[PHOTO OF ED MACKEY, JOE REIS, MARK PINNEY, AND TOM GEISELMAN]
Increased Coal-Handling Efficiency at Boswell

Teamwork is paying off in the coal yard at our largest power plant, Boswell Energy Center, near Cohasset, Minn. By modifying their coal-handling system, Boswell workers improved efficiency and eliminated the need for one dozer, saving its leasing, fuel, and maintenance costs. A new stacker and changes in conveyor routing make it possible to unload an entire train without moving coal to remote stockpiles, adding flexibility and efficiency in feeding the coal to the boilers. The improvement is too new to report cost savings, but they will be substantial. Among key members of the changeover team are, from left, Mark Pinney, fuels planner; Ed Mackey, utility operator; Tom Geiselman, engineer; and Joe Reis, senior instrument and control specialist.

Comparing Results from
1994 and 1993

Total electric sales increased 4% primarily because of increased sales to large industrial customers, wholesale customers and other power suppliers. Revenue increased $11.1 million from interim rates collected since March 1, 1994, and $7.8 million from the recovery of CIP expenses in 1994. Approval by the MPUC initiated recovery of CIP expenses beginning Jan. 1, 1994. Revenue was lowered by $12.4 million because of reduced demand revenue from National and lower rates associated with interruptible service. The Company also completed recovery of the remaining $3.9 million of coal contract buyout costs in March 1994, whereas 1993 included $18.5 million, a full year of recovery. Additionally, the unbilled revenue adjustment added $5.1 million to revenue in 1993.

Electric operations earned a return of 12.8% on average common equity devoted to electric utility plant in 1994, compared with 12.4% in 1993.

Comparing Results from
1993 and 1992

Despite work stoppages at two of the Company's largest industrial customers, revenue was slightly higher in 1993 due to increased sales to resale and other customers. In addition, a $5.1 million adjustment relating to the recognition of unbilled revenue increased 1993 electric utility operations revenue.

Electric operations earned a 12.4% return on average common equity devoted to the electric utility plant in 1993, compared with 14.4% in 1992. These returns do not include the recognition of unbilled revenue. The recognition of a $3.4 million revenue credit from a court decision contributed to the higher return in 1992.

Why Electric Utility Operations Revenue Increased or Decreased

	1994	1993
	(Change from previous year - in millions)	
Energy Sales (including demand and energy charges)	$(12.4)	$11.1
Unbilled Revenue	(5.1)	1.9
Rate Increases and Regulatory Adjustments	11.1	(3.9)
Conservation Cost Recovery	7.8	-
Fuel Clause Adjustments	(3.4)	(5.3)
Coal Sales	2.4	.8
Other	(4.9)	3.3
	$(4.5)	$7.9

Electric Revenue by Customer Group
(Graphic material omitted)

	1992	1993	1994
Other	49%	52%	51%
Paper & Wood Products	14%	14%	14%
Taconite & Iron Mining	37%	34%	35%
	100%	100%	100%

The taconite and iron mining industry, still the largest consumer of our power, provided 35% of electric operating revenue in 1994. Ten years ago it provided half.

Electric Sales
Billions of Kilowatt-hours
(Graphic material omitted)

	1992	1993	1994
Residential	0.888	0.927	0.941
Commercial	0.918	0.966	1.011
Taconite/Paper	5.940	5.891	6.099
Other Industrial	0.752	0.811	0.805
Resale & Other	0.838	1.199	1.333

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9.336	9.794	10.189

The medium blue section of the bar includes power sold to customers in our Large Power class that are served under long-term contracts.

1995 to reflect updated revenue and expense projections. The MPUC authorized an 11.6% return on equity invested in our electric utility.

Just as important to us for competitive reasons, the MPUC supported our request that the increase be larger for residential customers to reflect the higher cost of serving them and the need to keep the region's industrial customers competitive in their global markets.

As a result of the rate increase, rates for large industrial customers will rise less than 4%, while those for small businesses will go up 6.5%. The increase for residential customers will be phased in over three years: 13.5% beginning in 1995, 3.75% in January 1996 and another 3.75% in January 1997. Even after the full increase, our residential customers will still pay nearly 25% less than the 1994 national average.

The increase for large industrial users will be more than offset by savings in coal purchase and transportation costs, savings we are passing on to all customers. The savings result from new contracts negotiated with suppliers in recent years and whose full effect began being felt in 1994.

The MPUC's 1994 rate decision also allows us to recover through rates $1.3 million a year to pay for decommissioning coal-fired power plants when they reach the end of their useful lives.

The new rates are expected to go into effect in the second quarter of 1995. However, the Company began collecting an interim rate increase of 7% on March 1, 1994. In second quarter 1995 we expect to determine amounts of interim rate-related revenue, if any, the Company must refund with interest to customers. As of Dec. 31, 1994, the Company had reserved $6.1 million of the interim rate revenue for anticipated refunds.

The rate increase seems to have had little effect on the Company's good standing with customers. A recent opinion survey indicates that we have a favorable rating of 91% among residential customers, compared with 92% in 1993. Across the nation, a typical favorability rating for electric utilities is 71%.

Minnesota requires electric utilities to spend 1.5% of their electric revenue on conservation improvement programs (CIP) each year.

Because taconite and paper customers provide the bulk of Minnesota Power's electric operating revenue, the largest of these programs are targeted at them. CIP also funds demand-side management grants, awarded on a competitive basis to commercial and small industrial customers, as well as energy conservation initiatives aimed at all our customers. In 1995 we proposed a program that would allow us to provide low-cost financing for energy-saving investments.

State law allows utilities to recover state-approved conservation program costs through an annual customer billing adjustment. In January 1994 the Company began recovering ongoing 1994 CIP spending and $8.2 million of CIP spending from previous years. The billing adjustment, which must be reauthorized by the MPUC annually, has been allowing us to recover not only what we spend on these energy-saving programs, but also "lost margins" associated with power saved as a result of them. 1994 electric operating revenue included $7.8 million of CIP-related revenue. About $5.7 million for CIP expenditures was included in operating expenses.

SWL&P also offers electric and gas conservation programs to its Wisconsin customers in accord with Wisconsin state policies.

Our nine largest customers, accounting for about 49% of electric operating revenue, are served under long-term contracts.

The contracts, which in January 1995 averaged over six years in length, each require 10 megawatts or more of power and have termination dates from April 1997 to December 2005. Five of these customers are taconite producers and four are paper manufacturers.

[PHOTO OF JIM JORDAN, SKIP VANDAMME, BOB FONGER, RON CLARK, RANDY BURKHART AND BRIAN DENSTON]
Teamwork Works at SWL&P

While working at SWL&P's new water treatment plant, Brian Denston developed forearm pain requiring treatment and physical therapy. He felt it was caused by strain from raking sludge off the walls of the plant's reclaim clarifier. After studying the problem, Brian and his colleagues decided to design an electric pump to do the job. Ergonomic improvements like this help keep the lid on insurance costs. Pictured, clockwise from left: Jim Jordan, Skip VanDamme, Bob Fonger, Ron Clark, Randy Burkhart and Denston.

The contracts provide that, even at low electric usage levels, these customers will pay us enough to cover most of the fixed costs of having capacity available to serve them, including a return on equity. The contracts require four years notice before they can be cancelled, although the rates paid under the contracts are subject to change through the regulatory process governing all retail electric rates.

In December 1994 Minnesota Power asked the MPUC to approve two additional rates for retail customers. First, an economic development rate would give discounts to customers who invest in new capital improvements or equipment and increase electrical load on our system. Second, an incremental sales rider to an existing contract would allow more flexibility for some customers to operate above their specified contract demand levels in certain months and pay only energy charges for the incremental load.

For the next five years we are projecting relative stability in overall kilowatt-hour sales. While taconite production in 1995 is expected to continue at near-record levels, the longer-term future of this cyclical industry is less certain. While we are doing all we can to help all our taconite customers remain competitive, it is possible that production will decline gradually some time after the year 2000.

Company generating stations in 1994 burned 3.4 million tons of coal, the cost of which is our largest operating expense.

In December 1991 we paid Peabody Coal Company $35 million to terminate its long-term coal contract two years ahead of the scheduled termination date. The cost was amortized monthly and collected from customers through a fuel adjustment provision until March 1994. Revenue collected this way amounted to $3.9 million in 1994, $18.5 million in 1993, and $14.5 million in 1992. Savings from the new coal supply agreements are being passed on to customers.

In 1993 Minnesota Power entered into a contract with Peabody that extends through May 1997 for up to two-thirds of our coal needs. The rest will be purchased on the spot market through one-year agreements, taking advantage of favorable market conditions. We are exploring supply options beyond 1997 that provide for a mix of long-, intermediate- and short-term purchases. We believe adequate supplies of low-sulfur, sub-bituminous coal will continue to be available.

In February 1993 the Company renegotiated two contracts with Burlington Northern Railroad to deliver coal to our plants through December 2003 at reduced rates. These new contracts also provide for better access to all major coal production areas within the Powder River Basin of Montana and Wyoming.

How Power Contracts Protect Us
Minimum Annual Revenue and Demand
under Contracts in effect as of Jan. 31, 1995

	Minimum Revenue	Megawatts
1995	$90.5 million	550
1996	$78.1 million	481
1997	$75.5 million	464
1998	$61.5 million	372
1999	$32.3 million	190

The Company believes revenue from contracts with large industrial customers will substantially exceed the minimum contract amounts. In fact, assuming the new rates and large power contracts that are pending MPUC approval are put in place, annual minimum revenue will increase $16 million to $28 million for each year through 1999.

Sources of Electricity
(Graphic material omitted.)

	Percentage
Coal	52
Hydro	6
Purchased	20
Lignite	22

	100

Low-sulfur coal, our major fuel, comes from the Powder River Basin in Montana and Wyoming.

Annual Load Factor

(Graphic material omitted.)

	1989	1990	1991	1992	1993	1994
Minnesota Power	80%	85%	82%	82%	86%	82%
Utility Industry Average	62%	60%	61%	61%	61%	61%

Our annual load factor, the ratio of average electrical load to peak load, is the highest of any major U.S. utility, mainly because of our large industrial customers.

Average Cost of Fuel for Electric Generation
Cents per Million BTU
(Graphic material omitted.)

	1989	1990	1991	1992	1993	1994
Minnesota Power	112.1	113.6	114.5	118.9	115.6	97.0
West North Central Region	118.4	119.2	118.4	118.7	111.9	
Total Electric Utility Industry	174.0	174.1	169.6	166.6	166.6	

The dip in average fuel costs in 1994 resulted from renegotiation of coal supply and transportation contracts. Fuel costs from the Square Butte generating unit are included in Minnesota Power fuel costs.

A lignite-fired minemouth power plant in North Dakota provides us with an economical supply of electricity.

Under an agreement extending through 2007, the Company purchases 71% (about 307 megawatts during summer months and 322 megawatts during winter months) of the output of a mine-mouth generating unit owned by the Square Butte Electric Cooperative. The Square Butte unit is one of two units at Minnkota Power Cooperative's Milton R. Young Generation Station near Center, N.D.

Square Butte has the option, upon five years advance notice, to reduce our share of the unit's output to 49%. Minnesota Power has the option, though not the obligation, to continue to purchase 49% of the output at market-based prices after 2007 and through the end of the plant's economic life. Minnesota Power must pay any Square Butte costs and expenses that have not been paid by Square Butte when due, regardless of whether or not we receive any power from that unit.

While many utilities and their customers will face higher costs to comply with clean-air legislation, we expect to meet future requirements without major spending.

Burning low-sulfur fuels and equipped with pollution control equipment, our power plants already operate at or near the sulfur dioxide emission limits set for the year 2000 by the Federal Clean Air Act Amendments of 1990. To meet nitrogen oxide emission limits for 2000, we expect to install new burner technology. Total clean-air compliance costs cannot be accurately estimated yet, as regulations are not final.

A settlement was reached in 1994 in an Environmental Protection Agency Superfund action to clean up pollution at a northern Minnesota oil refinery site. Minnesota Power, along with roughly 130 other companies and several government entities, agreed on a $37 million proposal, which was submitted for approval to regulatory agencies.

Under the settlement, Minnesota Power's share of cleanup costs is about $314,000, all of which has been paid. Other related legal and internal costs have totaled about $550,000 since 1990, when the suit was initiated. Cleanup is expected to begin in 1995. Minnesota Power's electric utility is not the subject of any other environmental lawsuits.

BNI Coal mined a record 4.4 million tons of lignite coal, produced its highest-ever net income of $3.1 million, and had no lost-time accidents in 1994.

Already North Dakota's lowest-cost producer of lignite - 24% less expensive than the next-lowest supplier in terms of cost per British thermal unit of energy in 1994 - BNI Coal should further increase its efficiency with the addition of $5 million in new scrapers and bulldozers in 1995.

BNI Coal's lignite is burned at the nearby Milton R. Young Station's two generating units. Thanks largely to its economical coal supply, the Young plant in 1993, for the third consecutive year, achieved the second-lowest production cost of any power plant in the United States. Its production cost of 10.33 mills per kilowatt-hour was more than 47% lower than the average for all coal-fired plants.

BNI Coal's reserves exceed 500 million tons, leaving ample supply for expanded production if additional markets for lignite can be developed. This is a challenge because lignite's high moisture content hampers long-distance shipping. BNI Coal is working with Minnkota and other interested parties to upgrade the quality of the lignite through a process that reduces moisture and sulfur content.

[PHOTO OF STEVE HOVEY.]

BNI Cuts Haul Costs 20%

Minnesota Power's BNI Coal mine at Center, N.D., has replaced eight haul trucks of varying capacities and speeds with five new ones that perform the same job better. The Kress trucks, manufactured in Brimfield, Ill., carry 180 tons per trip, operating faster, safer, and with less driver fatigue. The bottom line, according to Pit Operations Manager Steve Hovey, who led the team that justified and planned the changeover, is a 20% cut in average haul costs.

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

Southern States Utilities, which serves about 149,000 customers, is Florida's largest privately held supplier of water and wastewater services, four times as large as any other independent water utility in the state.

As such, SSU represents part of the solution to Florida's historically fragmented water service, a welcome change in a state facing a serious collective water supply challenge. The company is working with Florida regulators and legislators to address concerns such as non-viable systems, environmental care and conservation.

SSU has been granted cost-share funding from the South Florida Water Management District to build an aquifer storage and recovery facility to help meet long-term water needs of Marco Island, where the water supply is deteriorating due to intrusion of brackish sea water. This facility will allow SSU to store surplus fresh water in underground limestone formations until it is needed in high-demand winter months. In addition, the Southwest Florida Water Management District granted SSU cost-share funding for a wastewater reuse project at our Spring Hill plant.

By concentrating on customer service, improved earnings, growth, working with regulators, and leadership in solving Florida's water supply problems, SSU demonstrates Minnesota Power's dedication to a long-term investment in water services that will benefit customers, employees, shareholders and the natural environment.

With its service area gaining population at 3% a year, SSU sees opportunities for growth in its water business.

To stimulate internal growth, SSU encourages land developers to build within or adjacent to existing service areas. External growth is expected through further acquisitions and through offering management services to public utilities that prefer to own, but not operate, their systems.

SSU continues to hold the line on expenses while adopting new measures to improve performance, concentrating on high standards of customer service, stewardship of water resources and the environment.

Strategic planning initiatives include continuing employee training in new and evolving technology. Automation is helping increase productivity and customer service. Periodic research asks customers to evaluate company performance and guide SSU in making improvements.

A new water testing laboratory at Deltona, Fla., scheduled for July 1995 completion, will increase efficiency by centralizing most lab procedures, reducing costs and dependence on outside providers. It will assure that SSU's service meets or exceeds all state and federal water quality standards.

SSU did not file a general rate case in 1994, but plans in 1995 to request an interim annual rate increase of about $10

[PHOTO OF SHARON ALECK]
Financial Health Counts, Too

When Sharon Aleck of our Heater Utilities affiliate saw an increase coming in Heater's group medical premiums, she did a little actuarial calculating. Finding that premiums had greatly exceeded claims in a recent period, Sharon started negotiating with the insurance company. The result: what might have been a $100,000-plus increase in annual premiums became an $18,000 decrease, even though the number of employees covered grew from 68 to 77.

million and could be seeking as much as $12 million in additional annual revenue in final rates. New facilities added since 1992 are not yet included in our rate base for earnings purposes. Further, mandated regulatory compliance cost increases during the same period, particularly for environmental protection, have raised operating expenses and should also be recovered in rates.

Our 1995 filing will include innovations in rate design that will benefit both customers and shareholders. In addition to the previously authorized uniform rates, we will propose before the Florida Public Service Commission (FPSC) water conservation incentives and a consistent policy on charges for service availability. These measures, coupled with continuing efforts to contain expenses, are expected to improve and provide more consistent earnings.

SSU applies uniform rates in most of the areas it serves. This rate design policy, originally approved by the FPSC in 1993, was reaffirmed in August 1994.

Uniform rates recognize that SSU, operating as a statewide utility system, provides economical service to all customers, regardless of their location. A uniform rate policy, applied today in many other states, also prevents "rate shock" by spreading the cost of capital improvements, reduces rate case preparation expenses, and can help promote water conservation. In a state facing a future water supply deficit, uniform rates represent sound public policy and a long-term benefit to customers and shareholders.

By Florida law, water and wastewater utilities may make an annual index filing to recover inflation in system operation and maintenance expenses, thus delaying or avoiding the costs of full rate case filings. Similarly, another Florida law allows water and wastewater utilities to file annually to recover increased purchased water and wastewater treatment costs and property tax increases. Through these filings in 1993 and 1994, SSU requested $3 million in annual rate increases and was allowed $2.9 million.

From 1992 through 1994 our Heater Utilities subsidiary has been granted annual water utility rate increases totaling $1.6 million of $2.4 million requested since 1991 from regulatory authorities in North Carolina and South Carolina. Rate decisions are expected by mid-1995 on additional requested rate increases totaling $334,000. Heater is filing for rate increases affecting about 19,000 customers in North Carolina early in 1995.

SSU's earnings reflected the sale of our water and wastewater facilities at Venice Gardens to Sarasota County for $37.6 million, resulting in a $19.1 million gain.

This sale was negotiated in anticipation of an eminent domain action by the County, which is purchasing private utilities in an effort to consolidate services. Venice Gardens has about 15,500 customers.

In October 1994 SSU requested approval from the FPSC to buy Orange Osceola Utilities, Inc. for about $13 million. Orange Osceola serves 17,000 customers in a 2,800-acre residential development near Kissimmee, Fla., close to Walt Disney World. SSU expects to conclude this acquisition in mid-1995.

Revenue from Water Utility Operations
Millions of Dollars
(Graphic material omitted.)

	1992	1993	1994
Water	35.5	42.0	45.4
Wastewater	13.0	20.2	23.5
Sanitation	4.7	3.2	3.1
Gain on Sale of Assets	0.4	0.0	19.2
	53.6	65.4	91.2

The sale of our Venice Gardens facilities gave a lift to revenue in 1994, but above-average rainfall cut water use in Florida and doused prospects for a better return from ongoing water utility operations.

Number of Water Utility Customers
In Thousands
(Graphic material omitted.)

	1992	1993	1994
Water	140.1	142.3	139.0
Wastewater	50.9	52.6	46.7
Sanitation	11.2	11.5	11.8
	202.2	206.4	197.5

Our water utility customer base shrank by 15,500 in 1994 with the sale of our Venice Gardens water facilities to Sarasota County, Fla. Our pending purchase of a utility in Kissimmee, near Walt Disney World, would add roughly that many customers in 1995.

Upgrading Our Water Systems
1994 Florida Capital Expenditures

To meet regulatory requirements	$11.2 million
To meet growth demands	$6.9 million
To improve quality of service	$2.3 million
Other	$3.2 million
Total	$23.6 million

1994 Financial Performance

Above-normal rainfall in Florida and customer conservation curtailed water consumption in 1994, dampening anticipated returns from water utility operations.

Although net income from continuing operations increased from 1993, it still fell short of authorized rates of return. Narrowing the gap between actual and allowed earnings is a continuing challenge. Without the gain from the sale of the Venice Gardens facilities, SSU's return on equity in 1994 would have been 2.8%.

In contrast to Florida's heavy rainfall, 1994 was a dry year in the Carolinas, helping Heater Utilities achieve an 8.6% average return on equity. Heater recorded about 5% growth in its overall customer base, which included 7.5% growth in the Raleigh-Durham area.

Heater may lose 3,300 customers in an eminent domain action begun in January 1995 for its Seabrook, S.C., assets. The price Heater will receive will be determined by court proceedings.

[REPRODUCTION OF NEWSPAPER CLIPPINGS FROM THE ORLANDO SENTINEL ARTICLES "RAIN BRINGS TROUBLES TO ALL PARTS OF STATE" AND "IT HAS RAINED, IT HAS POURED THROUGHOUT '94."]

1994 rainfall was 41% above average in the Orlando area, decreasing water consumption and lowering SSU revenue. Authorities cautioned, however, that this temporary replenishment of the Florida aquifer does not reduce the need for continuing water management, conservation and action to address the sources of the state's long-term water deficit.

[PHOTO OF RICH SULLO]

Works Better, Costs Less

Treatment of drinking water distributed by SSU includes adding a trace of chlorine. When the Florida Department of Environmental Protection ordered utilities to install chlorination alarms on unattended water facilities, Rich Sullo, who works at SSU's Deltona Lakes Plant, had a better idea. He designed an alarm system that assures proper chlorination and, if there's a problem, shuts down the well and electronically notifies the main plant. This saves time and water while maintaining quality standards. Commercially available alarms monitor chlorine levels but lack the shutdown feature and cost three times as much.

Comparing Financial Results from 1994, 1993 and 1992

The sale of Venice Gardens assets contributed a $19.1 million gain to water utility operations revenue and income. Operating revenue increased slightly due to new rates. Consumption levels in 1994 were 8% lower than 1993, reflecting abnormally high rainfall in Florida during most of the last half of the year.

SSU and Heater had combined net income of $13.3 million in 1994, $1.4 million in 1993 and a net loss of $2.3 million in 1992. The revenue from water and wastewater treatment services increased approximately 8% in 1993 because of higher water rates that have become effective at various dates since June 1992.

INVESTMENTS AND CORPORATE SERVICES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

. . . .

For many years non-utility investments have contributed substantially to Minnesota Power earnings. Their mission is twofold:

- To achieve a higher rate of return on investments than we are limited to in the regulated sectors of our business; and,
- To keep funds available for reinvestment in existing businesses or the acquisition of new businesses.

Over the past decade, our securities investment portfolio has contributed more than $150 million in earnings. However, its contributions declined significantly in 1994.

Reflecting the volatility of financial markets during the year, some of the stocks in the portfolio declined in value. A more disturbing development, however, was a $10.1 million, or 21-cent-per-share write-off of one specific investment. The investment had been designed to protect the Company against fluctuations caused by interest rate volatility, but we believe the fund manager failed to follow the stated investment strategy and exposed the fund to rising interest rates.

Investments and Corporate Services also includes our investment in Capital Re Corp., a leading U.S. reinsurer of municipal bonds and other financial guarantees.

While this firm primarily focuses on municipal bonds, it also reinsures non-municipal debt obligations and private mortgages.

Primary insurance companies buy reinsurance from Capital Re to guarantee the timely payment of principal and interest on investment-quality debt. Bonds reinsured by Capital Re automatically receive an upgrade to a AAA credit rating, which lowers the issuers' interest costs and provides an additional level of comfort to investors. Minnesota Power owns 21% of Capital Re and appoints two members of its board of directors.

Minnesota Power also owns 80% of Lehigh Acquisition Corp., which has contributed substantially to our earnings in recent years.

Its real estate properties include 8,100 undeveloped home sites and an additional 5,000 acres of unimproved property near and in the community of Lehigh Acres, which is about 15 miles east of Fort Myers, Fla.

During the year, the community was enhanced by the opening of Lehigh Senior High School on a site largely donated by the company. A massive new Wal-Mart Center, roughly three times the size of a typical Wal-Mart outlet, is under construction at a site near where Lehigh owns most of the remaining commercially zoned land. A new medical center has also opened, and Lehigh continues to recruit businesses for the community's industrial park.

Lehigh sells properties to certified developers who build and sell well-designed, affordable homes.

Because Lehigh Acres is primarily an affordable first home and retirement community, growth is partly driven by the ability of retirees in the Midwest and Northeast to sell their existing homes. Rising economies in those areas should boost sales. Also, with the introduction of direct flights from Germany to Florida, Lehigh Acres is becoming a flourishing German community, complete with German restaurants and newspapers, and German-speaking customer service personnel.

In 1994 Lehigh formalized procedures to begin constructing $5.2 million in water and wastewater facilities in Lehigh Acres using funds held in escrow. The funds are restricted for payment of such construction expenditures. Based on revised procedures, which accelerated use of the funds, and plans to build the facilities over the next five years, Lehigh recognized approximately $4.5 million of income in March 1994. The Company's share of this income totaled $3.6 million.

Lehigh, which contributed $10.2 million to corporate earnings in 1994, continues to be highly profitable for Minnesota Power. The plan is to sell the Lehigh property as opportunities arise. We anticipate the sales will be completed over the next five years.

Income could receive a boost in 1995 from real estate-related tax benefits that came with Minnesota Power's purchase of Lehigh Corp. in 1991. The benefits are recorded on Lehigh's books as $26.9 million of net deferred tax assets, offset by a reserve. In keeping with established accounting principles, management reviews the assets quarterly; when it's deemed "more likely than not" that any portion of them will be realized, that portion will be recognized as income and the reserve reduced accordingly. A portion of the assets may be recognized as income in 1995 as Lehigh reviews its business plan, including the timing and sale of its real estate holdings.

Lake Superior Paper Industries, jointly owned by subsidiaries of Pentair, Inc. and Minnesota Power, rebounded in fourth quarter 1994 from the weak prices of recent years.

Demand for its supercalendered groundwood paper is at a historical peak. Economic recovery in Europe aided LSPI's turnaround by providing a market for Finnish paper that had in recent years been shipped to the United States, depressing prices here.

LSPI production for the year reached the record level of 241,000 tons, exceeding the mill's designed capacity. Productivity outpaced all competing supercalendered paper machines and resulted in the company's being named the world's most efficient SCA mill. The eight-year-old mill achieved this without investing additional capital. Breakthroughs came about as a result of empowered employees continually finding better, more efficient ways of getting things done.

LSPI should be able to capitalize on the favorable paper market industry experts project to continue through at least 1996. No new paper-making machines are scheduled to begin operations in that time period, and paper prices have increased by 14 percent since September 1994. LSPI's goals are to continually improve productivity and to further reduce costs while providing high-quality customer service.

When we decided to go into the joint venture that led to the start-up of LSPI, our goals were to create jobs, gain a new industrial customer for our electric utility business, launch a business with expansion potential, and earn a profit on our investment. These goals have largely been achieved. The plant provides more than 300 jobs in the mill plus another 300 in logging and trucking. It requires 48 megawatts of power.

Therefore, should a favorable opportunity arise through our joint venture partner's pursuit of a sale of its interest in LSPI, Minnesota Power would consider a sale of its interest. Among factors that would influence us in favor of a sale would be the expectation that the new owner would ultimately expand the mill to its full potential.

If LSPI is sold, the deal might also include the sale of Superior Recycled Fiber Industries, the pulp production plant that is adjacent to and operated by LSPI.

SRFI produces recycled pulp from office scrap paper. Commercial operations began at SRFI in November 1993. It produced 84,000 tons of recycled pulp and contributed $906,000 to Minnesota Power earnings in 1994.

As expected, demand for recycled paper gathered further momentum during the year, and this in turn spurred intense production efforts at SRFI.

The $78 million plant produces high-quality recycled pulp for making printing papers, such as Potlatch Corporation's Quintessence RemarqueTM used in this report.

SRFI's production rate at the end of 1994 exceeded the plant's designed capacity of 247 tons per day. The demand for recycled pulp will likely continue to rise as federal agency requirements for copying paper containing at least

[PHOTO OF MIKE COCHRAN, MARY SCHOENROCK, JOLYNN NILSON, KARLA STROMBECK, RUSS SCHUMACHER, AND DIANE STUART]

Improving Customer Service Spawns a New Business

"Know thy customer" is good advice for any business, and technology is helping us do this. In 1989 we formed a team to evaluate potential new customer information computer programs for our utility businesses. None of the available options satisfied the standards set by our team, so they designed their own system. After four years of hard work, Minnesota Power's Customer Information System is not only on-line and performing well, it is being profitably licensed to other companies around the world. Pictured, from left: Mike Cochran, Mary Schoenrock, JoLynn Nilson, Karla Strombeck, Russ Schumacher, and Diane Stuart helped organize and manage the project.

20% post-consumer waste take effect. SRFI's production is virtually sold out through 1995.

SRFI's goal is to increase production further by eliminating bottlenecks and further improving efficiency.

The chief challenge to further expansion of SRFI's business is the procurement of scrap paper. SRFI recycles nearly 10% of all office scrap paper collected in the United States. Although office sector sources are reasonably well developed, at least half of all scrap paper suitable for recycling is in private homes and no systematic means of recapturing it exists at this time.

[PHOTO OF DAVE EVENS]
Baffling the Bubbles

At the front end of LSPI's paper machine, there's a large cylindrical tank called a Deculator, where air bubbles are removed from water that carries pulp into the machine. Too many bubbles cause defects in the paper. Bubbles and turbulence problems had been increasing last year as LSPI sped up the machine. So LSPI's Dave Evens built a plastic replica of the Deculator to learn what was causing the excess turbulence, then designed modifying baffles to correct the problem. Now the machine runs faster, LSPI is saving $35,000 a year on defoaming additives, and the Finnish manufacturer of the Deculator is paying our mill an annual royalty on the improvement: U.S. Patent No. 5,236,475.

Comparing Financial Results from 1994, 1993 and 1992

Income from the Company's investments declined $19.7 million in 1994 primarily due to unfavorable conditions in the securities markets and a 21-cent-per-share write-off of the Company's $10.1 million investment in Granite Partners, a limited partnership that filed for bankruptcy protection in 1994. Capital Re contributed positively all three years. Investments and reinsurance income was $13.4 million lower in 1993 than in 1992, reflecting the adoption of new accounting principles, lower returns due to market conditions, and a $5.1 million gain from the redemption by the issuer of a preferred stock investment in 1992.

Investment income includes revenue of $31.7 million in 1994, $31 million in 1993, and $28.7 million in 1992 from operations and the sale of certain assets by Lehigh.

In December 1992, $15.5 million of debt issued for the purchase of the real estate properties and operations was extinguished, and Lehigh assumed some contingent liabilities for which it had previously been indemnified by the previous owner. This transaction resulted in a non-taxable extraordinary gain to Lehigh of approximately $7.2 million. The Company's two-thirds share of this gain contributed 16 cents to earnings per share in 1992.

LSPI returned to profitability in 1994, earning $3.1 million pre-tax, compared with a pre-tax loss of $3.7 million in 1993 and pre-tax income of $3.4 million in 1992. LSPI had total sales of $152 million in 1994, $143 million in 1993, and $150 million in 1992. The mill shipped 241,000 tons of paper in 1994, compared with 235,000 tons in 1993, and 220,000 tons in 1992. The Company's share of LSPI's pre-tax income was $1.5 million in 1994, compared with a $1.8 million pre-tax loss in 1993, and $1.7 million pre-tax income in 1992.

The Company has an 82.5% ownership interest in Reach All, a manufacturer of specialized truck-mounted lifting equipment used by utilities and governmental entities. The Company recognized Reach All pre-tax losses of $5.2 million in 1994, $764,000 in 1993, and $3.1 million in 1992.

As detailed in the consolidated statement of cash flows, cash flows from operating activities in 1994 were affected by a number of factors representative of normal operations.

The Company's Automatic Dividend Reinvestment and Stock Purchase Plan (DRIP) was amended in January 1993 to allow the DRIP to meet its needs by purchasing original-issue common shares from the Company or buying common shares on the open market. The DRIP has been buying on the open market since January 1994.

In 1994 SSU sold $10.3 million of inter-local tax-exempt bonds to finance several water projects in Florida. The bonds carry a variable interest rate currently at 3 1/2%. A portion of the proceeds from the Venice Gardens utility sale was used to redeem SSU's $15 million of First Mortgage Bonds, 15 1/2% Series due 1994.

The Company estimates its capital requirements through 2000 will be met primarily with internally generated funds.

Working capital, if and when needed, generally is provided by the sale of commercial paper. In addition, securities investments can be liquidated to provide funds for reinvestment in existing businesses or acquisition of new businesses, and approximately 900,000 original-issue shares of common stock are available for issuance through the DRIP. If the ADESA transaction is approved by ADESA shareholders, cash from the liquidation of investments is expected to be used for the $167 million purchase.

The Company is committed to guarantee a portion of LSPI's lease obligation to a maximum of $95 million and expects that short-term loans to LSPI will fluctuate during 1995 but may approximate the $35 million note receivable outstanding as of Dec. 31, 1994.

Minnesota Power's electric utility first mortgage bonds and secured pollution control bonds are currently rated the following investment grades: A3 by Moody's Investor Service, A- by Standard & Poor's, and A by Duff & Phelps. The disclosure of these security ratings is not a recommendation to buy, sell or hold the Company's securities.

In 1994 capital expenditures in our electric business consisted of routine plant improvements and upgrades. Our power supply and projected demand are in balance.

No new power plants or major changes to existing plants are expected in the 1995-2009 period. Future water utility capital expenditures include facility upgrades to meet environmental standards and new water and wastewater treatment facilities to accommodate customer growth.

Consolidated capital expenditures in 1994 totaled $81 million, including $45 million for the electric utility operations, $28 million for the water utility operations, $3 mil-

[PHOTO OF JOAN ADLER]
The Value of Safety

Lehigh Acquisition Corporation, our Florida real estate affiliate, employs people in building trades, site preparation, road construction and other jobs considered high-risk by insurers. Determined to do something about accidents and high workers' compensation premiums, Lehigh's Joan Adler designed a safety incentive program that slashed accident rates, lowered premiums, and garnered a premium refund of $99,116 in 1994. Another refund is expected in '95.

lion for the pulp production plant, and $5 million for an affordable housing project. Internally generated funds were used for capital expenditures for the electric business. Water utility and affordable housing capital expenditures were funded through long-term financing and with internally generated funds.

Capital expenditures are expected to be $65 million in 1995 and total about $232 million for 1996 through 1999. The 1995 amount includes $30 million for routine electric capital expenditures, $26 million for upgrades, water reuse projects and new water facilities, and $9 million for coal mining equipment and other capital expenditures. The Company expects to finance the majority of its capital expenditures with internally generated funds.

We increased our common dividend in January 1995, the 25th consecutive annual increase.

In 1994 the Company paid out 98% of its per-share earnings in dividends. Given the lack of major construction needs and the liquidity of our securities investment portfolio, we do not believe this high payout ratio to be detrimental in the short run.

Over the longer term, Minnesota Power's goal is to reduce dividend payout to 70% of earnings. We expect to do this by increasing earnings rather than reducing dividends. Our goal is for earnings per share to grow from their 1994 level of $2.06 to a minimum of $3.25 by the year 2000. Our corporate strategic plan calls for about one-third of earnings to come from electric utility operations, another third from water utility operations, and the remainder from our Investments and Corporate Services area.

Capital Spending
Millions of Dollars
(Graphic material omitted.)

	1992	1993	1994
Electric Utility	45	58	45
Water Utility	32	20	28
Investments and Corporate Services	32	43	9
	109	121	82

In 1994 capital spending totaled $81 million, 31% less than the previous year.

Projected Capital Spending
(Graphic material omitted.)

	1995	1996	1997	1998	1999
Millions of Dollars	65	61	57	57	57

Capital spending for the 1995-99 period is expected to average 39% below the levels of the past five years. Most will be funded from internal sources.

Price Ranges and Dividends Paid Per Share

		New York Stock Exchange			American Stock Exchange		
		Common			5% Series Preferred		
Quarter		High	Low	Dividends Paid	High	Low	Dividends Paid
1994 -	First	$33	$28	$0.505	$73	$68	$1.25
	Second	30 1/8	25	0.505	68 1/2	61	1.25
	Third	28 1/8	25	0.505	64	60 1/4	1.25
	Fourth	26 5/8	24 3/4	0.505	64	55	1.25
	Annual			$2.02			$5.00
1993 -	First	$36 1/2	$32 5/8	$0.495	$72 1/2	$62	$1.25
	Second	36 3/8	34	0.495	71	68 1/2	1.25
	Third	36 1/2	35 1/4	0.495	73 1/2	69 1/4	1.25
	Fourth	35 1/2	30	0.495	74	68 1/2	1.25
	Annual			$1.98			$5.00

	American Stock Exchange		
	$7.36 Series Preferred		
Quarter	High	Low	Dividends Paid
1994 - First	$105	$100	$1.84
Second	101	93 3/4	1.84
Third	96	88 3/4	1.84
Fourth	91 5/8	84 3/4	1.84
Annual			$7.36
1993 - First	$100	$95 1/2	$1.84
Second	103	97	1.84
Third	105	100	1.84
Fourth	104	99	1.84
Annual			$7.36

The Company has paid dividends without interruption on its common stock since 1948, the date of initial distribution of the Company's common stock by American Power & Light Company, the former holder of all such stock. Listed above are dividends paid per share and the high and low prices for the Company's common and preferred stock as reported by The Wall Street Journal, Midwest Edition. On Dec. 31, 1994, there were approximately 27,000 common stock shareholders. On Jan. 25, 1995, the Board of Directors declared a quarterly dividend of 51 cents, payable March 1, 1995, to common stock shareholders of record on Feb. 15, 1995.

Independent Accountant

To the Shareholders and
Board of Directors of Minnesota Power

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

Effective January 1, 1993, the Company changed its method of accounting for income taxes and the employee stock ownership plan as discussed in Notes 13 and 15, respectively, to the consolidated financial statements.

Price Waterhouse LLP

Minneapolis, Minnesota
January 24, 1995

Management

The consolidated financial statements and other financial information were prepared by management, which is responsible for their integrity and objectivity. The financial statements have been prepared in conformity with generally accepted accounting principles as applied to regulated utilities and necessarily include some amounts that are based on informed judgments and best estimates of management.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls designed to provide assurance, on a cost effective basis, that transactions are carried out in accordance with management's authorizations and that assets are safeguarded against loss from unauthorized use or disposition. The system includes an organizational structure which provides an appropriate segregation of responsibilities, careful selection and training of personnel, written policies and procedures, and periodic reviews by the internal audit department. In addition, the Company has a personnel policy which requires all employees to maintain a high standard of ethical conduct. Management believes the system is effective and provides reasonable assurance that all transactions are properly recorded and have been executed in accordance with management's authorization. Management modifies and improves its system of internal accounting controls in response to changes in business conditions. The Company's internal audit staff is charged with the responsibility for determining compliance with Company procedures.

Five directors of the Company, not members of management, serve as the Audit Committee. The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent accountants to discuss auditing and financial matters and to assure that each is carrying out its responsibilities. The internal auditors and the independent accountants have full and free access to the Audit Committee without management present.

Price Waterhouse LLP, independent accountants, is engaged to express an opinion on the financial statements. Their audit is conducted in accordance with generally accepted auditing standards and includes a review of internal controls and a test of transactions to the extent necessary to allow them to report on the fairness of the operating results and financial condition of the Company.

Arend Sandbulte

Arend J. Sandbulte
Chairman and President

David G. Gartzke

David G. Gartzke
Chief Financial Officer

Minnesota Power
Consolidated Balance Sheet

December 31	1994	1993
	In thousands	
Assets		
Plant and Other Assets		
Electric utility operations	$ 784,931	$ 780,207
Water utility operations	295,451	303,714
Investments and corporate services	362,006	319,924
Total plant and other assets	1,442,388	1,403,845
Current Assets		
Cash and cash equivalents	27,001	31,674
Trading securities	74,046	98,244
Trade accounts receivable (less reserve of $1,041 and $1,565)	51,105	50,336
Notes and other accounts receivable	61,654	48,362
Fuel, material and supplies	26,405	20,764
Prepayments and other	25,927	22,589
Total current assets	266,138	271,969
Deferred Charges		
Regulatory	74,919	59,917
Other	24,353	24,795
Total deferred charges	99,272	84,712
Total Assets	$1,807,798	$1,760,526
Capitalization and Liabilities		
Capitalization		
Common stock without par value, 65,000,000 shares authorized; 31,246,557 and 31,206,803 shares outstanding	$ 371,178	$ 370,681
Unearned ESOP shares	(76,727)	(80,721)
Net unrealized gain (loss) on securities investments	(5,410)	1,488
Retained earnings	272,646	271,177
Total common stock equity	561,687	562,625
Cumulative preferred stock	28,547	28,547
Redeemable serial preferred stock	20,000	20,000
Long-term debt	601,317	611,144
Total capitalization	1,211,551	1,222,316
Current Liabilities		
Accounts payable	36,792	35,680
Accrued taxes	41,133	42,542
Accrued interest and dividends	14,157	13,812
Notes payable	54,098	20,475
Long-term debt due within one year	12,814	7,294
Other	23,799	10,542
Total current liabilities	182,793	130,345
Deferred Credits		
Accumulated deferred income taxes	192,441	187,436
Contributions in aid of construction	87,036	97,190
Regulatory	55,996	60,520
Other	77,981	62,719
Total deferred credits	413,454	407,865
Commitments and Contingencies		
Total Capitalization and Liabilities	$1,807,798	$1,760,526

The accompanying notes are an integral part of these statements.

Consolidated Statement of Income

For the year ended December 31	1994	1993	1992
	In thousands except per share amounts		
Operating Revenue and Income			
Electric utility operations	$453,182	$457,719	$449,803
Water utility operations	91,224	65,463	53,595
Investments and corporate services	93,376	66,425	72,799
Total operating revenue and income	637,782	589,607	576,197
Operating Expenses			
Fuel and purchased power	157,687	170,277	168,483
Operations	270,604	215,066	193,155
Administrative and general	79,922	75,091	75,986
Interest expense	52,070	43,534	47,479
Total operating expenses	560,283	503,968	485,103
Income from Equity Investments	5,300	3,929	4,352
Operating Income	82,799	89,568	95,446
Income Tax Expense	21,466	26,947	26,989
Income Before Extraordinary Item	61,333	62,621	68,457
Extraordinary gain on early extinguishment of debt	-	-	4,831
Net Income	61,333	62,621	73,288
Dividends on preferred stock	(3,200)	(3,342)	(3,807)
Tax benefits of ESOP dividends	-	-	3,206
Earnings Available for Common Stock	$ 58,133	$ 59,279	$ 72,687
Average Shares of Common Stock	28,239	26,987	29,442
Earnings Per Share of Common Stock			
Before extraordinary item	$2.06	$2.20	$2.31
Extraordinary item	-	-	0.16
Total earnings per share	$2.06	$2.20	$2.47
Dividends Per Share of Common Stock	$2.02	$1.98	$1.94

Consolidated Statement of Retained Earnings

For the year ended December 31	1994	1993	1992
	In thousands		
Balance at Beginning of Year	$271,177	$265,648	$252,926
Net income	61,333	62,621	73,288
Redemption and retirement of stock	-	(425)	(2,847)
Tax benefits of ESOP dividends	-	-	3,206
Total	332,510	327,844	326,573
Dividends Declared			
Preferred stock	3,200	3,342	3,807
Common stock	56,664	53,325	57,118
Total	59,864	56,667	60,925
Balance at End of Year	$272,646	$271,177	$265,648

The accompanying notes are an integral part of these statements.

Consolidated Statement of Cash Flows

For the year ended December 31	1994	1993	1992
		In thousands	
Operating Activities			
Net income	$ 61,333	$ 62,621	$ 73,288
Depreciation	50,236	43,508	39,071
Amortization of coal contract termination costs	3,920	18,460	14,553
Deferred income taxes	6,201	5,517	1,940
Deferred investment tax credits	(2,478)	(2,035)	(1,568)
Pre-tax gain on sale of plant assets	(19,147)	(812)	(360)
Extraordinary gain on early extinguishment of debt	-	-	(4,831)
Changes in operating assets and liabilities			
Notes and accounts receivable	(14,061)	(11,999)	(21,623)
Fuel, material and supplies	(5,641)	4,226	7,513
Accounts payable	1,112	(1,170)	1,628
Other current assets and liabilities	29,133	2,473	(12,421)
Other deferred credit - unbilled revenue	-	(5,070)	5,070
Other - net	5,857	7,024	(3,946)
Cash from operating activities	116,465	122,743	98,314
Investing Activities			
Proceeds from sale of investments in securities	59,339	242,950	275,284
Proceeds from sale of plant	37,361	6,584	2,745
Additions to investments	(97,620)	(266,276)	(243,296)
Additions to plant	(80,161)	(68,156)	(72,782)
Changes to other assets - net	(10,699)	(54,763)	(31,215)
Cash for investing activities	(91,780)	(139,661)	(69,264)
Financing Activities			
Issuance of common stock	1,033	57,605	892
Issuance of long-term debt	21,982	171,571	295,286
Issuance of preferred stock	-	-	20,000
Changes in notes payable	33,623	(33,496)	24,105
Reductions of long-term debt	(26,132)	(105,256)	(294,073)
Redemption of preferred stock	-	(2,000)	(25,248)
Dividends on preferred and common stock	(59,864)	(56,667)	(60,925)
Reacquired and retired common stock	-	-	(1,567)
Cash (for) from financing activities	(29,358)	31,757	(41,530)
Change in Cash and Cash Equivalents	(4,673)	14,839	(12,480)
Cash and Cash Equivalents at Beginning of Period	31,674	16,835	29,315
Cash and Cash Equivalents at End of Period	$ 27,001	$ 31,674	$ 16,835
Supplemental Cash Flow Information			
Cash paid during the period for			
Interest (net of capitalized)	$48,385	$41,840	$45,337
Income taxes	$20,584	$24,490	$21,344
Noncash Investing and Financing Activities (Note 2)			

The accompanying notes are an integral part of these statements.

1 Business Segments

Thousands	Consolidated	Electric Utility Operations: Electric	Electric Utility Operations: Coal	Water Utility Operations
For the Year Ended Dec. 31				
1994				
Revenue and income	$ 637,782	$426,183	$26,999	$ 91,224
Operation and other expense	457,977	313,560	20,438	47,754
Depreciation expense	50,236	35,094	1,352	8,936
Interest expense	52,070	19,057	1,035	12,214
Income from equity investments	5,300	-	-	-
Operating income (loss)	82,799	58,472	4,174	22,320
Income tax expense (benefit)	21,466	23,140	1,114	8,733
Net income (loss)	$ 61,333	$ 35,332	$ 3,060	$ 13,587
Capital expenditures	$ 80,953	$ 42,705	$ 1,957	$ 27,636
Total assets	$1,807,798	$933,784	$28,353	$326,015
Accumulated depreciation	$ 582,075	$471,285	$17,598	$ 88,404
Construction work in progress	$ 27,619	$ 21,736	-	$ 5,883
1993				
Revenue and income	$ 589,607	$433,117	$24,602	$ 65,463
Operation and other expense	415,839	318,813	18,609	42,550
Depreciation expense	44,595	32,774	1,095	9,792
Interest expense	43,534	18,860	1,024	9,997
Income from equity investments	3,929	-	-	-
Operating income (loss)	89,568	62,670	3,874	3,124
Income tax expense (benefit)	26,947	25,120	1,150	1,055
Net income (loss)	$ 62,621	$ 37,550	$ 2,724	$ 2,069
Capital expenditures	$ 120,696	$ 50,992	$ 6,670	$ 19,635
Total assets	$1,760,526	$910,039	$27,998	$329,578
Accumulated depreciation	$ 546,706	$443,285	$16,097	$ 86,609
Construction work in progress	$ 31,227	$ 18,019	-	$ 13,208
1992				
Revenue and income	$ 576,197	$426,042	$23,761	$ 53,595
Operation and other expense	398,139	308,024	18,426	40,002
Depreciation expense	39,485	30,902	881	7,530
Interest expense	47,479	27,504	958	8,343
Income from equity investments	4,352	-	-	-
Operating income (loss)	95,446	59,612	3,496	(2,280)
Income tax expense (benefit)	26,989	18,849	1,007	(681)
Extraordinary item	4,831	-	-	-
Net income (loss)	$ 73,288	$ 40,763	$ 2,489	$ (1,599)
Capital expenditures	$ 109,432	$ 43,559	$ 1,562	$ 32,224
Total assets	$1,625,504	$865,787	$22,806	$321,659
Accumulated depreciation	$ 509,542	$419,751	$14,803	$ 74,971
Construction work in progress	$ 28,552	$ 19,524	-	$ 9,028

Thousands For the Year Ended Dec. 31	Investments and Corporate Services: Portfolio, Reinsurance & Other	Investments and Corporate Services: Real Estate	Investments and Corporate Services: Paper & Pulp
1994			
Revenue and income	$ 8,462	$31,653	$ 53,261
Operation and other expense	9,583	20,510	46,132
Depreciation expense	78	276	4,500
Interest expense	16,226	12	3,526

Income from equity investments	2,973	-	2,327
Operating income (loss)	(14,452)	10,855	1,430
Income tax expense (benefit)	(12,597)	691	385
Net income (loss)	$ (1,855)	$10,164	$ 1,045
Capital expenditures	$ 4,889	$569	$ 3,197
Total assets	$308,612	$35,900	$175,134
Accumulated depreciation	$ 74	-	$ 4,714
Construction work in progress	-	-	-
1993			
Revenue and income	$ 29,570	$31,029	$ 5,826
Operation and other expense	6,946	22,523	6,398
Depreciation expense	6	230	698
Interest expense	12,839	15	799
Income from equity investments	5,795	-	(1,866)
Operating income (loss)	15,574	8,261	(3,935)
Income tax expense (benefit)	(371)	1,861	(1,868)
Net income (loss)	$ 15,945	$ 6,400	$ (2,067)
Capital expenditures	-	-	$ 43,399
Total assets	$301,548	$31,801	$159,562
Accumulated depreciation	-	-	$ 715
Construction work in progress	-	-	-
1992			
Revenue and income	$ 44,137	$28,662	
Operation and other expense	9,233	21,387	$ 1,067
Depreciation expense	1	163	8
Interest expense	8,694	1,744	236
Income from equity investments	2,682	-	1,670
Operating income (loss)	28,891	5,368	359
Income tax expense (benefit)	7,606	-	208
Extraordinary item	-	4,831	-
Net income (loss)	$ 21,285	$10,199	$ 151
Capital expenditures	-	-	$ 32,087
Total assets	$290,667	$31,633	$ 92,952
Accumulated depreciation	-	-	$ 17
Construction work in progress	-	-	-

Includes a $19.1 million pre-tax gain from the sale of certain water plant assets.

Includes a $10.1 million pre-tax loss from the write-off of an investment.

Includes a $5.2 million pre-tax loss from the equipment manufacturing business.

Includes $3.6 million of net income related to escrow funds.

Pulp mill operations began in November 1993.

The extraordinary gain is a result of an early extinguishment of debt.

2 Summary of Significant Accounting Policies

System of Accounts. The accounting records of Minnesota Power are maintained in accordance with generally accepted accounting principles.

Principles of Consolidation. The consolidated financial statements include the accounts of the Company and all of its majority owned subsidiary companies. All material intercompany balances and transactions between subsidiaries have been eliminated in consolidation. The prior years consolidated financial statements have been reclassified to present comparable information for all years.

Plant and Depreciation. Plant is recorded at original cost. The cost of additions to plant and replacement of retirement units of property are capitalized. Maintenance costs and replacements of minor items of property are charged to expense as incurred. Costs of depreciable units of plant retired are eliminated from the plant accounts. Such costs plus removal expenses less salvage are charged to accumulated depreciation. Plant stated on the balance sheet includes construction work in progress and is net of accumulated depreciation. (See note 1.)

Various pollution abatement facilities are leased from municipalities which have issued pollution control revenue bonds to finance the cost of the facilities. The cost of the facilities and the related debt obligation, which is guaranteed by the Company, has been recorded as electric plant and long-term debt, respectively.

Depreciation of utility plant is computed using rates based on estimated useful lives of the various classes of property. Provisions for book depreciation of the average original cost of depreciable property approximated 3% in 1994, 2.9% in 1993 and 2.7% in 1992. In 1995 the Company will begin recovering through rates approved by the MPUC in November 1994 approximately $1.3 million each year to pay for decommissioning of coal-fired power plants.

Contributions in aid of construction (CIAC), recorded at estimated original cost, relate to water and wastewater plant contributed to the Company by developers and customers. CIAC is amortized on the straight-line method over the estimated life of the asset to which it relates when placed in service. Amortization of CIAC reduces depreciation expense.

The Company's water plant includes plant held for future use which consists primarily of distribution and collection systems that will be placed in service as additional customers are connected to the systems. These systems are not depreciated until placed in service. The Company had $34.9 and $35.2 million of plant held for future use at Dec. 31, 1994 and 1993. CIAC funded approximately $21 million of plant held for future use in 1994 and 1993.

Fuel, Material and Supplies. Fuel, materials and supplies are stated at the lower of cost or market. Cost is determined by the average cost method.

Deferred Regulatory Charges and Credits. The Company is subject to the provisions of SFAS 71, "Accounting for the Effects of Certain Types of Regulation." The Company capitalizes as deferred regulatory charges incurred costs which are expected to be recovered in future utility rates. Deferred regulatory credits represent amounts expected to be credited to customers in rates. (See note 3.)

Revenue and Income Recognition.

Electric Utility Operations. The Company files for periodic rate revisions with the Minnesota Public Utilities Commission (MPUC), the Federal Energy Regulatory Commission (FERC), and the Public Service Commission of Wisconsin. The MPUC had regulatory authority over approximately 77% in 1994, 76% in 1993 and 79% in 1992 of the Company's total electric utility operations revenue. Interim rates in Minnesota are placed into effect, subject to refund with interest, pending a final decision by the MPUC.

Customer meters are read and bills are rendered on a cycle basis. Revenue is accrued for service provided but not yet billed. The service rates of the Company to all classes of customers include fuel adjustment clauses under which fuel and purchased energy costs above or below the base levels in rate schedules are billed or credited to customers. In addition, billings to retail electric customers reflect an annual billing adjustment mechanism applied monthly for recovery of CIP expenditures.

During 1994, 1993 and 1992, revenue derived from one major customer was $60.2, $59.6 and $57.8 million, respectively. Revenue derived from another major customer was $45.3, $45 and $47 million, respectively.

Water Utility Operations. The Company provides water service to communities in Florida, North Carolina, South Carolina and Wisconsin. Water rates are under the jurisdiction of various state and county regulatory authorities. Billings are rendered on a cycle basis. Revenue is accrued for water sold but not billed.

Investments and Corporate Services. Investments and corporate services includes revenue from the sale of pulp and real estate, and income from securities investments. Pulp and real estate revenue is recognized on the accrual basis. Securities investments are accounted for in accordance with SFAS 115, adopted on Dec. 31, 1993. (See note 4.)

Income Taxes. Investment tax credits for utility property are amortized over the service life of the related property. Deferred taxes are provided on temporary differences between the book and tax basis of assets and liabilities which will have a future impact on taxable income.

Unamortized Expense, Discount and Premium on Debt. Expense, discount and premium on debt are deferred and amortized over the lives of the related issues.

Statement of Cash Flows. The Company considers all investments purchased with maturities of three months or less to be cash equivalents.

Noncash financing activities in 1994, 1993 and 1992 included $3.6, $3.7 and $2.7 million, respectively, relating to debt service on the ESOP promissory note and the ESOP debt guaranteed by the Company. (See note 15.) Other noncash financing activities in 1993 included the issuance of 140,648 shares of common stock, with a market value at the time of issuance of approximately $4.9 million, in exchange for an additional 13.4% ownership interest in Lehigh.

3 Regulatory Matters

Electric Utility Rate Proceedings. In January 1994 the Company filed with the MPUC a request for a final annual rate increase from all retail electric customers of $34 million, or 11.8%, and a 12.5% return on equity. In August 1994 the Company reduced its requested annual increase of $34 million to $27 million for 1994 and $23 million for 1995 because of reductions in the projected cost of service and the addition of long-term contract commitments by a taconite customer. On Feb. 17, 1994, the MPUC voted to approve the Company's requested annual interim rate increase of $20 million, or 7%. This interim rate increase began on March 1, 1994, subject to refund with interest, and will continue until final rates are effective.

In November 1994, the MPUC granted the Company an increase in annual electric operating revenue of $19 million and an 11.6% return on equity. Rates for large industrial customers will increase less than 4%, while the rate for small businesses will increase 6.5%. The rate increase for residential customers will be phased in over three years: 13.5% beginning in 1995, 3.75% in January 1996 and another 3.75% in January 1997. In 1994 the Company collected $17.2 million of interim revenue subject to refund with interest. The Company has reserved $6.1 million of the interim revenue for anticipated refunds. Final rates are expected to be effective in the second quarter of 1995.

In January 1994 the Company began recovering ongoing 1994 CIP expenditures and $8.2 million of deferred CIP expenditures incurred prior to Dec. 31, 1993, through an annual billing adjustment mechanism approved by the MPUC. Through the adjustment the Company is allowed to recover current and deferred CIP expenditures and a lost margin associated with power saved as a result of these programs. The adjustment is revised annually to reflect CIP expenditures that differ from the base level included in the rate schedules. The Company collected $7.8 million of CIP related revenue in 1994.

Water Utility Rate Proceedings. In 1993 the FPSC and certain Florida counties approved final annual rate increases totaling $16 million of $21.2 million requested by SSU. The FPSC ordered uniform rates for 90 water and 37 wastewater systems in SSU's 1992 consolidated rate filing in Florida. Uniform rates are based on companywide costs rather than costs related to individual systems. In 1993 the FPSC initiated a separate investigation to determine if, as a matter of policy, uniform rates are appropriate for Florida water utilities. In August 1994 the FPSC reaffirmed the appropriateness of the uniform rate structure.

Under Florida law, water and wastewater utilities may make an annual index filing designed to recover inflationary costs associated with operation and maintenance expenses. The law's intent is to provide inflationary relief to utilities, thus delaying or avoiding the costs associated with full rate case filings. Under another Florida law, water and wastewater utilities may make an annual pass-through filing to recover increased purchased water and wastewater treatment costs and property tax increases. The FPSC approved annual rate increases totaling $2.9 million of the $3 million requested in SSU's 1993 and 1994 index filings and 1994 pass-through filings.

Peabody Contract Buyout. In 1991 Minnesota Power and Peabody Coal Company (Peabody) executed an agreement to terminate the 1968 Coal Supply Contract between the parties (the Coal Contract) two years ahead of the scheduled termination date.

In accordance with orders issued by the MPUC and the FERC, the Company used the retail and resale fuel adjustment clauses to pass through to electric customers the $35 million charge (plus a return on the funds used to make the payment) paid by the Company in December 1991 to terminate the Coal Contract. The early termination allowed the Company to purchase lower-priced coal on the open market and eliminated all of the Company's future responsibility relating to the Coal Contract. The impact of this ratemaking treatment on the consolidated income statement was the recognition of $3.9, $18.5, and $14.5 million in 1994, 1993, and 1992 of the Coal Contract termination costs as fuel expense and the recovery of these costs in revenue through the fuel adjustment clauses.

Deferred Regulatory Charges and Credits. Based on current rate treatment, the Company believes it will continue to recover from ratepayers all deferred regulatory charges.

Summary of Deferred Regulatory Charges and Credits	Dec. 31, 1994	Dec. 31, 1993
	In thousands	
Deferred Charges		
SFAS 109 - Income taxes	$22,977	$23,596
SFAS 106 - Postretirement benefits	12,834	6,549
CIP	10,471	8,172
Premium on reacquired debt	9,119	9,892
Other	19,518	11,708
	74,919	59,917
Deferred Credits		

SFAS 109 - Income taxes	55,996	60,520
Net deferred regulatory charges and credits	$18,923	$ (603)

4 Financial Instruments

Securities Investments. The majority of the Company's securities investments are investment-grade stocks of other utility companies and are considered by the Company to be conservative investments.

The Company classifies its investments in equity and debt securities in three categories: Trading securities are those bought and held principally for near-term sale. They are recorded on the balance sheet at fair value as part of current assets, with changes in fair value during the period included in earnings. Held-to-maturity securities are those the Company has the ability and intent to hold to maturity. They are recorded at amortized cost in investments and corporate services on the balance sheet. Available-for-sale securities are those that do not fit either of the previous two categories. They are recorded at fair value in investments and corporate services on the balance sheet. Changes in fair value during the period are recorded net of tax as a separate component of common stock equity. If the fair value of any available-for-sale or held-to-maturity securities declines below cost and the decline is considered other than temporary, the securities are written down to fair value and the losses charged to earnings. Realized gains and losses are computed on each specific investment sold.

Summary of Securities	Cost	Gross Unrealized Gain	Gross Unrealized (Loss)	Fair Value
		In thousands		
Dec. 31, 1994				
Trading				$ 74,046
Available-for-sale				
Common stock	$ 10,636	$ 86	$(1,748)	$ 8,974
Preferred stock	117,860	2,747	(3,893)	116,714
	$128,496	$2,833	$(5,641)	125,688
Held-to-maturity				
Leveraged preferred stock	$ 2,013			2,013
Total securities investments				$127,701
Dec. 31, 1993				
Trading				$ 98,244
Available-for-sale				
Common stock	$ 11,267	$ 306	$ (463)	$ 11,110
Preferred stock	91,191	3,101	(407)	93,885
	$102,458	$3,407	$ (870)	104,995
Held-to-maturity				
Leveraged preferred stock	$ 7,179			7,179
Total securities investments				$112,174

The net unrealized gain (loss) on securities investments on the balance sheet at Dec. 31, 1994, includes $3.8 million from the Company's share of Capital Re's unrealized holding losses.

	Year Ended Dec. 31, 1994
	In thousands
Trading securities	
Change in net unrealized holding gains included in earnings	$ 253
Available-for-sale securities	
Proceeds from sales	$53,559
Gross realized gains	$ 1,194
Gross realized (losses)	$(2,902)

Off-Balance-Sheet Risks. In portfolio strategies designed to reduce market risks, the Company sells common stock securities short and enters into short sales of treasury futures contracts.

Selling common stock securities short is intended to reduce market price risks associated with holding common stock securities in the Company's trading securities portfolio. Transactions involving short sales of common stock are completed on average within 90 days from when the transactions were entered into. Realized and unrealized gains and losses from short sales of common stock securities are included in investment income.

Treasury futures are used as a cross hedge to reduce interest rate risks associated with holding fixed dividend preferred stocks included in the Company's available-for-sale portfolio. Changes in market values of treasury futures are recognized as an adjustment to the carrying amount of the underlying hedged item. Gains and losses on treasury futures are deferred and recognized in investment income concurrently with gains and losses arising from the underlying hedged item. Generally, treasury futures contracts entered into have a maturity date of 90 days.

In 1994 SSU entered into a three year interest rate swap agreement to lower its overall cost of borrowing. SSU agreed with a counterparty to exchange, at specified intervals, the difference between fixed-rate and floating-rate interest amounts calculated by reference to a notional principal amount. The differential paid or received is accrued and recognized as adjustments to interest expense. The interest rate swap is subject to market risk as interest rates fluctuate.

The notional amounts summarized below do not represent amounts exchanged and are not a measure of the Company's financial exposure. The amounts exchanged are calculated on the basis of these notional amounts and other terms which relate to the change in interest rates and securities prices. The Company continually evaluates the credit standing of counterparties and market conditions with respect to its off-balance-sheet financial instruments. The Company does not expect any counterparties to fail to meet their obligations or any material adverse impact to its financial position from these financial instruments.

Summary of Off-Balance-Sheet Financial Instruments	Dec. 31, 1994	1993
	In thousands	
Short stock sales outstanding	$61,523	$79,081
Treasury futures	$31,700	$12,600
Interest rate swap	$20,000	-

Fair Value of Financial Instruments. The carrying amount of cash and cash equivalents, trading securities, notes and other accounts receivable, and notes payable approximates fair value because of the short maturity of those instruments. The Company records its trading and available-for-sale securities at fair value based on quoted market prices. The fair values for all other financial instruments were based on quoted market prices for the same or similar issues.

Summary of Fair Values	Dec. 31, 1994		Dec. 31, 1993	
	In thousands			
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$(601,317)	$(559,859)	$(611,144)	$(620,166)
Redeemable serial preferred stock	$ (20,000)	$ (19,550)	$ (20,000)	$ (21,450)
Short stock sales outstanding (trading)	-	$ 59,691	-	$ 79,448
Treasury futures	-	$ 31,433	-	$ 14,420
Interest rate swap	-	$ (589)	-	-

Concentration of Credit Risk. Financial instruments that subject the Company to concentrations of credit risk consist primarily of trade and other receivables. The Company sells electricity to about 17 customers in northern Minnesota's taconite and paper industries. At Dec. 31, 1994 and 1993, receivables from these customers totaled $8.5 and $7.6 million. The Company sells recycled pulp to about 20 paper manufacturers that are geographically dispersed. At Dec. 31, 1994 and 1993, receivables from these customers totaled $13.5 and $3.6 million. The Company does not obtain collateral to support receivables, but monitors the credit standing of major customers. The Company has not incurred and does not expect to incur significant credit losses.

5 Investment in Unconsolidated Affiliates

Capital Re Corporation. The Company has an equity ownership investment in Capital Re, a company engaged in financial guaranty reinsurance. In 1994 the Company purchased an additional 417,100 shares of Capital Re common stock for $8.8 million, which increased its ownership interest to 21.4%. The Company accounts for this investment under the equity method.

Summary of Capital Re Financial Information	Year Ended Dec. 31, 1994	1993	1992
	In thousands		
Investment portfolio	$650,200	$523,000	$443,700
Other assets	181,800	167,900	94,100
Liabilities	154,900	125,300	111,200
Deferred revenue	272,000	254,100	147,100
Net revenue	100,300	75,200	58,400
Net income	39,800	34,900	30,200
Company's equity in earnings from Capital Re	$ 8,138	$ 6,559	$ 5,733
Company's equity investment in Capital Re	$ 72,054	$ 60,216	$ 54,214
Fair value of the Company's equity investment in Capital Re	$ 86,662	$ 70,778	$ 58,409

Lake Superior Paper Industries. The Company is an equal participant with Pentair Duluth Corp., a wholly owned subsidiary of Pentair, Inc., in LSPI, a joint venture supercalendered paper mill in Duluth, Minn.

LSPI is obligated for approximately $33.4 million of annual lease payments for a 25-year operating lease extending to 2012 for paper mill equipment. LSPI sold the paper mill equipment in a sale-leaseback transaction at a gain that is being amortized over the lease term.

The Company is required to contribute capital to LSPI of at least $16 million in the form of equity or debt. As of Dec. 31, 1994, the Company had contributed $14.5 million of that investment in the form of equity. At Dec. 31, 1994 and 1993, the Company had a $35.1 and a $30.8 million short-term interest bearing note receivable from LSPI. The Company is committed to a maximum guaranty of $95 million to ensure its portion of LSPI's lease obligation.

The Company also is the guarantor of project compliance with environmental standards. The obligations of the Company are several and not joint with Pentair Duluth Corp. and Pentair, Inc. The Company accounts for the investment in LSPI by the equity method.

Summary of LSPI Financial Information	Year Ended Dec. 31, 1994	1993	1992
	In thousands		
Current assets	$ 50,425	$ 49,120	$ 42,048
Noncurrent assets	158,756	148,011	140,400
Current liabilities	32,972	34,769	60,726
Deferred gain	30,776	32,486	34,195
Other liabilities	73,500	61,000	15,000
Net sales	152,227	143,041	150,252
Gross profit	15,370	4,506	10,908
Partnership earnings (loss)	3,056	(3,650)	3,364
Company's equity in earnings from LSPI	$ 1,528	$ (1,813)	$ 1,670
Company's equity investment in LSPI	$ 35,967	$ 34,440	$ 36,252

Undistributed earnings. The Company's accumulated equity in the undistributed earnings of all unconsolidated affiliates included in consolidated retained earnings amounted to $51.2, $43.6 and $38.8 million at Dec. 31, 1994, 1993 and 1992.

6 Common Stock and Retained Earnings Restrictions

The Articles of Incorporation, mortgage, and preferred stock purchase agreements contain provisions that, under certain circumstances, would restrict the payment of common stock dividends. As of Dec. 31, 1994, no retained earnings were restricted as a result of these provisions.

Summary of Common Stock	Shares	Equity
	In thousands	
Balance Dec. 31, 1991	29,475	$307,166
1992 ESPP	29	892
Reacquired and retired stock	(51)	(441)
Other	-	473
Balance Dec. 31, 1992	29,453	308,090
1993 Public offering	1,000	34,570
ESPP	25	925
DRIP	588	20,805
Earned ESOP adjustment	-	995
Other	141	5,296
Balance Dec. 31, 1993	31,207	370,681
1994 ESPP	40	1,033
Other	-	(536)
Balance Dec. 31, 1994	31,247	$371,178

In 1993 the Company changed the method of accounting for its ESOP. Under the new method, the difference between the market value of the shares committed to be released from collateral when earned and the cost of the shares to the ESOP is recorded in common stock equity. (See note 15.)

In September 1993 the Company issued one million shares of new common stock in a public offering for $34.6 million. The net proceeds were used to fund a portion of the Company's investment in SRFI and for other corporate purposes.

In June 1993 the Company issued 140,648 shares of new common stock with a market value at the time of issuance of approximately $4.9 million in exchange for an additional 13.4% ownership interest in Lehigh.

In January 1993 the Company amended its Automatic Dividend Reinvestment and Stock Purchase Plan (DRIP). The amendment gave the Company the option to issue new common stock shares or continue to purchase shares on the open market for the DRIP. At Dec. 31, 1994, the Company had 912,281 shares of common stock authorized to be issued pursuant to the DRIP.

7 Preferred Stock

Summary of Cumulative Preferred Stock	Dec. 31, 1994	1993
	In thousands	
Preferred stock, $100 par value, 116,000 shares authorized; 5% Series - 113,358 shares outstanding, callable at $102.50 per share	$11,492	$11,492
Serial preferred stock, without par value, 1,000,000 shares authorized; $7.36 Series - 170,000 shares outstanding, callable at $103.34 per share	17,055	17,055
Total cumulative preferred stock	$28,547	$28,547

Summary of Redeemable Serial Preferred Stock	Dec. 31, 1994	1993
	In thousands	
Serial preferred stock A, without par value, 2,500,000 shares authorized;		
$6.70 Series - 100,000 shares outstanding, noncallable, redeemable in 2000 at $100 per share	$10,000	$10,000
$7.125 Series - 100,000 shares outstanding,noncallable, redeemable in 2000 at $100 per share	10,000	10,000

Total redeemable serial preferred stock	$20,000	$20,000

8 Long-Term Debt

Schedule of Long-Term Debt	Dec. 31, 1994	1993
	In thousands	
Minnesota Power		
First mortgage bonds		
7 3/8% Series due 1997	$ 60,000	$ 60,000
6 1/2% Series due 1998	18,000	18,000
6 1/4% Series due 2003	25,000	25,000
7 1/2% Series due 2007	35,000	35,000
7 3/4% Series due 2007	55,000	55,000
7% Series due 2008	50,000	50,000
6% Pollution control Series E due 2022	111,000	111,000
Pollution control revenue bonds due 1995-2010	35,405	36,125
Leveraged ESOP loan due 1995-2004	13,786	14,549
Other long-term debt	17,054	16,903
Subsidiary companies		
First mortgage bonds, 8.73% due 2013	45,000	45,000
Notes payable, 7.65% due 2003	41,864	45,000
Notes payable, 10.44% due 1999	30,000	30,000
Utility mortgage bonds, 15 1/2%	-	15,000
Other long-term debt	77,022	61,861
Less due within one year	(12,814)	(7,294)
Total long-term debt	$601,317	$611,144

Aggregate amounts of long-term debt maturing during each of the next five years are $12.8, $9.1, $72, $28.2 and $40.2 million in 1995, 1996, 1997, 1998 and 1999.

The sinking fund provision of the Company's Mortgage relating to the First Mortgage Bonds, 6 1/2% Series due 1998, requires the Company to deliver annually to the trustee cash and/or such bonds equal to $225,000, subject to certain adjustments. Property additions equal to 166.67% of principal amounts of bonds, otherwise required to be so redeemed, may be applied in lieu of cash or bonds. The Company has consistently pledged property additions to meet the sinking fund requirements.

Substantially all Company electric and water plant is subject to the lien of the mortgages securing various first mortgage bonds. The Company's 88% ownership of SRFI is subject to a lien securing certain nonrecourse long-term debt obligations.

In December 1994 SSU retired $15 million of 15 1/2% First Mortgage Bonds. A portion of the proceeds from the sale of certain water plant assets was used to fund the retirement.

9 Short-Term Borrowings and Compensating Balances

The Company had bank lines of credit, which make short-term financing available through short-term bank loans and provide support for commercial paper, aggregating approximately $72 million at Dec. 31, 1994 and 1993. At Dec. 31, 1994 and 1993, the Company had issued commercial paper with face values of $54 and $20 million, respectively, supported by bank lines of credit and liquidity provided by the Company's securities portfolio. Certain lines of credit require payment of a 1/8 of 1% commitment fee and others require maintenance of 5% compensating balances. Interest rates on commercial paper and borrowings under the lines of credit range from 5.5% to 9.5% at Dec. 31, 1994, and 3.5% to 7.5% at Dec. 31, 1993. The weighted average interest rate on short-term borrowings at Dec. 31, 1994 and 1993, was 5.7% and 3.5%. The total amount of compensating balances at Dec. 31, 1994 and 1993, was immaterial.

10 Square Butte

Purchased Power Contract

Under the terms of a 30-year contract with Square Butte that extends through 2007, the Company is purchasing 71% of the output from a mine-mouth, lignite-fired generating plant capable of generating up to 455 megawatts. This generating unit (Project) is located near Center, N.D. Reductions to about 49% of the output are provided for in the contract and, at the option of Square Butte, could begin after a five-year advance notice to the Company and continue for the remaining economic life of the Project. The Company has the option but not the obligation to continue to purchase 49% of the output after 2007.

The Project is leased to Square Butte through Dec. 31, 2007, by certain banks and their affiliates which have beneficial ownership in the Project. Square Butte has options to renew the lease after 2007 for essentially the entire remaining economic life of the Project.

The Company is obligated to pay Square Butte all Square Butte's leasing, operating and debt service costs (less any amounts collected from the sale of power or energy to others) that shall not have been paid by Square Butte when due. These costs include the price of lignite coal purchased by Square Butte under a cost-plus contract with BNI Coal. The Company's cost of power and energy purchased from Square Butte during 1994, 1993 and 1992 was $55.4, $56.5 and $54.1 million, respectively. The leasing costs of Square Butte included in the cost of power delivered to the Company totaled $19.3 million in 1994, $19.7 million in 1993 and $19.6 million in 1992, which included approximately $12, $12.5 and $12.9 million, respectively, of interest expense. The annual fixed lease obligations of the Company to Square Butte are $19.4 million from 1995 through 1999. At Dec. 31, 1994, Square Butte had total debt outstanding of $219 million. The Company's obligation is absolute and unconditional whether or not any power is actually delivered to the Company.

The Company's payments to Square Butte for power and energy are approved as purchased power expense for ratemaking purposes by both the MPUC and the FERC.

One principal reason the Company entered into the agreement with Square Butte was to obtain a power supply for large industrial customers. Present electric service contracts with these customers require payment of minimum monthly demand charges that cover most of the fixed costs associated with having capacity available to serve them. These contracts minimize the negative impact on earnings that could result from significant reductions in kilowatt-hour sales to industrial customers. The minimum contract term for the large industrial customers is 10 years, with a four-year cancellation notice required for termination of the contract at or beyond the end of the 10th year. Under terms of existing contracts, the Company would collect approximately $90.5, $78.1, $75.5, $61.5 and $32.3 million under current rate levels for firm power during the years 1995, 1996, 1997, 1998 and 1999, respectively, even if no power or energy were supplied to these customers after Dec. 31, 1994. However, following implementation of rate increases approved by the MPUC in November 1994, and the anticipated MPUC approval of pending contract amendments, this minimum contract revenue is expected to increase $16 to $28 million in each year. The minimum contract provisions are expressed in megawatts of demand, and if rates change, the amounts the Company would collect under the contracts will change in proportion to the change in the demand rate.

11 Jointly Owned Electric Facility

The Company owns 80% of Boswell Unit 4. While the Company operates the plant, certain decisions with respect to the operations of Boswell Unit 4 are subject to the oversight of a committee on which the Company and Wisconsin Public Power, Inc. SYSTEM (WPPI), the owner of the other 20% of Boswell Unit 4, have equal representation and voting rights. Each owner must provide its own financing and is obligated to pay its ownership share of operating costs. The Company's share of direct operating expenses of Boswell Unit 4 is included in the corresponding operating expense on the consolidated statement of income. The Company's 80% share of the original cost recorded in plant in service at Dec. 31, 1994 and 1993, was $306 million. The corresponding provisions for accumulated depreciation were $119 and $111 million.

12 Sale of Water Plant Assets

In December 1994 SSU sold all of the assets of its Venice Gardens water and wastewater utilities to Sarasota County in Florida, (the County) for $37.6 million. The sale increased 1994 net income by $11.8 million and contributed 42 cents to 1994 earnings per share. Water utility operations on the consolidated statement of income includes a pre-tax gain of $19.1 million from the sale. This sale was negotiated in anticipation of an eminent domain action by the County, which is purchasing private utilities in an effort to consolidate services.

13 Income Tax Expense

Schedule of Income Tax Expense (Benefit)	1994	1993	1992
		In thousands	
Current tax expense			
Federal	$14,656	$20,089	$20,593
State	3,087	3,376	6,024
	17,743	23,465	26,617
Deferred tax expense			
Federal	5,166	4,066	1,640
State	1,035	1,451	300
	6,201	5,517	1,940
Deferred tax credits	(2,478)	(2,035)	(1,568)
Total income tax expense	$21,466	$26,947	$26,989

Total income tax expense produced effective tax rates of 25.9%, 30.1% and 26.9% in 1994, 1993 and 1992, as compared to the federal statutory rate of 35% in 1994 and 1993, and 34% in 1992.

Reconciliation of Federal Statutory Rate to Effective Tax Rate	1994	1993	1992
		In thousands	
Tax computed at federal statutory rate	$28,979	$31,333	$34,139
Increases (decreases) in tax from			
State income taxes, net of federal income tax benefit	2,608	3,684	4,205
Basis difference in land	(2,433)	-	-
Income from unconsolidated subsidiaries	(985)	(2,885)	(5,277)
Income from escrow funds	(1,550)	-	-
Dividend received deduction	(2,867)	(3,295)	(4,888)
Tax credits	(2,478)	(2,097)	(1,568)
Other	192	207	378
Total income tax expense	$21,466	$26,947	$26,989

Adoption of SFAS 109. The Company adopted SFAS 109, "Accounting for Income Taxes" on a prospective basis in January 1993. The adoption of SFAS 109 changed the Company's method of accounting for income taxes from the deferred method (Accounting Principles Board Opinion No. 11) to an asset and liability approach. Prior to the adoption of SFAS 109, the Company had deferred the tax effects of timing differences between income for financial reporting purposes and taxable income. The asset and liability approach requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the carrying amounts (book value) and the tax basis of assets and liabilities.

Schedule of Deferred Tax Assets and Liabilities	Dec. 31, 1994	1993
	In thousands	
Deferred tax assets		
Contributions in aid of construction	$18,378	$15,808
Lehigh basis difference	26,878	31,475
Deferred compensation plans	7,856	7,104
Minimum tax credit carryover	11,094	8,008
Deferred gain	12,359	12,972
Depreciation	10,472	-
Investment tax credits	24,144	25,085
Other	22,289	9,865

Gross deferred tax assets	133,470	110,317
Deferred asset valuation allowance	(26,878)	(31,475)
Total deferred tax assets	106,592	78,842
Deferred tax liabilities		
Depreciation	198,174	174,613
AFDC	20,526	19,238
Capital lease	11,432	9,294
Investment tax credits	35,982	37,563
Other	32,919	25,570
Total deferred tax liabilities	299,033	266,278
Accumulated deferred income taxes	$192,441	$187,436

At Dec. 31, 1994, approximately $26.9 million of net deferred tax assets resulting from the original purchase of Lehigh are included on the Company's balance sheet. These assets are fully offset by the deferred asset valuation allowance because under the standards of SFAS 109 it is currently "more likely than not" that the value of these assets will not be realized. Management reviews the appropriateness of the valuation allowance quarterly. A reduction in the valuation allowance will result in recognition of income during the respective period.

A provision has not been made for taxes on $19.1 million of undistributed earnings which were earned prior to 1993 by Capital Re, an investment accounted for under the equity method. Those earnings have been and are expected to continue to be reinvested. The Company estimates that $7.9 million of tax would be payable on the pre-1993 undistributed earnings of Capital Re if the Company should sell its investment. The Company has recognized the income tax impact on undistributed earnings of Capital Re earned since Jan. 1, 1993.

14 Pension Plans and Benefits

Pension Plans. The Company's Minnesota, Wisconsin and Florida utility operations have noncontributory defined benefit pension plans covering eligible employees. Pension benefits for employees in Minnesota and Wisconsin are fully vested after five years and are based on years of service and the highest average monthly compensation earned during four consecutive years within the last 15 years of employment. Employees in Florida are fully vested after five years of credited service, with benefits based on years of service and average earnings. Company policy is to fund accrued pension costs, including amortization of past service costs over 5 to 30 years. Part of pension cost is capitalized as a cost of plant construction.

Schedule of Pension Costs	1994	1993	1992
		In thousands	
Service cost	$ 4,130	$ 3,436	$ 3,211
Interest cost	11,753	11,969	11,416
Actual return on assets	(15,103)	(30,590)	(19,630)
Net amortization	454	17,372	7,268
Net cost	$ 1,234	$ 2,187	$ 2,265

At Dec. 31, 1994, approximately 54% of pension plan assets were invested in equity securities, 28% in fixed income securities, 11% in other investments and 7% in Company common stock.

	Oct. 1,	
Pension Plans Funded Status	1994	1993
	In thousands	
Actuarial present value of benefit obligations		
Vested benefit obligation	$(126,250)	$(126,275)
Nonvested benefit obligation	(8,975)	(9,761)
Accumulated benefit obligation	(135,225)	(136,036)
Excess of projected benefit obligation over accumulated benefit obligation	(26,820)	(34,673)
Projected benefit obligation	(162,045)	(170,709)
Plan assets at fair value	195,942	200,862
Plan assets in excess of projected benefit obligation	33,897	30,153
Unrecognized net gain	(33,767)	(27,678)
Prior service cost not yet recognized in net periodic pension cost	6,647	3,091
Unrecognized net obligation at Oct. 1, 1985, being recognized over 20 years	2,104	2,310
Prepaid pension cost recognized on the consolidated balance sheet	$ 8,881	$ 7,876

The weighted average discount rate for 1994 and 1993 was 8.25% and 7%. Projected pension obligations assume pay increases averaging 6% for each of 1994 and 1993. The assumed long-term rate of return on assets was 8.75% for 1994 and 8.5% for 1993 and 1992.

BNI Coal and Heater have defined contribution pension plans covering eligible employees. The aggregate annual pension cost for these plans was about $600,000 in 1994 and $700,000 in 1993 and in 1992.

Postretirement Benefits. The Company provides certain health care and life insurance benefits for retired employees. SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," adopted Jan. 1, 1993, changed the Company's method of accounting for these costs requiring that they be recognized during employment. Prior to the adoption of SFAS 106, the Company recognized these costs as they were paid. Postretirement benefit costs recognized in 1992 under the Company's prior accounting method were $918,000.

As of Dec. 31, 1994, the Company has deferred $12.8 million of postretirement benefit costs in excess of those allowed in existing rates. Pursuant to a rate order issued by the MPUC in November 1994, the Company will recover in electric rates, the retail portion ($11.7 million) of these deferred costs over a five year period beginning in 1995.

Schedule of Postretirement Benefit Costs	1994	1993
	In thousands	
Service cost	$2,545	$2,609
Interest cost	4,389	4,875
Actual return on plan assets	(125)	(321)
Amortization of transition obligation	3,085	3,133
Net periodic cost	9,894	10,296
Net deferral	(6,285)	(6,549)
Net cost	$3,609	$3,747

Company policy is to fund the net periodic postretirement costs and the amortization of the costs deferred as the amounts are collected in rates. The Company will fund these benefits using Voluntary Employee Benefit Association (VEBA) trusts and an irrevocable grantor trust. The Company will make the maximum tax deductible contributions to the VEBAs. The remainder of the funds will be placed in the irrevocable grantor trust until the funds can be used to make tax deductible contributions to the VEBAs. The funds in the irrevocable grantor trust do not qualify as plan assets for purposes of SFAS 106.

Postretirement Benefit Plan Funded Status	Dec. 31, 1994	1993
	In thousands	
Accumulated postretirement benefit obligation		
Retirees	$(18,879)	$(18,631)
Fully eligible participants	(17,221)	(16,029)
Other active participants	(25,151)	(29,454)
	(61,251)	(64,114)
Plan assets	2,486	720
Accumulated postretirement benefit in excess of plan assets	(58,765)	(63,394)
Unrecognized transition obligation	45,040	51,948
Accrued postretirement benefit obligation	$(13,725)	$(11,446)

For measurement purposes, it was assumed per capita health care benefit costs would increase 13.3% in 1994 and that cost increases would thereafter decrease 1% each year until stabilizing at 5.3% in 2002. Accelerating the rate of assumed health care cost increases by 1% each year would raise the 1994 transition obligation by $8.1 million and service and interest costs by a total of $1.4 million. The weighted average discount rate used in estimating accumulated postretirement benefit obligations was 8.25% for 1994 and 7% for 1993. The expected long-term rate of return on plan assets was 8.75% for 1994 and 8.5% for 1993.

Postemployment Benefits. The Company provides certain postemployment benefits to employees and their dependents during the time period following employment but before retirement. On Jan. 1, 1994, the Company adopted SFAS 112, "Employers' Accounting for Postemployment Benefits," which recognizes the estimated future cost of providing postemployment benefits on an accrual basis over the active service life of employees. Adoption of SFAS 112 resulted in a $2.2 million transition obligation. As a result of a rate order issued by the MPUC in November 1994, the Company deferred $1.6 million of the transition obligation which is being recovered in electric rates over a three-year period beginning in 1994. Prior to the 1994 adoption of SFAS 112, the Company recognized postemployment benefit expenses as they were paid.

15 Employee Stock Plans

Employee Stock Ownership Plan. The Company has sponsored an ESOP since 1975, amending it in 1989 and 1990 to establish two leveraged accounts.

The 1989 leveraged ESOP account covers all non-union Minnesota and Wisconsin employees who work more than 1,000 hours per year and have one year of service. The ESOP used the proceeds from a $16.5 million, 15-year loan at 9.125%, guaranteed by the Company, to purchase 633,489 shares of Minnesota Power common stock on the open market in early 1990. These shares fund employee benefits totaling not less than 2% of the participants' salaries.

The 1990 leveraged ESOP account covers Minnesota and Wisconsin employees who participated in the non-leveraged ESOP plan prior to Aug. 4, 1989. The ESOP issued a $75 million promissory note at 10.25% with a term not to exceed 25 years to the Company (Employer Loan) as consideration for 2.8 million shares of newly issued Minnesota Power common stock in November 1990. These shares are used to fund a benefit at least equal to the value of the following: (a) dividends on shares held in participants' 1990 leveraged ESOP accounts which are used to make loan payments, and (b) the tax savings generated from deducting all dividends paid on shares currently in the ESOP which were held by the plan on Aug. 4, 1989.

The loans will be repaid with dividends received by the ESOP and with employer contributions. ESOP shares acquired with the loans were initially pledged as collateral for the loans. The ESOP shares are released from collateral and allocated to participants based on the portion of total debt service paid in the year.

The Company accounts for the ESOP in accordance with the American Institute of Certified Public Accountants' (AICPA) Statement of Position 93-6 (SOP 93-6).

The adoption in 1993 of SOP 93-6 decreased 1993 net income by $5.2 million and reduced the average number of shares outstanding for the 1993 EPS calculation by 3,114,067 shares. The net impact was a 6 cent increase in 1993 earnings per share.

Prior to 1993, the Company accounted for the ESOP in accordance with AICPA Statement of Position 76-3. ESOP loans, the note receivable and unallocated ESOP shares pledged as collateral for the loans were recorded in the financial statements the same as under SOP 93-6. All ESOP shares were treated as outstanding. The Company recognized interest income and interest expense on the Employer Loan to the ESOP in the financial statements. The Company calculated interest and compensation expense by first reducing interest expense and then compensation expense by the amount of dividends paid on leveraged shares charged to retained earnings. Compensation expense was computed using the cost basis to the ESOP of the shares. In 1992, the Company realized $3.2 million in tax benefits from the deduction of dividends paid on the unallocated shares used to make the debt service payments. These tax benefits were recorded directly to retained earnings and included in the EPS computation. Under SOP 93-6, these tax benefits are included in income tax expense.

Schedule of ESOP Compensation and Interest Expense	Year Ended Dec. 31, 1994	1993	1992
	In thousands		
Interest expense	$1,328	$1,361	$9,351
Dividends used to pay debt service	-	-	(8,201)
Net interest expense	1,328	1,361	1,150
Compensation expense	2,037	2,396	3,235
Total	$3,365	$3,757	$4,385

Schedule of ESOP Shares	Dec. 31, 1994	1993
	In thousands	

Allocated shares	1,635	1,664
Shares released for allocation	49	40
Unreleased shares	2,903	3,055
Total ESOP shares	4,587	4,759
Fair value of unreleased shares	$73,305	$100,039

Employee Stock Purchase Plan. The Company has an Employee Stock Purchase Plan (ESPP). At Dec. 31, 1994, 254,553 shares of common stock were held in reserve for future issuance under the ESPP. The ESPP permits each employee to buy up to $23,750 per year in Company common stock. Purchases are at 95% of the stock's closing market price on the first day of each month. At Dec. 31, 1994, 389,739 shares had been issued under the ESPP.

16 Quarterly Financial Data
(Unaudited)

Information for any one quarterly period is not necessarily indicative of the results which may be expected for the year. Previously reported quarterly information has been revised to reflect reclassifications to conform with the 1994 method of presentation. These reclassifications had no effect on previously reported consolidated net income.

The first quarter ended March 31, 1994, included a decrease in net income of $6 million from the write-off of an investment and an increase in net income of $3.6 million related to escrow funds. Net income for the fourth quarter ended Dec. 31, 1994, included an increase of $11.8 million from the sale of certain water plant assets and a decrease of $2.2 million from the Company's equipment manufacturing business.

The first quarter ended March 31, 1993, included $1.7 million in net income from the redemption of a preferred stock investment. The third quarter ended Sept. 30, 1993, included $2.2 million from the one-time adjustment relating to deferred revenue for electric service provided but not yet billed.

	Quarter Ended			
	March 31	June 30	Sept. 30	Dec. 31
	In thousands except earnings per share			
1994				
Operating revenue and income	$150,568	$152,304	$155,822	$179,088
Operating income	10,845	18,740	20,202	33,012
Net income	9,368	12,970	15,199	23,796
Earnings available for common stock	8,568	12,170	14,399	22,996
Earnings per share of common stock	0.30	0.44	0.51	0.81
1993				
Operating revenue and income	$151,913	$144,908	$140,878	$151,908
Operating income	27,183	19,179	24,569	18,637
Net income	17,749	13,116	17,347	14,409
Earnings available for common stock	16,898	12,270	16,501	13,610
Earnings per share of common stock	0.64	0.46	0.61	0.49

Abbreviations or Acronyms	Term
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center Units No. 1, 2, 3 and 4
BTUs	British thermal units
Capital Re	Capital Re Corporation
CIP	Conservation Improvement Programs
Company	Minnesota Power & Light Company and its Subsidiaries
DRIP	Automatic Dividend Reinvestment and Stock Purchase Plan
Energy Act	National Energy Policy Act of 1992
ESOP	Employee Stock Ownership Plan
ESPP	Employee Stock Purchase Plan
FERC	Federal Energy Regulatory Commission
FPSC	Florida Public Service Commission
Heater	Heater Utilities, Inc.
Lehigh	Lehigh Acquisition Corporation
LSPI	Lake Superior Paper Industries
Minnesota Power	Minnesota Power & Light Company and its Subsidiaries
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MW	Megawatt(s)
MWh	Megawatt-hour
National	National Steel Pellet Co.
Note ___	Note ___ to the consolidated financial statements in the Minnesota Power 1994 Annual Report
Peabody	Peabody Coal Company
Reach All	Reach All Partnership
SFAS	Statement of Financial Accounting Standards
Square Butte	Square Butte Electric Cooperative
SRFI	Superior Recycled Fiber Industries Joint Venture
SSU	Southern States Utilities, Inc.
SWL&P	Superior Water, Light and Power Company

These abbreviations or acronyms are used throughout this document.

DIRECTORS

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Merrill K. Cragun
President, Cragun Corp.
(resort and conference center), Brainerd
Director since 1991

Dennis E. Evans
President and Chief Executive Officer,
Hanrow Financial Group, Ltd.
(merchant banking), Minneapolis
Director since 1986

Sister Kathleen Hofer
President and Chief Executive Officer, St. Mary's Medical Center (hospital) and Chair and Chief Executive Officer of the Benedictine Health System (parent corporation for a number of nonprofit health care providers), Duluth
Director since 1994

Peter J. Johnson
President and Chief Executive Officer,
Hoover Construction Co. (highway and heavy construction contractor) and Chairman, Michigan Limestone Operations (producer of limestone for steel and construction industries), Tower, Minn.
Director since 1994

Mary E. Junck
Publisher and CEO of The Baltimore Sun
(daily and Sunday newspapers), Baltimore
Director since 1992

Robert S. Mars, Jr.
Chairman, W.P. & R.S. Mars Co.
(industrial equipment and supply)
and President, Conveyor Belt Service, Inc.
(conveyor belt maintenance and repair), Duluth
Director since 1970

Paula F. McQueen
President and Treasurer - Secretary
PGI Incorporated (real estate development), Partner of Webb, McQueen & Co. (accounting firm) and Chief Executive Officer of Allied Engineering & Testing Inc. (engineering and materials testing), Punta Gorda, Fla.
Director since 1993

Robert S. Nickoloff
Chairman, Medical Innovation Capital, Inc. and General Partner of Medical Innovation Fund (venture capital firms) and self-employed as an attorney, St. Paul
Director since 1986

Jack I. Rajala
President, Rajala Lumber Co. and Rajala Mill Co. (lumber manufacturing and trading), Grand Rapids
Director since 1985

Charles A. Russell
President and Chief Executive Officer,
Norwest Bank Minnesota North, N.A., Duluth
Director since 1985

Arend J. Sandbulte
Chairman, President and Chief Executive Officer, Minnesota Power, Duluth
Director since 1983, President since 1984, CEO since 1988 and Chairman since 1989

Donald C. Wegmiller
President and Chief Executive Officer ,
Management Compensation Group/HealthCare (national executive compensation and benefits consulting firm), Minneapolis
Director since 1992

Executive Committee
Sandbulte - Chairman; Hofer, Junck, McQueen and Russell

Audit Committee
Wegmiller - Chairman; Junck, McQueen, Russell and Hofer

Executive Compensation Committee

Nickoloff - Chairman; Evans, Russell and Wegmiller

Electric Utility Operations Committee
Sandbulte - Chairman; Cragun, Hofer, Johnson and Mars

Principal Corporate, Subsidiary and Joint Venture Officers
. . . .

Executive Management Team
Arend J. Sandbulte, 61
Chairman, President and Chief Executive Officer

Robert D. Edwards, 50
Executive Vice President and Chief Operating Officer

Jack R. McDonald, 57
Executive Vice President - Finance and Corporate Development

Donnie R. Crandell, 51
Senior Vice President - Corporate Development

David G. Gartzke, 51
Senior Vice President - Finance and Chief Financial Officer

Allen D. Harmon, 43
Group Vice President - Electric Utility Operations

Warren L. Candy, 45
Vice President - Boswell Energy Center

Roger P. Engle, 46
Vice President - Customer Operations

Eugene G. McGillis, 60
Vice President
President - Superior Water, Light and Power

Gerald B. Ostroski, 54
Vice President
President - Synertec

Charles M. Reichert, 57
Vice President
President - BNI Coal, Ltd.

Kevin G. Robb, 48
Vice President - Generation
President - Rainy River Energy Corp.

Stephen D. Sherner, 44
Vice President - Power Marketing and Delivery

Geraldine R. VanTassel, 53
Vice President - Corporate Resource Planning

John J. Carhart, Jr., 53
President and Chief Executive Officer - Reach All

William E. Grantmyre, 49
President - Heater Utilities

Philip R. Halverson, 46
General Counsel and Corporate Secretary

John C. Hosler, 48
Interim President - Lake Superior Paper Industries

William I. Livingston, 48
President - Lehigh Corporation

Mark A. Schober, 39
Corporate Controller

Scott W. Vierima, 43
Interim President - Southern States Utilities

James K. Vizanko, 41
Corporate Treasurer

Dennis L. Hollingsworth, 60

Assistant Vice President - Corporate Development

Steven W. Tyacke, 43
Assistant General Counsel

INVESTOR INFORMATION AND SERVICES
. . . .

For shareholder information and assistance, write to Shareholder Services at our corporate headquarters address or call:

Toll-free phone: 1-800-535-3056
Duluth area number: 723-3974
FAX: 218-720-2502

Dividend Reinvestment Plan

Shareholders and our electric utility customers may buy Company common stock by reinvesting their dividends or by making cash payments of from $10 per payment to $10,000 a quarter. No brokerage fee or commission is charged. To enroll in the Automatic Dividend Reinvestment and Stock Purchase Plan, contact Shareholder Services. We belong to the National Association of Investors Corporation and participate in NAIC's Low Cost Investment Plan.

Direct Dividend Deposit

At your request, we'll automatically deposit dividends in your checking or savings account. To sign up for this free service, request an authorization form from Shareholder Services. They'll also need a voided personal check (write "VOID" across its face) or a bank deposit slip showing the number of the account to receive your dividends.

Ending Duplicate Mailings

If you're getting duplicate mailings from us and would prefer not to, contact Shareholder Services.

Replacing Dividend Checks,
Stock Certificates

If you don't receive your dividend check within 10 days of the payment date, or if your check has been lost or destroyed, call Shareholder Services. Call us also if a stock certificate is lost, destroyed or stolen; we'll send you the necessary forms needed to replace it. Replacing certificates takes time and involves some expense.

Stock as a Gift

Minnesota Power stock makes a good gift for birthdays, graduation and other special occasions. Shareholder Services will provide, on request, a special gift letter to accompany a gift of Minnesota Power stock.

Change of Address

Please let Shareholder Services know if your address changes.

Form 10-K and Statistical Supplement

The Company's Form 10-K Annual Report to the Securities and Exchange Commission is available upon request. A Statistical Supplement to the 1994 Annual Report is also available. Contact Shareholder Services for them; there's no charge.

Analyst Inquiries

Security analysts seeking information about the Company may contact Timothy J. Thorp, Manager-Investor Relations. Phone 218-723-3953/FAX 218-723-3940.

Annual Meeting

Our Annual Meeting of Shareholders is held the second Tuesday in May. Shareholders are invited to attend the 1995 Annual Meeting, beginning at 2 p.m. May 9 at the Duluth Entertainment Convention Center, 350 Harbor Drive, Duluth.

Stock Exchange Listings

Minnesota Power common stock is listed on the New York Stock Exchange under the symbol MPL. The American Stock Exchange lists our 5% Preferred Stock (MPL pf 5) and Serial Preferred Stock, $7.36 Series (MPL pf 7.36). Daily price quotes on our common stock may be found in many newspapers under the New York Stock Exchange composite transactions listing.

Transfer Agents for Common and
Preferred Stocks

Minnesota Power, Duluth

Norwest Bank Minnesota, N.A.

Registrars for Common and Preferred Stocks

First Bank National Association
Norwest Bank Minnesota, N.A.

Common Stock Dividend Payment Dates

March 1, June 1, Sept. 1 and Dec. 1

Preferred Stock Payment Dates

Jan. 1, April 1, July 1 and Oct. 1

Annual Report

This annual report and the financial statements it contains are submitted for the general information of the shareholders of the Company and not in connection with the sale or offer for sale of, or solicitation of an offer to buy, any securities.

[LOGO OF MINNESOTA POWER]
Corporate Headquarters
30 W. Superior Street
Duluth, MN 55802

[PHOTO OF DAVE EVENS]

[PHOTO OF RICH SULLO]

[PHOTO OF JOAN ADLER]

[PHOTO OF ERIC NORBERG AND DAVE MCMILLAN]

Bulk Rate
U.S. Postage
PAID
Minnesota Power

[LOGO OF MINNESOTA POWER]
30 West Superior Street
Duluth, Minnesota 55802-2093

EXHIBIT 23(a)

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (No. 33-51989) of the Minnesota Power and Affiliated Companies Employee Stock Purchase Plan of our report dated January 24, 1995, appearing on page 24 of the Annual Report to Shareholders which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report on the Financial Statement Schedule which appears on page 31 of this Form 10-K.

We also consent to the incorporation by reference in the Registration Statement on Form S-8 (No. 33-32033) of the Minnesota Power and Affiliated Companies Supplemental Retirement Plan of our report dated January 24, 1995, appearing on page 24 of the Annual Report to Shareholders which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report on the Financial Statement Schedule which appears on page 31 of this Form 10-K.

We also consent to the incorporation by reference in the Prospectus constituting part of the Registration Statement on Form S-3 (No. 33-51941) of the Minnesota Power & Light Company Common Stock of our report dated January 24, 1995, appearing on page 24 of the Annual Report to Shareholders which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report on the Financial Statement Schedule which appears on page 31 of this Form 10-K.

We also consent to the incorporation by reference in the Prospectus constituting part of the Registration Statement on Form S-3 (No. 33-50143) of the Minnesota Power & Light Company Common Stock of our report dated January 24, 1995, appearing on page 24 of the Annual Report to Shareholders which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report on the Financial Statement Schedule which appears on page 31 of this Form 10-K.

We also consent to the incorporation by reference in the Prospectus constituting part of the Registration Statement on Form S-3 (No. 33-56134) of the Minnesota Power & Light Company Automatic Dividend Reinvestment and Stock Purchase Plan of our report dated January 24, 1995, appearing on page 24 of the Annual Report to Shareholders which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report on the Financial Statement Schedule which appears on page 31 of this Form 10-K.

We also consent to the incorporation by reference in the Prospectus constituting part of the Registration Statement on Form S-3 (No. 33-55240) of the Minnesota Power & Light Company First Mortgage Bonds of our report dated January 24, 1995, appearing on page 24 of the Annual Report to Shareholders which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report on the Financial Statement Schedule which appears on page 31 of this Form 10-K.

We also consent to the incorporation by reference in the Prospectus constituting part of the Registration Statement on Form S-3 (No. 33-45551) of the Minnesota Power & Light Company Serial Preferred Stock, Cumulative, Without Par Value of our report dated January 24, 1995, appearing on page 24 of the Annual Report to Shareholders which is incorporated in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report on the Financial Statement Schedule which appears on page 31 of this Form 10-K.

PRICE WATERHOUSE LLP
Minneapolis, Minnesota
March 24, 1995

EXHIBIT 23(b)

CONSENT OF GENERAL COUNSEL

The statements of law and legal conclusions under "Item 1. Business" in the Company's Annual Report on Form 10-K for the year ended December 31, 1994, have been reviewed by me and are set forth therein in reliance upon my opinion as an expert.

I hereby consent to the incorporation by reference of such statements of law and legal conclusions in Registration Statement Nos. 33-51941, 33-50143, 33-56134, 33-55240, and 33-45551 on Form S-3, and Registration Statement Nos. 33-51989 and 33-32033 on Form S-8.

Philip R. Halverson
Duluth, Minnesota
March 24, 1995