Check appropriate box:

☐ Original signed form

Conformed copy

Form Approved
OMB No. 1902-0021
(Expires 7/31/95)

FERC Form No. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR141.1. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
NORTHERN STATES POWER COMPANY (MINNESOTA)	Dec. 31, 19 93

Deloitte & Touche

400 One Financial Plaza
120 South Sixth Street
Minneapolis, Minnesota 55402-1844

Telephone: (612) 397-4000
Facsimile: (612) 397-4450

INDEPENDENT AUDITORS' REPORT

Northern States Power Company (Minnesota)
Minneapolis, Minnesota

We have audited the balance sheets of Northern States Power Company (Minnesota) (the Company) as of December 31, 1993 and 1992 and the related statements of income for the years then ended, and the related statement of retained earnings and cash flow for the year ended December 31, 1993, included on pages 110 through 123K of the accompanying Federal Energy Regulatory Commission Form 1. 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 in accordance with generally accepted auditing standards. Those standards 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As required by the Federal Energy Regulatory Commission (FERC), the Company accounts for its investment in majority owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues, and expenses of these subsidiaries, as required by generally accepted accounting principles. In addition, as required by the FERC, the Company has classified $168,715,000 of deferred income tax assets as deferred debits rather than as a current asset (as to the current portion) and as an offset to deferred income tax liabilities in deferred credits (as to the noncurrent portion) as required by generally accepted accounting principles. If generally accepted accounting principles were followed, net utility plant would be increased by $660,209,000, current assets by $117,018,000, other long-term assets would be decreased by $363,591,000, current liabilities would be increased by $288,941,000, and long-term debt and other long-term liabilities by $123,634,000 as of December 31, 1993. Furthermore, operating revenues would be increased by $196,603,000, operating expenses by $140,140,000, cash provided by operating activities by $84,370,000, cash used in investing activities by $182,473,000, cash used in financing activities would be decreased by $130,066,000, and other income and deductions would be decreased by $39,600,000 for the year ended December 31, 1993. Accounting for the investments in majority owned subsidiaries on the equity method and classifying certain deferred income tax assets as deferred debits, rather than in accordance with generally accepted accounting principles, have no effect on net income and no material effect on retained earnings.

In our opinion, except for the effects of not consolidating majority owned subsidiaries and of classifying certain deferred income tax assets as deferred debits, as discussed in the preceding paragraph, the financial statements referred to above present fairly, in all material respects, the financial position of Northern States Power Company (Minnesota) as of December 31, 1993 and 1992 and the results of its operations for the years ended December 31, 1993 and 1992 and its cash flows for the year ended December 31, 1993, in conformity with generally accepted accounting principles. Also, in our opinion, the information presented in the financial statements referred to above is presented fairly, in all material respects, in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

As discussed in Note 3 to the financial statements, the Company changed its method of accounting for postretirement health care costs in 1993 and revenue recognition in 1992.

Our audits were conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The additional information regarding utility operating income by utility departments on the statement of income is presented for purposes of additional analysis and is not a required part of the basic financial statements. This additional information is the responsibility of the Company's management. Such information has been subjected to the auditing procedures applied in our audits of the basic financial statements and, in our opinion, is fairly stated in all material respects when considered in relation to the basic financial statements taken as a whole.

Deloitte & Touche

February 7, 1994

INSTRUCTIONS FOR FILING THE FERC FORM NO. 1

GENERAL INFORMATION

I. Purpose

This form is a regulatory support requirement (18 CFR 141.1). It is designed to collect financial and operational information from major electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. This report is also secondarily considered to be a non-confidential public use form supporting a statistical publication (Financial Statistics of Selected Electric Utilities), published by the Energy Information Administration.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 CFR 101), must submit this form.

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) One million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered,
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit an original and six (6) copies of this form to:

Office of the Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, NE.
Room 3110
Washington, DC 20426

Retain one copy of this report for your files.

(b) Submit immediately upon publication, four (4) copies of the latest annual report to stockholders and any *annual* financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. (Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Page 4, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared.) Mail these reports to:

Chief Accountant
Federal Energy Regulatory Commission
825 N. Capitol St., NE.
Room 946
Washington, DC 20426

(c) For the CPA certification, submit with the original submission, or within 30 days after the filing date for this form, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984):

(i) Attesting to the conformity, in all material aspects, of the below listed (schedules and) pages with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the chief accountant's published accounting releases), and

(ii) Signed by independent certified public accountants or an independent licensed public accountant, certified or licensed by a regulatory authority of a State or other political subdivision of the U.S. (See 18 CFR 41.10-41.12 for specific qualifications.)

Schedules	Reference Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

When accompanying this form, insert the letter or report immediately following the cover sheet. When submitting after the filing date for this form, send the letter or report to the Chief Accountant at the address indicated at III (b).

III. What and Where to Submit (Continued)

(c) Continued

Use the following form for the letter or report unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

In connection with our regular examination of the financial statement of for the year ended on which we have reported separately under date of we have also reviewed schedules of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

State in the letter or report, which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies to meet their requirements free of charge from:

Legal Reference and Records Management Branch
Federal Energy Regulatory Commission
941 North Capitol Street, NE.
Room 3100 ED-12.1
Washington, DC 20426
(202) 208-2474

IV. When to Submit:

Submit this report form on or before April 30th of the year following the year covered by this report.

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for this collection of information is estimated to average 1,215 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, DC 20426 (Attention: Michael Miller, ED-12.3); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR 101) (U.S. of A.). Interpret all accounting words and phrases in accordance with the U.S. of A.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting year, and use for statement of income accounts the current year's amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous annual report. Enter the word "None" where it truly and completely states the fact.

GENERAL INSTRUCTIONS (Continued)

IV. For any page(s) that is not applicable to the respondent, either

(a) Enter the words "Not Applicable" on the particular page(s), or

(b) Omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2, 3, and 4.

V. Complete this report by means which result in a permanent record. Complete the original copy in permanent black ink or typewriter print, if practical. The copies, however, may be carbon copies or other similar means of reproduction provided the impressions are clear and readable.

VI. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" at the top of each page is applicable only to resubmissions (see VIII. below).

VII. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses. ( ).

VIII. When making revisions, resubmit only those pages that have been changed from the original submission. Submit the same number of copies as required for filing the form. Include with the resubmission the Identification and Attestation page, page 1. Mail dated resubmissions to:

Chief Accountant
Federal Energy Regulatory Commission
825 North Capitol Street, NE.
Room 946
Washington, DC 20426

IX. Provide a supplemental statement further explaining accounts or pages as necessary. Attach the supplemental statement (8½ by 11 inch size) to the page being supplemented. Provide the appropriate identification information, including the title(s) of the page and the page number supplemented.

X. Do not make references to reports of previous years or to other reports in lieu of required entries, except as specifically authorized.

XI. Wherever (schedule) pages refer to figures from a previous year, the figures reported must be based upon those shown by the annual report of the previous year, or an appropriate explanation given as to why the different figures were used.

XII. Respondents may submit computer printed schedules (reduced to 8½ by 11) instead of the preprinted schedules if they are in substantially the same format.

DEFINITIONS

I. Commission Authorization (Comm. Auth.)—The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent—The person, corporation, licensee, agency, authority, or other legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. 791a-825r)

"Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to wit:

...(3) 'corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities' as hereinafter defined;

(4) 'person' means an individual or a corporation;

(5) 'licensee' means any person, State, or municipality licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality' means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the laws thereof to carry on the business of developing, transmitting, utilizing, or distributing power;...."

(11) 'project' means a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or forebay reservoirs directly connected therewith, the primary line or lines transmitting power therefrom to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, lands, or interest in lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered—

(a) To make investigations and to collect and record data concerning the utilization of the water resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign. commerce, and concerning the location, capacity, development costs, and relation to markets of power sites,...to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every licensee and every public utility shall file with the Commission such annual and other periodic or special reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies."

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the form or forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed...."

GENERAL PENALTIES

"Sec. 315. (a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this Act or any rule or regulation of the Commission thereunder, to submit any information or document required by the Commission in the course of an investigation conducted under this Act,...shall forfeit to the United States an amount not exceeding $1,000 to be fixed by the Commission after notice and opportunity for hearing...."

FERC FORM NO 1:

ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

<table>
<tr><th colspan="3">IDENTIFICATION</th></tr>
<tr><td colspan="2">01 Exact Legal Name of Respondent
Northern States Power Company (Minnesota)</td><td>02 Year of Report
Dec. 31, 1993</td></tr>
<tr><td colspan="3">03 Previous Name and Date of Change (If name changed during year)</td></tr>
<tr><td colspan="3">04 Address of Principal Business Office at End of year (Street, City, State, Zip Code)
414 Nicollet Mall, Minneapolis, Minnesota 55401</td></tr>
<tr><td colspan="2">05 Name of Contact Person
Patricia J. Walstad</td><td>06 Title of Contact Person
Administrator-External Financial Reports</td></tr>
<tr><td colspan="3">07 Address of Contact Person (Street, City, State, Zip Code)
414 Nicollet Mall, Minneapolis, Minnesota 55401</td></tr>
<tr><td>08 Telephone of Contact Person, Including Area Code
(612) 330-6820</td><td>09 This Report is
(1) X An Original
(2) A Resubmission</td><td>10 Date of Report (Mo, Da, Yr)
04-29-94</td></tr>
<tr><th colspan="3">ATTESTATION</th></tr>
<tr><td colspan="3">The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.</td></tr>
<tr><td>01 Name
Mr. Roger D. Sandeen</td><td rowspan="2">03 Signature
Roger D. Sandeen</td><td rowspan="2">04 Date Signed (Mo, Da, Yr)
04-29-94</td></tr>
<tr><td>02 Title
Vice President, Controller & Chief Information Officer</td></tr>
<tr><td colspan="3">Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willingly to make to any Agency or Department of United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.</td></tr>
</table>

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1993

LIST OF SCHEDULES (Electric Utility)

Enter in column (d) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none," "not applicable," or "NA."

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1993

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits) (Continued)			
Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261	Ed. 12-88	
Taxes Accrued, Prepaid and Charged During Year	262-263	Ed. 12-90	
Accumulated Deferred Investment Tax Credits	266-267	Ed. 12-89	
Other Deferred Credits	269	Ed. 12-88	
Accumulated Deferred Income Taxes—Accelerated Amortization Property	272-273	Ed. 12-89	
Accumulated Deferred Income Taxes—Other Property	274-275	Ed. 12-89	
Accumulated Deferred Income Taxes—Other	278-277	Ed. 12-93	
Other Regulatory Liabilities	278	New 12-93	
INCOME ACCOUNT SUPPORTING SCHEDULES			
Electric Operating Revenues	300-301	Ed. 12-90	
Sales of Electricity by Rate Schedules	304	Ed. 12-90	
Sales for Resale	310-311	Ed. 12-88	
Electric Operation and Maintenance Expenses	320-323	Rev. 12-93	
Number of Electric Department Employees	323	Ed. 12-88	
Purchased Power	326-327	Rev. 12-90	
Transmission of Electricity for Others	328-330	Rev. 12-90	
Transmission of Electricity by Others	332	Rev. 12-90	
Miscellaneous General Expenses—Electric	335	Ed. 12-87	
Depreciation and Amortization of Electric Plant	336-338	Ed. 12-88	
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	340	Ed. 12-87	
COMMON SECTION			
Regulatory Commission Expenses	350-351	Ed. 12-90	
Research, Development and Demonstration Activities	352-353	Ed. 12-87	
Distribution of Salaries and Wages	354-355	Ed. 12-88	
Common Utility Plant and Expenses	356	Ed. 12-87	
ELECTRIC PLANT STATISTICAL DATA			
Electric Energy Account	401	Rev. 12-90	
Monthly Peaks and Output	401	Rev. 12-90	
Steam-Electric Generating Plant Statistics (Large Plants)	402-403	Ed. 12-89	
Hydroelectric Generating Plant Statistics (Large Plants)	406-407	Ed. 12-89	407 NA
Pumped Storage Generating Plant Statistics (Large Plants)	406-409	Ed. 12-88	NA
Generating Plant Statistics (Small Plants)	410-411	Ed. 12-87	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 19 93

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
ELECTRIC PLANT STATISTICAL DATA (Continued)			
Transmission Line Statistics	422-423	Ed. 12-87	
Transmission Lines Added During Year	424-425	Ed. 12-86	
Substations	426-427	Ed. 12-86	
Electric Distribution Meters and Line Transformers	429	Ed. 12-88	
Environmental Protection Facilities	430	Ed. 12-88	
Environmental Protection Expenses	431	Ed. 12-88	
Footnote Data	450	Ed. 12-87	
Stockholders' Reports Check appropriate box:			
☒ Four copies will be submitted.			
☐ No annual report to stockholders is prepared.			

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Roger D. Sandeen
Vice President, Controller and
Chief Information Officer
414 Nicollet Mall
Minneapolis, Minnesota 55401

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

The respondent was incorporated under the laws of the State of Minnesota in June 1909.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver of trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

4. State the classes of utility and other services furnished by respondent during the year in each State in which the respondent operated.

During the year 1993 the respondent furnished electric utility and gas utility service in the States of Minnesota and North Dakota; and electric utility service in the State of South Dakota.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) YES ...Enter the date when such independent accountant was initially engaged: ____________________

(2) X NO

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or combination of such organizations jointly held control over the respondent at end of year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.
2. If the above required information is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be listed provided the fiscal years for both the 10-K report and this report are compatible.

This page is Not Applicable

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interest.
4. If the above required information is available from the SEC 10K Report Form filing, a specific reference to the report form (i.e. year and company title) may be listed in column (a) provided the fiscal years for both the 10-K and this report are compatible.

DEFINITIONS

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without intermediary.
3. Indireet control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without consent of the other, as where the voting controlis equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
Northern States Power Company (Wisconsin)	Electric, gas utility and holding company	100.00	
Chippewa and Flambeau Improvement Company	Owning and operating water storage reservoirs	75.86	(1)
Clearwater Investments, Inc.	Affordable housing	100.00	(1)
NSP Lands	Real estate holdings	100.00	(1)
United Power and Land	Real estate holdings	100.00	
Cormorant Corporation	Holds rights to coal and lignite deposits	100.00	
First Midwest Auto Park, Inc.	Parking ramp	100.00	
Cenergy, Inc.	Natural gas marketing and energy services	100.00	
Viking Gas Transmission Company	Natural gas transmission	100.00	
Eloigne Company	Affordable housing	100.00	
NEO Corporation	Development of small scale waste to energy opportunities utilizing landfill gas	100.00	
NRG Energy, Inc.	Non-regulated energy products and services	100.00	
Golden Gate Energy I, Inc	Cogeneration	100.00	(2)
Golden Gate Energy II, Inc	Cogeneration	100.00	(2)
Graystone Corporation	Uranium Enrichment	100.00	(2)
Hanford Energy I, Inc	Cogeneration	100.00	(2)
NRG Construction Services	Construction services	100.00	(2)
NRG Energy Center, Inc.	District heating and cooling system	100.00	(2)
NRG Energy Jackson Valley I, Inc.	Waste-fuel/cogeneration	100.00	(2)
NRG Energy Jackson Valley II, Inc.	Waste-fuel/cogeneration	100.00	(2)
NRG International, Inc.	Investment in international energy projects	100.00	(2)
NRG Operating Services, Inc.	Energy project operating and maintenance services	100.00	(2)
NRG Resource Recovery	Operator of refuse-to-fuel conversion facility	0.00	(3)
NRG Thermal Corporation	Steam lines	0.00	(4)
Okeechobee Power I, Inc	Independent Power Producer	100.00	(2)
Okeechobee Power II, Inc	Independent Power Producer	100.00	(2)
Okeechobee Power III, Inc	Independent Power Producer	100.00	(2)
San Joaquin Valley Energy I, Inc.	Biomass waste-fuel/cogeneration	100.00	(2)
San Joaquin Valley Energy IV, Inc.	Biomass waste-fuel/cogeneration	100.00	(2)
Scoria Incorporated	Coal Drying Facility	100.00	(2)
Wolverine Energy I, Inc.	Cogeneration	100.00	(2)

Notes:

(1) Indirect control through the Wisconsin Company

(2) Indirect control through NRG Energy, Inc.

(3) Reorganized operations included within NRG Energy, Inc. as of December 7, 1992.

(4) Reorganized operations included within NRG Energy, Inc. as of May 19, 1993.

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policymaking functions.

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and date the change in incumbency was made.

3. Utilities which are required to file the same data with the Securities and Exchange Commission, may substitute a copy of item 4 of Regulation S-K (identified as this page). The substituted page(s) should be the same size as this page.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman of the Board & Chief Executive		
2	Officer	James J Howard	
3	President & Chief Operating Officer	Edward M Theisen	
4	VP & Chief Financial Officer	Edward J McIntyre	
5	VP - Minnesota Electric	Vincent E Beacom	
6	VP & General Counsel	Gary R Johnson	
7	President, NSP Generation	Leon R Eliason	
8	VP - Customer Operations	Loren L Taylor	
9	VP - Finance & Treasurer	Arland D Brusven	
10	VP - Public & Environmental Affairs	Joseph L Wolf (Note 1)	
11	VP - Human Resources	Cynthia L Lesher	
12	VP - Customer Services	Robert H Schulte	
13	VP - Controller & Chief Information Officer	Roger D Sandeen	
14	President, NSP Gas	Keith H Wietecki	
15	VP - Corporate Secretary & Financial Counsel	Hollies M Winston (Note 2)	
16	VP - Nuclear Generation	Douglas D Anthony	
17	VP - Corporate Strategy	Jackie A Currier	
18			
19			
20			
21			
22			
23			
24			
25			
26	Notes:		
27	1. This position was eliminated on May 10, 1993.		
28	2. Hollies M Winston resigned September 30, 1993 and Gary R Johnson assumed		
29	the duties of acting Corporate Secretary at that time.		
30			
31	As part of a reorganization, in early 1993, several officer titles and responsibilities have changed from 1992.		
32			
33			
34			
35			
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38			
39			
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41			
42			
43			
44			
45	(c) Salary for Year does not include accrued vacations and represents salary paid as officer.		

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of directors who are officers of the respondent.
2. Designate members of the Executive Committee by an asterisk and the Chairman of the Executive Committee by a double asterisk.

Name (and Title) of Director (a)	Principal Business Address (b)
H LYMAN BRETTING	P O BOX 113, 3401 E. 2ND STREET ASHLAND, WISCONSIN
DAVID A CHRISTENSEN	P O BOX 5107, 205 E. 6TH STREET SIOUX FALLS, SOUTH DAKOTA
W JOHN DRISCOLL	2090 FIRST NATIONAL BANK BUILDING ST PAUL, MINNESOTA
DALE L HAAKENSTAD	RETIRED
JAMES J HOWARD, CHAIRMAN AND CEO	414 NICOLLET MALL MINNEAPOLIS, MINNESOTA
ALLEN F JACOBSON	30 E. 7TH STREET ST PAUL, MINNESOTA
RICHARD M KOVACEVICH	SIXTH AND MARQUETTE MINNEAPOLIS, MINNESOTA
DOUGLAS W LEATHERDALE	385 WASHINGTON STREET ST PAUL, MINNESOTA
JOHN E PEARSON	80 S. 8TH STREET MINNEAPOLIS, MINNESOTA
G M PIESCHEL	P O BOX 126, 101 N MARSHALL SPRINGFIELD, MINNESOTA
DR. MARGARET R PRESKA	1983 PREMIER DRIVE MANKATO, MINNESOTA
A PATRICIA SAMPSON	11 DELL PLACE MINNEAPOLIS, MINNESOTA
EDWIN M THEISEN, PRESIDENT AND COO	414 NICOLLET MALL MINNEAPOLIS, MINNESOTA

SECURITY HOLDERS AND VOTING POWERS

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on the date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if since the previous compilation of a list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the title of officers and directors included in such list of 10 security holders.

2. If any security other than stock carries voting rights, explain in a supplemental statement the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.

3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.

4. Furnish particulars (details) concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give date of the latest closing of the stock book prior to end of year, and state the purpose of such closing:	2. State the total number of votes cast in the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy	3. Give the date and place of such meeting:
The stock book was not closed.	Total: 50,953,102 By Proxy: 50,953,102	April 28, 1993 1001 Marquette Avenue Minneapolis, MN

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): 12-31-93 Total Votes (b)	Common Stock (c)	Preferred Stock (d)(1)	Other (e)(2)
4	TOTAL votes of all voting securities	69,829,577	66,879,577	825,000	2,125,000
5	TOTAL number of security holders	88,773	86,404	1,048	1,321
6	TOTAL votes of security holders listed below	47,917,828	45,659,753	386,806	1,871,269
7	Cede & Co				
8	Box 20, Bowling Green Station				
9	New York, New York	36,686,154	34,516,069	333,954	1,836,131
10					
11	First Trust Co., Inc				
12	Trustee of NSP-ESOP				
13	W555 First National Bank Building				
14	St. Paul, MN	5,480,803	5,480,803		
15					
16	NSP Agent				
17	414 Nicollet Mall				
18	Minneapolis, MN	4,626,608	4,626,608		

4. See Note 6 on pages 123B and 123C concerning options outstanding.

SECURITY HOLDERS AND VOTING POWERS (Continued)

Line No.	Name (Title) and Address of Security Holder (a)	Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
19	Kray & Co.				
20	120 Lasalle Street				
21	Chicago, IL	788,126	751,212	22,086	14,828
22					
23	Philadep & Co				
24	1900 Market Street				
25	Philadelphia, PA	186,337	162,761	5,766	17,810
26					
27	West Publishing				
28	P O Box 64526				
29	St Paul, MN	38,000	38,000		
30					
31	Margaret L Wendt Foundation				
32	1325 Liberty Bank Building				
33	Buffalo, NY	35,000	35,000		
34					
35	Personal Service Insurance				
36	P O Box 1226				
37	Columbus, OH	32,300	29,800		2,500
38					
39	NECO LTD INT				
40	P O Box 1087				
41	La Crosse, WI	25,000		25,000	
42					
43	Theodore M Koenigs				
44	W 136 N 7707 N Hills Dr				
45	Menomonee Falls, WI	19,500	19,500		
46					
47					
48					
49					
50					
51					
52					
53					

(1) Cumulative Preferred Stock $3.60 series.

(2) All other series of Cumulative Preferred Stock. Instruction 3. The holders of the 275,000 shares of Preferred Stock of the $3.60 series are entitled to three votes for each share held, and the holders of all other series are entitled to one vote for each share held, provided however, that when dividends payable on the Preferred Stock of any series outstanding are in default in an amount equivalent to four full quarter-yearly dividends thereon, and until such default shall have been remedied, the holders of shares of Preferred Stock, voting as a class, are entitled to elect the smallest number of directors necessary to constitute a majority of the Board of Directors and the holders of shares of Common Stock voting as a class, are entitled to elect the remaining directors.

In electing directors, shareholders may cumulate their votes in the manner provided in the Minnesota Business Corporation Act.

The affirmative vote or consent of the holders of various specified percentages of Preferred Stock is required to (A) increase the authorized amount or (B) prejudicially change the terms of the Preferred Stock, authorize stock (A) senior to or (B) on a parity with the Preferred Stock, issue additional Preferred Stock unless certain net income and capital ratio requirements are met, issue or assume unsecured indebtedness under specified conditions, or merge or consolidate under specified conditions.

IMPORTANT CHANGES DURING THE YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none""not applicable" or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therfore and state from whom the franchise rights were acquired. If acquired without the payment consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholda (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other conditions. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, developement, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by instructions 1 to 11 above, such notes may be attached to this page.

Item No. 1 – Respondent obtained franchises from representative local governmental bodies of the following incorporated communities without payment of consideration.

Community	Date of Expiration	Community	Date of Expiration
City of Northfield-Elec	10-18-2012	City of Jordan-Elec	03-14-2013
City of Northfield-Gas	10-18-2012	City of West Concord-Elec	05-04-2013
City of Gaylord-Elec	09-15-2012	City of Vadnais Heights-Elec	04-19-2013
City of Waterville-Elec	11-20-2012	City of Butterfield-Elec	05-02-2013
City of Clearwater-Gas	02-15-2013	City of Landfall-Elec	05-11-2013
City of Goodhue-Elec	02-10-2013	City of Landfall-Gas	05-11-2013
City of Buffalo-Gas	10-04-2012	City of Glyndon-Elec	05-11-2013
City of Oriska-Gas	11-01-2012	City of Clear Lake-Elec	06-06-2013
City of Tower City-Gas	11-02-2012	City of Clear Lake-Gas	04-04-2018
City of Cassleton-Gas	02-28-2013	City of Hugo-Elec	08-15-2013
City of Dennison-Elec	11-09-2012	City of Hugo-Gas	08-15-2013
City of Garvin-Elec	02-03-2013	City of Trosky-Elec	10-04-2013
City of Elysian-Elec	02-07-2013	City of Clear Lake-Elec	06-06-2013
City of Pine Island-Elec	04-19-2013	City of Foley-Elec	09-06-2013

IMPORTANT CHANGES DURING THE YEAR (Continued)

Item No. 2 – None

Item No. 3 – The Company purchased certain electric transmission facilities consisting of the 500kv Forbes Substation from Minnesota Power for $4 million. The purchase was completed in December 1993 by delivery of a bill of sale effective as of December 31, 1993. Commission approval was obtained by order dated October 19,1993, Docket No. EC93–019–000. Journal entries were submitted to the Commission on a filing made by Minnesota Power & Light and Northern States Power Company on July 14, 1993. Journal entries to transfer amounts from Account 102 were submitted to the Commission on December 20, 1993.

Item No. 4 – None

Item No. 5 – None

Item No. 6 – See pages 256–257 for detail of the amount of long–term debt obligations incurred and page 121 for the net increase (decrease) in short–term debt (including commercial paper) obligations during 1993. Also, see Notes 7 and 8 on page 123C for additional information on long–term and short–term debt. These securities issuances are within levels authorized by the Minnesota Public Utilities Commission in its Docket No. G, E002/S–92–1281.

Item No. 7 – None

Item No. 8 –

Classification	1993 Annual Average Salary Increase
1) Union	3.0% of base payroll
2) Nonunion non–exempt clerical and technical	3.3% of base payroll
3) Exempt	3.3% of base payroll

Item No. 9 – See Note 2 on page 123A for discussion of regulatory proceedings completed during 1993 and pending as of year–end. Also, see Note 15 on pages 123H, 123I, 123J, and 123K for a discussion of major contracts, agreements, commitments, legal proceedings, and environmental issues relevant to 1993. While the final impact on pending legal and environmental proceedings at year end is not known, the Company has recorded an accrual representing the best current cost estimate of these proceedings.

On July 14, 1993, the Company filed a lawsuit in US District Court for the District of Minnesota. The suit was filed in the interest of the Company's ratepayers against Westinghouse Electric Corp. (Westinghouse), the manufacturer of the Prairie Island steam generators, because of problems with the steam generators susceptiblity to corrosion. The Company seeks to recover the past and future costs of inspections, maintenance, modifications and repairs made to the the Prairie Island steam generators and related systems as a result of Westinghouse defects. The defects are "serious" in that they have caused the Company to incur significant expenditures in order to ensure that Prairie Island is a safe and economically efficient generating station. Safety has not been, nor will be compromised in any way as a result of the defects because the plant has been and continues to be well–maintained. The amount recoverable from Westinghouse under this proceeding, if any, is not determinable at this time.

Item No. 10 – None

Item No. 11 – None

Item No. 12 – Not Applicable

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance At Beginning Of Year (c)	Balanee At End Of Year (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	$5,605,106,697	$5,790,729,277
3	Construction Work in Progress (107)	200-201	147,438,774	188,244,939
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,752,545,471	5,978,974,216
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	2,292,818,841	2,500,492,895
6	Net Utility Plant (Enter Total of line 4 less 5)		3,459,726,630	3,478,481,321
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	711,517,075	749,077,634
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	630,548,575	673,668,821
9	Net Nuclear Fuel (Enter Total of line 7 less 8)		80,968,500	75,408,813
10	Net Utility Plant (Enter Total of lines 6 and 9)		3,540,695,130	3,553,890,134
11	Utility Plant Adjustments (116)	122		
12	Gas Stored Underground-Noncurrent (117)			
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)	221	68,419,396	31,628,343
15	(Less) Accum. Prov. for Depr. and Amort. (122)		16,679,019	7,639,099
16	Investments in Associated Companies (123)			
17	Investment in Subsidiary Companies (123.1)	224-225	340,728,160	459,815,200
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
19	Noncurrent Portion of Allowances	228-228		
20	Other Investments (124)		19,016,082	18,009,040
21	Special Funds (125-128)		68,801,690	101,379,842
22	TOTAL Other Property and Investments (Total of lines 14 thru 17, 19-21)		480,286,309	603,193,326
23	CURRENT AND ACCRUED ASSETS			
24	Cash (131)		7,059,338	18,203,188
25	Special Deposits (132-134)			
26	Working Funds (135)		300,527	283,720
27	Temporary Cash Investments (136)		3,843,339	2,797,324
28	Notes Receivable (141)		3,737,136	3,536,094
29	Customer Accounts Receivable (142)		160,017,489	186,670,897
30	Other Accounts Receivable (143)		42,054,092	37,845,168
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,399,820	3,274,939
32	Notes Receivable from Associated Companies (145)		24,300,000	23,966,967
33	Accounts Receivable from Assoc. Companies (146)		18,464,336	20,001,108
34	Fuel Stock (151)	227	31,541,763	17,331,390
35	Fuel Stock Expenses Undistributed (152)	227	(1,157,623)	(1,635,737)
36	Residuals (Elec) and Extracted Products (153)	227	3,075,370	2,969,676
37	Plant Materials and Operating Supplies (154)	227	98,675,318	96,144,662
38	Merchandise (155)	227		
39	Other Materials and Supplies (156)	227	116,392	309,484
40	Nuclear Materials Held for Sale (157)	202-203/227		
41	Allowances (158.1 and 158.2)	228-228		
42	(Less) Noncurrent Portion of Allowances			
43	Stores Expenses Undistributed (163)	227	760,183	421,539
44	Gas Stored Underground - Current (164.1)		10,687,150	12,028,387
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		4,357,539	5,106,008
46	Prepayments (165)		8,952,914	8,525,500
47	Advances for Gas (166-167)			
48	Interest and Dividends Receivable (171)			
49	Rents Receivable (172)		104,693	115,918
50	Accrued Utility Revenues (173)		84,182,223	94,065,423
51	Miscellaneous Current and Accrued Assets (174)		461,928	421,893
52	TOTAL Current and Accrued Assets (Total of lines 24 thru 51)		$498,134,287	$525,833,670

See accompanying notes to financial statements.

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance At Beginning Of Year (c)	Balance At End Of Year (d)
53	DEFERRED DEBITS			
54	Unamortized Debt Expenses (181)		$8,445,266	$8,129,987
55	Extraordinary Property Losses (182.1)	230		
56	Unrecovered Plant and Regulatory Study Costs (182.2)	230		
57	Other Regulatory Assets (182.3)	232	0	265,691,768
58	Prelim. Survey and Investigation Charges (Electric) (183)		(17,096)	(17,096)
59	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)			
60	Clearing Accounts (184)		2,397,020	1,520,117
61	Temporary Facilities (185)		148,907	15,320
62	Miscellaneous Deferred Debits (186)	233	219,519,719	4,201,540
63	Def. Losses from Disposition of Utility Plt. (187)			
64	Research, Devel. and Demonstration Expend. (188)	352-353		
65	Unamortized Loss on Reacquired Debt (189)		28,147,948	37,672,612
66	Accumulated Deferred Income Taxes (190)	234	143,565,652	168,715,436
67	Unrecovered Purchased Gas Costs (191)		8,362,160	5,234,817
68	TOTAL Deferred Debits (Enter Total of lines 54 thru 67)		410,569,576	491,164,501
69	TOTAL Assets and Other Debits (Enter Total of lines 10, 11, 12, 22, 52, and 68)		$4,929,685,302	$5,174,081,631

See accompanying notes to financial statements.

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance At Beginning Of Year (c)	Balance At End Of Year (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	$156,495,900	$167,198,943
3	Preferred Stock Issued (204)	250-251	275,000,000	240,000,000
4	Capital Stock Subscribed (202, 205)	252		
5	Stock Liability for Conversion (203, 206)	252		
6	Premium on Capital Stock (207)	252	370,383,786	547,381,939
7	Other Paid-In Capital (208-211)	253	(6,983)	(3,351,793)
8	Installments Received on Capital Stock (212)	252	935,865	209,540
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254	123	0
11	Retained Earnings (215, 215.1, 216)	118-119	919,566,866	932,915,826
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	179,737,609	193,393,071
13	(Less) Reacquired Capital Stock (217)	250-251	5,112,850	10,887,336
14	TOTAL Proprietary Capital (Enter Total of lines 2 thru 13)		1,897,000,070	2,066,860,190
15	LONG-TERM DEBT			
16	Bonds (221)	256-257	1,011,100,000	919,900,000
17	(Less) Reacquired Bonds (222)	256-257		
18	Advances from Associated Companies (223)	256-257		
19	Other Long-Term Debt (224)	256-257	167,935,591	270,785,494
20	Unamortized Premium on Long-Term Debt (225)		734,990	365,614
21	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,992,405	4,197,582
22	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)		1,175,778,176	1,186,853,526
23	OTHER NONCURRENT LIABILITIES			
24	Obligations Under Capital Leases - Noncurrent (227)		225,687	26,118
25	Accumulated Provision for Property Insurance (228.1)			
26	Accumulated Provision for Injuries and Damages (228.2)			
27	Accumulated Provision for Pensions and Benefits (228.3)			
28	Accumulated Miscellaneous Operating Provisions (228.4)		0	40,345,500
29	Accumulated Provision for Rate Refunds (229)			
30	TOTAL Other Noncurrent Liabilities (Enter Total of lines 24 thru 29)		225,687	40,371,618
31	CURRENT AND ACCRUED LIABILITIES			
32	Notes Payable (231)		146,561,000	106,200,000
33	Accounts Payable (232)		178,631,876	202,209,064
34	Notes Payable to Associated Companies (233)			
35	Accounts Payable to Associated Companies (234)		6,038,521	5,736,854
36	Customer Deposits (235)		1,325,198	1,782,117
37	Taxes Accrued (236)	262-263	152,824,210	170,072,664
38	Interest Accrued (237)		21,725,161	18,763,109
39	Dividends Declared (238)		43,219,842	46,195,050
40	Matured Long-Term Debt (239)			
41	Matured Interest (240)			
42	Tax Collections Payable (241)		7,601,824	9,675,185
43	Miscellaneous Current and Accrued Liabilities (242)		4,520,522	21,248,292
44	Obligations Under Capital Leases-Current (243)		470,602	199,568
45	TOTAL Current and Accrued Liabilities (Enter Total of lines 32 thru 44)		$562,918,756	$582,081,903

See accompanying notes to financial statements.

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance At Beginning Of Year (c)	Balance At End Of Year (d)
46	DEFERRED CREDITS			
47	Customer Advances for Construction (252)		$2,049,409	$1,699,089
48	Accumulated Deferred Investment Tax Credits (255)	266-267	173,706,850	161,221,559
49	Deferred Gains from Disposition of Utility Plant (256)			
50	Other Deferred Credits (253)	269	283,124,444	69,549,069
51	Other Regulatory Liabilities (254)	278	0	220,690,983
52	Unamortized Gain on Reacquired Debt (257)			
53	Accumulated Deferred Income Taxes (281-283)	272-277	834,881,910	844,753,694
54	TOTAL Deferred Credits (Enter Total of lines 47 thru 53)		1,293,762,613	1,297,914,394
55				
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
68	TOTAL Liabilities and Other Credits (Enter Total of lines 14, 22, 30, 45 and 54)		$4,929,685,302	$5,174,081,631

See accompanying notes to financial statements.

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (i,k,m,o) in a similar manner to a utility department. Spread the amount(s) over lines 02 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in accounts 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7,9 and 10 for Natural Gas Companies using accounts 404.1,404.2,404.3,407.1 and 407.2.
4. Use page 122 for important notes regarding the statement of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenue or costs to which the contingency relates and the tax effects with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	$2,207,389,413	$1,992,300,663
3	Operating Expenses			
4	Operation Expenses (401)	320-323	1,275,556,521	1,160,571,839
5	Maintenance Expenses (402)	320-323	135,956,382	158,764,072
6	Depreciation Expense (403)	336-338	232,121,656	206,704,733
7	Amort. & Depl. of Utility Plant (404-405)	336-338	2,921,671	2,440,426
8	Amort. of Utility Plant Acq. Adj. (406)	336-338		
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
11	Regulatory Debits (407.3)		220,362	237,889
12	(Less) Regulatory Credits (407.4)			
13	Taxes Other Than Income Taxes (408.1)	262-263	208,944,806	191,513,787
14	Income Taxes - Federal (409.1)	262-263	78,894,522	55,118,864
15	- Other (409.1)	262-263	22,480,714	14,937,092
16	Provision for Deferred Income Taxes (410.1)	234,272-277	107,962,704	53,810,843
17	(Less) Provision for Deferred Income Taxes-Cr.(411.1)	234,272-277	96,972,718	46,961,091
18	Investment Tax Credit Adj. - Net (411.4)	266	(8,120,581)	(8,420,780)
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)			
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		1,959,966,039	1,788,717,674
24	Net Utility Operating Income (Enter Total of line 2 less 23) (Carry forward to page 117 line 25)		$247,423,374	$203,582,989

See accompanying notes to financial statements.

STATEMENT OF INCOME FOR THE YEAR (Continued)

settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases and a summary of the adjustments made to balance sheet and income expense accounts.

7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be attached at page 122.

8. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.

9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on page 122 or in a supplemental statement.

ELECTRIC UTILITY		GAS UTILITY		ELEC PLANT LEASED TO OTHERS		
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	Line No.
						1
$1,859,115,428	$1,716,245,440	$347,621,102	$275,403,839	$652,883	$651,384	2
						3
1,003,222,959	945,380,222	272,333,562	215,191,617			4
127,428,617	150,197,603	8,527,765	8,566,469			5
217,074,160	192,923,685	15,047,496	13,781,048			6
2,726,630	2,279,580	195,041	160,846			7
						8
						9
						10
220,362	237,889					11
						12
188,321,631	173,187,027	20,623,175	18,326,760			13
73,017,985	51,982,601	5,876,537	3,136,263			14
20,806,216	14,087,171	1,674,498	849,921			15
95,325,937	49,977,910	12,636,767	3,832,933			16
89,872,511	44,722,118	7,100,207	2,238,973			17
(7,672,244)	(7,996,083)	(448,337)	(424,697)			18
						19
						20
						21
						22
1,630,599,742	1,527,535,487	329,366,297	261,182,187			23
$228,515,686	$188,709,953	$18,254,805	$14,221,652	$652,883	$651,384	24

See accompanying notes to financial statements.

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	OTHER UTILITY		OTHER UTILITY		OTHER UTILITY	
	Current Year (k)	Previous Year (l)	Current Year (m)	Previous Year (n)	Current Year (o)	Previous Year (p)
1						
2						
3						
4						
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21						
22						
23						
24						

Not Applicable

See accompanying notes to financial statements.

ITEM NO. 5

(a) Rate proceedings under FERC Docket No. RP88-259 involving respondent's purchase of gas for resale from Northern Natural Gas Company may result in refunds which will be passed on to the Company's customers through the purchased gas adjustment clause in the Company's rate schedule.

(b) Shortly after year end 1993, the Minnesota electric retail rate case was settled, as discussed in Note 2 on page 123A. Refunds were fully recorded as noted below in Item 6.

(c) Rate proceedings under FERC Docket No. ER91-21-000 (filed in October 1990) concerning "open access" electric transmission services tariff are still pending. It is currently unknown whether any refunds will be required as a result of these proceedings.

ITEM NO. 6

(a)	Accrued customer refunds account balance 12-31-92 (Account 254)	$145,976
	Refunds received from suppliers to be passed on to customers	265,472
	Interest accrued on accounts	10,317
	Accrued customer refunds account balance 12-31-93	$421,765

Note: The amount passed on to respondent's customers through the operation of the purchased gas adjustment clauses in rates for 1993 was zero.

(b) See Note 2 on page 123A for discussion of known refund obligation which was recorded in account 242. On January 31, 1994, an appeal of the MPUC's determination on the allowed return on equity was filed with the Minnesota Court of Appeals by the Minnesota Department of Public Service, the Office of the Minnesota Attorney General and the Minnesota Energy Consumers intervenor groups. The appeal concerns the method of calculating the rate of return on common equity for both the Minnesota electric and gas retail cases. The amount at issue is approximately $7 million in annual revenues for the Company. The ultimate financial impact of this appeal, if any, is not determinable at this time and no refund liability has been recorded. A decision by the court is expected by the end of 1994.

See accompanying notes to financial statements.

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	Ref. Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
25	Net Utility Operating Income (Carried forward from page 114)		$247,423,374	$203,582,989
26	Other Income and Deductions			
27	Other Income			
28	Nonutility Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)		3,663,781	3,121,497
30	(Less) Costs and Exp. of Merchandising, Job & Contract Work (416)		3,343,256	2,834,688
31	Revenues From Nonutility Operations (417)		41,995,529	41,939,285
32	(Less) Expenses of Nonutility Operations (417.1)		30,858,874	33,598,283
33	Nonoperating Rental Income (418)		(60,938)	(70,685)
34	Equity in Earnings of Subsidiary Companies (418.1)	119	39,836,437	33,364,131
35	Interest and Dividend Income (419)		7,499,293	3,120,462
36	Allowance for Other Funds Used During Construction (419.1)		6,634,528	8,086,160
37	Miscellaneous Nonoperating Income (421)		596,069	(301,282)
38	Gain on Disposition of Property (421.1)		454,439	1,195,023
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		66,417,008	54,021,620
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)		187,608	(20)
42	Miscellaneous Amortization (425)	340		
43	Miscellaneous Income Deductions (426.1-426.5)	340	6,022,581	10,079,360
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		6,210,189	10,079,340
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263	1,163,664	1,205,539
47	Income Taxes - Federal (409.2)	262-263	9,451,648	3,922,418
48	Income Taxes - Other (409.2)	262-263	2,084,236	690,600
49	Provision for Deferred Inc. Taxes (410.2)	234,272-277	(7,356,908)	(4,551,198)
50	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234,272-277	578,498	849,806
51	Investment Tax Credit Adj.- Net (411.5)	266	(103,112)	(192,192)
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Income and Deduct. (Enter Total of 46 thru 52)		4,661,030	225,361
54	Net Other Income and Deductions (Enter Total of lines 39,44,53)		55,545,789	43,716,919
55	Interest Charges			
56	Interest on Long-Term Debt (427)		85,826,326	85,695,033
57	Amort. of Debt Disc. and Expense (428)	258-259	1,100,523	866,743
58	Amortization of Loss on Reacquired Debt (428.1)		1,518,285	1,309,249
59	(Less) Amort. of Premium on Debt - Credit (429)	258-259	96,492	100,667
60	(Less) Amortization of Gain on Reacquired Debt - Credit (429.1)			
61	Interest on Debt to Assoc. Companies (430)	340	9,174	10,834
62	Other Interest Expense (431)	340	7,931,210	4,220,814
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		5,059,841	5,629,737
64	Net Interest Charges (Total of lines 56 thru 63)		91,229,185	86,372,269
65	Income Before Extraordinary Items (Enter Total of lines 25, 54 and 64)		211,739,978	160,927,639
66	Extraordinary Items			
67	Extraordinary Income (434)		0	0
68	(Less) Extraordinary Deductions (435)		0	0
69	Net Extraordinary Items (Enter Total of line 67 less line 68)		0	0
70	Income Taxes - Federal and Other (409.3)	262-263	0	0
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)		0	0
72	Cumulative effect of Accounting Change - net of income taxes		0	45,511,646
73	Net Income (Enter Total of lines 61 and 67)		$211,739,978	$206,439,285
	Earnings per Average Common Share		$3.02	$3.04

See accompanying notes to financial statements.

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.

2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436–439 inclusive). Show the contra primary account affected in column (b).

3. State the purpose and amount for each reservation or appropriation of retained earnings.

4. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.

5. Show dividends for each class and series of capital stock.

6. Show separately state and federal income tax effect on items shown in Account 439, Adjustments to Retained Earnings.

7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or apportioned as well as the totals eventually to be accumulated.

8. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance – Beginning of Year		$919,500,202
2	Changes (Identify by prescribed retained earnings accounts)		
3	Adjustments to Retained Earnings (Account 439)		
4	Credit:		
5	Credit:		
6	Credit:		
7	Credit:		
8	Credit:		
9	TOTAL Credits to Retained Earnings (Account 439) (Total of lines 4 thru 8)		
10	Debit: Reaquisition of Preferred Stock		1,068,305
11	Debit:		
12	Debit:		
13	Debit:		
14	Debit:		
15	TOTAL Debits to Retained Earnings (Account 439)(Total of lines 10 thru 14)		1,068,305
16	Balance Transferred from Income (Account 433 less Account 418.1)		171,903,543
17	Appropriations of Retained Earnings (Account 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Account 436)(Total of lines 18 thru 21)		0
23	Dividends Declared – Preferred Stock (Account 437)		
24	All Series		14,580,002
25			
26			
27			
28			
29	TOTAL Dividends Declared – Preferred Stock (Account 437)(Total of lines 24 thru 28)		14,580,002
30	Dividends Declared – Common Stock (Account 438)		
31			168,614,756
32			
33			
34			
35			
36	TOTAL Dividends Declared – Common Stock (Account 438)(Total of lines 31 thru 35)		168,614,756
37	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		25,708,480
38	Balance – End of Year (Enter Total of lines 01, 09, 15, 16, 22, 29, 36 and 37)		$932,849,162

See accompanying notes to financial statements,

STATEMENT OF RETAINED EARNINGS FOR THE YEAR (Continued)

Line No.	Item (a)	Amount (b)
	APPROPRIATED RETAINED EARNINGS (Account 215) State balance and purpose of each appropriated retained earnings amount at end of year and give accounting entries for any applications of appropriated retained earnings during the year.	
39		
40		
41		
42		
43		
44		
45	TOTAL Appropriated Retained Earnings (Account 215)	
	APPROPRIATED RETAINED EARNINGS - AMORTIZATION RESERVE, FEDERAL (Account 215.1) State below the total amount set aside through appropriations of retained earnings as of the end of the year, in compliance with the provisions of Federally granted hydroelectric project licenses held by the respondent. If any reductions or changes other than the normal annual credits hereto have been made during the year, explain such items in a footnote.	
46	TOTAL Appropriated Retained Earnings - Amortization Reserve, Federal (Account 215.1)	$66,664
47	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1)	66,664
48	TOTAL Retained Earnings (Account 215, 215.1, 216)	$932,915,826
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)	
49	Balance - Beginning of Year (Debit or Credit)	$179,737,609
50	Equity in Earnings for Year (Credit) (Account 418.1)	39,836,437
51	(Less) Dividends Received (Debit)	25,708,480
52	Other Changes (Explain) - Note 1	(472,495)
53	Balance - End of year	$193,393,071

Note 1 - Transfer From/(To) Appropriated Retained Earnings by Subsidiary
Northern States Power Company (NSP) (Wisconsin), a wholly owned subsidiary of the Company, transferred a portion of its Unappropriated Retained Earnings to Appropriated Retained Earnings. The impact on the Company is a reduction of Unappropriated Undistributed Subsidiary Earnings.

See accompanying notes to financial statements.

STATEMENT OF CASH FLOWS

1. If the notes to the cash flow statement in the respondents annual stockholders report are applicable to this statement, such notes should be attached to page 122. Information about noncash investing and financing should be provided on page 122. Provide also on page 122 a reconciliation between "Cash and Cash Equivalents at End of Year" with related amounts on the balance sheet.
2. Under "Other" specify significant amounts and group others.
3. Operating Activities – Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing activities should be reported in those activities. Show on Page 122 the amount of interest (net of amounts capitalized) and income taxes paid.

Line No.	Description (See Instructions for Explanation of Codes) (a)	Amounts (b)
1	Net Cash Flow from Operating Activities	
2	Net Income (Line 72(c) on page 117)	$211,739,978
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	245,734,073
5	Amortization of Nuclear Fuel	43,120,245
6	Amortization of Deferred Debits/Credits	3,852,891
7		
8	Deferred Income Taxes (Net)	3,054,579
9	Investment Tax Credit Adjustment (Net)	(8,223,693)
10	Net (Increase) Decrease in Receivables	(23,488,560)
11	Net (Increase) Decrease in Inventory	14,780,567
12	Net (Increase) Decrease in Allowances Inventory	0
13	Net Increase (Decrease) in Payables and Accrued Expenses	38,496,534
14	Net (Increase) Decrease in Other Regulatory Assets	(5,321,957)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(17,324,876)
16	(Less) Allowance for Other Funds Used During Construction–Equity	(6,634,528)
17	(Less) Undistributed Earnings from Subsidiary Companies	(39,836,437)
18	Other: Increase in Accrued Utility Revenues	(9,883,200)
19	Accrued Rate Refund Liability	12,235,000
20	Miscellaneous Changes in Working Capital	3,673,338
21	FASB 106 – Postretirement Healthcare Accrual	15,035,425
21a	Cash provided by changes in other assets and liabilities	(3,544,810)
22	Net Cash Provided by (Used in) Operating Activities (Total of lines 2 thru 21)	477,464,569
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (including land):	
26	Gross Additions to Utility Plant (less nuclear fuel) – Electric and Gas	(233,169,059)
27	Gross Additions to Nuclear Fuel	(37,560,558)
28	Gross Additions to Common Utility Plant	(26,691,348)
29	Gross Additions to Nonutility Plant	(2,699,732)
30	(Less) Allowance for Other Funds Used During Construction–Equity	6,634,528
31	Other:	
32		
33		
34	Cash Outflows for Plant (Total of Lines 26 thru 33)	(293,486,169)
35		
36	Acquisition of Other Noncurrent Assets (d) – External Decommissioning Fund	(32,578,444)
37	Proceeds from Disposal of Noncurrent Assets (d)	0
38		
39	Investments in and Advances to Assoc. and Subsidiary Companies	(122,380,110)
40	Contributions and Advances from Assoc. and Subsidiary Companies – Dividends	25,708,480
41	Disposition of Investments in (and Advances to)	
42	Associated and Subsidiary Companies	32,200,000
43		
44	Purchase of Investment Securities (a)	0
45	Proceeds from Sales of Investment Securities (a)	0

See accompanying notes to financial statements.

STATEMENT OF CASH FLOWS (Continued)

4. Investing Activities:
Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on page 122.
Do not include on this statement the dollar amount of leases capitalized per US of A General Instruction 20; instead provide a reconciliation if the dollar amount of leases eapitalized with plant cost on page 122.

5. Codes Used:
(a) Net proceeds or payments; (b) Bonds, debentures and other long term debt; (c) Include commercial paper;
(d) Identify separately such items as investments, fixed assets, intangibles, etc.

6. Enter on page 122 clarifications and explanations.

Line No.	Description (See Instructions for Explanation of Codes) (a)	Amounts (b)
46	Loans Made or Purchased	
47	Collections on Loans	
48		
49	Net (Increase) Decrease in Receivables	
50	Net (Increase) Decrease in Inventory	
51	Nct (Increase) Decrease in	
52	Allowances Held for Speculation	
53	Net Increase (Decrease) in Payables and Accrued Expenses–Construction Related	1,233,465
54	Other: Miscellaneous other investing activities	1,007,042
55		
56	Net Cash Provided by (Used in) Investing Activities	
57	(Total of lines 34 thru 55)	(388,295,736)
58		
59	Cash Flows from Financing Activities	
60	Proceeds from Issuance of:	
61	Long-Term Debt (b)	345,613,859
62	Preferred Stock	
63	Common Stock	183,653,879
64	Other:	
65		
66	Net Increase in Short-Term Debt (c)	
67	Other:	
68		
69		
70	Cash Provided by Outside Sources (Total of lines 61 thru 69)	529,267,738
71		
72	Payment for Retirement of:	
73	Long-Term Debt (b)	(351,666,186)
74	Preferred Stock - (Including Premium)	(36,092,000)
75	Common Stock	
76	Other:	
77		
78	Net Decrease in Short-Term Debt (c)	(40,361,000)
79		
80	Dividends on Preferred Stock - Paid	(15,306,252)
81	Dividends on Common Stock - Paid	(164,913,298)
82	Net Cash Provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	(79,070,998)
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22, 57, and 83)	10,097,835
87		
88	Cash and Cash Equivalents at Beginning of Year	10,902,677
89		
90	Cash and Cash Equivalents at End of Year	21,000,512

See accompanying notes to financial statements.

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.

2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.

3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.

4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.

5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.

6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be attached hereto.

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Certain reclassifications have been made to 1992 amounts on the Balance Sheet (Accounts 153 and 253), on the Statement of Income (Account 407.3) and on Page 322 (Conservation Improvement Program expenses in Account 908) to conform to the 1993 presentation. These reclassifications had no effect on net income or earnings per share.

Subsidiaries - Consistent with the FERC reporting requirements, the Company carries its investment in its subsidiaries at cost plus equity in undistributed earnings since acquisition. The net investment in such subsidiaries is included in Other Property and Investments, and the results of subsidiaries' operations are included in Other Income and Deductions.

Revenues - Revenues are recognized based on services provided to customers each month. Because customer utility meters are read and billed on a cycle basis, unbilled revenues (and related energy costs) are estimated and recorded for services provided from the monthly meter-reading dates to month-end. (See Note 3 for discussion of accounting change in 1992.)

The Company's rate schedules, applicable to substantially all of its customers, include cost-of-energy adjustment clauses, under which rates are adjusted to reflect changes in average costs of fuels, purchased power and gas purchased for resale.

Utility Plant and Retirements - Utility plant is stated at original cost. The Company's utility plant and construction expenditures consist of approximately 90% electric and 10% gas. The cost of additions to utility plant includes contracted work, direct labor and materials, allocable overheads, and allowance for funds used during construction. The cost of units of property retired, plus net removal cost, is charged to the accumulated provision for depreciation and amortization. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses.

Allowance for Funds Used During Construction (AFC) - AFC, a non-cash item, is computed by applying a composite pretax rate, representing the cost of capital for construction, to qualified Construction Work in Progress (CWIP). The rates were 7.4% in 1993 and 8.0% in 1992. The amount of AFC capitalized as a construction cost in CWIP is credited to other income and interest charges. AFC amounts capitalized in CWIP are included in utility rate base for establishing utility service rates.

Depreciation - For financial reporting purposes, depreciation is computed by applying the straight-line method over the estimated useful lives of various property classes. The Company files with the Minnesota Public Utilities Commission (MPUC) an annual review of remaining lives for electric and gas production properties. The 1993 study, as approved by the MPUC, recommended an increase of approximately $0.9 million in annual depreciation accruals. The 1992 study, as approved by the MPUC, recommended no change in 1992 depreciation. The Company also submitted in 1993 an average service life filing for transmission, distribution and general properties, which is filed every five years. The filing, as approved by the MPUC, increased depreciation by approximately $4.7 million from 1992 levels. Depreciation provisions, as a percentage of the average balance of depreciable property in service, were 3.49 percent in 1993 and 3.35 percent in 1992.

Decommissioning - Depreciation expense includes an annual provision for the estimated decommissioning costs for the Company's nuclear plants, calculated using an internal/external sinking fund method. The calculation is designed to provide for full accrual and rate recovery of the future decommissioning costs, including reclamation and removal, over the estimated operating lives of the Company's nuclear plants. (See Note 14.)

Nuclear Fuel Expense - The original cost of nuclear fuel is amortized to fuel expense on the basis of energy expended. Nuclear fuel expense also includes a disposal cost of 0.1 cent per kilowatt-hour sold from nuclear generation, as required by the Nuclear Waste Policy Act of 1982. (See Note 14.)

Environmental Costs - Costs related to environmental remediation are accrued when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. When a single estimate of the liability cannot be determined, the low end of the estimated range is recorded. Costs are charged to expense (or deferred as a regulatory asset based on expected recovery from customers in future rates) if they relate to the remediation of conditions caused by past operations or if they are not expected to benefit future operations. Where the expenditure relates to facilities currently in use (such as pollution control equipment), the costs are capitalized and depreciated over the future service periods. Estimated costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience. Accrued obligations are regularly adjusted as new information is received. For sites where the Company has been designated as one of several potentially responsible parties, the amount accrued represents the Company's estimated share of the cost. The Company intends to treat any future costs related to decommissioning and restoration of its power plants and substation sites as a removal cost of retirement through plant depreciation expense.

Income Taxes - All subsidiaries of NSP record income taxes in accordance with Statement of Financial Accounting Standards (SFAS) No. 109 - Accounting for Income Taxes. SFAS No. 109 requires the use of the liability method of accounting for deferred income taxes. Before 1993, NSP followed SFAS No. 96 - Accounting for Income Taxes, resulting in substantially the same accounting as SFAS No. 109.

Income taxes are deferred for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by law to be in effect when the temporary differences reverse. Due to the effects of regulation, current income tax expense is provided for the reversal of certain temporary differences previously accounted for by the flow-through method. Also, regulation results in the creation of certain regulatory assets and liabilities related to income taxes as discussed in Note 9.

Investment tax credits are deferred and amortized over the estimated lives of the related property.

Inventories - Materials and Supplies Inventories are carried at average cost.

Short-Term Investments - The Company carries its Short-Term Investments at cost which approximates market. The Company considers certain debt instruments (primarily commercial paper) with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

Regulatory Deferrals - As a regulated utility, the Company accounts for certain income and expense items under the provisions of SFAS No. 71 - Accounting for the Effects of Regulation. In doing so, certain costs that would otherwise be charged to expense are deferred as regulatory assets based on expected recovery from customers in future rates. Likewise, certain credits that would otherwise be reflected as income are deferred as regulatory liabilities based on expected flowback to customers in future rates. Management's expected recovery of deferred costs and expected flowback of deferred credits are generally based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistent with ratemaking treatment as established by regulators. Pages 232 and 278 describe in more detail the nature and amounts of these regulatory deferrals.

Supplemental Cash Flow Disclosures - During 1993, the Company made cash payments of $87,920,142 for interest (net of amounts capitalized) and $101,566,444 for income taxes. Cash and cash equivalents consist of cash ($18,203,188 - Account 131) and temporary cash investments ($2,797,324 - Account 136).

One significant non-cash transaction occurred in 1993. On Dec. 31, 1993 a portion of the Company's refuse-derived fuel processing operations were transferred to NRG Energy, Inc., a wholly owned subsidiary of the Company. The transaction was accounted for at historical cost and had no impact on the results of operations in 1993. The following is a summary of amounts transferred:

	Debit/(Credit)
Nonutility Property (Net)	($25,822,568)
Current and Accrued Assets	(1,936,499)
Deferred Debits	(301,674)
Current and Accrued Liabilities	1,709,642
Accumulated Deferred Income Taxes	9,669,521
	($16,681,578)
Note Receivable from NRG Energy, Inc.	9,466,697
Equity Investment in NRG Energy, Inc. Common Stock	7,214,881
	$16,681,578

2. RATE MATTERS - 1993 RATE INCREASES

Minnesota Jurisdiction - In November 1992, the Company filed applications for 1993 rate increases with the MPUC totaling $119.1 million and $14.9 million for Minnesota retail electric and natural gas customers, respectively. This represented annual increases of approximately 9 percent and 5.8 percent, respectively. In December 1992, the MPUC issued orders granting interim increases (subject to refund) of $71.2 million (5.4 percent) for electric service and $8.4 million (3.3 percent) for gas service, effective Jan. 1, 1993. In June 1993, the Company adjusted its proposed electric rate increase to $112.3 million and its gas rate request to $12.4 million.

The Company received initial orders from the MPUC in September 1993 for both the gas and electric cases. Final orders came in December 1993 for the gas case and in January 1994 for the electric case, allowing annualized retail rate increases of $10.0 million (3.9 percent) for gas and $72.2 million (5.4 percent) for electric. The return on equity granted in both cases was 11.47 percent. Refunds of interim electric rates collected are required in the amount of approximately $12 million and are expected to be paid in May 1994. No refunds of interim gas rates collected are required. Final gas and electric rates were implemented in March and April 1994, respectively.

On Jan. 31, 1994, an appeal of the MPUC's determination on the allowed return on equity was filed with the Minnesota Court of Appeals by the Minnesota Department of Public Service, the Office of the Minnesota Attorney General and the Minnesota Energy Consumers intervenor groups. The appeal concerns the method of calculating the rate of return on common equity for both the electric and gas cases. The amount at issue is approximately $7 million in annual revenues for the Company. The ultimate financial impact of this appeal, if any, is not determinable at this time. A decision by the court is expected by the end of 1994.

Other Jurisdictions - The Company's approved annualized rate increase of $4.8 million (5.3 percent) for North Dakota electric customers was effective April 21, 1993. The Company's approved annualized rate increase of $4.2 million (6.5 percent) for South Dakota electric customers has been in effect since May 1, 1993. Increased annualized wholesale electric rates of $0.9 million (3.6 percent) were accepted by the FERC for nine Minnesota Company wholesale customers, effective Sept. 21, 1993.

3. ACCOUNTING CHANGES

Postretirement Benefits - See Note 10 for discussion of NSP's 1993 change in accounting for postretirement medical and death benefits. There was no material effect on net income from this change due to rate recovery of the expense increases. Of the $17 million in 1993 cost increases over 1992 due to adoption of SFAS No. 106, about $4.5 million was capitalized, $12 million was deferred to be amortized over rate recovery periods in 1994-1996 and about $0.5 million was expensed but essentially offset by rate increases.

Income Taxes - As discussed in Note 1, NSP adopted SFAS No. 109 - Accounting for Income Taxes, effective Jan. 1, 1993. Adoption of SFAS No. 109 had no effect on earnings or financial condition due to its similarity to SFAS No. 96 - Accounting for Income Taxes, which NSP adopted in 1988 and which SFAS No. 109 supersedes.

Revenue Recognition - Effective Jan. 1, 1992, the Company changed its revenue recognition method to include the accrual of estimated unbilled revenues for electric and gas service. This change results in a better matching of revenues and expenses, and is consistent with predominant utility industry practice and the ratemaking principles in the Company's primary jurisdiction (Minnesota).

The effect on 1992 income before accounting changes was an increase of approximately $9.8 million (16 cents per share), while the effect on total 1992 earnings was an increase of approximately $55.3 million (88 cents per share).

1994 Changes - In 1994, NSP will adopt SFAS No. 112 - Accounting for Postemployment Benefits and a new accounting standard for employers' transactions with ESOP plans. SFAS No. 112 requires the accrual of certain employee costs (such as injury compensation and severance) to be paid in future periods. The adoption of these new accounting standards is not expected to have a material effect on NSP's resnlts of operations or financial condition.

4. BUSINESS ACQUISITIONS

Viking Gas Transmission Company - On June 10, 1993, the Company aequired 100 percent of the stock of Viking Gas Transmission Company (Viking) from Tenneco Gas, a unit of Tenncco, Inc., in Houston, Texas, for approximately $45 million, $32 million of which was financed with subsidiary debt. Viking, which is now a wholly owned subsidiary of the Company, owns and operates a 500-mile interstate natural gas pipeline serving portions of Minnesota, Wisconsin and North Dakota. Viking presently operates exclusively as a transporter of natural gas for third-party shippers under authority granted by the FERC. Rates for Viking's transportation services are regulated by the FERC. (See Note 12.)

Minneapolis Energy Center - On Ang. 20, 1993, NRG Energy, Inc. (NRG), a wholly owned subsidiary of the Company, acquired the assets of the Minneapolis Energy Center, a district heating and cooling system in downtown Minneapolis, Minn. The system uses steam and chilled water generating facilities to heat and cool buildings for about 85 heating and 25 cooling customers. The purchase price was $110 million, $84 million of which was financed with subsidiary debt. The purchase price primarily included facilities, long-term service agreements and goodwill.

Cenergy, Inc. - On Oct. 1, 1993, Cenergy, Inc., a non-regulated subsidiary of the Company, acquired certain assets of Centran Corporation, a natural gas marketing company. Cenergy, Inc., a national marketer of energy services with approximately 30 employees and approximately 300 customers, is headquartered in Minneapolis, Minn., and has additioual offlces in Houston and Corpus Christi, Texas; Louisville, Ky.; and Chesapeake, Va. The purchase price was $4 million. Assets purchased included proven oil and gas reserves, office equipment and a customer marketing data base.

Operating Results - The following represents unaudited operating results presented on a pro forma basis as if the acquisitions described above occurred on Jan. 1, 1992.

	Year Ended Dec. 31	
	1993	1992
Net income	$212.6 million	$204.9 million
Earnings per share	$ 3.04	$ 3.01

5. CUMULATIVE PREFERRED STOCK

At Dec. 31, 1993 and 1992, the Company had authorized 7,000,000 shares of Cumulative Preferred Stock and had 2,400,000 shares and 2,750,000 shares outstanding, respectively.

The Company has two series of adjustable rate proferred stock. The dividend rates are calculated quarterly and are based on prevailing rates of certain taxable government debt securities indices. At Dec. 31, 1993, the annualized dividend rates were $5.50 for Series A and $5.50 for Series B.

At Dec. 31, 1993, the various preferred stock series were callable at prices per share ranging from $102.00 to $103.75, plus accrued dividends. In 1993, the Company redcemed all 350,000 shares of its $7.84 series Cumulative Preferred Stock at $103.12 per share. In 1992, the Company redeemed all 250,000 shares of its $8.80 series Cumulative Preferred Stock at $103.35 per share.

6. COMMON STOCK AND INCENTIVE STOCK PLANS

The Company's common shares have a par value of $2.50 per share. At Dec. 31, 1993 and 1992, 160,000,000 shares were authorized and 66,879,577 and 62,598,360 shares were issued and outstanding, respectively, excluding common stock equivalents.

The Company's Articles of Incorporation and First Mortgage Indenture provide for certain restrictions on the payment of cash dividends on common stock. At Dec. 31, 1993, the payment of cash dividends on common stock was not restricted.

NSP has an Executive Long-Term Incentive Award Stock Plan that permits granting non-qualified stock options. The options currently granted may be exercised one year from the date of grant and are exercisable thereafter for up to nine years. The plan also allows certain employees to receive other awards for restricted stock, stock appreciation rights and other performance awards. Performance awards are valued in dollars, but are paid in shares based on market price at the time of payment. Transactions under the various stock incentive programs, which may result in the issuance of new shares, were as follows:

Stock Awards (Thousands of shares)	1993	1992
Outstanding Jan. 1	528.7	403.3
Options granted	196.9	201.8
Other stock awards	9.5	.8
Options and awards exercised	(174.3)	(57.0)
Options and awards forfeited	(22.2)	(20.1)
Other	(1.5)	(.1)
Outstanding at Dec. 31	537.1	528.7
Option price ranges:		
Unexercised at Dec. 31	$33.25-$43.50	$33.25-$40.94
Exercised during the year	$33.25-$40.94	$33.25-$36.44

Using the treasury stock method of accounting for outstanding stock options, the weighted average number of shares of common stock outstanding for the calculation of primary earnings per share includes any dilutive effects of stock options and other stock awards as common stock equivalents. The total average number of common and equivalent shares outstanding for 1993 were 65,211,274. The difference between shares used for primary and fully diluted earnings per share was not material.

7. LONG-TERM DEBT

The annual sinking-fund requirements of the Company's First Mortgage Indentures are the amounts necessary to redeem 1% of the highest principal amount of each series of first mortgage bonds at any time outstanding, excluding those series issued for pollution control and resource recovery financings and excluding certain other series totaling $280 million. The Company may and has applied property additions in lieu of cash, as permitted by the Company's First Mortgage Indenture, on all series except for the Series due July 1, 2019, 9 1/8%. At Dec. 31, 1993, the interest rates on the Company's First Mortgage Bonds ranged from 5 3/4% to 9 3/8%.

The variable rate First Mortgage Bonds Series due March 2011, and the variable rate City of Becker Pollution Control Revenue Bonds Series due March 2019, and September 2019, are redeemable upon seven days' notice at the option of the bondholder. Their tax-exempt interest rates are subject to change, weekly or at various periods, and are based on prevailing rates for similar issues. The interest rates applicable to these issues averaged 3.0 percent, 2.6 percent and 2.5 percent, respectively, at Dec. 31, 1993.

The Company has entered into an interest rate swap agreement with the underwriter of the $100 million First Mortgage Bond Series due October 1997, which effectively converts the interest cost for this debt from a fixed rate of 5 7/8% to a variable rate (3.38% at Dec. 31, 1993). The variable rate changes semiannually. Interest rate swap transactions are recognized as an adjustment of interest expense over the term of the agreement.

Except for minor exclusions, all real and personal property is subject to the liens of the first mortgage indentures.

Maturities and sinking-fund requirements on long-term debt are as follows: 1994, $86,052,700; 1995, $36,587,921; 1996, $56,960,000; 1997, $133,365,000; and 1998, $48,520,000.

On Jan. 24, 1994, the Company notified bondholders that $150 million of First Mortgage Bonds would be redeemed on Feb. 24, 1994. These bonds were redeemed and refinanced using new First Mortgage Bond proceeds obtained in February 1994.

8. SHORT-TERM CREDIT LINES

The Company has approximately $215 million of commercial bank credit lines under commitment fee arrangements. These credit lines make short-term financing available in the form of bank loans and support for commercial paper sales. There were no borrowings against these credit lines at Dec. 31, 1993 and 1992. The following is a summary of information regarding short-term commercial paper borrowings (in thousands of dollars).

	1993	1992
Balance at end of year	$106,200	$146,561
Weighted average interest rate	3.3%	3.6%
Maximum month end amount outstanding during the year	$172,280	$162,000
Average amount outstanding during the period (computed on a daily basis)	$76,966	$80,957
Weighted average interest rate during the year (computed on a daily basis)	3.3%	3.6%

9. INCOME TAX EXPENSE

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate (35% in 1993 and 34% in 1992) to net income before income tax expense. The reasons for the difference are as follows (in thousands):

	1993	1992
Tax computed at statutory rate	$111,819	$103,543
Increases (decreases) in tax from:		
State income taxes, net of federal income tax benefit	16,807	15,309
Equity in subsidiary earnings	(13,943)	(11,344)
Tax credits recognized	(8,224)	(8,613)
Net-of-tax AFC included in book depreciation	4,403	4,518
Use of the flow-through method for depreciation in prior years	6,530	5,211
Effect of tax rate changes for plant-related items	(4,222)	(4,782)
Nontaxable allowance for funds used during construction (AFC)-equity included in book income	(2,322)	(2,749)
Dividends paid on common shares held by ESOP	(3,009)	(3,245)
Other - net	(97)	252
Total income tax expense	$107,742	$ 98,100
Effective federal and state income tax rate on earnings of the Company	38.5%	36.2%

Income tax expense is comprised of the following (in thousands of dollars):

	1993	1992
Included in utility operating expenses:		
Current federal tax expense	$ 78,895	$ 55,119
Current state tax expense	22,481	14,937
Deferred federal tax expense	8,481	5,443
Deferred state tax expense	2,509	1,407
Tax credits recognized	(8,121)	(8,421)
Total	104,245	68,485
Included in other income and expense:		
Current federal tax expense	9,452	3,922
Current state tax expense	2,084	691
Deferred federal tax expense	(6,719)	(4,430)
Deferred state tax expense	(1,217)	(971)
Tax credits recognized	(, 103	(, 192
Total	$ (3,497)	$ (,980)
Deferred income taxes included in Acconnting Change	0	30,595
Total income tax expense	$107,742	$ 98,100

The components of the Company's deferred income taxes at Dec. 31 were as follows (in thousands):

	1993	1992
Deferred tax liabilities:		
Differences between book and tax bases of property	$775,397	$758,122
Net SFAS 109 adjustments to deferred taxes (see below)	(54,123)	(41,473)
Tax benefit transfer leases	81,778	90,917
Regulatory assets and other	41,701	27,316
Total deferred tax liabilities included in deferred credits	$844,753	$834,882
Deferred tax assets:		
Differences between book and tax bases of property	$126,419	$115,549
Deferred compensation, vacation and other accrued liabilities not currently deductible	35,247	22,433
Other	7,049	5,584
Total deferred tax assets included in deferred debits	$168 7,15	$143 566
Net deferred tax liability	$676,038	$691,316

The Omnibus Budget Reconciliation Act of 1993 (the Act) was signed into law on Aug. 10, 1993, and increased the federal corporate income tax rate from 34 percent to 35 percent retroactive to Jan. 1, 1993. Deferred tax liabilities were increased for the rate change by approximately $29.6 million. However, due to regulatory deferral of utility tax adjustments, earnings were reduced by immaterial adjustments to deferred tax liabilities related to non-regulated operations.

The adoption of SFAS 109 in 1993 and SFAS 96 in 1988 resulted in adjustments to deferred tax balances. Due to the effects of regulation, these adjustments were not recorded in income but were recorded as regulatory assets and regulatory liabilities. The SFAS 109 regulatory liabilities presented on page 278 represent the net amount expected to be reflected in future customer rates based on the collection in prior ratemaking of deferred income tax amounts in excess of the actual liabilities recorded by NSP. This excess is the net effect of the use of flow-through tax accounting in prior ratemaking and the impact of changes in statutory income tax rates in 1981, 1986-87 and 1993. The SFAS 109 regulatory assets presented on page 232B represent the gross-up of AFC that had previously been recorded in plant on a net-of-tax basis.

10. PENSION PLANS AND OTHER POSTRETIREMENT BENEFITS

Pension Benefits - The Company has a non-contributory, defined benefit pension plan that covers substantially all employees. Benefits are based on a combination of years of service, the employee's highest average pay for 48 consecutive months and Social Security benefits.

For regulatory purposes, the Company's pension expense is determined and recorded under the aggregate-cost method. SFAS No. 87 - Employers' Accounting for Pensions provides that any difference between the pension expense recorded for ratemaking purposes and the amounts determined under SFAS No. 87 should be recorded as assets or liabilities on the balance sheet.

Net periodic pension cost for the Company and its subsidiaries include the following components:

	Dec. 31, 1993		Dec. 31, 1992
(Thousands of dollars)	Total NSP	Company Portion	Total NSP
Service cost-benefits earned during the period	$25,015	$21,343	$24,080
Interest cost on projected benefit obligation	71,075	61,331	69,853
Actual return on assets	(152,019)	(131,242)	(115,455)
Net amortization and deferral	66,299	57,271	39,019
Net periodic pension cost determined under SFAS No. 87	10,370	8,703	17,497
Costs recognized due to actions of regulators	5,117	5,117	2,741
Total pension costs recorded during the period	15,487	13,820	20,238
Less costs recognized for 1988 early retirement program			(165)
Net periodic pension cost recognized for ratemaking	$15,487	$13,820	$20,073

The funded status of the plan as of Dec. 31 is as follows:

(Thousands of dollars)			
Actuarial present value of benefit obligation:			
Vested	$655,002	$564,647	$614,446
Nonvested	139 346	119 001	129 183
Accumulated benefit obligation	$794,348	$683,648	$743,629
Projected benefit obligation	$974,160	$841,591	$914,019
Plan assets at fair value	1 244 650	1 073 982	1 156 782
Plan assets in excess of projected benefit obligation	(270,490)	(232,391)	(242,763)
Unrecognized prior service cost	(22,580)	(19,500)	(14,790)
Unrecognized net actuarial gain	315,049	271,441	269,086
Unrecognized net transitional asset	767	663	843
Net pension liability included in deferred credits	$22,746	$20,213	$12,376

The weighted average discount rate used in determining the actuarial present value of the projected obligation was 7 percent in 1993 and 8 percent in 1992. The rate of increase in future compensation levels used in determining the actuarial present value of the projected obligation was 5 percent in 1993 and 6 percent in 1992. While the 1993 assumption changes had no effect on 1993 pension costs, the effect of the changes in 1994 is expected to be a cost decrease of approximately $3 million. The assumed long-term rate of return on assets used for cost determinations under SFAS No. 87 was 8 percent in 1993 and 1992. The effect of the 1992 change in the assumed rate of return was an increase of approximately $4 million in the estimated SFAS No. 87 net periodic pension cost in 1992. Plan assets principally consist of common stock of public companies and U.S. government securities.

Postretirement Health Care - Effective Jan. 1, 1993, the Company adopted the provisions of SFAS No. 106 - Employers' Accounting for Postretirement Benefits Other Than Pensions. SFAS No. 106 requires the actuarially determined obligation for postretirement health care and death benefits to be fully accrued by the date employees attain full eligibility for such benefits, which is generally when they reach retirement age. This is a significant change from the Company's prior policy of recognizing benefit costs on a cash basis after retirement. In conjunction with the adoption of SFAS No. 106, the Company elected to amortize on a straight-line basis over 20 years the unrecognized accumulated postretirement benefit obligation (APBO) of $184.7 million for current and future retirees. This obligation considers anticipated 1994 plan design changes, including Medicare integration, increased retiree cost sharing and managed indemnity measures not in effect in 1993.

Prior to 1993, the Company funded benefit payments to retirees internally. While the Company generally prefers to continue using internal funding of benefits paid and accrued, significant levels of external funding have been imposed by the Company's regulators, as discussed below, including the use of tax-advantaged trusts. Plan assets held in such trusts as of Dec. 31, 1993, consisted of investments in equity mutual funds and cash equivalents.

The following table sets forth the health care plan's funded status in 1993 for the Company and its subsidiaries.

(Millions of dollars)	Dec. 31, 1993 Total NSP	Dec. 31, 1993 Company Portion	Jan. 1, 1993 Total NSP
AFBO:			
Retirees	$120.2	$103.4	$105.8
Fully eligible plan participants	18.8	15.8	18.8
Other active plan participants	90.8	76.4	91.0
Total APBO	229.8	195.6	215.6
Plan assets	6.1	3.7	0
APBO in excess of plan assets	223.7	191.9	215.6
Unrecognized net actuarial loss	(1.3)	(1.4)	
Unrecognized transition obligation	(204.8)	(175.5)	(215.6)
Postretirement benefit obligation included in deferred credits	$ 17.6	$ 15.0	$ 0

The assumed health care cost trend rate used in measuring the APBO at Dec. 31, 1993, was 14.1 percent for those under age 65 and 8.0 percent for those over age 65. The assumed cost trend rates are expected to decrease each year until they reach 4.5 percent for both age groups in the year 2004, after which they are assumed to remain constant. The trend rates used in the Jan. 1, 1993, calculations were 15.1 percent and 9.0 percent, respectively, eventually decreasing to 5.5 percent in 2004. A 1-percent increase in the assumed health care cost trend rate for each year would increase the APBO as of Dec. 31, 1993, by approximately 17 percent, and service and interest cost components of the 1993 net periodic postretirement cost by approximately 20 percent. The assumed discount rate used in determining the APBO was 7 percent for Dec. 31, 1993, and 8 percent for Jan. 1, 1993, compounded annually. The assumed long-term rate of return on assets used for cost determinations under SFAS No. 106 was 8 percent for both measurement dates. While the assumption changes made for the Dec. 31 calculations had no effect on 1993 beuefit costs, the effect of the changes in 1994 is expected to be a cost decrease of approximately $2 million.

In 1992 the Company recognized $10,441,198 as the cost attributable to postretirement health care and death benefits based on payments made. The Company's net annual periodic postretirement benefit cost recorded for 1993 consists of the following components (in millions of dollars):

Service cost-benefits earned during the year	$ 3.8
Interest cost (on service cost and APBO)	14.9
Actual return on assets	(.1)
Amortization of transition obligation	9.2
Net amortization and deferral	.1
Net periodic postretirement health care cost under SFAS No. 106	27.9
Costs deferred due to actions of regulators	(12.1)
Net periodic postretirement health care cost recognized for ratemaking	$15.8

Regulators of the Company's retail rates in Minnesota and North Dakota have allowed full recovery of increased benefit costs under SFAS No. 106, effective in 1993. Expense recognition and rate recovery of increased 1993 accrual costs for Minnesota have been deferred until 1994 through 1996, consistent with rate orders received. External funding was required in Minnesota to the extent it is tax advantaged; funding must begin by the next general rate filing for Minnesota.

Rate increases for Minnesota wholesale electric customers were approved by the FERC and provided recovery of accrued SFAS No. 106 benefits under new rates beginning in September 1993. The FERC has required external funding for all benefits paid and accrued under SFAS No. 106.

The impact of adopting SFAS No. 106 on other utility jurisdictions and non-regulated operations was not material.

ESOP - NSP also has a leveraged Employee Stock Ownership Plan (ESOP) that covers substantially all employees. Employer contributions to this plan are generally made to the extent the Company realizes a tax savings on its income statement from dividends paid on shares held by the ESOP. Contributions to the ESOP in 1993 and 1992, which approximate expenses determined under the shares-allocated method, were $6,281,000 and $6,415,000, respectively. ESOP contributions have no material effect on the Company's earnings because the contributions (net of tax) are essentially offset by the tax savings provided by the dividends paid on ESOP shares. (See Note 9.)

11. FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated Dec. 31 fair values of the Company's financial instruments are as follows:

	1993		1992	
(Thousands of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash, cash equivalents and short-term investments	$21,001	$21,001	$10,903	$10,903
Long-term decommissioning investments	$101,378	$110,130	$68,800	$72,180
Long-term debt	$1,186,854	$1,231,692	$1,175,778	$1,225,071

For cash, cash equivalents and short-term investments, the carrying amount approximates fair value because of the short maturity of those instruments. The fair values of the Company's long-term investments in an external nuclear decommissioning fund are estimated based on quoted market prices for those or similar investments. The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or the current rates offered to the Company for debt of the same remaining maturities.

12. RELATED PARTY TRANSACTIONS

Interchange Agreement - The electric production and transmission costs of the entire NSP system are shared by the Company and its Wisconsin subsidiary. A FERC approved agreement (Interchange Agreement) between the two companies provides for the sharing of all costs of generation and transmission facilities of the NSP system, including capital costs. Billings under the Interchange Agreement which are included in the Statement of Income are as follows (in thousands of dollars):

	1993	1992
Operating revenues:		
Electric	$175,240	$167,143
Gas	267	214
Operating expenses:		
Purchased and interchange power	46,632	46,943
Gas purchased for resale	56	55
Other operations	25,531	23,728

Gas Purchases - Since June 10, 1993, the Company has purchased approximately $762,000 of natural gas from its new subsidiary, Viking (see Note 4), under a long-term contract expiring in 1994.

13. JOINT PLANT OWNERSHIP

The Company is a participant in a jointly owned 855 megawatt coal-fired electric generating unit called Sherburne County Generating Station Unit No. 3 (Sherco 3), which began commercial operation Nov. 1, 1987. Undivided interests in Sherco 3 are owned by the Company (59%) and Southern Minnesota Municipal Power Agency (41%). The Company is the operating agent under the joint ownership agreement. The Company's share of related expenses for Sherco 3 since commercial operations began are included in operating expenses. The Company's share of the cost recorded in Plant in Service at Dec. 31, 1993 and 1992 was $584,822,000 and $582,799,000, respectively. The corresponding accumulated provisions for depreciation were $114,251,000 and $96,035,000, respectively.

14. NUCLEAR ACCOUNTING MATTERS

Decommissioning - Decommissioning of all nuclear facilities is planned to occur in the years 2010-2022 using the prompt dismantlement method. The total obligation for decommissioning is expected to be funded approximately 45 percent by internal funds and 55 percent by external funds. Based on a 1990 study, the Company estimates total decommissioning costs will approximate $750 million in 1993 dollars, for which the Company has recorded $302 million in the accumulated provision for depreciation; $101 million of this balance has been deposited in external trust funds. An updated study will not be used for recording decommissioning accruals until approved by the MPUC. Such approval is not expected to occur until after the Minnesota Legislature makes its decision on fuel storage at the Company's Prairie Island nuclear plant. (Sec Note 15.) Decommissioning costs accrued in 1993 and 1992 were $43 million and $40 million, respectively.

Nuclear Fuel Disposal - Fuel expense includes disposal expenses assessed under the Nuclear Waste Policy Act of 1982 of $8.7 million and $6.8 million for 1993 and 1992, respectively. Disposal expenses reflect reductions of $2.6 million in 1993 and $3.7 million in 1992 due to a change in the basis of charging customers, retroactive to 1983. Nuclear fuel expense in 1993 also includes about $1 million for a portion of the 1993 payment to the U.S. Department of Energy (DOE) for the decommissioning and decontamination of the DOE's uranium enrichment facility. The Company's total DOE assessment of $46 million was made in 1993. This assessment will be payable in annual installments (including $3.1 million in 1993) for up to 15 years and will be expensed on a monthly basis in the 12 months following each payment. Future installments are subject to inflation adjustments under DOE rules. The FERC has approved wholesale ratemaking recovery of these assessments as paid through the cost-of-energy adjustment clause. Since the Company's retail regulators currently fully conform to the FERC's cost-of-energy adjustment clause procedures, management also expects recovery of these DOE assessments in retail ratemaking as payments are made each year.

15. COMMITMENTS AND CONTINGENT LIABILITIES

The Company presently estimates utility capital expenditures, including acquisitions of nuclear fuel, will be $336 million in 1994 and $1.5 billion for 1994-1998. There also are contractual commitments for the disposal of spent nuclear fuel.

Rental expense under operating leases were approximately $24.5 and $22.5 million for 1993 and 1992, respectively.

The Company's Wisconsin subsidiary presently estimates its utility capital expenditures will be $61 million in 1994 and $302 million for 1994-1998. The Company's non-regulated subsidiary, NRG Energy, Inc., is currently evaluating potential investments in various energy projects. Capital spending for all non-regulated projects of the Company and its subsidiaries is estimated to be as much as $130 million in 1994 and $540 million for the five-year period 1994-1998.

Fuel Contracts - The Company has long-term contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts, which expire in various years between 1994 and 2013, require minimum contractual purchases and deliveries of fuel, and additional payments for the rights to purchase coal in the future. In total, the Company is committed to the purchase and receipt of approximately $374 million of coal, $129 million of nuclear fuel and $308 million of natural gas, or to make payments in lieu thereof, under these contracts. Because the Company has other sources of fuel available and because suppliers are expected to continue to provide reliable fuel supplies, risk of loss from non-performance under these contracts is not considered significant. In addition, the Company's risk of loss (in the form of increased costs) from market price changes in fuel is mitigated through the cost-of-energy adjustment provision of the ratemaking process, which provides for recovery of nearly all fuel costs.

Power Agreements - The Company has executed several agreements with the Manitoba Hydro-Electric Board (MH) for hydroelectricity. A summary of the agreements is as follows:

	Years	Megawatts
Participation Power Purchases	1994-2005	500
Seasonal Participation Power Purchase 1994-1996	1994	150
	1995-1996	250
Seasonal Peaking Power Purchases	1994-1996	200
Seasonal Diversity Exchanges:		
Summer exchanges from MH	1994	400
	1995-2014	150
	1997-2016	200
Winter exchanges to MH	1995-2014	150
	1996-2015	200
	2015-2017	400
	2018	200

The cost of the participation power purchase commitment is based on 80 percent of the costs of owning and operating Sherco 3 (adjusted to 1993 dollars). The total estimated annual costs for all MH agreements are $68.2 million for 1994 and approximately $70 million thereafter. These commitments, which represent about 38 percent of MH's output capability in 1993, account for approximately 13 percent of the Company's 1993 system capability. The risk of loss from non-performance by MH is not considered significant and the risk of loss from market price changes is mitigated through cost-of-energy rate adjustments.

The Company and MH jointly have made commitments to provide additional transmission capacity to accomplish the seasonal diversity exchanges and to provide 200 megawatts of transmission capacity for United Power Association. The Company's agreements with MH call for the addition of facilities that will allow the Company's existing 500-kilovolt line from Winnipeg to the Twin Cities to accommodate the additional levels of transactions. The Company and MH began construction of the facilities in early 1992, received all the necessary approvals in 1993 and expect to complete construction in 1995.

The Company has an agreement with Minnkota Power Cooperative (MPC) for the purchase of summer season capacity and energy. From 1994 through 2001, the Company will buy 150 megawatts of summer season capacity for $12.4 million annually. From 2002 through 2015, the Company will purchase 100 megawatts of capacity for $10.0 million annually. Energy under the agreement will be priced against the cost of fuel consumed per megawatt-hour at the Coyote Generating Station in North Dakota. The Company also has three seasonal (summer) purchase power agreements, with MPC, Minnesota Power and Rochester Public Utility, for the purchase of 270 megawatts in 1994 and 250 megawatts in 1995 and 1996. The annual cost of this capacity will be approximately $3 million.

The Company has agreements with several non-regulated entities to purchase electric capacity and associated energy. The total annual cost of current commitments for non-regulated installed capacity ranges from approximately $18 million for 119 megawatts in each of the years 1994-2011, decreasing thereafter to $0.8 million in 2033. The Company is negotiating a new power-purchase agreement with an independent power producer, which is expected to provide an additional 232 megawatts of electric capacity and associated energy beginning in 1997.

Nuclear Insurance - The Company's public liability for claims resulting from any nuclear incident is limited to $9.4 billion under the 1988 Price-Anderson amendment to the Atomic Energy Act of 1954. The Company has secured $200 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $9.2 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in ease of a nuclear accident. The Company is subject to assessments of $79.3 million for each of its three licensed reactors to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $10 million per reactor during any one year.

The Company purchases insurance for property damage and decontamination clean-up costs with coverage limits of $2.35 billion for the Prairie Island nuclear plant site and $2.15 billion for the Monticello nuclear plant site. The Prairie Island coverage consists of $950 million from American Nuclear Insurers/Mutual Atomic Energy Liability Underwriters (ANI/MAELU) and $1.4 billion from Nuclear Electric Insurance Limited (NEIL). The Monticello coverage consists of $750 million from ANI/MAELU and $1.4 billion from NEIL. Under the insuring agreement with NEIL, the Company is subject to assessments of up to $23.3 million in each calendar year, 7.5 times the amount of its annual premium.

NEIL also provides insurance coverage for increased costs of generation and purchased power resulting from an accidental outage of a nuclear generating unit. Under the policy, the Company is subject to assessments of up to $6.7 million in each calendar year, five times the amount of its annual premium.

Environmental Contingencies - Other Noncurrent Liabilities and Deferred Credits include accruals of $48 million at Dec. 31, 1993 for estimated costs associated with environmental reclamation, restoration and cleanup activities. Approximately $40 million of the liability (in account 228.4) relates to a 1993 DOE assessment as discussed in Note 14. Other estimates have been recorded for expected environmental costs associated with manufactured gas plant sites formerly used by the Company and other waste disposal sites as discussed below.

These environmental liabilities do not include accruals recorded (and collected from customers in rates) for future decommissioning costs related to the Company's nuclear generating plants. Consistent with predominant industry practice, the Company's decommissioning accruals are included in Accnmulated Provision for Amortization of Nuclear Fuel Assemblies as discussed in Notes 1 and 14. The FERC, the FASB and the SEC currently are reviewing the accounting and reporting guidelines for decommissioning cost accruals. Until such guidelines require a different presentation, the Company plans to continue its current reporting of plant decommissioning obligations as accumulated depreciation.

The Company has not developed any specific site restoration and exit plans for its fossil fuel plants, hydroelectric plants or substation sites as it currently intends to operate at these sites indefinitely. If such plans were developed in the future, the Company would intend to treat the costs as a removal cost of retirement and include it in depreciation expense. However, removal costs are estimated based on historical experience and an accrual is currently included in depreciation expense.

As discussed in Note 14, the Company includes in its fuel expense charges for pre-funding of the federal nuclear fuel disposal program.

The Company has met or exceeded the removal and disposal requirements for polychlorinated biphenyls (PCB) equipment as required by state and federal regulations. The Company has removed nearly all PCB capacitors, transformers and equipment from its distribution system and power plants. Any future cleanup or remediation costs for past PCB disposal is unknown at this time. Minimal costs are expected to be incurred for future removal and disposal of PCB equipment. PCB-contaminated mineral oil is detoxified and beneficially reused or burned for energy recovery at a permitted facility.

The Company has been designated by the Environmental Protection Agency (EPA) as a "potentially responsible party" (PRP) for eight waste disposal sites to which the Company sent materials. Under applicable law, the Company, along with each PRP, could be held jointly and severally liable for the total remediation costs of all eight sites, which are estimated to approximate $85 million. However, the amount could be in excess of $85 million. The Company is not aware of the other parties' inability to pay or if responsibility for any of the sites is disputed by any party. The Company's share of the costs associated with these eight sites is approximately $2.5 million. Of this amount, about $1.4 million has already been paid in connection with two of the eight sites for which the Company has settled with the EPA and other PRPs. For the remaining six sites, neither the amount of cleanup costs nor the final method of their allocation among all designated PRPs has been determined. However, the Company has recorded an estimate of future costs of approximately $1 million for all six sites. While it is not feasible to determine the outcome of these matters, amounts accrued represent the best current estimate of the Company's future liability for the cleanup costs of these sites. It is the Company's practice to vigorously pursue and, if necessary, litigate with insurers to recover costs. Through litigation, the Company has recovered from other PRPs a portion of the remedial costs paid to date. Management believes costs incurred in connection with the sites, which are not recovered from insurance carriers or other parties, might be allowed recovery in future ratemaking. Until the Company is identified as a PRP, it is not possible for the Company to predict the timing or amount of any costs associated with cleanup sites other than those discussed above.

The Company also is continuing to investigate 14 properties either presently or previously owned by the Company, which were at one time sites of gas manufacturing, gas storage plants or gas pipelines. The purpose of this investigation is to determine if waste materials are present, if such materials constitute an environmental or health risk, if the Company has any responsibility for remedial action and if recovery under the Company's insurance policies can contribute to any remediation costs. Of the 14 gas sites under investigation, the Company has already remediated one site and is actively taking remedial action at four of the sites. The Company has paid $3.1 million to date on these sites. The one remediated site continues to be monitored. The Company currently estimates its liability for these four sites to be approximately $5 million with payment expected over the next one to five years. The estimate is based on prior experience and includes investigation, remediation and litigation costs. The possible range of the liability for these four sites could be from $5 million to approximately $11 million, depending on the extent of contamination. As for the other nine sites, the Company currently estimates its liability to be approximately $2 million. This estimate assumes the development and remediation of one site with the remaining eight sites requiring only monitoring. The time frame for payment of these costs currently is undeterminable. While it is not feasible to determine the precise outcome of all of these matters, the accruals recorded represent the current best estimate of the costs of any required cleanup or remedial actions at the Company's former gas operating sites. Management also believes that costs incurred in connection with the sites, which are not recovered from insurance carriers or other parties, might be allowed recovery in future ratemaking.

The Clean Air Act, including the Amendments of 1990 (the Clean Air Act), imposes stringent limits on emissions of sulfur dioxide and nitrogen oxides by electric utility generating plants. The legislation enacted in 1990 is extremely complex and its overall financial impact on the Company will depend on the final interpretation and implementation of rules to be issued by the EPA. The Company is participating in the rulemaking process for the development of regulations that achieve the goals of the legislation in a reasonable and cost-effective manner. The Company has expended significant funds over the years to reduce sulfur dioxide emissions at its plants. Additional construction expenditures may be required to comply with parts of the Clean Air Act. Based on revised emission standards proposed by the EPA in 1993, the Company's excess emission allowances available under the Clean Air Act may be significantly reduced. Because the Company is only beginning to implement some provisions of the Clean Air Act, its overall financial impact is unknown at this time. The majority of the Company's power plants meet state and federal limits for opacity and air quality. Capital expenditures will be required for opacity compliance in 1994-1998 at certain facilities, and such costs are considered in the capital expenditure commitments disclosed previously. The Company plans to seek recovery of these expenditures in future rate proceedings.

In October 1992, the Company disclosed to the Minnesota Pollution Control Agency, the EPA and the Nuclear Regulatory Commission that reports on halogen content of water discharged at the Company's Prairie Island nuclear generating plant were based on estimates of halogen content rather than actual physical samples of water discharged as required by the plant's permit. Even though the water discharges at the plant did not exceed the halogen levels allowed under the permit, the applicable state and federal statutes would permit the imposition of fines, the institution of criminal sanctions and/or injunctive relief for the reporting violations. Corrective actions were taken by the Company, and the Company cooperated with state and federal authorities in the investigation of the reporting violations. No civil or criminal actions against the Company have been announced.

Environmental liabilities are subject to considerable uncertainties that affect the Company's ability to estimate its share of the ultimate costs of remediation and pollution control efforts. Such uncertainties involve the nature and extent of site contamination, the extent of required cleanup efforts, varying costs of alternative cleanup methods and pollution control technologies, changes in environmental remediation and pollution control requirements, the potential effect of technological improvements, the number and financial strength of other potentially responsible parties at multi-party sites and the identification of new environmental cleanup sites. The Company has recorded and/or disclosed its best estimate of expected future environmental costs and obligations as discussed previously.

Legal Claims - In the normal course of business, the Company is a party to routine claims and litigation arising from prior and current operations. The Company is actively defending these matters and has recorded an estimate of the probable cost of settlement or other disposition. On July 22, 1993, a natural gas explosion occurred on the Company's distribution system in St. Paul, Minn. Total damages are estimated to exceed $1 million. The Company has a self-insured retention deductible of $1 million, with general liability coverage of $150 million, which includes coverage for all injuries and damages. While four lawsuits have been filed, the litigation following this incident is in a preliminary stage and the ultimate costs to the Company are unknown at this time.

Operating Contingency - The Company is experiencing uncertainty regarding its ability to store used nuclear fuel from its Prairie Island nuclear generating facility. The facility stores its used nuclear fuel on an interim basis in a storage pool in the plant, pending the availability of a U.S. Department of Energy high-level radioactive waste storage or permanent disposal facility, or a private interim storage facility. At current operating levels, the pool will be filled in 1994 so the Company has proposed to augment Prairie Island's interim storage capacity by using steel containers for dry storage of used nuclear fuel on the plant site. Without additional onsite storage or significant modification of normal plant operations, Prairie Island Unit 2 would be shutdown in May 1995 and Prairie Island Unit 1 would be shutdown in February 1996. These two units supply about 20 percent of the Company's output. The Company has obtained a Certificate of Need from the MPUC allowing use of a limited number of steel containers, providing adequate storage at least through the year 2001. The Nuclear Regulatory Commission has also issued a license approving a dry storage facility on the plant site for Prairie Island's used fuel. However, in June 1993, the Minnesota Court of Appeals decided that the additional temporary storage facilities must be approved by the Minnesota Legislature. The Company has requested such approval from the Legislature and expects a decision on this issue during the current session, which began on Feb. 22, 1994. A bill allowing construction of the storage facility has been passed by the Minnesota State Senate (Senate). The Minnesota State House of Representatives (House) has passed a bill prohibiting the construction of the dry cask storage at Prairie Island. A conference committee composed of Senate and House members started to meet in late April 1994 to consider compromises between the two bills passed in the House and the Senate. The ultimate outcome of this legislative proceeding is unknown at this time.

The Company's net investment in the Prairie Island generating facility at Dec. 31, 1993, was $520 million. Future plant decommissioning costs in excess of amounts not accrued and collected in rates were $247 million at Dec. 31, 1993. Should the facility need to be shut down due to the full utilization of spent fuel storage capacity, the Company would request recovery of, and a return on, its investment and recovery of unrecorded plant decommissioning costs through utility rates. However, at this time the regnlators' ultimate response to such a request is unknown. Without the generating capability of the Prairie Island facility, the Company estimates that an incremental increase in purchased power and fuel expenses of at least $200 million per year could be incurred. To the extent such additional costs represent energy purchases, current rate treatment provides recovery through cost-of-energy adjustments to customer rates. The Company will request recovery of costs associated with additional capacity purehases or investments in new plants through general rate filings. However, at this time the need for such costs and the regulators' nltimate response to such a request is unknown. The Company estimates that the present value of the cost of supplying replacement power and recovering its investment in the plant and unrecognized decommissioning costs will be $1.8 billion.

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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)	Electric (c)
1	UTILITY PLANT		
2	In Service		
3	Plant in Service (Classified)	$5,783,005,757	$5,195,020,225
4	Property Under Capital Leases	225,686	225,686
5	Plant Purchased or Sold	14,761	14,761
6	Completed Construction not Classified	0	0
7	Experimental Plant Unclassified		
8	TOTAL (Enter Total of lines 3 thru 7)	5,783,246,204	5,195,260,672
9	Leased to Others	2,580,245	2,580,245
10	Held for Future Use	4,680,443	719,389
11	Construction Work in Progress	188,244,939	158,196,606
12	Acquisition Adjustments	222,385	222,385
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)	5,978,974,216	5,356,979,297
14	Accum. Prov. for Depr., Amort., & Depl.	2,500,492,895	2,242,417,749
15	Net Utility Plant (Enter total of line 13 less 14)	3,478,481,321	3,114,561,547
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION		
17	In Service:		
18	Depreciation	2,478,354,019	2,239,039,385
19	Amort. and Depl. of Producing Nat. Gas Land and Land Rights	0	
20	Amort. of Underground Storage Land and Land Rights	0	
21	Amort. of Other Utility Plant	20,703,047	1,942,536
22	TOTAL in Service (Enter Total of lines 18 thru 21)	2,499,057,066	2,240,981,921
23	Leased to Others		
24	Depreciation	1,435,828	1,435,828
25	Amortization and Depletion		
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)	1,435,828	1,435,828
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	TOTAL Held for Future Use (Ent. Tot. of lines 28 and 29)	0	0
31	Abandonment of Leases (Natural Gas)		
32	Amort. of Plant Acquisition Adj.		
33	TOTAL Accumulated Provisions (Should agree with line 14 above)(Enter Total of lines 22, 26, 30, 31, and 32)	$2,500,492,895	$2,242,417,749

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION (Continued)

Gas (d)	Telephone (e)	Other(specify) (f)	Other(specify) (g)	Common (h)	Line No.
					1
					2
$421,887,225				$166,098,307	3
					4
					5
				0	6
					7
421,887,225	0	0	0	166,098,307	8
					9
				3,961,053	10
6,094,158				23,954,175	11
					12
427,981,384	0	0	0	194,013,536	13
160,620,636	0			97,454,509	14
267,360,748	0	0	0	96,559,027	15
					16
					17
160,620,636				78,693,999	18
					19
					20
0				18,760,510	21
160,620,636	0	0	0	97,454,509	22
					23
					24
					25
0	0	0	0	0	26
					27
					28
					29
0	0	0	0	0	30
					31
					32
$160,620,636	0	0	0	$97,454,509	33

NUCLEAR FUEL MATERIALS (Accounts 120.1 through 120.6 and 157)

1. Report below the cost incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.

2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of Item (a)	Balance Beginning of Year (b)	Changes During Year Additions (c)
1	Nuclear Fuel in Process of Refinement, Conversion Enrichment & Fabrication (120.1)		
2	Fabrication	6,854,292	7,632,460
3	Nuclear Materials	22,439,861	28,392,689
4	Allowance for Funds Used during Construction	274,132	1,046,801
5	(Other Overhead Construction Costs)	157,013	488,609
6	SUBTOTAL (Enter Total of lines 2 thru 5)	29,725,298	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	0	51,928,233
9	In Reactor (120.3)	192,891,567	52,391,628
10	SUBTOTAL (Enter Total of lines 8 and 9)	192,891,567	
11	Spent Nuclear Fuel (120.4)	488,900,210	41,090,409
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum. Prov. for Amortization of Nuclear Fuel Assemblies (120.5)	630,548,576	
14	TOTAL Nuclear Fuel Stock (Enter Total lines 6, 10, 11, and 12 less line 13)	80,968,499	
15	Estimated Net Salvage Value of Nuclear Materials in line 9	N/A (4)	
16	Estimated Net Salvage Value of Nuclear Materials in line 11	N/A (4)	
17	Estimated Net Salvage Vulue of Nuclear Materials in Chemical Processing		
18	Nuclear Materials Held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other		
22	TOTAL Nuclear Materials Held for Sale (Enter Total of lines 19, 20 and 21)		

NUCLEAR FUEL MATERIALS (Accounts 120.1 through 120.6 and 157) (Continued)

Changes During the Year			
Amortization (d)	Other Reduction (Explain in a footnote) (e)	Balance End of Year (f)	Line No.
			1
	11,491,687 (1)	2,995,065	2
	38,883,565 (1)	11,948,985	3
	1,118,695 (1)	202,238	4
	434,286 (1)	211,336	5
		15,357,624	6
			7
	51,928,233 (2)	0	8
	41,090,409 (3)	204,192,786	9
		204,192,786	10
	463,395 (5)	529,527,224	11
			12
43,120,245		673,668,821	13
		75,408,813	14
			15
			16
			17
			18
			19
			20
			21
			22

Footnotes for page 202 & 203

(1) Classified to Account 120.2
(2) Transferred to Account 120.3
(3) Transferred to Account 120.4
(4) Not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982.
(5) Reinserted into the reactor.

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified - Electric.

3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.

4. Enclose in parentheses credit adjustments of plant accounts, to indicate the negative effect of such accounts.

5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including

Line No.	Account (a)	Balance Beginning Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	$1,012,103	$0
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	1,012,103	0
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,143,689	$14,679
9	(311) Structures and Improvements	280,243,499	1,164,795
10	(312) Boiler Plant Equipment	901,719,580	6,458,708
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	222,077,304	807,737
13	(315) Accessory Electric Equipment	141,061,821	581,757
14	(316) Misc. Power Plant Equipment	58,272,116	403,903
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	1,611,518,009	9,431,579
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights	855,341	289,769
18	(321) Structures and Improvements	274,566,472	4,204,444
19	(322) Reactor Plant Equipment	563,568,176	10,350,939
20	(323) Turbogenerator Units	136,410,277	1,549,574
21	(324) Accessory Electric Equipment	184,426,967	5,938,482
22	(325) Misc. Power Plant Equipment	129,791,711	5,370,218
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)	1,289,618,944	27,703,426
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights	1,699,082	0
26	(331) Structures and Improvements	432,438	9,708
27	(332) Reservoirs, Dams, and Waterways	2,656,022	56,801
28	(333) Water Wheels, Turbines, and Generators	1,041,886	98,413
29	(334) Accessory Electric Equipment	253,702	48,999
30	(335) Misc. Power Plant Equipment	42,069	0
31	(336) Roads, Railroads, and Bridges		
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	6,125,199	213,921
33	D. Other Production Plant		
34	(340) Land and Land Rights	586,004	1,595,211
35	(341) Structures and Improvements	2,358,586	19,838
36	(342) Fuel Holders, Products, and Accessories	3,364,005	1,963
37	(343) Prime Movers		
38	(344) Generators	60,635,941	201,963
39	(345) Accessory Electric Equipment	2,812,601	1,012,654

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

reversals of the prior years tentative account distribution of these accounts. Careful observance of the above instructions and the text of Accounts 101 and 106 will avoid serious omissions of the reported amount of plant actually in service at the end of the year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
				(301)	2
				(302)	3
$0	$0	$0	$1,012,103	(303)	4
0	0	0	1,012,103		5
					6
					7
0	0	(348)	8,158,020	(310)	8
173,713	0	5,892	281,240,473	(311)	9
1,718,102	9,092	69,040	906,538,318	(312)	10
				(313)	11
38,439	(1,741)	0	222,844,861	(314)	12
407,529	0	0	141,236,049	(315)	13
292,267	0	(69,559)	58,314,193	(316)	14
2,630,050	7,351	5,025	1,618,331,914		15
					16
0	0	0	1,145,110	(320)	17
30,844	0	199,629	278,939,701	(321)	18
1,350,052	(3,566)	(38,287)	572,527,210	(322)	19
9,971	0	0	137,949,880	(323)	20
58,070	0	(195,978)	190,111,401	(324)	21
3,421,439	0	(3,961)	131,736,529	(325)	22
4,870,376	(3,566)	(38,597)	1,312,409,831		23
					24
231	0	0	1,698,851	(330)	25
0	0	0	442,146	(331)	26
0	0	0	2,712,823	(332)	27
0	0	0	1,140,299	(333)	28
0	0	0	302,701	(334)	29
0	0	0	42,069	(335)	30
				(336)	31
231	0	0	6,338,889		32
					33
0	0	0	2,181,215	(340)	34
2,100	0	0	2,376,324	(341)	35
0	0	0	3,365,968	(342)	36
				(343)	37
0	0	0	60,837,904	(344)	38
32,000	0	0	3,793,255	(345)	39

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106)(Continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
40	(346) Misc. Power Plant Equipment	$426,000	$13,003
41	TOTAL Other Production Plant (Enter Total of lines 34 thru 40)	70,183,137	2,844,632
42	TOTAL Production Plant (Enter Total of lines 15, 23, 32, and 41)	2,977,445,289	40,193,558
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	36,117,765	189,404
45	(352) Structures and Improvements	7,961,532	919,826
46	(353) Station Equipment	191,271,373	43,172,625
47	(354) Towers and Fixtures	92,548,402	0
48	(355) Poles and Fixtures	91,104,549	2,098,823
49	(356) Overhead Conductors and Devices	111,798,987	4,544,465
50	(357) Underground Conduit	4,784,351	0
51	(358) Underground Conductors and Devices	4,320,123	0
52	(359) Roads and Trails		
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	539,907,082	50,925,143
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	8,751,603	702,174
56	(361) Structures and Improvements	18,083,309	630,089
57	(362) Station Equipment	206,411,222	11,410,864
58	(363) Storage Battery Equipment		
59	(364) Poles, Towers, and Fixtures	135,217,211	6,709,394
60	(365) Overhead Conductors and Devices	155,442,700	11,688,419
61	(366) Underground Conduit	72,425,432	3,675,737
62	(367) Underground Conductors and Devices	324,131,236	28,518,943
63	(368) Line Transformers	214,443,407	5,675,786
64	(369) Services	116,937,272	8,748,370
65	(370) Meters	83,852,627	4,450,210
66	(371) Installations on Customer Premises	6,816,821	5,278,660
67	(372) Leased Property on Customer Premises	178,509	0
68	(373) Street Lighting and Signal Systems	20,688,418	980,384
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	1,363,379,767	88,469,030
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	4,759,585	0
72	(390) Structures and Improvements	42,062,624	387,342
73	(391) Office Furniture and Equipment	7,119,905	2,265,990
74	(392) Transportation Equipment	37,835,595	202,734
75	(393) Stores Equipment	1,978,252	2,985
76	(394) Tools, Shop and Garage Equipment	15,431,847	2,684,874
77	(395) Laboratory Equipment	5,967,636	352,542
78	(396) Power Operated Equipment	5,327,805	0
79	(397) Communieation Equipment	35,475,246	429,256
80	(398) Miscellaneous Equipment	329,468	84,227
81	SUBTOTAL (Enter Total of lines 71 thru 80)	156,287,963	6,409,950
82	(399) Other Tangible Property		
83	TOTAL General Plant (Enter Total of lines 81 and 82)	156,287,963	6,409,950
84	TOTAL (Accounts 101 and 106)	$5,038,032,204	$185,997,681
85	(102) Electric Plant Purchased (See Instr. 8)		
86	(Less) (102) Electric Plant Sold (See Instr. 8)		
87	(103) Experimental Plant Unclassified		
88	TOTAL Electric Plant in Service	$5,038,032,204	$185,997,681

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
$0	$0	$0	$439,003	(346)	40
34,100	0	0	72,993,669		41
7,534,757	3,785	(33,572)	3,010,074,303		42
					43
28,158	0	(4,081)	36,274,930	(350)	44
0	0	(330,537)	8,550,821	(352)	45
1,561,351	0	37,630	232,920,277	(353)	46
1,675	0	114,434	92,661,161	(354)	47
231,182	(122)	186,849	93,158,917	(355)	48
288,457	(308)	(256,769)	115,797,918	(356)	49
0	0	0	4,784,351	(357)	50
0	0	0	4,320,123	(358)	51
				(359)	52
2,110,823	(430)	(252,474)	588,468,498		53
					54
646,497	0	(617,999)	8,189,281	(360)	55
191,771	0	66,618	18,588,245	(361)	56
2,850,572	(10,764)	214,820	215,175,570	(362)	57
				(363)	58
886,974	(2,373)	11,063	141,048,321	(364)	59
2,405,575	0	5,271	164,730,815	(365)	60
236,075	0	48,508	75,913,602	(366)	61
3,281,691	0	28,140	349,396,628	(367)	62
1,592,066	70,505	0	218,597,632	(368)	63
578,688	0	(41,711)	125,065,243	(369)	64
2,017,623	(1,077,136)	(54,850)	85,153,228	(370)	65
0	0	0	12,095,481	(371)	66
0	0	0	178,509	(372)	67
128,840	0	0	21,539,962	(373)	68
14,816,372	(1,019,768)	(340,140)	1,435,672,517		69
					70
4,546	0	0	4,755,039	(389)	71
3,657	0	0	42,446,309	(390)	72
41,908	0	7,787	9,351,774	(391)	73
2,444,453	0	47,301	35,641,177	(392)	74
13,118	0	(2,124)	1,965,995	(393)	75
126,273	0	33,281	18,023,729	(394)	76
38,657	0	0	6,281,521	(395)	77
342,323	0	59,849	5,045,331	(396)	78
29,073	0	(4,738)	35,870,691	(397)	79
2,457	0	0	411,238	(398)	80
3,046,465	0	141,356	159,792,804		81
				(399)	82
3,046,465	0	141,356	159,792,804		83
$27,508,417	($1,016,413)	($484,830)	$5,195,020,225		84
				(102)	85
					86
				(103)	87
$27,508,417	($1,016,413)	($484,830)	$5,195,020,225		88

COMPLETED CONSTRUCTION NOT CLASSIFIED - ELECTRIC (ACCOUNT 106)

Account distributions of tentative classification of additions and retirements included in columns (c) and (d), respectively, on pages 204-207.

	Additions		Retirements	
Account	Reversal of Prior Years	Year 1993	Reversal of Prior Years	Year 1993
311				
312				
314				
315				
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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

1. Report below the information called for concerning electric plant leased to others.
2. In column (c) give the date of Commission authorization of the lease of electric plant to others.

Line No.	Name of Lessee (Designate associated companies with an asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	St. Regis Corporation	115 - 13.8 KV Substation and	N/A	N/A	$2,580,245
2		115 KV Transmission Line #5509			
3		and a portion of a Transmission			
4		Sub			
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47	Total				$2,580,245

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.

2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Land and Land Rights:			
2	3–Distribution Substation Sites			$242,126
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21	Other Property:			
22	1–Distribution Substation Structure & Improvement			184,874
23	9–Underground Conduit			270,787
24	2–Transmission Lines			21,602
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47	Total			$719,389

Next Page is 216

CONSTRUCTION WORK IN PROGRESS–ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction, Account 107.
2. Show items relating to "research, development and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work In Progress – Electric (Account 107) (b)
1	Production Plants:	
2	PI–Independent Spent Fuel Storage Facility	$9,149,972
3	PI–Simulator Computer System Upgrade	168,683
4	PI–Repl Vari–Drive on Charging Pumps	199,477
5	MNGP–CAS and SAS Upgrades	156,773
6	PI–Exclusion Fence Gatehouse	158,460
7	PI–LAN Infrastructure Expansion	158,282
8	MNGP–Pooled Inventory Management Equipment	712,349
9	PI–Security System Graphics Package	101,163
10	PI–Spent Fuel Cask Procurement	5,078,144
11	MNGP–Primary Containment Enhancement Mark I	187,644
12	PI–Reactor Coolant Centerline Drain Down Modifications	172,774
13	PI–Safeguard Diesel Generator Addition	6,371,326
14	MNGP–RPV Reference Leg Backfill System	283,995
15	MNGP–MELLLA Installation	108,204
16	PI–PIMS Spare Parts	169,051
17	PI–Control Board Human Factors Modifications	664,298
18	Monti–New Simulator Computer	648,242
19	MNGP–CO6 Control Room Panel Human Factor Modifications	150,431
20	PI–480V MCC Capacity Addition	207,022
21	PI–Incore Thermocouple Connector Upgrade	562,967
22	Standby Generation	1,364,766
23	Pathfinder–Gas Pipeline	193,770
24	Key City–Blank Start Improvements	201,242
25	Angus Anson–Combustion Turbine Plant	51,512,637
26	S1&2–CEM Upgrades	173,684
27	RV–No.6 Bottom Ash Hopper	143,090
28	RV–Fire Protection Improvements	399,815
29	SH–Wet ESP Project Phase III	514,079
30	BD–No.3 Boiler Sootblowers	129,436
31	RV–Clean Air Act Emmission Monitors	258,082
32	MNV–Install CEMS System	245,277
33	SH–Closure of #1 Scrubber Solids Pond	227,868
34	BD–CEM Installation	432,293
35	SH–Low NOX Burners Unit 2	2,706,382
36	King–Permit Application/Waste Management	170,318
37	S3–AQCS Landfill Cell 2	187,492
38	Lake Benton–Wind Generation	479,999
39	Various Production	3,510,253
40		
41		
42		
43	TOTAL Production Plants	$88,259,740

CONSTRUCTION WORK IN PROGRESS-ELECTRIC (Account 107) (Continued)

1. Report below descriptions and balances at end of year of projects in process of construction, Account 107.
2. Show items relating to "research, development and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work In Progress - Electric (Account 107) (b)
1	Transmission Plants:	
2	Ln 0979-Increase Operating Temperature	$182,479
3	Ln 0889-CNCPKW to 400MVA	220,846
4	Manitoba-Minnesota Transmission Upgrade (MMTU)	283,884
5	Red Wing River Crossing Rebuild	445,697
6	Twin Cities Transformer Capacity Addition	167,165
7	Roseau Co Sub-Series Compensation	241,518
8	Ln 0825-Install Tap to Buffalo Ridge Sub	250,196
9	Chisago Sub-Increase Capacity	286,486
10	Forbes Sub-Static Compensation	23,830,105
11	Buffalo Ridge Sub-Construct New Sub	106,657
12	Pathfinder Sub-Replace Carrier & Modify	106,058
13	Ln 5401-Install Arrestors	256,270
14	Ln 0790-Install Arrestors	123,137
15	Ln 0871-Rebuild 1.6 Miles	163,085
16	Roseau Sub-Install 60MVAR Capacitors	132,343
17	Chisago Sub-Series Compensation	104,546
18	Blue Lake Sub-Black Start Improvements	208,379
19	Inver Hills Sub-Black Start Improvements	156,347
20	Parkers Lake Sub-Black Start Improvements	259,837
21	Wilmarth Sub-Black Start Improvements	194,385
22	Granite City Sub-Black Start Improvements	185,702
23	Ln 5506-Rebuild Tap	809,214
24	Benton Co Sub-Black Start Improvements	161,584
25	Ln 0727-Relocate for Highway Widening	367,248
26	Ln 0730-Relocate Line	683,783
27	Ln 0704-Rebuild Line	230,839
28	Microwave Installations-Various Locations	203,534
29	Ln 0982-Increase OPR Temperature	120,928
30	Ln 0714-Rebuild Line	186,396
31	Ln 0885-Reconductor Line	140,282
32	Sheyenne Sub-Install 240 MVAR of Capacity	308,286
33	Prairie Sub-Static Compensation	280,832
34	Forbes Sub-Install 500KV Bus	3,443,889
35	Various Transmission	2,662,304
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42		
43	TOTAL Transmission Plants	$37,504,241

CONSTRUCTION WORK IN PROGRESS-ELECTRIC (Account 107) (Continued)

1. Report below descriptions and balances at end of year of projects in process of construction, Account 107.
2. Show items relating to "research, development and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work In Progress - Electric (Account 107) (b)
1	Distribution Plants:	
2	Savers Switch-Residential Load Control	$433,684
3	West Byron Sub-Construct Sub	299,076
4	Excelsior Sub-Increase Transformer Capacity	107,463
5	Network Systems-Various Locations	417,630
6	Grain Exchange Vault-Deck Replacement	101,951
7	North Star Steel-Install Transformer	224,604
8	Long Lake Sub-Install 2nd 25 MVA Transformer	413,586
9	Cliff Ave Sub-Install Transformer	157,416
10	Minnehaha Sub-Install Transformer	382,823
11	Basset Creek Sub-Construct Substation	898,025
12	Line Transformers	1,908,296
13	Chemolite Sub-Feeder for 3M Company	143,475
14	Woodbury Sub-Construct Sub	1,013,734
15	Hastings Sub-Install TA Switches	101,673
16	Various Distribution	14,212,003
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43	TOTAL Distribution Plants	$20,815,439

CONSTRUCTION WORK IN PROGRESS-ELECTRIC (Account 107) (Continued)

1. Report below descriptions and balances at end of year of projects in process of construction, Account 107.
2. Show items relating to "research, development and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work In Progress - Electric (Account 107) (b)
1	General Plants:	
2	SCADA/AGC/PCM-Distributed Architecture System	$194,053
3	PSAD-Analysis Data Base	120,645
4	SYOP-Stability Workstation	261,345
5	Computer Equipment	510,664
6	Tools & Work Equipment	124,317
7	Chestnut Serv Ctr-Renovation	608,454
8	Ultrasonic Calibration Equipment	133,806
9	Line Clearance Data Terminals	160,389
10	GIS Project	1,761,038
11	MNGP-Champs Management Information System	449,562
12	PI-Management Software Upgrade	576,879
13	Various General	2,459,170
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43	TOTAL General Plants	$7,360,322

CONSTRUCTION WORK IN PROGRESS-ELECTRIC (Account 107) (Continued)

1. Report below descriptions and balances at end of year of projects in process of construction, Account 107.
2. Show items relating to "research, development and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work In Progress – Electric (Account 107) (b)
1	General Office Projects:	
2		
3	Various Construction Projects-Payment Withheld Pending Final Acceptance	
4	of Contract Work	$1,550,287
5		
6	Various Construction Projects In PAS Interim Accounts	491,200
7		
8	Real Estate Taxes For Construction Work In Progress	1,768,795
9		
10	Undistributed Construction Overheads	186,548
11		
12	TOTAL General Office Projects	3,996,830
13		
14		
15	Research, Development and Demonstration:	
16		
17	Miscellaneous R & D	260,034
18		
19	TOTAL R & D	260,034
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43	GRAND TOTAL	$158,196,606

CONSTRUCTION OVERHEADS-ELECTRIC

1. List in column (a) the kinds of overheads according to titles used by respondent. Charges for outside professional services for engineering fees and management or supervision fees capitalized should be shown as separate items.
2. On page 218 furnish information concerning construction overheads.
3. A respondent should not report "none" to this page if no overhead apportionments are made, but rather should explain on page 218 the accounting procedures employed and the amounts of engineering, supervision and administrative costs etc. which are directly charged to construction.
4. Enter on this page engineering, supervision, administrative and allowance for funds used during construction, etc., which are first assigned to a blanket work order and then prorated to construction jobs.

Line No.	Description of Overhead (a)	Total Amount Charged for the Year (b)
1	Administrative and General Expense	$2,693,572
2	Engineering and Supervision - Prorate	12,501,884
3	Engineering and Supervision - Direct	1,772,884
4	Engineering Services (Outside)	8,206,562
5	Allowance for Funds Used During Construction	7,639,504
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46	TOTAL	$32,814,406

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GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extent of work, etc. the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Electric Plant instructions 3 (17) of the Uniform System of Accounts.
3. Where a net-of-tax rate for borrowed funds is used show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

Net of Tax Rate for Borrowed Funds = Gross Rate for Borrowed Funds - (Gross Rate for Borrowed Funds x Income Tax Rate)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

For line 1(5), column (d) below, enter the rate granted in the last rate proceeding. If such is not available, use the average rate earned during the preceding three years.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Dollars in thousands

Line No.	Title (a)		Amount (b)	Capitalization Ratio (Percent) (c)		Cost Rate Percentage (d)
(1)	Average Short-Term Debt	S	77,018			
(2)	Short Term Interest				s	3.26
(3)	Long-Term Debt	D	1,120,281	38.10	d	8.00
(4)	Preferred Stock	P	275,000	9.35	p	5.93
(5)	Common Equity	C	1,545,181	52.55	c	12.10
(6)	Total Capitalization		2,940,462	100.00		
(7)	Average Construction Work in Progress Balance	W	203,274			

2. Gross Rate for Borrowed Funds

s(S/W) + d(D/(D+P+C)) * (1-(S/W)) 3.13

3. Rate for Other Funds

[1-(S/W)] * [p(P/(D+P+C)) + c(C/(D+P+C))] 4.29

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 3.14

b. Rate for Other Funds - 4.13 Total - 7.27

Semi-Annual Compounding
Effective Total - 7.40%

The actual rate used for 1993 was within .25% of the calculated rate above.

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE (Continued)

Administrative and General Expenses

This overhead has been established to accumulate the amount of Administrative and General expenses allocable to construction activities in the current year. Charges to this overhead are cleared to construction work orders on the basis of the ratio of the total expenses to the total construction charges, exclusive of leased and loaned property, station type transformers and regulators in reserve.

The major portion of Employee Pension and Benefits (Account 926) and Injuries and Damages (Account 925) allocable to construction have been cleared to construction work orders on the basis of direct construction labor through a labor loading factor.

Portions of accounts 920, 921, 922, 926, and 408.1 were determined as applicable to construction.

Engineering and Supervision Prorate

This overhead has been established to accumulate the expenditures of respondent's Engineering Department. The engineering and supervision are cleared to construction and removal work orders, on the basis of the ratio of the total engineering charges to the total construction and removal expense exclusive of all equipment classified as general plant (other than communication equipment), leased and loaned property, station type transformers and regulators in reserve, line transformers and regulators, meters, gas regulators, land rights and purchase of operating units or systems.

Engineering and Supervision Direct

This overhead has accumulated the expenditures of respondent's Engineering Department as applicable to certain specific projects. Engineering personnel time and expenses are cleared to construction on a time card basis.

Engineering Services (Outside)

This overhead has been established to accumulate all expenditures made to other companies, firms or individuals engaged by the respondent to plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction and removal work. Charges to this overhead are cleared to specific construction and removal projects.

Allowance for Funds used during Construction

Allowance for funds used during construction is charged to construction projects when the period of construction charges will be over thirty days, such overheads cease when the project is placed in service. The rate for allowance for funds used during construction was 7.4%, effective January 1, 1993 through December 31, 1993.

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during the year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for electric plant in service, pages 204-207, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	$2,049,048,379	$2,047,671,457		$1,376,922
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	209,464,648	209,464,648		
4	(413) Exp. of Elec. Plt. Leas. to Others	66,217			66,217
5	Transportation Expenses-Clearing	2,906,600	2,906,600		
6	Other Clearing Accounts	2,183,646	2,183,646		
7	Other Accounts (Specify):				
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	214,621,111	214,554,894		66,217
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	26,817,846	26,814,004		3,842
12	Cost of Removal	5,678,499	5,675,030		3,469
13	Salvage (Credit)	6,818,271	6,818,271		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	25,678,074	25,670,763		7,311
15	Other Debit or Credit Items (Describe):				
16	Adjustments (Credit)	(2,483,798)	(2,483,798)		
17	Balance End of Year (Enter Total of lines 1, 9, 14, 15, and 16)	$2,240,475,214	$2,239,039,386		$1,435,828

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
18	Steam Production	$653,585,359	$653,585,359		
19	Nuclear Production	790,680,292	790,680,292		
20	Hydraulic Production - Conventional	3,652,449	3,652,449		
21	Hydraulic Production - Pumped Storage				
22	Other Production	57,550,562	57,550,562		
23	Transmission	201,102,081	200,465,364		$636,717
24	Distribution	469,848,211	469,049,100		799,111
25	General	64,056,260	64,056,260		
26	TOTAL (Enter Total of lines 18 thru 25)	$2,240,475,214	$2,239,039,386		$1,435,828

Footnotes:

Line 11, column (c): Electric Plant in Service Book Cost of Plant retired is $14,981 less than Depreciable Plant Retired pages 204-207, column D (excluding land) because occasionally plant retirements do not get cleared to reserve in the current month.

Line 16, column (c): Includes retirement adjustments of $-775,008; net transfer between utilities of $152,060; net changes in Electric Retirement Work In Progress of $-1,860,849.

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NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with an asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases or transfers of Nonutility Property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.
5. Minor items (5% of the Balance at the End of the Year for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service (line 44), or (2) other nonutility property (line 45).

Line No.	Description and Location (a)	Balance Beginning of Year (b)	Purchases/Sales Transfers etc. (c)	Balanee at End of Year (d)
1	Property Previously Devoted to Public Services:			
2				
3	12-58 Underground Conduit and Manholes Acq From T.C.R.T.	$71,925		$71,925
4	12-58 Formerly PT Fargo Diesel Plant Site	200,954		200,954
5	11-87 Portion of 69KV Line No. 0708	90,210		90,210
6	12-89 Portion of 34.5KV Line No. 0507	43,136	(43,136)	0
7	12-89 Portion of 69KV Line No. 0734	33,614		33,614
8				
9		439,839	(43,136)	396,703
10				
11	Other Nonutility Property:			
12				
13	05-76 Easements-Line 0854 (Parkers Lake-Crow River)	50,099	(210)	49,889
14	1968-1972 Easements-Line 0864 (Coon Rapids-St Cloud)	44,490		44,490
15	07-80 Easements-Line 0985 (Sherburne County-Parkers Lake)	60,533		60,533
16	05-76 Easements-Line 5701 (Moorehead-Twin Cities)	63,053		63,053
17	11-82 Wescott Propane Plant-House & Garage	82,000		82,000
18	06-83 Easements-Line 0871 (Moore Lake-West Coon Rapids)	90,193		90,193
19	10-83 Cedar Lake Substation Site	173,629		173,629
20	1984-1986 Sherburne County-House & Outbuildings	324,000		324,000
21	1985 500KV Line No. 5703-House, Garage Etc	139,770		139,770
22	1992 Shady Oak Substation	0	644,982	644,982
23	1985-1990 Refuse Derived Fuel (RDF)	66,402,849	(37,454,119)	28,948,730
24	1993 CNG Compressor-Reinforced Thermo Poruducts, Inc	0	25,755	25,755
25	1993 Liberty Paper Steam Line		25,252	25,252
26	1992-1993 Renaissance Square Ultra Power Monitor	17,286	11,868	29,154
27	1991 Grand Forks Boiler Plant	121,421		121,421
28		67,569,323	(36,746,472)	30,822,851
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45	Minor Items Previously Devoted to Public Service	107,951	(1,445)	106,506
46	Minor Items-Other Nonutility Property	302,283		302,283
47	TOTAL	$68,419,396	($36,791,053)	$31,628,343

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INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investment in Subsidiary Companies.
2. Provide subheading for each company and list thereunder the information called for below. Subtotal by company and give a total in columns (e), (f), (g) and (h).

(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.

(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment but which are not subject to current settlement. With respect to each advance show whether the advance is a note or an open account. List each note giving date of issuance, maturity date, and specify whether the note is a renewal.

3. Report separately the equity in undistributed subsidiary earnings since acquisition. The total in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Northern States Power Company (Wis)			
2	Common Stock - par value $100 per share			
3	per share 1938 - 1988 (See (f) on page 224B)			$96,750,946
4	Undistributed subsidiary earnimgs since acquisition			192,252,826
5	Total			289,003,772
6				
7				
8	United Power and Land Company			
9	Common Stock - par value $100 per share			14,020,000
10	Undistributed subsidiary earnings since acquisition			1,242,788
11	Advances - open account			200,000
12	Total			15,462,788
13				
14				
15	Cormorant Corporation			
16	Common Stock - par value $10 per share			1,275,000
17	Undistributed subsidiary earnings since acquisition			(752,331)
18	Total			522,669
19				
20				
21	First Midwest Auto Park, Inc.			
22	Common Stock - par value $1.00 per share			3,330,605
23	Undistributed subsidiary earnings since acquisition			716,116
24	Total			4,046,721
25				
26				
27	NRG Energy, Inc.			
28	Notes Receivable	12-31-93	12-01-06	0
29	Common Stock - par value $100 per share			45,414,000
30	Undistributed subsidiary earnings since acquisition			(13,721,790)
31	Total			31,692,210
32				
33				
34	Eloigne Company			
35	Common Stock - no par value			0
36	Undistributed subsidiary earnings since acquisition			0
37	Total			0
38				
39				
40				
41				
42				

INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes or accounts that were pledged, designate such securities, notes or accounts in a footnote and state the name of pledgee and purpose of the pledge.

5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization and case or docket number.

6. Report in column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.

7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between the cost of investment (or other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).

8. Report on Line 42, column (a) the total cost of Account 123.1.

Equity in Subsidiary Earnings for Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
		$96,750,946		3
$38,006,519		204,078,370	see page 224B(b)(d)	4
38,006,519		300,829,316		5
				6
				7
				8
		14,020,000		9
866,164		2,148,108	see page 224B(c)	10
			see page 224B(e)	11
866,164		16,168,108		12
				13
				14
				15
		1,275,000		16
(46,640)		(798,971)		17
(46,640)		476,029		18
				19
				20
				21
		3,330,605		22
503,641		1,219,757		23
503,641		4,550,362		24
				25
				26
				27
		9,466,697	see page 224B(a)	28
		112,128,881	see page 224B(a)	29
(95,155)		(13,816,945)		30
(95,155)		107,778,633		31
				32
				33
				34
		8,250,000	see page 224B(a)	35
(107,500)		(146,656)	see page 224B(c)	36
(107,500)		8,103,344		37
				38
				39
				40
				41
				42

INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1)

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Viking Gas Transmission Company			
2	Common Stock – par value $5.00 per share			
3	Undistributed subsidiary earnings since acquisition			
4	Total			
5				
6				
7	NEO Corporation			
8	Common Stock – no par value			
9	Undistributed subsidiary earnings since acquisition			
10	Total			
11				
12				
13	Cenergy, Inc			
14	Common Stock – no par value			
15	Undistributed subsidiary earnings since acquisition			
16	Total			
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	TOTAL Cost of Account 123.1 $459,815,200		TOTAL	$340,728,160

INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

Equity in Subsidiary Earnings for Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		13,000,000	see page 224B(a)	2
853,332		853,332		3
853,332		13,853,332		4
				5
				6
				7
		$200,000	see page 224B(a)	8
($15,934)		(15,934)		9
(15,934)		184,066		10
				11
				12
				13
		8,000,000	see page 224B(a)	14
(127,990)		(127,990)		15
(127,990)		7,872,010		16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
$39,836,437		$459,815,200		42

INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.2)(Continued)

(a) During 1993 the following investment activities took place:

Purchased stock in Eloigne Company totaling $8,250,000
Purchased stock in Viking Gas totaling $45,000,000
Repurchase of stock by Viking Gas totaling $32,000,000
Purchased stock in NEO Corporation totaling $200,000
Purchased stock in Cenergy Inc totaling $8,000,000
Transfer of Refuse-derived fuel operations to NRG Energy, Inc. in exchange for stock totaling $7,214,881
Transfer of Refuse-derived fuel operations to NRG Energy, Inc. in exchange for a Note Receivable totaling $9,466,697
Purchased stock in NRG Energy,Inc totaling $59,500,000

(b) In 1993, Undistributed subsidiary earnings for Northern States Power Company (Wis) was reduced by $472,495 due to subsidiary appropriation of retained earnings.

(c) In 1993, Undistributed subsidiary earnings resulting from affordable housing investments of ($39,156) was transferred from United Power and Land Company to Eloigne Company.

(d) Dividends of $25,708,480 were paid to the Company by Northern States Power Company (Wis) in 1993.

(e) The $200,000 advance to United Power and Land Company was repaid in 1993.

(f) As of January 2, 1938, incident to recapitalization of Northern States Power Company (Delaware) and Northern States Power Company (Wisconsin) respondent acquired 149,472 shares of common stock of Northern States Power Company (Wisconsin). This acquisition was effective pursuant to SEC Order No. 46-102 dated December 28, 1938, Pub. Serv. Comm. of Wis. Docket No. 2-SB-97 dated May 6, 1938, and Pub. Serv. Comm. of Wis. No. 2-SB-116 dated December 19, 1938.

Subsequent acquisitions and commission approvals are as follows:

Year	Shares Acquired	Name of Commission	Date of Authorization	Case or Docket No.
1939	25,327	S E C	March 21, 1939	32-132
		P S C of Wis	March 9, 1939	2-SB-119
1947	5,201	S E C	April 11, 1947	70-1490-1
		P S C of Wis	April 22, 1947	2-SB-282
1948	60,000	S E C	June 30, 1948	70-1859
		P S C of Wis	June 15, 1948	2-SB-331
1949	15,000	S E C	Oct. 31, 1949	70-2247
		P S C of Wis	Oct. 18, 1949	2-SB-378
1950	30,000	S E C	July 14, 1950	70-2427
		P S C of Wis	June 30, 1950	2-SB-418
1954	40,000	S E C	April 2, 1954	70-3221
		P S C of Wis	March 25, 1954	2-SB-555
1957	56,929	F P C	Oct. 25, 1957	E-6774
		P S C of Wis	Oct. 18, 1957	2-SB-694
1958	1,855	F P C	Sept. 12, 1958	E-6834
1973	127,928	* P S C of Wis	March 22, 1973	2-SB-1274
1976	188,288	**P S C of Wis	July 1, 1976	4220-SB-2
1987	124,000	P S C of Wis	Dec. 30, 1986	4220-SB-103
1988	38,000	P S C of Wis	Dec. 22, 1987	4220-SB-106
		P S C of Wis	Jan. 7, 1988	
		P S C of MI	Dec. 22, 1987	U-8937

* 33-1/3% stock dividend

** Approximately 3 for 2 stock dividend

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MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.

2. Give an explanation of important inventory adjustments during year (on a supplemental page) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected - debited or credited. Show separately debits or credits to stores expense-clearing, if applicable.

Line No.	Account (a)	Balance Beginning Of Year (b)	Balance End of Year (c)	Department(s) Which Use Material (d)
1	Fuel Stock (Account 151)	$31,541,763	$17,331,390	
2	Fuel Stock Expenses Undistributed (Account 152)	(1,157,623)	(1,635,737)	
3	Residuals and Extracted Products (Account 153)	3,075,370	2,969,676	
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	67,296,567	40,592,277	All Utilities
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	14,406,596	41,445,885	All Utilities
8	Transmission Plant (Estimated)	98,675	12,043,555	All Utilities
9	Distribution Plant (Estimated)	6,413,896	620,083	All Utilities
10	Assigned to - Other	10,459,584	1,442,862	All Utilities
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	98,675,318	96,144,662	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)	116,392	309,484	
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)	760,183	421,539	
16	Liquified Natural Gas Stored (Account 164)	15,044,689	17,134,395	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	$148,056,092	$132,675,409	

Note: The allocation method used to estimate account 154 by function was changed in 1993.

ALLOWANCES (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions on lines 36-40.

Line No.	Allowanee Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	1994 No. (d)	1994 Amt. (e)
1	Balance-Beginning of Year	0	$0	0	$0
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow.)	0	$0	0	$0
5	Returned by EPA	0	$0	0	$0
6					
7	Purchases/Transfers:				
8					
9	None				
10					
11					
12					
13					
14					
15	Total	0	$0	0	$0
16					
17	Relinguished During Year				
18	Charges to Account 509	Not Applicable		Not Applicable	
19	Other:				
20					
21	Sales/Transfers:				
22					
23	None				
24					
25					
26					
27					
28	Total	0	$0	0	$0
29	Balance-End of Year	0	$0	0	$0
30					
31	Sales:				
32	Net Sales Proceeds (Assoc. Co.)	0	$0	0	$0
33	Net Sales Proceeds (Other)	0	$0	0	$0
34	Gains	0	$0	0	$0
35	Losses	0	$0	0	$0
	Allowances Withheld (Aecount 158.2)				
36	Balance-Beginning of Year	0	$0	1,075	$0
37	Add: Withheld by EPA	1,831	$0	1,831	$0
38	Deduct: Returned by EPA	0	$0	0	$0
39	Sales	(756)	$0	(756)	$0
40	Balance-End of Year	1,075	$0	2,150	$0
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)		$15,121	NSP (Wisconsin)	
44	Net Sales Proceeds (Other)		$88,467	Deferred (Account 254)	
45	Gains				
46	Losses				

ALLOWANCES (Accounts 158.1 and 158.2)(Continued)

6. Report on line 5 allowances returned by the EPA. Report on line 39 the EPA's sales of the withheld allowances. Report on lines 43–46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on lines 8–14 the names of vendors/transferors of allowances acquired and identify assoc. companies (See "assoc. company" under "Definitions" in the Uniform System of Acts.)
8. Report on lines 22–27 the names of purchasers/transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on lines 32–35 & 43–46 the net sales proceeds and gains or losses from allowance sales.

1995		1996		1997–1999 Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
0	$0	4,158	$0	8,316	$0			1
								2
								3
4,158	$0	4,158	$0	12,474	$0			4
0	$0	0	$0	0	$0			5
								6
								7
								8
								9
								10
								11
								12
								13
								14
0	$0	0	$0	0	$0			15
								16
								17
Not Available		Not Available		Not Available				18
								19
								20
								21
								22
								23
								24
								25
								26
								27
0	$0	0	$0	0	$0			28
4,158	$0	8,316	$0	20,790	$0			29
								30
								31
0	$0	0	$0	0	$0			32
0	$0	0	$0	0	$0			33
0	$0	0	$0	0	$0			34
0	$0	0	$0	0	$0			35
2,150	$0	3,225	$0	4,300	$0			36
1,831	$0	1,906	$0	0	$0			37
0	$0	0	$0	0	$0			38
(756)	$0	(831)	$0	0	$0			39
3,225	$0	4,300	$0	4,300	$0			40
								41
								42
								43
								44
								45
								46

ALLOWANCES (Accounts 158.1 and 158.2)(Continued)

Pages 228 and 229 have been prepared based upon the following assumptions:

1) Since NSP's substitution plan has not been approved by the EPA, the data reflects no substitution and shows only the known Clean Air Act allowance allocations.

2) All allowances are valued at $0 from EPA.

3) NSP has made no sales or purchases other than those sold by EPA auction, and has no plans to do so.

4) NSP distributed $8,376 from 1993 EPA Auction to Southern Minnesota Municipal Power Agency for their ownership share of Sherburne County 3.

5) Pending the filing and approval of the Company's proposed ratemaking treatment by regulators, all gains from sale of allowances have been deferred as a regulatory liability.

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of loss, the date of Commission authorization to use Account 182.1 and period of amortization (mo, yr, to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Not Applicable					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission authorization to use Account 182.2, and period of amortization (mo, yr, to mo, yr).] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Not Applicable					
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

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OTHER REGULATORY ASSETS (Account 182.3)

1. Reporting below the particulars (details) called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).

2. For regulatory assets being amortized, show period of amortization in column (a).

3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	Credits: Account Charged (c)	Credits: Amount (d)	Balance at End of Year (e)
1	D.O.E. Decommissioning & Decontamination	46,552,500	518	1,034,500	45,518,000
2	(Amortization 1993-2007)				
3					
4	Conservation - Electric				
5	Transferred from Account 186	944,662			
6		43,670,117	131	8,269	
7			142	546	
8			182.3	10,166	
9			184.1	1,178,180	
10			186	993,427	
11			232	594,053	
12			419	1,761	
13			419.1	529,075	
14			432	396,116	
15			456	1,648,578	
16			908	5,534,827	
17			910	488	
18			921	3,320	
19			930.2	35,429,078	(1,713,105)
20	Conservation - Gas				
21	Transferred from Account 186	143,099			
22		2,521,549	131	19,922	
23			182.3	57,164	
24			184.1	43,888	
25			232	560,467	
26			419.1	16,883	
27			908	788,739	
28			930.2	925,134	252,451
29	SD Conservation - Electric				
30	Transferred from Account 186	(49,628)			
31		2,530,451	108	86,813	
32			143	819	
33			184.1	4,235	
34			232	450,729	
35			419.1	15,927	
36			432	7,262	
37			908.0	65,873	
38			930.2	767,596	1,081,569
39					
40	Pathfinder Decommissioning				
41	Transferred from Account 186	12,744,063			
42		330,554	143	250	
43			232	268,678	12,805,689
44					
45					

OTHER REGULATORY ASSETS (Account 182.3)

1. Reporting below the particulars (details) called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory assets being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	Credits: Account Charged (c)	Credits: Amount (d)	Balance at End of Year (e)
1	Pathfinder Decommissioning - MN				
2	Transferred from Account 186	(10,883,003)			
3		156,937	426.5	433,552	(11,159,618)
4					
5	Pathfinder Decommissioning - ND				
6	Transferred from Account 186	(765,659)			
7		11,041	426.5	30,502	(785,120)
8					
9	Pathfinder Decommissioning - SD				
10	Transferred from Account 186	(293,617)			
11	(Amortization 1990 - 1994)		407.3	136,326	(429,943)
12					
13	Pathfinder Decommissioning - Wholesale				
14	Transferred from Account 186	(296,955)			
15	(Amortization 1990 - 1993)		407.3	84,035	(380,990)
16					
17	Conservation Rate Base				
18	Transferred from Account 186	24,731,421			
19		33,486,450	131	30,765	
20			132	5,719	
21			143	16,443	
22			154	1,086,574	
23			165	322	
24			182.3	22,810	
25			184	66	
26			184.1	1,333,600	
27			186	837,668	
28			232	870,667	
29			415	10	
30			419.1	367	
31			432	270	54,012,590
32					
33	Accumulated Conservation Amortization				
34	Transferred from Account 186	(6,622,579)			
35		127,240	184.1	10,294,739	
36			930.2	183,661	(16,973,739)
37	State of Minnesota Energy Efficiency Programs				
38	Transferred from Account 186	869,314			
39		3,193,780	131	1,594	
40			142	1,442,786	
41			143	950	
42			184	8,464	
43			184.1	115,955	
44			232	633,118	1,860,227

OTHER REGULATORY ASSETS (Account 182.3)

1. Reporting below the particulars (details) called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory assets being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	Credits: Account Charged (c)	Credits: Amount (d)	Balance at End of Year (e)
1	City of St Paul Energy Efficiency Programs	85,295	232	268	85,027
2					
3	South Dakota Ratemaking Adjustments				
4	Transferred from Account 186	5,954,000			
5		560,000	426.5	268,000	6,246,000
6					
7	Deferred Compensation Plan Costs - SFAS 87				
8	Transferred from Account 186	764,000			
9		575,000			1,339,000
10					
11	Deferred Postretirement Healthcare Costs - SFAS 106	14,273,749	926	1,556,298	12,717,451
12					
13	SFAS 109 - Pre 1988 Debt AFC				
14	Transferred from Account 186	76,759,000			
15		67,831,451	182.3	5,093,000	
16			190	2,451	139,495,000
17					
18	SFAS 109 - Post 1987 Equity AFC Gross Up				
19	Transferred from Account 186	15,147,000			
20		2,995,000	283	24,000	18,118,000
21					
22	SFAS 109 - Pre 1988 Debt AFC Gross Up				
23	Transferred from Account 186	94,201,000			
24		3,627,000	182.3	67,829,000	
25			254	25,588,000	
26			283	4,411,000	0
27					
28	Interest Expense - Income Tax				
29	Transferred from Account 186	1,801,769			
30		1,479,270	131	933	
31			236	202,225	
32			431	759,500	2,318,381
33					
34	Interest Expense - Sales Tax	108,447		0	108,447
35					
36	Environmental Cleanup	1,294,854	131	161,273	1,133,581
37					
38	Minor Items				
39		110,655	232	7,926	
40			908	14,291	
41			930.2	45,568	42,870
42					
43					
44					
45					
46	TOTAL	440,669,227		174,977,459	265,691,768

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MISCELLANEOUS DEFERRED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous debits.
2. For any deferred debit being amortized, show period of amortization in column (a).
3. Minor items (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balancc at (b)	Debits (c)	Credits Account Charged (d)	Credits Amount (e)	Balance at End of Year (f)
1	Miscellaneous Projects	0	332,590	143	5,183	
2				184.1	5	
3				232	86,456	240,946
4						
5	Relocation Project - Other than	82,118	188,984	107	125	
6	State Hwy Project			108	34,750	
7				131	12,812	
8				143	42,274	
9				154	22	
10				184	1,715	
11				232	16,850	162,554
12						
13	State Hwy Relocation Project	51,168	139,675	108	19,119	
14				143	73,405	
15				184	1,942	
16				232	4,180	92,197
17						
18	Claims	1,519,021	5,825,960	107	772	
19				131	2,803,485	
20				143	5,608	
21				154	10	
22				184	2,878	
23				184.1	299	
24				232	1,169,114	
25				925	7,090	3,355,725
26						
27	DSM Tracker Accum Depreciation	0	0	184.1	188,820	(188,820)
28						
29	Shelf Registration - Fees-Bonds	56,761	195,227	181	141,939	110,049
30						
31	Shelf Registration (1993)	0	206,926	181	58,000	148,926
32						
33	Claims-Construction Projects	1,521	344,011	107	105,589	
34				143	6,055	
35				184	10,206	
36				232	97,270	126,412
37						
38						
39	Deferred Project Expenditures	0	138,145			138,145
40						
41						
42	Conservation - Electric	944,662		182.3	944,662	0
43						
44	Conservation - Gas	143,099		182.3	143,099	0
45						
46	SD Conservation - Electric	(49,628)		182.3	(49,628)	0
47						
48	Pathfinder Decommissioning - Total	12,744,063		182.3	12,744,063	0
49						

MISCELLANEOUS DEFERRED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous debits.
2. For any deferred debit being amortized, show period of amortization in column (a).
3. Minor items (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	Credits: Account Charged (d)	Credits: Amount (e)	Balance at End of Year (f)
1	Pathfinder Decommissioning - MN	(10,883,003)		182.3	(10,883,003)	0
2						
3	Pathfinder Decommissioning - ND	(765,659)		182.3	(765,659)	0
4						
5	Pathfinder Decommissioning - SD	(293,617)		182.3	(293,617)	0
6						
7	Pathfinder Decommissioning - Whsl	(296,955)		182.3	(296,955)	0
8						
9	Conservation - Rate Base	24,731,421		182.3	24,731,421	0
10						
11	Accumulated Conservation Amortization	(6,622,579)		182.3	(6,622,579)	0
12						
13	State of Minnesota Energy Efficiency Program	869,314		182.3	869,314	0
14						
15	South Dakota Ratemaking Adjustments	5,954,000		182.3	5,954,000	0
16						
17	Deferred Compensation Plan	764,000		182.3	764,000	0
18	Costs - SFAS 87					
19						
20	SFAS 96 - Pre 1988 Debt AFC	76,759,000		182.3	76,759,000	0
21						
22	SFAS 96 - Post 1987 Equity AFC	15,147,000		182.3	15,147,000	0
23	Gross Up					
24						
25	SFAS 96 - Pre 1988 Debt AFC	94,201,000		182.3	94,201,000	0
26	Gross Up					
27						
28	Interest Expense - Income Tax	1,801,769		182.3	1,801,769	0
29						
30	Minor Items	2,661,243	1,625,966	107	140,452	
31				108	55,396	
32				131	788,293	
33				154	300,869	
34				181	505,418	
35				232	2,433,532	
36				312	46,778	
37				426	315	
38				563	750	15,406
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc Work in Progress					
48	DEFERRED REGULATORY COMMISSION					
49	EXPENSES (see pages 350-351)	0				0
50	TOTAL	$219,519,719				$4,201,540

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Account 190		
2	Electric (See Electric Other)	$134,713,613	$158,850,454
3	Gas (See Gas Other)	3,400,594	5,284,148
4	TOTAL Operating (Enter Total lines 2, 3)	$138,114,207	$164,134,602
5			
6	Non Operating	$5,451,445	$4,580,834
7			
8	TOTAL (Account 190) (Total of lines 2, 3, 6)	$143,565,652	$168,715,436
9			

NOTES

Electric (Other)

Accounts Payable-Ad Valorem Coal	$0	$62,113
Accounts Payable-Workers Compensation	$0	$177,506
Avoided Tax Interest	$8,934,328	$9,450,106
Bad Debts	666,736	1,093,791
CASAR Stock Awards	0	(78,233)
Coal Reclamation Reserve	960,388	1,118,924
Customer Advances	1,220,067	750,823
Customer Energy Conservation Loans	(28,818)	0
Deferred Compensation	7,414,891	8,123,82[illegible]
Deferred Connection Fees	7,265,645	8,272,111
Early Retirement Obligation	4,218,983	3,793,152
Executive Incentive Pay	(1,543)	3,328
Accrued Lawsuits Pending	1,885,096	1,944,044
Accrued Medical Claims	391,244	3,618,814
End of Life Nuclear Fuel Amortization	1,810,953	2,857,120
Nuclear Fuel Disposal - Prairie Island	10,444,218	10,448,043
Nuclear Plant - Decommissioning Provisions	82,500,141	90,515,363
Rate Increase	(674,486)	908,326
Saver Switches - Minnesota	387,466	572,337
Saver Switches - North Dakota	0	1,850
Saver Switches - South Dakota	(1,628)	47,594
Severance Accrual	0	937,125
Sherco Training Costs	289,836	0
Spare Parts Inventory Reserve-Customer Refund	467,219	110,369
Trust Fund Interest Capitalized	1,207,584	1,116,978
Unbilled Revenue	0	1,911,096
Unfunded Pension Costs	0	5,532,071
Vacation Reserve	5,355,293	5,561,882
	$134,713,613	$158,850,454

ACCUMULATED DEFERRED INCOME TAXES (Account 190)(Continued)

	Balance at Beginning of Year (b)	Balance at End of Year (c)
Gas (Other)		
Avoided Tax Interest	$191,738	$266,458
Accounts Payable–Workers Compensation	$0	$17,106
Bad Debts	56,170	61,622
CASAR Stock Awards	0	(7,535)
Customer Advances	257,736	0
Customer Energy Conservation Loans	8,036	0
Deferred Compensation	684,032	748,874
Deferred Conncction Fees	1,029,875	2,120,426
Early Retirement Obligation	337,782	296,769
Executive Incentive Pay	(230)	216
Accrued Lawsuits Pending	305,874	312,453
Accrued Medical Claims	36,617	331,826
Severance Accrual	0	90,258
Unfunded Pension Costs	0	532,814
Vacation Reserve	492,964	512,861
	$3,400,594	$5,284,148
Nonutility		
Various RDF	$10,547	$0
Bad Debts for RDF	199,776	70,262
Reference Plant Design Costs	1,047,672	1,047,672
Environmental & Regulatory Reserve	4,193,450	3,462,900
	$5,451,445	$4,580,834

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CAPITAL STOCK (Accounts 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e. year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to the end of year.

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value Per Share (c)	Call Price at End of Year (d)
1	Cumulative Preferred Stock	7,000,000		
2	$3.60 Series		100.00	103.75
3	$4.08 Series		100.00	102.00
4	$4.10 Series		100.00	102.50
5	$4.11 Series		100.00	103.73
6	$4.16 Series		100.00	103.75
7	$4.56 Series		100.00	102.47
8	$6.80 Series		100.00	103.19
9	$7.00 Series		100.00	103.20
10	Variable Rate series A		100.00	103.00
11	Adjustable Rate Series B		100.00	103.00
12				
13	Total Preferred Stock (1)			
14				
15				
16				
17	Common Stock (2)	160,000,000	$2.50	
18	Leveraged Common Stock held by			
19	Employee Stock Ownership Plan			
20				
21				
22				
23	(1) New York Stock Exchange except			
24	Series A and B			
25				
26	(2) New York Stock Exchange, Chicago			
27	Stock Exchange and Pacific Stock			
28	Exchange			
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

CAPITAL STOCK (Accounts 201 and 204)(Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.

5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at the end of the year.

6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Outstanding Per Balance Sheet		Held by Respondent: As Reacquired Stock (Account 217)		Held by Respondent: In Sinking and Other Funds		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	Line No.
						1
275,000	$27,500,000					2
150,000	15,000,000					3
175,000	17,500,000					4
200,000	20,000,000					5
100,000	10,000,000					6
150,000	15,000,000					7
200,000	20,000,000					8
200,000	20,000,000					9
300,000	30,000,000					10
650,000	65,000,000					11
						12
2,400,000	$240,000,000					13
						14
						15
						16
66,879,577	$167,198,943					17
						18
		239,940	($10,887,336)			19
						20
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						24
						25
						26
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CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL STOCK, AND INSTALLMENTS RECEIVED ON CAPITAL STOCK

(Accounts 202 and 205, 203 and 206,207, 212)

1. Show for each of the above accounts the amount applying to each class and series of capital stock.
2. For Account 202, Common Stock Subscribed, and Account 205, Preferred Stock Subscribed, show the balance due on each class at the end of the year.
3. Describe in a footnote the agreement and transactions under which conversion liability existed under account 203, Common Stock Liability for Conversion, or Account 206, Preferred Stock Liability for Conversion, at the end of the year.
4. For premium of Account 207, Capital Stock, designate with an asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	Number of Shares (b)	Amount (c)
1	Account 207–Premium on Capital Stock		
2			
3	Common Stock	22,178,286	$9,860,222 *
4	* Excess of stated value over par value arising pursuant to amendment of Articles of Incorporation		
5	on May 2, 1951, whereby the Common Stock was changed from shares without par value of $5 each.		
6			
7			
8	Excess of consideration received over par value on Common Stock issued:		
9			
10	Year		
11	1952	2,361,932	6,099,313
12	1954	2,439,712	11,032,995
13	1956	1,341,840	7,908,071
14	1957	352,600	1,674,850
15	1958	30,608	229,560
16	1959	1,904,066	16,184,56[illegible]
17	1960	379,336	3,224,356
18	1964	35,948	539,220
19	1965	1,544,016	21,616,224
20	1969	2,161,622	23,777,842
21	1970	3,458,596	28,533,417
22	1972	3,804,456	35,282,538
23	1973	4,184,902	40,802,795
24	1974	4,600,000	28,750,000
25	1975	3,598,714	32,487,831
26	1976	4,336,954	41,706,787
27	1977	495,958	5,980,264
28	1978	874,670	8,726,553
29	1979	1,341,418	12,013,023
30	1980	386,516	2,995,959
31	1982	563,010	6,321,599
32	1983	616,116	8,631,736
33	1984	641,316	10,603,925
34	1985	592,244	12,096,414
35	1992	56,956	1,869,212
36	1993	4,281,217	177,021,848
37			
38	Reduction of premium associated with retirement of Treasury Stock in 1991	(1,539,432)	(9,058,701)
39			
40	Total Premium on Common Stock		$546,912,414
41			
42			
43			
44			
45			
46			

CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL STOCK, AND INSTALLMENTS RECEIVED ON CAPITAL STOCK (Continued)

(Accounts 202 and 205, 203 and 206,207, 212)

1. Show for each of the above accounts the amount applying to each class and series of capital stock.
2. For Account 202, Common Stock Subscribed, and Account 205, Preferred Stock Subscribed, show the balance due on each class at the end of the year.
3. Describe in a footnote the agreement and transactions under which conversion liability existed under account 203, Common Stock Liability for Conversion, or Account 206, Preferred Stock Liability for Conversion, at the end of the year.
4. For premium of Account 207, Capital Stock, designate with an asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	Number of Shares (b)	Amount (c)
1	* Excess of consideration received over stated value of stocks originally issued without par value.		
2			
3	Premium of $2.75 per share on Cumulative Preferred Stock, $3.60 Series	46,240	$127,160
4	Premium of $0.4278 per share on Cumulative Preferred Stock, $4.10 Series	175,000	74,865
5			
6	Excess of stated value over par value arising pursuant to amended Articles of Incorporation on		
7	May 2, 1951, whereby the Preferred Stock was changed from shares without par value to share		
8	having a par value of $100 each.		
9			
10	Cumulative Preferred Stock, $4.10 Series	175,000	52,500
11			
12			
13	Premium on Cumulative Preferred Stock issued and sold.		
14			
15	17 cents per share, $4.08 Series, April 1954	150,000	25,500
16	12.6 cents per share, $4.11 Series, August 1954	200,000	25,200
17	6 cents per share, $4.16 Series, March 1956	100,000	6,000
18	19 cents per share, $4.56 Series, July 1964	150,000	28,500
19	18 cents por share, $6.80 Series, May 1968	200,000	36,000
20	46.9 cents per share, $7.00 Series, January 1969	200,000	93,800
21			
22	Total Premium on Preferred Stock		$469,525
23			
24			
25			
26			
27	TOTAL		$547,381,939
28			
29	Account 212-Installments Received on Capital Stock		
30	Installments Received on Capital Stock		$209,540
31			
32			
33			
34			
35	TOTAL		$209,540
36			
37			
38			
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46			

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, page 112. Add more columns for any account if deemed nccessary. Explain changes made in any account during the year and give the account entries effecting such change.

(a) Donations Received from Stockholders (Account 208) - State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par at Stated Value of Capital Stock (Account 209) - State amount and give brief explanation of the capital changes which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits and balance at end of year with a designation of the nature of each credit and debit identified by class and series of stock to which related.

(d) Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211 - Miscellaneous Paid-In Capital	
2		
3	Expenses incurred for the issuance of new common stock in 1993 and 1992.	(3,351,793)
4		
5		
6		
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39		
40	TOTAL	($3,351,793)

DISCOUNT ON CAPITAL STOCK (Account 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off during the year and specify the amount charged.

Line No.	Class and Series of Stock (a)	Amount (b)
1	Not Applicable	
2		
3		
4		
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CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of year of capital stock expenses for each class and series of capital stock.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Not Applicable	
2		
3		
4		
5		
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21		
22	TOTAL	

Next Page is 256

LONG–TERM DEBT (Accounts 221, 222, 223, and 224)

1. Report by balance sheet account the particulars (details) concerning long–term debt included in Accounts 221 – Bonds, 222 – Reacquired Bonds, 223 – Advances from Associated Companies, and 224 – Other Long–Term Debt.
2. In column (a), for new issues, give Commission authorized numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.
6. In column (b) show principal amount of bond or other long–term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long–term debt originally issued.
8. In column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give Commission Authorization numbers and dates) (a)		Principal Amount of Debt Issued (b)		Total Expense Premium or Discount (c)
1	Account 221				
2	First Mortgage Bonds Series Due:				
3	September 1, 1993	4.375	15,000,000		192,458
4				(D)	18,750
5	June 1, 1995	6.125	30,000,000		498,242
6				(P)	(505,500)
7	August 1, 1996	5.875	45,000,000		642,670
8				(P)	(675,000)
9	October 1, 1997	6.50	30,000,000		382,379
10				(P)	(225,000)
11	October 1, 1997	5.875	100,000,000		600,000
12				(D)	195,000
13	May 1, 1998	6.75	45,000,000		417,278
14					
15	October 1, 1999	8.00	45,000,000		581,838
16				(D)	1,724,400
17	December 1, 2000	5.75	100,000,000		1,090,479
18				(D)	517,000
19	March 1, 2001	8.00	50,000,000		890,040
20				(P)	(750,000)
21	June 1, 2001	8.25	50,000,000		629,578
22				(P)	(375,000)
23	March 1, 2002	7.375	50,000,000		550,036
24				(P)	(150,000)
25	February 1, 2003	7.50	50,000,000		428,694
26				(P)	(375,000)
27	April 1, 2003	6.375	80,000,000		858,430
28				(D)	320,000
29	January 1, 2004	8.375	75,000,000		748,735
30				(P)	(375,000)
31	May 1, 2005	9.50	80,000,000		963,885
32				(D)	400,000
33					

LONG-TERM DEBT (Accounts 221, 222, 223, and 224) (Continued)

Also, give in a footnote the date of the Commission's authorization of treatment other than specified by the Uniform System of Accounts.

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.

11. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt-credit.

12. In a supplemental statement, give explanatory particulars (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during the year. Give Commisssion authorization numbers and dates.

13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including the name of pledgce and purpose of the pledge.

14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at the end of the year, describe the securities in a footnote.

15. If interest expense was incurred during the year on any obligations retired or reacquired before the end of the year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, Interest on Long- Term Debt and Account 430, Interest on Debt to Associated Companies.

16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total without reduction for amounts held by respondent) (h)	Interest For Year Amount (i)	Line No.
						1
						2
09-01-63	09-01-93	09-01-63	09-01-93	0	437,500	3
						4
06-01-67	06-01-95	06-01-67	06-01-95	30,000,000	1,837,500	5
						6
08-01-66	08-01-96	08-01-66	08-01-96	45,000,000	2,643,750	7
						8
10-01-67	10-01-97	10-01-67	10-01-97	30,000,000	1,950,000	9
						10
10-01-92	10-01-97	10-01-92	10-01-97	100,000,000	3,439,669	11
						12
05-01-68	05-01-98	05-01-68	05-01-98	45,000,000	3,037,500	13
						14
10-01-69	10-01-99	10-01-69	10-01-99	0	3,503,226	15
						16
12-01-93	12-01-00	12-01-93	12-01-00	100,000,000	271,528	17
						18
03-01-71	03-01-01	03-01-71	03-01-01	0	3,892,473	19
						20
06-01-71	06-01-01	06-01-71	06-01-01	0	4,014,113	21
						22
03-01-72	03-01-02	03-01-72	03-01-02	50,000,000	3,687,500	23
						24
02-01-73	02-01-03	02-01-73	02-01-03	50,000,000	3,750,000	25
						26
04-01-93	04-01-03	04-01-93	04-01-03	80,000,000	3,655,000	27
						28
01-01-74	01-01-04	01-01-74	01-01-04	75,000,000	6,281,250	29
						30
05-01-75	05-01-05	05-01-75	05-01-05	0	2,502,040	31
						32
						33

LONG-TERM DEBT (Accounts 221, 222, 223, and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221 - Bonds, 222 - Reacquired Bonds, 223 - Advances from Associated Companies, and 224 - Other Long-Term Debt.
2. In column (a), for new issues, give Commission authorized numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.
6. In column (b) show principal amount of bond or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. In column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give Commission Authorization numbers and dates) (a)		Principal Amount of Debt Issued (b)	Total Expense Premium or Discount (c)
1	December 1, 2005	6.125	70,000,000	512,250
2				(D) 644,700
3	July 1, 2019	9.125	100,000,000	1,282,154
4				(D) 875,000
5				
6				
7				
8	June 1, 2020	9.375	$100,000,000	$310,676
9				(D) 875,000
10	Burnsville Pollution Control			
11	Series C	6.2	8,800,000	279,847
12				
13	Pollution Control			
14	Series J, K and L	Var	13,700,000	788,833
15				
16	Becker Pollution Control			
17	Series G	10.375	100,000,000	2,777,371
18				(D) 750,000
19	Ramsey & Washington Counties			
20	Resource Recovery Series I	Var	27,700,000	611,625
21				
22				
23				
24	Account 221 Total			
25				
26				
27				
28				
29	Account 224			
30				
31	Public Improvements		1,691,819	
32				
33	Genstar	9.00	9,484	

LONG-TERM DEBT (Accounts 221, 222, 223, and 224) (Continued)

Also, give in a footnote the date of the Commission's authorization of treatment other than specified by the Uniform System of Accounts.

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt-credit.
12. In a supplemental statement, give explanatory particulars (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during the year. Give Commisssion authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt sccurities give particulars (details) in a footnote including the name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have bcen nominally issued and are nominally outstanding at the end of the year, describe the securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before the end of the year, include such interest exponse in column (i). Explain in a footnote any difference between the total of eolumn (i) and the total of Account 427, Interest on Long- Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any Iong-tern debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total without reduction for amounts held by respondent) (h)	Interest For Year Amount (i)	Line No.
12-01-93	12-01-05	12-01-93	12-01-05	70,000,000	202,465	1
						2
07-01-89	07-01-19	07-01-89	07-01-19	99,000,000	9,125,000	3
						4
						5
						6
						7
06-01-90	06-01-20	06-01-90	06-01-20	$100,000,000	$9,375,000	8
						9
						10
03-01-76	03-01-96	03-01-76	03-01-96	8,800,000	545,600	11
						12
						13
07-01-81	03-01-11	07-01-81	03-01-11	13,700,000	322,250	14
						15
						16
12-01-83	12-01-13	12-01-83	12-01-13	0	9,510,417	17
						18
						19
12-01-84	12-01-06	12-01-84	12-01-06	23,400,000	1,533,575	20
						21
						22
						23
				919,900,000	75,517,356	24
						25
						26
						27
						28
						29
						30
				527,409	142,958	31
						32
02-17-82	12-27-96			18,876	853	33

LONG-TERM DEBT (Accounts 221, 222, 223, and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221 - Bonds, 222 - Reacquired Bonds, 223 - Advances from Associated Companies, and 224 - Other Long-Term Debt.
2. In column (a), for new issues, give Commission authorized numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.
6. In column (b) show principal amount of bond or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. In column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give Commission Authorization numbers and dates) (a)		Principal Amount of Debt Issued (b)	Total Expense Premium or Discount (c)
1	Mankato Service Center	10.00	441,980	
2				
3	ESOP Loan	Var	$15,000,000	
4				
5	ESOP Loan	Var	15,000,000	
6				
7	Guar Agmt - Poll Cont (1)			
8	Red Wing	5.69	28,750,000	$346,087
9	Monticello 1975	7.40	3,500,000	97,713
10	Monticello 1973	5.41	7,600,000	141,625
11				(D) 39,000
12				
13	Ind Dev Rev Bonds			
14	Sioux Falls	5.78	940,000	41,652
15	Inver Grove Hts 1975	7.125	1,000,000	29,598
16				
17	Non-collateralized Poll Cont			
18	Becker 1987	7.25	9,000,000	257,088
19				
20	Anoka Cty Series 1985	7.00	29,750,000	605,664
21				
22	Becker Poll Cont 1989A	6.80	60,000,000	784,380
23				(D) 1,050,000
24				
25	Becker Poll Cont 1992A	Var	27,900,000	251,542
26				
27	Becker Poll Cont 1993A	Var	50,000,000	250,642
28				
29	Becker Poll Cont 1993B	Var	50,000,000	202,213
30				
31	Becker RDF Landfill	11.00	160,000	
32				
33	Account 224 Total			
34				
35	(1) Pollution Control financing at average interest rates			
36				
37	Grand Total Long-term Debt			

LONG–TERM DEBT (Accounts 221, 222, 223, and 224) (Continued)

Also, give in a footnote the date of the Commission's authorization of treatment other than specified by the Uniform System of Accounts.

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.

11. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt–credit.

12. In a supplemental statement, give explanatory particulars (details) for Accounts 223 and 224 of net changes during the year. With respect to long–term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during the year. Give Commisssion authorization numbers and dates.

13. If the respondent has pledged any of its long–term debt securities give particulars (details) in a footnote including the name of pledgee and purpose of the pledge.

14. If the respondent has any long–term debt securities which have been nominally issued and are nominally outstanding at the end of the year, describe the securities in a footnote.

15. If interest expense was incurred during the year on any obligations retired or reacquired before the end of the year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, Interest on Long- Term Debt and Account 430, Interest on Debt to Associated Companies.

16. Give particulars (details) concerning any long–term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total without reduction for amounts held by respondent) (h)	Interest For Year Amount (i)	Line No.
09–01–91	08–01–03			191,873	21,350	1
						2
03–21–91	07–20–93			$0	$79,560	3
						4
04–20–93	04–20–93			10,887,336	259,318	5
						6
						7
05–01–73	Various	05–01–73	05–01–03	25,250,000	1,443,250	8
07–01–75	02–01–03	07–01–75	02–01–03	3,500,000	259,000	9
02–01–73	Various	02–01–73	02–01–03	6,100,000	331,808	10
						11
						12
						13
10–01–73	Various	10–01–73	12–01–98	310,000	20,276	14
02–01–75	01–01–95	01–01–75	01–01–95	1,000,000	71,250	15
						16
						17
12–01–87	12–01–05	12–01–87	12–01–05	9,000,000	652,500	18
						19
12–01–85	12–01–08	12–01–85	12–01–08	26,100,000	1,598,001	20
						21
07–01–89	04–01–07	07–01–89	04–01–07	60,000,000	4,080,000	22
						23
						24
03–01–92	03–01–19	03–01–92	03–01–19	27,900,000	655,667	25
						26
09–01–93	09–01–19	09–01–93	09–01–19	50,000,000	340,524	27
						28
09–01–93	09–01–19	09–01–93	09–01–19	50,000,000	352,655	29
						30
12–31–91	Various			0	0	31
						32
				270,785,494	10,308,970	33
						34
						35
						36
				$1,190,685,494	$85,826,326	37

Note 1

Detail for Account 224 of net changes during the year:

	Balance 12-31-92	Additions	Reductions	Balance 12-31-93
Public Improvements	$1,658,578	$14,661	$1,145,830	$527,409
Genstar	18,022	854		18,876
Mankato Service Center	201,141		9,268	191,873
ESOP Loan	5,112,850		5,112,850	0
ESOP Loan	0	15,000,000	4,112,664	10,887,336
Guar Agmt - Poll Cont				
Red Wing	25,750,000		500,000	25,250,000
Monticello 1975	3,500,000			3,500,000
Monticello 1973	6,400,000		300,000	6,100,000
Ind Dev Rev Bonds				
Sioux Falls	365,000		55,000	310,000
Inver Grove Hts 1975	1,000,000			1,000,000
Non-collateralized Poll Cont				
Becker 1987	9,000,000			9,000,000
Anoka Cty Series 1985	26,950,000		850,000	26,100,000
Becker Poll Cont 1989A	60,000,000			60,000,000
Becker Poll Cont 1992A	27,900,000			27,900,000
Becker RDF Landfill	80,000		80,000	0
	$167,935,591	$15,015,515	$12,165,612	$170,785,494

Note 2

Details regarding the treatment of unamortized debt expense, premium or discount associated with issues redcemed during the year.

The unamortized debt expense, premium or discount associated with debt issues redeemed or refinanced during the year are amortized over the life of the new bond.

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RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same details furnished on Schedule M-I of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.

2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with the taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member and, basis of allocation, assignment, or sharing of the consolidated tax among the group members.

3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	$211,739,978
2	Reconciling Items for the Year: Equity in Earnings of Subsidiary Companies	(39,836,437)
3	Total Income Tax Expense	107,742,007
4	Taxable Income Not Reported on Books	94,050,845
5		
6		
7		
8	Deductions Recorded on Books Not Deducted for Return	333,721,257
9		
10		
11		
12		
13	Income Recorded on Books Not Included in Return	(7,021,438)
14		
15		
16		
17		
18	Deductions on Return Not Charged Against Book Income	(441,080,662)
19		
20		
21		
22		
23		
24		
25		
26	Federal Tax Net Income	$259,315,550
27	Show Computation of Tax:	
28		
29	35.00% of Federal Tax Net Income	$90,655,443
30		
31	Plus:	
32	Adjustment of Prior Years	(2,308,273)
33		
34		
35		
36	Total Federal Income Tax Payable	$88,347,170
37		
38		
39		
40		
41		
42		
43		
44		

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME
FOR FEDERAL INCOME TAXES (Continued)

ATTACHMENT TO PAGE 261 -

TAXABLE INCOME NOT REPORTED ON BOOKS:	Amount
Income Earned on Annuity Payments	$55,943
CIAC - Connection Fees	7,174,807
Customer Advances	31,899
South Dakota AFDC Adj and Amortization	292,000
Spare Parts Inventory Reserve	220,367
Tax Benefit Transfers Lease Rental Income	77,624,318
Unbilled Revenues	8,651,511
Total to Page 261	$94,050,845

DEDUCTION RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:	
Ad Valorem Coal Tax	$20,914
Accounts Payable Severance Accrual	603,172
Bad Debt Reserve	261,413
Book Depreciation	241,117,106
Book Nuclear Fuel Expense	51,865,819
Clearing Account Reversal	3,900,562
Coal Restoration Reserve	1,022,231
Decommissioning and Decontamination	1,034,500
Deferred Compensation	1,096,705
Deferred Gas Costs	3,127,343
Executive Incentive Plan	8,668
Interest Capitalized Under IRC Sect 263A	917,493
Meal and Entertainment Expenses - 20% Exclusion	600,000
Medical Deductions	6,660,000
Pathfinder Deferred Asset Decrease	454,811
Accrued Pending Lawsuits	1,081,500
Accrued Pension Expense	14,792,402
Preferred Dividends	301,920
Prepaid Insurance	294,199
Prepaid Maintenance Costs	17,039
Spare Parts Change of Accounting	3,701,134
Vacation Reserve	842,326
Total to Page 261	$333,721,257

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:	
Book Income - AFDC Equity	($4,856,412)
Book Income - Tax Benefit Transfers	(2,148,465)
Rate Increase Refund	(16,561)
Total to Page 261	($7,021,438)

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME
FOR FEDERAL INCOME TAXES (Continued)

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:	Amount
Amortization fo Debt Discount, Premium & Expenses	($3,662,711)
CASAR and DESAR Stock Awards	(112,275)
Non-Qualified Externally Funded Nuclear Decommissioning	(522,730)
Early Retirement Amortization	(1,278,571)
Conservation Improvement Program Regulatory Asset Increase	(17,629,249)
ESOP Dividends & Plan Contributions	(8,597,819)
Nuclear Fuel Removal Fee - 1 M/KWH	(8,745,574)
Environmental & Regulatory Reserve	(1,823,413)
State Income Tax Deduction	(24,564,950)
Tax Benefit Transfer Amortization Expense	(99,665)
Tax Benefit Transfer Interest Expense	(53,196,197)
Tax Depreciation	(303,814,053)
Tax Removal Cost Over Book Accrual	(6,129,818)
Tax Repair Allowance Expense	(10,123,885)
Wealth Op Increase in CSV and Premium Expense	(664,609)
Workers Compensation	(115,143)
Total to Page 261	($441,080,662)

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME
FOR FEDERAL INCOME TAXES (Continued)

Northern States Power Company (Minnesota) is a member of an affiliated group which will file a consolidated Federal Income Tax Return for the year 1993. The other members of the affiliated group and the Federal Income tax provision of each are:

Northern States Power Company (Wisconsin)	$13,794,082
United Power and Land Company	469,000
Cenergy, Inc.	(21,688)
Cormorant Corporation	(26,000)
Eloigne Corporation	(58,000)
First Midwest Auto Park Inc.	273,000
NEO Corporation	(1,000)
NRG Energy, Inc.	(3,106,573)
Viking Gas Transmission Company	58,756

The consolidated Federal Income tax liability is apportioned among the member companies based on the stand-alone method. The stand-alone method allocates the consolidated federal income tax liability among the companies based on the recognition of the benefits/burdens contributed by each member to the consolidated return. Under the stand-alone method, the sum of the amounts allocated to the member companies equals the consolidated amount.

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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged directly to final accounts (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to portions of prepaid taxes chargeable to current year and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such a manner that the total tax for each state and subdivision can be readily ascertained.

Line No.	Kind of Tax (See Instruction 5) (a)		BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Paid During Year (e)	Adjustments (f)(2)
			Taxes Accrued (b)(1)	Prepaid Taxes (c)			
1	FEDERAL TAXES						
2							
3	Income Tax	1993	(5,142,580)		88,346,170	76,577,969	(4,124,562)
4							
5							
6							
7	FICA	1993	72,299		24,747,386	24,786,989	0
8		1992				0	
9							
10							
11	Fed Unemployment	1993	11,797		417,630	423,282	0
12		1992				0	
13							
14							
15	Super Fund	1993	0		0	0	
16		1992				0	0
17							
18	Use	1993	0		0	0	0
19		1992				0	
20							
21	TOTAL FEDERAL		(5,058,484)	0	113,511,186	101,788,240	(4,124,562)
22							
23	STATE TAXES-MINNESOTA						
24							
25	Income Tax	1993	1,144,736		23,463,883	23,872,945	420,351
26							
27							
28							
29	Unemployment	1993	(142,968)		2,068,049	2,084,744	
30		1992					
31							
32							
33	Motor Vehicle	1993	207		2,956	21,211	
34		1992					
35							
36	LOCAL TAXES-MINNESOTA						
37							
38	Real Estate	1993	90,406,310		95,752,518		
39		1992				90,285,094	0
40							
41							

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State Income Taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).

6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.

7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.

8. Enter accounts to which taxes charged were distributed in columns (i) thru (l). In column (i), report the amounts charged to Accounts 408.1 and 409.1 for Electric Department only. Group the amounts charged to 408.1, 409.1, 408.2 and 409.2 under other accounts in column (i). For taxes charged to other accounts or utility plant, show the number of the appropriate balanee sheet account, plant account or subaccount.

9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED (Show utility dept where applicable and acct charged)				
(Taxes Accrued Account 236) (g)(3)	Prepaid Taxes (included in Account 165) (h)	Electric (Accounts 408.1 & 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustment to Ret. Earnings (Account 439) (k)	Other (l)	Line No.
						1
						2
2,501,059		73,017,985	0		5,876,537 Gas Utility	3
					9,451,648 409.2	4
					(0) Other	5
						6
32,696		16,504,123	0		1,735,181 Gas Utility	7
					3,006,807 107 & 108	8
					3,501,274 Other	9
						10
6,145		269,455			29,109 Gas Utility	11
					54,292 107 & 108	12
					64,774 Other	13
						14
0		0			0 Gas Utiltiy	15
						16
						17
0		0			0 184	18
						19
						20
2,539,900	0	89,791,563	0	0	23,719,623	21
						22
						23
						24
1,156,025		19,768,992	0		1,591,022 Gas Utility	25
0					2,103,870 409.2	26
					(1) Other	27
						28
(159,663)		1,409,996			136,078 Gas Utility	29
					239,894 107 & 108	30
					282,082 Other	31
						32
(18,048)		0			2,956 184	33
						34
						35
						36
						37
95,873,733		92,397,322			1,545,777 Gas Utility	38
					649,215 107	39
					1,160,204 408.2	40
					0 Other	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

Line No.	Kind of Tax (See Instruction 5) (a)		BALANCE AT BEGINNING OF YEAR Taxes Accrued (b)(1)	Prepaid Taxes (c)	Taxes Charged During Year (d)	Paid During Year (e)	Adjustments (f)(2)
1	Personal Property	1993	56,956,835		61,777,161		
2		1992				56,857,660	0
3							
4	GROSS EARNINGS-MINNESOTA						
5							
6	Minneapolis	1993	770,302		9,999,992	9,293,800	
7		1992				770,302	
8							
9	St Paul	1993	1,028,163		14,157,419	13,192,315	
10		1992				1,028,163	
11							
12	South St Paul	1993	101,623		409,679	307,000	
13		1992				101,623	
14							
15	White Bear Lake	1993	124,343		134,382	0	
16		1992				124,343	
17							
18	Winona	1993	254,162		558,312	440,721	
19		1992				254,162	
20							
21	Lake City	1993	31,012		34,538	0	
22		1992				31,012	
23							
24	West St Paul	1993	211,684		435,293	207,262	
25		1992				211,684	
26							
27	Coon Rapids	1993	24,610		309,291	286,533	
28		1992				24,610	
29							
30	Grand Forks	1993	0		0	0	
31		1992					
32	FRANCHISE-						
33	E Grand Forks	1993	38,533		55,303	0	
34		1992				38,533	
35							
36	Moorhead	1993	33,028		246,763	213,653	
37		1992				33,028	
38							
39	Moundsview	1993	0		196,234	172,708	
40		1992				0	
41							
42	St Cloud	1993	98,173		1,065,117	967,496	
43		1992				98,173	
44							
45	TOTAL MINNESOTA		151,080,753	0	210,666,888	200,918,774	420,351
46							
47	STATE TAXES-NORTH DAKOTA						
48							
49	Income Taxes	1993	916,088		1,101,066	553,729	
50							
51							
52	Unemployment	1993	(322)		11,108	11,173	
53		1992					
54							

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED (Show utility dept where applicable and acct charged)				
(Taxes Accrued Account 236) (g)(3)	Prepaid Taxes (included in Account 165) (h)	Electric (Accounts 408.1 & 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustment to Ret. Earnings (Account 439) (k)	Other (l)	Line No.
61,876,336		50,423,801			11,140,711 Gas Utility	1
					42,721 107	2
					169,928 Other	3
						4
						5
706,192		9,972,814			27,178 Other	6
						7
						8
965,104		10,115,904			3,955,576 Gas Utility	9
					85,939 Other	10
						11
102,678		214,308			193,717 Gas Utility	12
					1,654 Other	13
						14
134,382		134,176			206 Other	15
						16
						17
117,591		558,260			52 Other	18
						19
						20
34,538		0			34,034 Gas Utility	21
					504 Other	22
						23
228,031		434,259			1,034 Other	24
						25
						26
22,757		308,548			743 Other	27
						28
						29
0		0			0 Other	30
						31
						32
55,303		0			55,386 Gas Utility	33
					(83) Other	34
						35
33,111		0			246,733 Gas Utility	36
					30 Other	37
						38
23,526		119,931			75,738 Gas Utility	39
					565 Other	40
						41
97,621		790,671			273,820 Gas Utility	42
					626 Other	43
						44
161,249,218	0	186,648,981	0	0	24,017,908	45
						46
						47
						48
1,463,425		1,037,224	0		83,476 Gas Utility	49
					(19,634) 409.2	50
						51
(387)		6,282			1,494 Gas Utility	52
					1,686 107 & 108	53
					1,646 Other	54

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

Line No.	Kind of Tax (See Instruction 5) (a)		BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Paid During Year (e)	Adjustments (f)(2)
			Taxes Accrued (b)(1)	Prepaid Taxes (c)			
1	Motor Vehicle	1993	(56)		13,146	13,146	
2		1992					
3							
4	Personal Property	1993	2,296,477		2,535,132		
5		1992				2,294,958	0
6							
7	LOCAL TAXES-NORTH DAKOTA						
8							
9	Real Estate	1993	(1,028)		4,914		
10		1992				5,901	0
11							
12	FRANCHISE-NORTH DAKOTA						
13							
14	Fargo	1993	121,292		1,223,145	1,091,178	
15		1992				121,292	
16							
17	Grand Forks	1993	163,321		675,172	502,279	
18		1992				163,320	
19							
20	Larimore	1993	3,062		13,563	10,377	
21		1992				3,062	
22							
23	Hatton	1993	1,983		8,195	6,117	
24		1992				1,983	
25							
26	TOTAL NORTH DAKOTA		3,500,817	0	5,585,440	4,778,513	0
27							
28	STATE TAXES-SOUTH DAKOTA						
29							
30	Motor Vehicle	1993	(283)		11,351	11,351	
31		1992					
32							
33	Personal Property	1993	2,031,683		1,619,129	0	0
34		1992				2,024,536	
35							
36	Unemployment	1993	(2,425)		6,854	6,947	
37		1992				0	
38							
39	Workers Compensation	1993	0		0	1,175	
40		1992					
41	LOCAL TAXES-SOUTH DAKOTA						
42							
43	Real Estate	1993	108,800		72,830		
44		1992				72,830	0
45							
46	TOTAL SOUTH DAKOTA		2,137,775	0	1,710,163	2,116,839	0
47							
48	STATE TAXES-WISCONSIN						
49							
50	Unemployment	1993	2,046		482	0	
51		1992					
52							
53	TOTAL WISCONSIN		2,046	0	482	0	0
54	TOTAL-ALL TAXES		151,662,907	0	331,474,159	309,602,366	(3,704,211)

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED (Show utility dept where applicable and acct charged)					
(Taxes Accrued Account 236) (g)(3)	Prepaid Taxes (included in Account 165) (h)	Electric (Accounts 408.1 & 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustment to Ret. Earnings (Account 439) (k)	Other (l)		Line No.
(56)		0			13,146	184	1
							2
							3
2,536,652		1,853,038			681,015	Gas Utility	4
					1,079	107	5
					0	Other	6
							7
							8
(2,015)		1,268			186	Gas Utility	9
					3,460	408.2	10
					0	Other	11
							12
							13
131,966		867,857			338,896	Gas Utility	14
					16,392	Other	15
							16
172,895		477,388			179,721	Gas Utility	17
					18,063	Other	18
							19
3,186		13,537			26	Other	20
							21
							22
2,078		8,183			12	Other	23
							24
							25
4,307,744	0	4,264,777	0	0	1,320,664		26
							27
							28
							29
(283)		0			11,351	184	30
							31
							32
1,626,276		1,363,334			253,703	107	33
					2,092	Other	34
							35
(2,518)		4,346			3	Gas Utility	36
					1,430	107 & 108	37
					1,075	Other	38
(1,175)		0					39
							40
							41
							42
108,800		72,830					43
							44
							45
1,731,100	0	1,440,510	0	0	269,654		46
							47
							48
							49
2,528		0			0	107 & 108	50
					482	Other	51
							52
2,528	0	0	0	0	482		53
169,830,489	0	282,145,832	0	0	49,328,330		54

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

Notes:

(1) Does not include: State & Local Use Taxes of $1,161,304, State Excise (Gasoline) of $0.

(2) Adjustments for Income Taxes are as follows:
Federal: Intercompany Transactions, Transfer of Refuse-derived Fuel operations to subsidiary, Other.
Minnesota: Intercompany Transactions, Transfer of Refuse-derived Fuel operations to subsidiary, Other.

(3) Does not include: State & Local Use Taxes of $242,175, State Excise (Gasoline) of $0.

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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	$9,089,515				($372,356)	$452,579
4	7%						
5	10%	135,190,399		$0		(6,986,541)	(646,188)
6							
7							
8	TOTAL	144,279,914		0		(7,358,897)	(193,609)
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Gas Utility						
12	4%	412,991				(30,782)	(584)
13	10%	9,316,721		0		(394,859)	425
14							
15	Total	9,729,712		0		(425,641)	(159)
16							
17	Common Utility						
18	4%	35,030				(2,595)	(3)
19	10%	1,021,627		0		(115,630)	(24,047)
20							
21	Total	1,056,657		0		(118,225)	(24,050)
22							
23	NON-OPERATING						
24							
25	Telephone Related						
26	4%	0				0	0
27	10%	0		0		0	0
28							
29	Total	0		0		0	0
30							
31	Non Utility						
32	10%	16,109,469		0		0	(2,686,899)
33							
34	Non Utility - RDF						
35	10%	2,531,099		0		(103,112)	(1,574,701)
36							
37							
38	TOTAL	$173,706,851		$0		($8,005,875)	($4,479,418)
39							
40	(a) Common Allocation						
41	Electric	$862,271		0		($99,498)	($20,240)
42	Gas	$194,386		0		($18,727)	($3,810)
43	Telephone	$0		0		$0	$0
44							
45							
46							
47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (Continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	Adjustment Explanation		Line No.
		1) Adjustments consist of:		1
		- True-ups of deferred tax credits recorded to reflect difference		2
$9,169,738		between tax returns filed and prior year accounting accruals:		3
		Affecting income	(217,818)	4
127,557,670		Not affecting income	0	5
				6
		- Amortization of non-utility tax benefit transfer (safe harbor)		7
136,727,408		lease credits which have no income effect	(2,686,899)	8
		- Transfer of non-utility assets and associated tax credits		9
		to wholely owned subsidiary	(1,574,701)	10
				11
381,625		- Miscellaneous income adjustments	0	12
8,922,287				13
		TOTAL	(4,479,418)	14
9,303,912				15
		2) Credits are flowed-through (amortized) to income ratably over the		16
		estimated life of the property.		17
32,432				18
881,950		3) Reconciliation of page 114, line 18:		19
		- Allocations to current year's net income		20
914,382		(column (f) on page 266)	(8,005,875)	21
				22
		- Less non-utility portion	103,112	23
				24
		- Return to accrual adjustments per (1) above	(217,818)	25
0				26
0		- Miscellaneous income adjustments per (1) above	0	27
				28
0		Utility Investment Tax Credit Adjustment	(8,120,581)	29
				30
				31
13,422,570				32
				33
				34
853,286				35
				36
				37
$161,221,558				38
				39
				40
$742,533				41
$171,849				42
$0				43
				44
				45
				46
				47
				48

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	Debits		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Accrued Pension Benefit-Make up Costs	$3,285,000		$0	$336,000	$3,621,000
2						
3	Deferred Compensation Obligations – MN	764,000		0	575,000	1,339,000
4						
5	Spare Parts Inventory	0	456	241,801	474,375	232,574
6						
7	Environmental & Regulatory Reserves	10,500,000	242*	370,571	100,000	
8			447	306,540		
9						9,922,889
10						
11						
12	Deferred Compensation Plan Obligation –	10,669,759	232	214,049	2,137,362	
13	Wealth Op		253	1,421,337		
14			253WI	70,093		
15			421	111,972		
16			NRG	379,852		10,609,818
17						
18	Deferred Compensation Plan Obligation –	3,087,561	184.1	15,678	1,018,503	
19	Wealth Op #2		232	7,979		
20			253	121,316		
21			253WI	55,600		
22			421	64,817		
23			NRG	152,189		3,688,485
24						
25	Incentive Pay Retirement Allocation	1,058,550	253WI	4,225	64,160	
26			421	5,380		
27			NRG	40,325		1,072,780
28						
29						
30	Deferred Compensation Plan Obligation –	1,722,192	232	1,929,403	2,008,713	
31	Retirees		253	401,872		
32			421	8,778		1,390,852
33						
34	Deferred Compensation Plan Obligation –	760,628	232	3,935	59,833	
35	Fixed Income Option		253	300		
36			NRG	9,461		806,765
37						
38	Deferred Compensation Plan Obligation –	541,696	253	1,154	89,866	
39	Fixed Income Option – Interest		253WI	1,357		
40			421	7,789		621,262
41						
42						
43						
44						

* Rate refund liability transferred as a result of the final MN electric retail rate order.

OTHER DEFERRED CREDITS (Account 253)(Continued)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Line No.	Description of Other Deferred Credit (a)	Balance at Beginning of Year (b)	Debits: Contra Account (c)	Debits: Amount (d)	Credits (e)	Balance at End of Year (f)
1	Settlements	$0	184.1	$750,000	$978,333	
2			921	65,000		$163,333
3						
4	Accrued Post Retirement Health Care	0	184.1	16,012,382	47,918,556	
5	Liability - SFAS 106		182.3	14,273,749		
6			242	2,597,000		15,035,425
7						
8	Koch Maintenance Reimbursement	0	591	135,717	950,000	814,283
9	(Amortization 1993 - 1999)					
10						
11	Accrued Pension Contributions	0			8,703,000	8,703,000
12						
13	Early Retirement Pension Liability	11,510,000				11,510,000
14						
15	Pension Cost Differences - SFAS 87	2,017,000	254	2,017,000		0
16						
17	Midwest Gas - ND PGA Refund	3,192	254	3,192		0
18						
19	Northern Natural Gas - PGA Refund	142,783	254	142,783		0
20						
21	Spare Parts Inventory	80,567	254	80,567		0
22						
23	Deferred - Income Tax Credit	3,340,076	254	3,340,076		0
24						
25	SFAS 96 - Pre 1988 Debt AFC	29,296,000	254	29,296,000		0
26						
27	SFAS 96 - Unamortized ITC Gross Up	103,809,000	254	103,809,000		0
28						
29	SFAS 96 - Effects of Rate Change	94,745,000	254	94,745,000		0
30						
31	DOE Fuel Disposal Fee Refund	4,582,241	254	4,582,241		0
32						
33	Minor Items	1,209,199	131	207,838	2,715,133	
34			142	264,937		
35			184.1	52,862		
36			232	1,200		
37			447	670,000		
38			924	2,709,893		17,603
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49						
50						
51	TOTAL	$283,124,444		$281,704,210	$68,128,834	$69,549,069

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ACCUMULATED DEFERRED INCOME TAXES-ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	$4,796,674		$435,164
5	Other			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	4,796,674		435,164
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16	Other (Specify)			
17	TOTAL (Account 281)(Total of 8, 15 and 16)	$4,796,674		$435,164
18	Classification of TOTAL			
19	Federal Income Tax	$4,796,674		$435,164
20	State Income Tax			
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES-ACCELERATED AMORTIZATION PROPERTY (Account 281)(Continued)

2. For Other (Specify), include deferrals relating to other income and deductions.
3. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Acct No (g)	Amount (h)	Acct No (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
						$4,361,510	4
							5
							6
							7
						4,361,510	8
							9
							10
							11
							12
							13
							14
							15
							16
						$4,361,510	17
							18
						$4,361,510	19
							20
							21

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES-OTHER PROPERTY (Account 282)(Continued)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	$697,965,281	$47,264,047	$28,919,179
3	Gas	42,194,679	6,255,262	1,286,166
4	Other (Define)	0	0	0
5	TOTAL (Enter Total of lines 2 thru 4)	740,159,960	53,519,309	30,205,345
6	Other (Non-Operating)	14,479,297		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	$754,639,257	$53,519,309	$30,205,345
10	Classification of TOTAL			
11	Federal Income Tax	$609,855,161	$42,641,314	$24,160,334
12	State Income Tax	$144,784,096	$10,877,994	$6,045,011
13	Local Income Tax			

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES-OTHER PROPERTY (Account 282)(Continued)

2. For Other (Specify), include deferrals relating to other income and deductions.
3. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Acct No (g)	Amount (h)	Acct No (i)	Amount (j)		
							1
			($133,566)		$1,073,645	$715,102,938	2
			3,890		154,144	47,013,521	3
			0			0	4
0	0		(129,676)		1,227,789	762,116,459	5
345,147	0		0		7,898,526	6,925,918	6
							7
							8
$345,147	$0		($129,676)		$9,126,315	$769,042,377	9
							10
$0	$0		($63,918)		$7,138,806	$621,133,417	11
$0	$0		($65,758)		$439,398	$149,111,923	12
			0				13

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES–OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For Other (Specify), include deferrals relating to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2				
3	Electric	(10,569,224)	35,514,179	21,691,506
4				
5				
6				
7				
8	Other	0	0	0
9	TOTAL Electric (Total of lines 3 thru 8)	(10,569,224)	35,514,179	21,691,506
10				
11	Gas	(4,901,492)	6,333,013	4,160,812
12				
13				
14				
15				
16	Other			
17	TOTAL Gas (Total of lines 11 thru 16)	(4,901,492)	6,333,013	4,160,812
18	Other (Non-Operating)	90,916,695	0	0
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	$75,445,979	$41,847,192	$25,852,318
20	Classification of TOTAL			
21	Federal Income Tax	$61,029,147	$32,574,019	$20,149,564
22	State Income Tax	$14,901,008	$9,273,173	$5,702,754
23	Local Income Tax	($484,176)		

NOTES

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)(Continued)

3. Provide in the space below explanations for pages 276 and 277. Include amounts relating to insignificant items listed under Other.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amount Debited to Account 410.2 (e)	Amount Credited to Account 411.2 (f)	Debits Acct No (g)	Debits Amount (h)	Credits Acct No (i)	Credits Amount (j)		
							1
							2
			1,414,520		12,380,000	(7,712,031)	3
							4
							5
							6
							7
0	0		0		0	0	8
0	0		1,414,520		12,380,000	(7,712,031)	9
							10
0	0		13,052		0	(2,716,239)	11
							12
							13
							14
							15
							16
0	0		13,052		0	(2,716,239)	17
(9,138,618)	0		0		0	81,778,077	18
($9,138,618)	$0		$1,427,572		$12,380,000	$71,349,807	19
							20
($7,947,535)	$0		$1,950,004		$9,650,210	$57,805,861	21
($1,191,083)	$0		($1,006,608)		$2,729,790	$13,543,946	22
			$484,176			$0	23

NOTES (Continued)

OTHER REGULATORY LIABILITIES (Account 254)

1. Reporting below the particulars (details) called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).

2. For regulatory liabilities being amortized, show period of amortization in column (a).

3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	DEBITS Account Credited (b)	DEBITS Amount (c)	Credits (d)	Balance at End of Year (e)
1	Pension Cost Differences - SFAS 87	186	4,952,253	8,052,253	
2	Transfer from Account 253			2,017,000	5,117,000
3					
4	Deferred Revenue - Citibank	142	5,556	72,225	66,669
5					
6	Midwest Gas - ND PGA Refund			29,979	
7	Transfer from Account 253			3,192	33,171
8					
9	Northern Natural Gas - PGA Refund	431	66	245,876	
10	Transfer from Account 253			142,783	388,593
11					
12	Spare Parts Inventory	456	47,610	3,662	
13	Transfer from Account 253			80,567	36,619
14					
15	Faribault Reimbursement	495	92,930	371,720	278,790
16	(Amortization 1993 - 1996)				
17					
18	Deferred - Income Tax Credits	237	267,664	798,388	
19		411.1	1,935,400		
20	Transfer from Account 253			3,340,076	1,935,400
21					
22	SFAS 109 - Pre 1988 Debt AFC	182.3	27,471,000		
23		283	1,825,000		
24	Transfer from Account 253			29,296,000	0
25					
26	SFAS 109 - Unamortized ITC Gross Up	283	3,833,000	4,306,000	
27	Transfer from Account 253			103,809,000	104,282,000
28					
29	SFAS 109 - Effects of Rate Changes	283	76,602,000	89,311,000	
30	Transfer from Account 253			94,745,000	107,454,000
31					
32	DOE Fuel Disposal Fee Refund	143	3,571,967		
33	Transfer from Account 253			4,582,241	1,010,274
34					
35	Emission Allowance			88,467	88,467
36					
37					
38					
39	TOTAL		120,604,446	341,295,429	220,690,983

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ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If increases or decreases from previous year (columns (c), (e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)(1)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$536,875,172	$489,641,624
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial) (3)	275,673,227	262,346,992
5	Large (or Industrial) (3)	678,834,916	623,375,961
6	(444) Public Street and Highway Lighting (4)	16,415,589	15,973,156
7	(445) Other Sales to Public Authorities	8,312,999	9,383,103
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	223,975	200,647
10	TOTAL Sales to Ultimate Consumers	1,516,335,878	1,400,921,483
11	(447) Sales for Resale	143,488,544	123,207,380
12	TOTAL Sales of Electricity	1,659,824,422	1,524,128,863
13	(Less) (449.1) Provision for Rate Refunds	0	0
14	TOTAL Revenue Net of Provision for Refunds	1,659,824,422	1,524,128,863
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,783,680	3,557,084
17	(451) Miscellaneous Service Revenues	3,561,522	2,789,456
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,561,042	2,188,584
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	190,384,762	183,581,453
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	199,291,006	192,116,577
27	TOTAL Electric Operating Revenues	$1,859,115,428	$1,716,245,440

ELECTRIC OPERATING REVENUES (Account 400)(Continued)

4. Commerical and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.

6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.

7. Include unmetered sales. Provide details of such sales in a footnote.

MEGAWATT HOURS SOLD		AVERAGE NO. OF CUSTOMERS PER MONTH		
Amount for Year (d)(2)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	Line No.
				1
7,464,634	7,106,001	1,040,991	1,027,013	2
				3
4,473,489	4,410,209	131,164	129,932	4
14,948,032	14,267,501	7,759	7,336	5
142,003	138,664	1,507	1,378	6
147,426	178,213	2,555	2,552	7
				8
12,404	11,306			9
27,187,988	26,111,894	1,183,976	1,168,211	10
7,622,098	6,206,075	60	62	11
34,810,086	32,317,969	1,184,036	1,168,273	12
				13
34,810,086	32,317,969	1,184,036	1,168,273	14

NOTES:

1) Includes unbilled revenues for 1993 which have been allocated by class, per FERC direction.

2) Includes MWH relating to unbilled revenues for 1993 which have been allocated by class, per FERC direction.

3) Commercial and industrial sales are classified as "Large" if customer has a minimum registered demand of 100 KW or more.

4) MWH sold for automatic protective lighting and street lighting purposes (unmetered) is estimated from connected load and hours of burning.

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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customers, average KWH per customer, and average per KWH, excluding data for Sales For Resale which is reported on pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedules and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in the number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate sebedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue ($'s) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (¢'s) per KWH Sold (f)
1	Residential					
2						
3	State of Minnesota					
4						
5	AA100 Res-SH	262,303	17,083,821	19,697	13,317	6.51
6	AA102 Res-SH-UG (CL)	407	26,290	19	20,950	6.46
7	AD100 Res-Duplex (CL)	19,097	1,388,558	2,162	8,833	7.27
8	AD110 Res Duplex	2	145	0	5,262	8.25
9	AJ100 Res-Duplex-SH (CL)	107	6,947	6	17,413	6.47
10	AR100 Res + AS100	4,120,922	306,711,074	666,278	6,185	7.44
11	AR102 Res-UG (CL)	22,013	1,638,057	2,190	10,054	7.44
12	Sub Total Res Serv	4,424,850	326,854,890	690,352	6,410	7.39
13						
14	AA103 Res-UG-SH	142,953	9,307,326	7,117	20,085	6.51
15	AD103 Res-Duplex-UG (CL)	112	8,053	8	14,054	7.16
16	AR103 Res-UG	1,369,430	103,445,751	161,671	8,471	7.55
17	Sub Total Res-UG	1,512,495	112,761,130	168,796	8,961	7.46
18						
19	AB000 Res TOD-SH-On	96	11,891	14	6,940	12.38
20	AB001 Res TOD-SH-Off	222	7,675	14 *	16,057	3.46
21	AB010 Res TOD-SH-On	12	1,357	2	7,472	11.47
22	AB011 Res TOD-SH-Off	28	978	2 *	17,893	3.45
23	AT000 Res TOD-On	137	20,559	39	3,532	15.05
24	AT001 Res TOD-Off	312	10,627	39 *	8,075	3.40
25	AT010 Res TOD-Opt-On	1	219	1	1,306	16.79
26	AT011 Res TOD-Opt-Off	6	224	1 *	6,161	3.63
27	Sub Total Res TOD Serv	815	53,530	112	7,394	6.57
28						
29	AB002 Res TOD-SH-UG-On	138	16,974	15	9,021	12.34
30	AB003 Res TOD-SH-UG-Off	326	11,173	15 *	21,351	3.43
31	AB012 Res TOD-SH-UG-Opt-On	3	448	1	3,305	13.55
32	AB013 Res TOD-SH-UG-Opt-Off	20	703	1 *	20,330	3.46
33	AT002 Res TOD-UG-On	76	11,970	22	3,479	15.70
34	AT003 Res TOD-UG-Off	194	6,581	22 *	8,862	3.39
35	AT012 Res TOD-UG-Opt-On	6	767	2	2,763	13.88
36	AT013 Res TOD-UG-Opt-Off	12	424	2 *	6,163	3.44
37	Sub Total Res TOD-UG	775	49,041	80	9,649	6.33
38						
39	AE100 Res Load Ctrl	235,500	16,332,859	28,070	8,390	6.94
40	AE103 Res Load Ctrl	170,961	12,218,886	19,555	8,743	7.15
41	AE110 Res Load Ctrl	8,805	584,647	765	11,509	6.64
42	AE113 Res Load Ctrl	2,521	170,492	195	12,950	6.76
43	AE120 Res Load Ctrl (CL)	127	8,866	12	10,189	7.01

SALES OF ELECTRICITY BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue ($'s) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (¢'s) per KWH Sold (f)
1	AE123 Res Load Ctrl (CL)	6	439	1	5,571	7.88
2	AF100 Res Load Ctrl - SH	2,249	139,088	106	21,153	6.18
3	AF103 Res Load Ctrl - SH	1,998	129,360	127	15,784	6.47
4	AF110 Res Load Ctrl - SH	881	53,333	40	22,313	6.05
5	AF113 Res Load Ctrl - SH	1,390	86,529	68	20,421	6.22
6	Sub Total Res Load Ctrl	424,439	29,724,499	48,939	8,673	7.00
7						
8	AL000 Energy Ctrl DF	4,966	179,688	377 *	13,158	3.62
9	AL003 Energy Ctrl DF-UG	4,629	167,439	383 *	12,097	3.62
10	AL110 Energy Ctrl DF-OPT	15	791	2 *	6,524	5.39
11	AL113 Energy Ctrl DF-UG-OPT	5	218	0 *	18,504	4.72
12	AL200 Energy Ctrl DF-Opt	172	6,881	16 *	10,505	3.99
13	AL203 Energy Ctrl DF-UG-Opt	196	8,144	19 *	10,559	4.15
14	Sub Total Energy Ctrl DF	9,983	363,160	797 *	12,517	3.64
15						
16	AW000 Limited Off-Pk	6	1,238	144 *	43	19.85
17	AW001 Limited Off Pk	1,870	54,482	146	12,854	2.91
18	Sub Total Limited Off-Pk	1,876	55,720	290	6,487	2.97
19						
20	AP008 Auto Prot Lgt (CL)	28	2,536	13 *	2,113	9.00
21	AP009 Auto Prot Lgt (CL)	5	371	1 *	4,582	8.09
22	AP018 Auto Prot Lgt (CL)	443	34,166	222 *	1,991	7.72
23	AP019 Auto Prot Lgt	122	14,575	95 *	1,288	11.92
24	AP029 Auto Prot Lgt	2,313	389,355	4,616 *	501	16.83
25	AP038 Auto Prot Lgt (CL)	5,851	571,121	6,904 *	847	9.76
26	AP049 Auto Prot Lgt	75	10,519	54 *	1,406	13.95
27	AP939 Auto Prot Lgt	49	5,778	17 *	2,937	11.69
28	Sub Total APL-Res	8,886	1,028,421	11,922 *	745	11.57
29						
30	AA970+AR970 Res-Net Unbilled	11,041	571,741			
31						
32	Sub-Total Res-MN	6,395,161	471,462,132	921,288	6,942	7.37
33	Refund		4,071,850			
34	Total Res-MN	6,395,161	467,390,282	921,288	6,942	7.31
35						
36	**State of South Dakota**					
37						
38	AA800 Res-SH + AS806	18,180	1,166,207	1,517	11,973	6.41
39	AR800 Res	229,951	17,708,782	33,998	6,763	7.70
40	Sub Total Res	248,131	18,874,989	35,515	6,986	7.61
41						
42	AA803 Res-UG-SH	8,987	541,417	389	23,092	6.02
43	AR803 Res-UG	97,605	7,439,013	10,332	9,446	7.62
44	Sub Total Res-UG	106,591	7,980,430	10,721	9,942	7.49
45						
46	AT800 Res TOD-On	6	878	1	6,393	13.73
47	AT801 Res TOD-Off	12	402	1 *	12,394	3.25
48	Sub Total Res TOD	19	1,280	2	9,394	6.81
49						
50	AE900 Res Load Ctrl	15,794	1,109,169	1,746	9,045	7.02
51	AE903 Res Load Ctrl-UG	17,995	1,286,434	1,751	10,279	7.15
52	AE910 Res Load Ctrl-WH	1,398	92,727	117	11,946	6.63
53	AE913 Res Load Ctrl-WH-UG	258	17,553	21	12,100	6.80
54	AF900 Res Load Ctrl-SH	663	38,179	32	21,045	5.76
55	AP903 Res Load Ctrl-SH	852	50,126	35	24,066	5.88
56	AF910 Res Load Ctrl-SH	396	22,737	19	20,565	5.74

SALES OF ELECTRICITY BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue ($'s) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (¢'s) per KWH Sold (f)
1	AP913 Res Load Ctrl-SH	476	27,552	22	22,069	5.78
2	Sub Total Res Load Ctrl	37,833	2,644,477	3,743	10,108	6.99
3						
4	AL800 Energy Ctrl N/D	211	7,716	13 *	16,419	3.66
5	AL803 Energy Ctrl N/D UG	263	9,698	18 *	14,591	3.69
6	Sub Total Energy Ctrl	473	17,414	31 *	15,352	3.68
7						
8	AL900 Res Dual Fuel-SH (CL)	32	1,158	2 *	18,007	3.67
9	AL903 Res Dual Fuel-SH UG (CL)	18	726	1 *	18,180	3.99
10	AL910 Res Dual Fuel-SH (CL)	2	97	0 *	8,240	4.73
11	Sub Total Res Dual Fuel	52	1,981	3	44,427	12.39
12						
13	AW800 Limited Off-Pk	0	2	1	8	-
14	AW801 Limited Off-Pk	11	342	1 *	11,158	3.06
15	Sub Total Limited Off-Pk	11	343	2	5,583	3.07
16						
17	AP818 Auto Prot Lgt (CL)	4	293	2 *	1,907	7.68
18	AP819 Auto Prot Lgt	5	737	4 *	1,273	14.47
19	AP829 Auto Prot Lgt	119	19,048	238 *	500	16.05
20	AP838 Auto Prot Lgt (CL)	283	26,238	332 *	852	9.29
21	AP839 Auto Prot Lgt	6	650	3 *	2,004	10.81
22	AP849 Auto Prot Lgt	5	657	4 *	1,273	12.91
23	Sub Total APL-Res	421	47,623	583 *	724	11.30
24						
25	AA970+AR970 Res-Net Unbilled	797	46,235			
26	Total Res-SD	394,328	29,614,772	50,600	7,793	7.51
27						
28	<u>State of North Dakota</u>					
29						
30	AA500 Res-SH	233,530	12,683,187	16,535	14,123	5.43
31	AD500 Res-Duplex (CL)	998	62,900	109	9,159	6.31
32	AJ500 Res-SH-Duplex (CL)	177	9,333	6	29,455	5.28
33	AR500 Res + AS600	351,902	22,188,870	46,137	7,627	6.31
34	Sub Total Res Serv	586,606	34,944,290	62,787	9,343	5.96
35						
36	AA503 Res-UG-SH	39,079	2,067,330	1,816	21,514	5.29
37	AR503 Res-UG	37,308	2,306,173	3,085	12,093	6.18
38	Sub Total Res-UG	76,387	4,373,503	4,901	15,585	5.73
39						
40	AE500 Res Load Ctrl A/C	2,238	131,718	203	11,044	5.89
41	AE503 Res Load Ctrl A/C-UG	564	34,181	50	11,393	6.06
42	AE510 Res Load Ctrl A/C & WH	874	49,828	68	12,797	5.70
43	AE513 Res Ld Ctrl A/C & WH-UG	177	10,465	14	12,815	5.90
44	AF500 Res Sp Heat Load Cntl A/C	671	33,575	27	25,145	5.01
45	AF503 Res SP Heat Load Cntl A/C	118	6,363	7	18,090	5.41
46	AF510 Res Sp Heat Load Cntl A/C	788	38,733	32	24,899	4.91
47	AF513 Res SP Heat Load Cntl A/C	95	4,874	5	21,103	5.13
48	Sub Total Res Load Ctrl A/C	5,525	309,738	406	13,688	5.61
49						
50	AB500 Res TOD-SH-On	26	2,745	5	5,349	10.44
51	AB501 Res TOD-SH-Off	74	2,141	5 *	15,105	2.88
52	AB510 Res TOD-SH-Opt-On	155	14,362	6	25,816	9.27
53	AB511 Res TOD-SH-Opt-Off	296	8,538	6 *	49,259	2.89
54	AT500 Res TOD-On	15	1,880	4	3,672	12.28
55	AT501 Res TOD-Off	52	1,510	4 *	12,516	2.90
56	Sub Total Res TOD	618	31,176	30	20,502	5.04

SALES OF ELECTRICITY BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue ($'s) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (¢'s) per KWH Sold (f)
1	AL500 Energy Ctrl DF	2,756	93,605	142 *	19,399	3.40
2	AL503 Energy Ctrl DF-UG	749	25,545	47 *	15,935	3.41
3	AL510 Energy Ctrl DF Non Dmd	30	1,154	1 *	22,551	3.84
4	AL513 Ener Ctrl DF UG Non Dmd	3	99	0 *	15,612	3.81
5	AL600 Energy Ctrl DF-Opt	587	21,269	31 *	19,191	3.62
6	AL603 Energy Ctrl DF-UG-Opt	203	7,364	8 *	26,485	3.63
7	Sub Total Energy Ctrl DF	4,328	149,037	229 *	18,913	3.44
8						
9	AW500 Limited Off-Pk	0	6	40	6	2.61
10	AW501 Limited Off-Pk	309	10,064	40 *	7,666	3.26
11	Sub Total Limited Off-Pk	309	10,071	80 *	3,833	3.26
12						
13	AP508 Auto Prot Ltg (CL)	1	92	1 *	1,980	9.24
14	AP518 Auto Prot Ltg (CL)	57	4,479	28 *	2,026	7.92
15	AP519 Auto Prot Ltg	17	1,970	14 *	1,275	11.37
16	AP529 Auto Prot Ltg	140	22,065	283 *	493	15.80
17	AP538 Auto Prot Ltg (CL)	297	27,185	342 *	866	9.17
18	AP549 Auto Prot Ltg	3	329	2 *	1,273	12.90
19	Sub Total APL-Res	514	56,119	670 *	767	10.93
20						
21	AA970+AR970 Res-Net Unbilled	857	(3,816)			
22						
23	Total Res-ND	675,144	39,870,118	69,103	9,770	5.91
24						
25	Minnesota Company					
26						
27	Total Residential	7,464,634	536,875,172	1,040,991	7,171	7.19
28						
29	Small Commercial & Industrial					
30						
31	State of Minnesota					
32						
33	DC100 Small General	728,080	54,457,152	64,696	11,276	7.48
34						
35	DK004 General-Sec + DS100	2,780,222	166,049,194	26,895	103,373	5.97
36	DK006 Off-Season Rider	3,207	249,987	58	55,451	7.80
37	DK014 General-Pri	9,194	584,141	79	116,876	6.35
38	Sub Total General-Sm	2,792,623	166,883,323	27,032	103,309	5.98
39						
40	DK104 Peak Ctrl-Sec-Sm (CL)	251	14,986	2	150,672	5.97
41	DP004 Peak Ctrl-Sec-SM	62,512	3,696,276	369	169,371	5.91
42	DP014 Peak Ctrl-Pri-SM	664	32,142	2	295,111	4.84
43	Sub Total Peak Ctrl Sm	63,427	3,743,404	373	170,046	5.90
44						
45	DT000 Sm Gen TOD-On	3,844	491,737	667	5,767	12.79
46	DT001 Sm Gen TOD-Off	8,298	255,354	667 *	12,449	3.08
47	DT070 Sm TOD-24HR On&Off	37,655	2,510,328	4,416	8,526	6.67
48	DT090 Sm TOD-Unmtrd-On	70	31,162	274	256	44.48
49	DT091 Sm TOD-Unmtrd-Off	508	16,287	275 *	1,850	3.20
50	Sub Total Sm Gen-TOD	50,375	3,304,868	6,299	7,999	6.56
51						
52	DT004 Gen TOD-On	67,814	5,878,868	781	86,885	8.67
53	DT005 Gen TOD-Off	124,532	3,358,515	781 *	159,554	2.70
54	Sub Total Gen TOD-Sm	192,345	9,237,382	1,562	123,219	4.80
55						
56						

SALES OF ELECTRICITY BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue ($'s) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (¢'s) per KWH Sold (f)
1	DP104 Peak Ctrl TOD-Sec-On	1,553	122,325	14	107,697	7.88
2	DP105 Peak Ctrl TOD-Sec-Off	2,524	67,914	14 *	175,059	2.69
3	DT104 Peak Ctrl TOD-Sec-On (CL)	7	2,826	2	3,404	41.52
4	DT105 Peak Ctrl TOD-Sec-Off (CL)	303	10,940	2 *	151,557	3.61
5	Sub Total Peak Ctrl TOD-Sm	4,386	204,006	32	133,594	4.65
6						
7	DC124 Direct Current (CL)	24	26,246	27	876	109.26
8						
9	DC108 NWB Tele Booth (CL)	6	578	15	389	9.92
10						
11	DL000 Energy-Ctrl DF	442	15,581	22 *	20,018	3.52
12	DL104 Energy Ctrl On-Pk	167	10,232	1		
13	DL105 Energy Ctrl Off-Pk	256	6,343	1		
14	DL200 Energy-Ctrk DF-OPT	11	417	1	10,959	3.80
15	Sub Total Energy Ctrl DF-Sm	876	32,572	25	34,910	3.72
16						
17	DW000 Limited Off-Pk-Sec 1P-On	42	8,468	39 *	1,096	19.99
18	DW001 Limited Off-Pk-Sec 1P-Off	474	14,372	39	12,261	3.03
19	DW060 Limited Off-Pk-Sec 3P-On	16	3,188	20 *	782	19.98
20	DW061 Limited Off-Pk-Sec 3P-Off	401	12,066	20	19,661	3.01
21	Sub Total Limited Off Pk	934	38,094	118	7,903	4.08
22						
23	DP008 Auto Prot Lgt (CL)	1,639	159,136	595 *	2,755	9.71
24	DP009 Auto Prot Lgt (CL)	839	67,005	118 *	7,097	7.98
25	DP018 Auto Prot Lgt (CL)	5,683	446,178	2,161 *	2,630	7.85
26	DP019 Auto Prot Lgt	1,788	230,186	1,028 *	1,740	12.87
27	DP029 Auto Prot Lgt	1,158	219,147	1,878 *	616	18.93
28	DP038 Auto Prot Lgt (CL)	3,360	337,738	3,293 *	1,020	10.05
29	DP049 Auto Prot Lgt	2,254	338,032	1,126 *	2,001	15.00
30	DP939 Auto Prot Lgt	7,328	869,773	1,757 *	4,172	11.87
31	Sub Total APL-Comm	24,049	2,667,196	11,956 *	2,011	11.09
32						
33	DC975 - Sm C&I-Net Unbilled	1,507	(239,951)			
34						
35	Sub-Total Sm C&I-MN	3,858,633	240,354,872	112,135	34,382	6.23
36	Refund		2,082,820			
37	Total Sm C&I-MN	3,858,633	238,272,052	112,135	34,382	6.18
38						
39	State of South Dakota					
40						
41	DC800 Small General	51,412	3,584,473	4,955	10,377	6.97
42						
43	DK804 General-Sec + DS806	176,361	10,743,639	1,826	96,575	6.09
44	DK814 General-Pri	232	25,229	10	22,457	10.87
45	DK834 General - Transm	2,322	101,156	1	2,786,042	4.36
46	Sub Total General-Sm	178,915	10,870,025	1,837	97,378	6.08
47						
48	DT800 Gen TOD-On	4	464	1	3,735	12.42
49	DT801 Gen TOD-Off	14	406	1 *	14,129	2.88
50	DT804 Gen TOD-On	2,894	255,309	43	67,174	8.82
51	DT805 Gen TOD-Off	5,929	158,664	43 *	137,612	2.68
52	Sub Total Gen TOD-Sm	8,841	414,844	88	100,273	4.69
53						
54	DW860 Limited Off-Pk-Sec 3P-On	0	26	1 *	128	-
55	DW861 Limited Off-Pk-Sec 3P-Off	0	120	1	205	58.54
56	Sub Total Limited Off-Pk	0	146	2	167	43.72

SALES OF ELECTRICITY BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue ($'s) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (¢'s) per KWH Sold (f)
1	DP808 Auto Prot Lgt (CL)	87	7,632	43 *	2,027	8.81
2	DP809 Auto Prot Lgt (CL)	2	169	0 *	4,932	8.24
3	DP818 Auto Prot Lgt (CL)	87	6,724	41 *	2,132	7.76
4	DP819 Auto Prot Lgt	33	4,124	23 *	1,440	12.41
5	DP829 Auto Prot Lgt	116	19,221	207 *	562	16.56
6	DP838 Auto Prot Lgt (CL)	235	22,104	258 *	914	9.39
7	DP839 Auto Prot Lgt	897	103,287	296 *	3,029	11.51
8	DP849 Auto Prot Lgt	140	18,860	91 *	1,546	13.44
9	Sub Total APL-Comm	1,598	182,122	959 *	1,667	11.40
10	DC975 - Sm C&I-Net Unbilled	575	(4,957)			
11						
12	Total Sm C&I-SD	241,341	15,046,652	7,841	30,782	6.23
13						
14	<u>State of North Dakota</u>					
15						
16	DC500 Small General	84,057	5,467,710	6,901	12,180	6.50
17						
18	DC503 Small General-UG	1	54	0	10,704	6.05
19						
20	DK504 General-Sec + DS600	270,906	15,892,065	2,616	103,551	5.87
21	DK506 Off Season Load Rider	37	3,388	1	27,602	9.21
22	DK514 General-Pri	472	24,457	4	120,444	5.18
23	Sub Total General-Sm	271,414	15,919,911	2,621	103,537	5.87
24						
25	DT500 Sm Gen TOD-On	75	7,617	10	7,225	10.12
26	DT501 Sm Gen TOD-Off	175	4,876	10 *	16,808	2.78
27	DT570 TOD-24Hr On & Off	1,416	81,788	142	10,003	5.77
28	DT590 Sm TOD-Unmtrd-On	15	1,415	1 *	14,976	9.45
29	DT591 Sm TOD-Unmtrd-Off	58	3,463	2	34,890	5.96
30	Sub Total Sm Gen TOD	1,740	99,158	165	10,539	5.70
31						
32	DT504 Gen TOD-On	3,907	342,311	51	77,102	8.76
33	DT505 Gen TOD-Off	7,623	202,351	51 *	150,456	2.65
34	Sub Total Gen TOD-Sm	11,530	544,662	102	113,779	4.72
35						
36	DT604 Gen TOD Pk-Ctrl-Sm-On (CL)	162	9,846	1	162,491	6.06
37	DT605 Gen TOD-Sm-Off (CL)	244	6,235	1 *	243,589	2.56
38	Sub Total Peak Ctrl TOD-Sm	406	16,081	2	203,040	3.96
39						
40	DC604 Direct Current (CL)	4	1,444	6	703	36.26
41						
42	DL500 Energy Ctrl DF	384	12,735	14 *	27,733	3.32
43	DL600 Energy Ctrl DF-Opt	353	14,120	11 *	32,868	4.00
44	Sub Total Energy Ctrl DF	737	26,856	25 *	29,978	3.64
45						
46	DW500 Limited Off-Pk-Sec 1P-On	1	241	16 *	53	28.67
47	DW501 Limited Off-Pk-Sec 1P-Off	269	7,947	16	16,819	2.95
48	DW560 Limited Off-Pk-Sec 3P-On	0	0	4 *	0	-
49	DW561 Limited Off-Pk-Sec 3P-Off	107	3,199	4	27,218	3.00
50	Sub Total Limited Off Pk	377	11,387	40	9,453	3.02
51						
52	DP508 Auto Prot Lgt	93	8,455	30 *	3,086	9.13
53	DP509 Auto Prot Lgt (CL)	79	5,312	15 *	5,181	6.76
54	DP518 Auto Prot Lgt (CL)	539	40,790	219 *	2,464	7.57
55	DP519 Auto Prot Lgt	196	23,437	115 *	1,694	11.99
56	DP529 Auto Prot Lgt	118	19,361	206 *	575	16.36

SALES OF ELECTRICITY BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue ($'s) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (¢'s) per KWH Sold (f)
1	DP538 Auto Prot Lgt (CL)	406	37,787	368 *	1,105	9.30
2	DP539 Auto Prot Lgt	1,137	122,706	296 *	3,841	10.79
3	DP549 Auto Prot Lgt	125	17,062	77 *	1,618	13.67
4	Sub Total APL-Comm	2,692	274,909	1,326 *	2,031	10.21
5						
6	DC975 - Sm C&I-Net Unbilled	558	(7,649)			
7						
8	Total Sm C&I-ND	373,515	22,354,523	11,188	33,389	5.98
9						
10	<u>Minnesota Company</u>					
11						
12	Total Small Comm & Ind	4,473,489	275,673,227	131,164	34,107	6.16
13						
14	<u>Large Commercial & Industrial</u>					
15	<u>State of Minnesota</u>					
16						
17	GA004 Area Development Rider	0	(55,926)	9	0	N/A
18						
19	GM004 Competitive Service Rider	0	(19,387)	1	0	N/A
20						
21	GK004 General-Sec	4,697,606	242,605,076	3,859	1,286,576	5.16
22	GK006 Off Season Rider	390	35,340	2	195,200	9.05
23	GK014 General-Pri	1,079,690	50,532,308	201	5,373,820	4.68
24	GK024 General-TT	3,437	144,536	1	3,436,800	4.21
25	GK034 General-Trans	34,187	1,345,315	1	34,186,880	3.94
26	Sub Total General-Lrg	5,815,310	294,662,575	4,064	1,430,962	5.07
27						
28	GK104 Peak Ctrl-Sec (CL)	183,513	9,371,639	225	814,405	5.11
29	GK114 Peak Ctrl-Pri (CL)	153,366	6,830,877	33	4,635,748	4.45
30	GP004 Peak Ctrl-Sec	870,908	44,929,869	919	947,755	5.16
31	GP006 Peak Ctrl	10,029	428,810	1	17,192,229	4.28
32	GP014 Peak Ctrl-Pri	372,162	16,193,643	87	4,290,053	4.35
33	GP034 Peak Ctrl-Trans	1,006	43,411	1	1,005,905	4.32
34	Sub Total Peak-Ctrl-Lrg	1,590,984	77,798,249	1,266	1,257,032	4.89
35						
36	GT004 Gen TOD-Sec-On	587,918	42,998,444	475	1,237,505	7.31
37	GT005 Gen TOD-Sec-Off	958,314	25,668,882	475 *	2,017,149	2.68
38	GT014 Gen TOD Pri-On	617,162	41,704,521	75	8,274,799	6.76
39	GT015 Gen TOD-Pri-Off	1,007,526	26,352,441	75 *	13,508,728	2.62
40	GT024 Gen TOD-TT-On	420,096	25,213,875	6	71,002,141	6.00
41	GT025 Gen TOD-TT-Off	748,179	19,119,091	6 *	126,452,856	2.56
42	Sub Total Gen TOD-Lrg	4,339,195	181,057,255	1,112	3,905,080	4.17
43						
44	GP104 Peak-Ctrl TOD-Sec-On	111,464	7,709,093	99	1,129,705	6.92
45	GP105 Peak-Ctrl TOD-Sec-Off	182,511	4,938,568	99 *	1,849,770	2.71
46	GP114 Peak-Ctrl TOD-Pri-On	234,369	15,416,875	28	8,370,336	6.58
47	GP115 Peak-Ctrl TOD-Pri-Off	363,235	9,613,964	28 *	13,011,407	2.65
48	GP116 Peak-Ctrl TOD-Pri-On Opt	11,306	794,461	1	11,305,950	7.03
49	GP117 Peak-Ctrl TOD-Pri-Off Opt	15,272	421,682	1 *	15,271,660	2.76
50	GP126 Peak-Ctrl TOD-TT-On Opt	44,649	2,653,140	1	41,214,905	5.94
51	GP127 Peak-Ctrl TOD-TT-Off Opt	73,891	1,859,786	1 *	73,891,330	2.52
52	GT104 Peak Ctrl TOD-Sec-On (CL)	21,358	1,557,223	29	740,750	7.29
53	GT105 Peak Ctrl TOD-Sec-Off (CL)	39,255	419,817	29 *	1,361,444	1.07
54	GT114 Peak Ctrl TOD-Pri-On (CL)	42,739	2,944,132	9	4,579,135	6.89
55	GT115 Peak Ctrl TOD-Pri-Off (CL)	60,350	1,585,025	9 *	6,466,115	2.63
56	GT124 Peak Ctrl TOD-TT-On (CL)	3,784	228,452	1	3,783,946	6.04

SALES OF ELECTRICITY BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue ($'s) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (¢'s) per KWH Sold (f)
1	GT125 Peak Ctrl TOD-TT-Off (CL)	4,416	111,222	1 *	4,416,054	2.52
2	GT134 Peak Ctrl TOD-Trans-On (CL)	56,859	2,824,941	1	97,472,589	4.97
3	GT135 Peak Ctrl TOD-Trans-Off (CL)	133,924	3,325,750	1 *	229,584,686	2.48
4	Sub Total Peak Ctrl TOD-Lrg	1,399,383	56,404,131	338	4,154,528	4.03
5						
6	GP206 Exp Peak-Ctrl On Pk	127	7,239	1	152,839	5.68
7	GP208 Exp Peak-Ctrl Off Pk	241	6,020	0 *	721,782	2.50
8	GP216 Exp Peak-Ctrl On Pk Pri	2,558	191,904	2	1,705,489	7.50
9	GP217 Exp Peak-Ctrl Mid Pk Pri	859	33,328	0 *	-	3.88
10	GP218 Exp Peak-Ctrl Off Pk Pri	8,163	212,745	1 *	13,993,095	2.61
11	GP236 Exp Peak-Ctrl On Pk Trans	53,665	3,545,257	1	107,329,380	6.61
12	GP237 Exp Peak-Ctrl Mid Pk Trans	23,861	771,539	0 *	95,443,560	3.23
13	GP238 Exp Peak-Ctrl Off Pk Trans	184,166	4,375,473	1 *	368,331,600	2.38
14	Sub Total Exp Peak Ctrl	273,639	9,143,506	6	60,808,689	3.34
15						
16	GL104 Energy Ctrl-Sec-On	11,847	711,454	14	841,236	6.01
17	GL105 Energy Ctrl-Sec-Off	17,014	435,667	14 *	1,208,125	2.56
18	GL114 Energy Ctrl-Pri-On	17,366	790,231	4	4,961,597	4.55
19	GL115 Energy Ctrl-Pri-Off	28,994	704,346	4 *	8,283,946	2.43
20	GL124 Energy Ctrl-TT-On	82,941	4,016,538	3	27,646,840	4.84
21	GL125 Energy Ctrl-TT-Off	154,996	3,841,162	3 *	51,665,167	2.48
22	Sub Total Energy Ctrl-Lrg	313,157	10,499,399	42	7,607,059	3.35
23						
24	GN014 Standby Service-Pri	0	129,962	3	0	-
25	GN034 Standby Service - Trans	0	76,149	1	0	-
26	Sub Total Standby Service	0	206,111	4	0	-
27						
28	GN114 Ford	17,349	718,114	1	17,348,800	4.14
29						
30	GW060 Limited Off-Pk-Sec 3P-On	8	1,544	7 *	23	19.98
31	GW061 Limited Off-Pk-Sec 3P-Off	618	16,684	7 *	88,230	2.70
32	Sub Total Limited Off-Pk	625	18,227	14 *	44,667	2.91
33						
34	GC975 LG C&I-Net Unbilled	41,050	336,406			
35						
36	Sub Total Large C&I-MN	13,790,693	630,768,658	6,857	2,012,824	4.57
37	Refund		5,415,489			
38	Total Large C&I-MN	13,790,693	625,353,169	6,857	2,012,824	4.53
39						
40	<u>State of South Dakota</u>					
41						
42	GK804 General-Sec	192,638	10,244,131	207	930,618	5.32
43	GK814 General-Pri	11,997	621,956	8	1,425,427	5.18
44	GK834 General Serv Trans	237	9,127	0	2,848,992	3.84
45	Sub Total General-Lrg	204,873	10,875,214	215	950,686	5.31
46						
47	GK904 Peak Ctrl-Sec (CL)	4,497	274,408	8	568,002	6.10
48	GM804 Econ Devel Rider	0	(20,914)	1	0	-
49	GP804 Peak-Ctrl-Sec	17,940	1,042,343	31	574,078	5.81
50	GP814 Peak-Ctrl-Pri	5,119	250,503	2	3,071,310	4.89
51	GP904 Peak-Cntl On Pk	128	12,559	1	219,007	9.83
52	GP905 Peak-Cntl Off Pk	123	3,431	1	210,250	2.80
53	GP914 Peak-Cntl Pri On Pk	6,695	432,967	1	7,303,521	6.47
54	GP915 Peak-Cntl Pri Off Pk	11,026	284,613	1	12,028,702	2.58
55	Sub Total Peak-Ctrl-Lrg	45,527	2,279,910	46	1,019,263	5.01
56						

SALES OF ELECTRICITY BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue ($'s) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (¢'s) per KWH Sold (f)
1	GT804 Gen TOD-On	24,887	1,927,210	22	1,157,524	7.74
2	GT805 Gen TOD-Off	41,339	1,108,504	21 *	1,930,247	2.68
3	GT814 Gen TOD-Pri-On	60,713	4,080,596	6	10,261,362	6.72
4	GT815 Gen TOD-Pri-Off	85,021	2,194,751	6 *	14,369,779	2.58
5	Sub Total Gen TOD-Lrg	211,960	9,311,062	55	3,871,424	4.39
6						
7	GL904 Energy Ctrl Sec-On	11,610	696,827	10	1,114,577	6.00
8	GL905 Energy Ctrl Sec-Off	18,876	463,161	10 *	1,812,054	2.45
9	GL914 Energy Ctrl Pri-On	5,613	268,743	2	2,928,736	4.79
10	GL915 Energy Ctrl Pri-Off	7,302	173,151	2 *	3,809,525	2.37
11	Sub Total Energy Ctrl-Lrg	43,401	1,601,882	24	1,759,490	3.69
12						
13	GW860 Limited Off-Peak-Sec 3P-On	5	970	1 *	4,840	20.04
14	GW861 Limited Off-Peak-Sec 3P-Off	9	297	1	8,880	3.35
15	Sub Total Limited Off-Peak	14	1,267	2	6,860	9.23
16						
17	GC975 Lrg C&I-Net Unbilled	2,656	(55,062)			
18	Total Large C&I-SD	508,431	24,014,274	342	1,488,453	4.72
19						
20	**State of North Dakota**					
21						
22	GK504 General-Sec	283,237	14,451,182	307	923,598	5.10
23	GK514 General-Pri	17,456	799,022	9	1,921,812	4.58
24	Sub Total General-Lrg	300,693	15,250,204	316	952,314	5.07
25						
26	GK604 Peak Ctrl-Sec (CL)	21,168	1,039,530	29	734,148	4.91
27	GP504 Peak Ctrl-Sec	21,982	1,166,590	48	454,021	5.31
28	GP514 Peak Ctrl-Pri	2,477	106,769	1	2,476,950	4.31
29	Sub Total Peak Ctrl TOD	45,627	2,312,890	78	583,093	5.07
30						
31	GT504 Gen TOD-On	49,275	3,572,479	50	985,494	7.25
32	GT505 Gen TOD-Off	77,168	1,983,030	50 *	1,545,932	2.57
33	GT514 Gen TOD On-Pri	3,350	202,486	2	1,674,792	6.05
34	GT515 Gen TOD Off-Pri	5,225	130,026	2 *	2,612,447	2.49
35	Sub Total Gen TOD	135,017	5,888,021	104	1,299,281	4.36
36						
37	GP604 Peak-Ctrl TOD-Sec-On	11,605	697,659	3	3,978,713	6.01
38	GP605 Peak-Ctrl TOD-Sec-Off	20,583	507,716	3 *	20,583,460	2.47
39	GP614 Peak-Ctrl TOD-Pri-On	1,010	51,133	0	1,010,125	5.06
40	GP615 Peak-Ctrl TOD-Pri-Off	1,606	40,200	0 *	1,605,875	2.50
41	GT604 Peak-Ctrl TOD-On-Sec (CL)	14,520	925,977	2	7,259,905	6.38
42	GT605 Peak-Ctrl TOD-Off-Sec (CL)	25,139	611,854	2 *	12,569,695	2.43
43	GT614 Peak-Ctrl TOD-On-Pri (CL)	405	34,195	1	405,450	8.43
44	GT615 Peak-Ctrl TOD-Off-Pri (CL)	700	18,794	1 *	700,290	2.68
45	Sub Total Peak-Ctrl TOD	75,569	2,887,527	12	5,965,972	3.82
46						
47	GL504 Peak Int-Sec-On (CL)	0	0	0	0	N/A
48	GL505 Peak Int-Sec-Off (CL)	0	0	0 *	0	N/A
49	Sub Total Peak Int (CL)	0	0	0	0	N/A
50						
51	GL604 Energy-Ctrl-Sec-On	21,184	1,190,128	20	1,041,838	5.62
52	GL605 Energy-Ctrl-Sec-Off	33,152	819,631	20 *	1,630,431	2.47
53	GL614 Energy-Ctrl-Pri-On	13,202	575,821	4	3,168,516	4.36
54	GL615 Energy-Ctrl-Pri-Off	20,703	462,960	4 *	20,702,670	2.24
55	Sub Total Energy-Ctrl-Lrg	88,241	3,048,540	48	1,800,836	3.45
56						

SALES OF ELECTRICITY BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue ($'s) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (¢'s) per KWH Sold (f)
1	GW560 Limited Off Peak-Sec-3P-On	0	0	1 *	0	-
2	GW561 Limited Off-Peak-Sec-3P-Off	55	1,545	1	55,120	2.80
3	Sub Total Limited Off-Peak	55	1,545	2	27,560	2.80
4						
5	GC975 Lg C&I-Net Unbilled	3,706	78,745			
6						
7	Total Large C&I-ND	648,908	29,467,473	560	1,154,812	4.54
8						
9	Minnesota Company					
10						
11	Total Large Comm & Ind	14,948,032	678,834,916	7,759	1,927,555	4.54
12						
13	Street & Highway Lighting					
14	State of Minnesota					
15						
16	GW061 Limited Off Pk 3P	0	0	1		
17						
18	KP008 OH St Ltg-Leased	37,656	8,296,820	456	82,653	22.03
19	KP009 UG St Ltg-Leased	7,992	2,828,481	152	52,667	35.39
20	KP089 UG St Ltg-Leased	575	70,605	5	114,929	12.29
21	KP099 Ornmtl UG St Ltg-Leased	311	92,165	3	101,002	29.59
22	Sub Total St Ltg-Leased	46,534	11,288,071	616	75,614	24.26
23						
24	KP108 OH St Ltg-Leased (CL)	91	12,414	3	33,012	13.67
25	KP109 UG St Ltg-Leased (CL)	12	2,420	0	-	19.79
26	Sub Total St Ltg-Leased (CL)	103	14,834	3	37,458	14.40
27						
28	KS009 Ornmtl St Ltg-Purch	19	1,547	0	225,612	8.23
29	KY009 Energy Only St Ltg-Purch (CL)	66,386	2,938,673	310	213,977	4.43
30	KT008 Traffic Control-Purch	(7)	15	1	(6,016)	(0.24)
31	Sub Total St Ltg-Purch	66,399	2,940,236	311	213,215	4.43
32						
33	KS109 Ornmtl St Ltg-Purch (CL)	892	65,176	31	28,999	7.31
34						
35	KY000 Energy Only-Metered	4,896	226,425	307	15,966	4.62
36						
37	KP208 OH St Ltg-St Paul	2,380	288,774	5	484,021	12.13
38						
39	KT974 St Ltg-Net Unbilled	568	21,229			
40						
41	Sub-Total St & Hwy Ltg-MN	121,771	14,844,744	1,273	95,738	12.19
42	Refund		137,000			
43	Total St & Hwy Ltg-MN	121,771	14,707,744	1,273	95,738	12.08
44						
45	State of South Dakota					
46						
47	KP808 OH St Ltg-Leased	1,300	281,302	35	37,058	21.64
48	KP809 UG St Ltg-Leased	116	44,127	11	10,334	37.96
49	Sub Total St Lgt-Leased	1,416	325,430	46	30,569	22.98
50						
51	KS809 Ornmtl St Lgt-Purch	245	14,137	5	45,909	5.77
52	KY809 Energy Only St Ltg-Purch	1,153	49,980	3	446,435	4.33
53	KY900 Energy Only-Metered (CL)	1,798	87,497	74	24,358	4.87
54	Sub Total St Ltg-Purch	3,197	151,615	82	39,101	4.74
55						
56	KY800 Energy Only-Metered-Purch	1,620	79,355	54	30,138	4.90

SALES OF ELECTRICITY BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue ($'s) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (¢'s) per KWH Sold (f)
1	KT974 St Ltg-Net Unbilled	145	5,565			
2						
3	Total St & Hwy Ltg-SD	6,378	561,964	182	35,075	8.81
4						
5	State of North Dakota					
6						
7	KP508 OH St Ltg-Leased	2,504	458,902	22	114,253	18.33
8	KP509 UG St Ltg-Leased	130	42,370	8	15,556	32.69
9	Sub Total St Ltg-Leased	2,634	501,272	30	87,063	19.03
10						
11	KS509 Ornmtl St Ltg-Purch	10,719	624,089	13	835,238	5.82
12	KY500 Energy Only-Metered-Purch	444	19,125	8	52,781	4.31
13	KY509 Energy Only St Ltg-Purch	14	706	0	-	4.88
14	Sub Total St Ltg-Purch	11,178	643,921	21	526,005	5.76
15						
16	KS609 Ornmtl St Ltg-Purch (CL)	48	3,901	1	47,655	8.19
17						
18	KT974 St Ltg-Net Unbilled	(5)	(3,213)			
19						
20	Total St & Hwy Ltg-ND	13,854	1,145,880	52	263,884	8.27
21						
22	Minnesota Company					
23						
24	Total St & Hwy Ltg	142,003	16,415,589	1,507	94,276	11.56
25						
26	Other Sales to Public Authorities					
27	State of Minnesota					
28						
29	M2000 Water Pumping N/D	2,105	133,467	205	10,258	6.34
30	M3000 Sewage Pumping N/D	6,470	439,818	962	6,727	6.80
31	Sub Total Sm Muni Pump N/D	8,575	573,285	1,167	7,348	6.69
32						
33	M2004 Water Pumping-Sec	30,874	2,085,718	365	84,509	6.76
34	M2014 Water Pumping-Pri	587	65,403	9	65,256	11.14
35	M2104 Water Pumping-Lg-Sec	34,660	1,988,474	98	355,182	5.74
36	M2114 Water Pumping-Lg-Pri	15,060	713,641	3	5,020,100	4.74
37	M3004 Sewage Pumping-Sec	23,573	1,339,504	239	98,598	5.68
38	M3104 Sewage Pumping-Lg-Sec	5,187	259,706	8	648,325	5.01
39	M3114 Sewage Pumping-Lg-Pri	3,469	163,674	3	1,156,253	4.72
40	Sub Total Muni Pumping	113,410	6,616,120	725	156,427	5.83
41						
42	M4008 Fire/CD Siren Serv	0	27,236	460	0	-
43						
44	M5104 Exc Energy-St Anthony	618	15,218	2	308,885	2.46
45						
46	M2970 Municipal-Net Unbilled	(524)	(30,690)			
47						
48	Sub Total Other Sales PA-MN	122,078	7,201,168	2,354	51,860	5.90
49	Refund		64,000			
50	Total Other Sales PA-MN	122,078	7,137,168	2,354	51,860	5.85
51						
52	State of South Dakota					
53						
54	M4808 Fire/CD Siren Serv	0	1,834	35	1	-
55						
56	M2970 Municipal-Net Unbilled	0	13			

SALES OF ELECTRICITY BY RATE SCHEDULES (Continued)

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue ($'s) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (¢'s) per KWH Sold (f)
1	Total Other Sales PA-SD	0	1,847	35	1	-
2						
3	**State of North Dakota**					
4						
5	M2500 Municipal Pumping N/D	671	37,560	66	10,112	5.60
6	M2504 Municipal Pumping-Sec	18,846	909,632	72	262,655	4.83
7	M2514 Municipal Pumping-Pri	5,851	226,933	1	5,851,200	3.88
8	Sub Total Mun Pumping	25,367	1,174,126	139	182,391	4.63
9						
10	M4508 Fire/CD Siren Serv	0	1,064	27	0	-
11						
12	M2970 Municipal-Net Unbilled	(20)	(1,206)			-
13						
14	Total Other Sales PA-ND	25,347	1,173,984	166	152,237	4.63
15						
16	**Minnesota Company**					
17						
18	Total Other Sales PA	147,426	8,312,999	2,555	57,690	5.64
19						
20	**Total Retail**					
21						
22	State of Minnesota	24,288,336	1,352,860,415	1,043,907	23,267	5.57
23	State of South Dakota	1,150,478	69,239,509	59,000	19,499	6.02
24	State of North Dakota	1,736,770	94,011,979	81,069	21,423	5.41
25						
26	Minnesota Company	27,175,584	1,516,111,903	1,183,976	22,953	5.58
27						
28	Interdepartmental Sales	12,404	223,975			1.81
29						
30	Total Sales to Ultimate Customer	27,187,988	1,516,335,878	1,183,976	22,963	5.58
31						
32	Sales for Resale	7,622,098	143,488,544	60	127,388,825	1.88
33	Refund					
34	Total Sales for Resale	7,622,098	143,488,544	60	127,388,825	1.88
35						
36	Total Sales of Electricity	34,810,086	1,659,824,422	1,184,036	29,400	4.77
37						
38						
39						
40						
41						
42						
43						
44						
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52						
53						
54						
55						
56						

SALES OF ELECTRICITY BY RATE SCHEDULES (Continued)

* Denotes Duplicate Number of Customers

Definition of Symbols :

1P - Single Phase	Lrg - Large	Purch - Purchased
3P - Three Phase	Muni - Municipal	SH - Electric Space Heating
(CL) - Closed	N/D - Non-Demand Metered	Sec - Secondary Voltage
(CN) - Cancelled	OH - Overhead Service	Sm - Small
Comm - Commercial	Off - Off Peak	St Ltg - Street Lighting
Ctrl - Controlled	On - On Peak	TOD - Time of Day
DF - Dual Fuel	Opt - Optional	TT - Trans Transformed Voltage
Gen - General	Ornmtl - Ornamental	Trans- Transmission Line Voltage
Ind - Industrial	PA - Public Authorities	UG - Underground Service
Int - Interruptible Service	Pri - Primary Voltage	WH - Controlled Water Heating

REVENUE FROM FUEL CLAUSE ADJUSTMENT

Residential	Minnesota	South Dakota	North Dakota	Total
Res Serv	(1,221,422)	(31,843)	(81,064)	(1,334,329)
Res-UG	(413,669)	(13,607)	(10,211)	(437,487)
Res TOD Serv	(239)	(1)	(83)	(323)
Res TOD-UG	(212)	N/A	N/A	(212)
Res LD Ctrl	(97,888)	(4,830)	369	(102,350)
Energy Ctrl DF	(3,085)	(88)	(349)	(3,521)
Limited Off-Pk	(568)	(1)	(24)	(592)
APL-Res	(2,259)	(56)	(54)	(2,369)
Res Dual Fuel-SH (CL)	N/A	(9)	N/A	(9)
Res Unbilled	(1,295,784)	(101,914)	(143,008)	(1,540,706)
Total Res	(3,035,125)	(152,348)	(234,423)	(3,421,897)

Small Comm & Industrial	Minnesota	South Dakota	North Dakota	Total
Small General	(203,762)	(7,694)	(12,275)	(223,731)
General-Sm	(768,800)	(24,278)	(42,927)	(836,005)
Gen TOD-Sm	(53,467)	(1,292)	(1,845)	(56,604)
Sm Gen-TOD	(14,256)	N/A	(254)	(14,510)
Peak Ctrl TOD-Sm	(1,900)	N/A	(67)	(1,967)
Peak Ctrl-Sec-Sm	(17,723)	N/A	N/A	(17,723)
Direct Current (CL)	(6)	N/A	(0)	(6)
Energy-Ctrl DF	(254)	N/A	(79)	(333)
Limited Off Pk	(249)	(0)	(37)	(286)
APL-Comm	(6,023)	(193)	(268)	(6,484)
NWB Tele Booth (CL)	(2)	N/A	N/A	(2)
Sm C&I Unbilled	(763,261)	(57,771)	(69,901)	(890,933)
Total Sm C&I	(1,829,702)	(91,228)	(127,654)	(2,048,584)

Large Comm & Industrial	Minnesota	South Dakota	North Dakota	Total
General-Lrg	(1,593,364)	(29,051)	(52,502)	(1,674,916)
Peak-Ctrl-Lrg	(441,612)	(7,197)	(4,798)	(453,608)
Gen TOD-Lrg	(1,204,583)	(34,284)	(17,633)	(1,256,499)
Peak Ctrl TOD-Lrg	(406,501)	N/A	(12,175)	(418,677)
Exp Peak Ctrl	(90,101)	(6,218)	(15,292)	(111,611)
Energy Ctrl-Lrg	(70,936)	6	(3)	(70,933)
Limited Off-Pk	(159)	N/A	N/A	(159)
Ford	(6,858)	N/A	N/A	(6,858)
Lg C&I Unbilled	(2,562,289)	(116,018)	(100,353)	(2,778,660)
Total Large C&I	(6,376,403)	(192,761)	(202,757)	(6,771,922)

Street & Highway Lighting	Minnesota	South Dakota	North Dakota	Total
St Ltg-Leased	(12,079)	(169)	(288)	(12,536)
St Ltg-Leased (CL)	(26)	N/A	N/A	(26)
St Ltg-Purch	(17,241)	(435)	(1,182)	(18,858)
Ornmtl St Lgt-Purch (CL)	(234)	N/A	(5)	(239)
Energy Only-Metered	(1,293)	(193)	N/A	(1,486)
St Ltg-St Paul	(621)	N/A	N/A	(621)
St & Hwy Ltg Unbilled	(25,910)	(1,489)	(2,480)	(29,879)
Total St & Hwy Ltg-MN	(57,404)	(2,286)	(3,955)	(63,645)

Other Sales to Pub Authority	Minnesota	South Dakota	North Dakota	Total
Sm Muni Pump	(2,650)	N/A	N/A	(2,650)
Muni Pumping	(32,586)	N/A	(3,890)	(36,475)
Exc Energy-St Anthony	(281)	N/A	N/A	(281)
Other Sales Unbilled	(25,637)	0	(3,665)	(29,302)
Total Other Sales PA	(61,153)	0	(7,555)	(68,708)

Grand Total	(11,359,788)	(438,624)	(576,344)	(12,374,756)

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SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (pages 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain liable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)(41)	Actual Demand (MW): Average Monthly NCP Demand (e)(41)	Actual Demand (MW): Average Monthly CP Demand (f)
1	City of Ada	RQ	390	1,317	3,774	
2	City of Anoka	RQ	420	35,481	35,481	
3	City of Arlington	RQ	421	2,618	2,618	
4	City of Brownton	RQ	422	840	840	
5	City of Buffalo	RQ	423	9,145	9,469	
6	City of Chaska	RQ	424	25,008	26,552	
7	City of East Grand Forks	RQ	387	5,636	17,730	
8	City of Fairfax	RQ	400	510	2,161	
9	City of Kasota	RQ	426	598	598	
10	City of Kasson	RQ	427	3,405	3,405	
11	City of Kenyon	RQ	394	2,539	2,539	
12	City of LeSueur	RQ	392	12,676	12,676	
13	City of Madelia	RQ	397	5,036	5,036	
14	City of Melrose	RQ	401	6,989	12,503	

SALES FOR RESALE (Account 447)(Continued)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in [illegible]ote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal - Non - RQ" in column (a) after this listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).

5. In column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d),(e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatthours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in columns (g) through (k) must be subtotalled based on the RQ/ Non-RQ grouping (see Instruction 4), and then totalled on the last line of the schedule. The "Subtotal-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on page 401, line 24.

10. Footnote entries as required and provided explanations following all required data.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h + i + j) (k)	Line No.
5,237	63,204	113,601	148 (40)	176,953	1
212,698	3,513,414	5,294,171	(134,848) (40)	8,672,737	2
14,138	258,913	306,689	13,603 (40)	579,205	3
4,650	83,085	101,087	5,295 (40)	189,467	4
53,742	887,812	1,165,656	(8,774) (40)	2,044,694	5
150,386	2,447,145	3,264,665	(29,691) (40)	5,682,119	6
30,951	352,205	671,332	(6,008) (40)	1,017,529	7
2,907	49,511	63,045	1,105 (40)	113,661	8
2,962	58,012	64,236	4,563 (40)	126,811	9
18,295	330,519	396,823	17,494 (40)	744,836	10
12,770	246,438	276,990	(965) (40)	522,463	11
77,837	1,253,668	1,691,884	(16,666) (40)	2,928,886	12
29,294	488,860	635,395	(4,475) (40)	1,119,780	13
48,357	678,490	1,048,862	(7,075) (40)	1,720,277	14

SALES FOR RESALE (Account 447)(Continued)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)(41)	Actual Demand (MW) Average Monthly NCP Demand (e)(41)	Average Monthly CP Demand (f)
15	City of No St Paul	RQ	429	12,322	12,322	
16	City of Olivia	RQ	388	803	4,760	
17	City of Sauk Centre	RQ	449	NA	NA	
18	City of Shakopee	RQ	431	19,700	19,700	
19	City of Sioux Falls	RQ	413	3,728	10,732	
21	City of Winthrop	RQ	433	2,651	2,651	
22	Northern States Power Co. (WI)	RQ	154	NA	NA	
23	Unbilled Revenue					
24	Subtotal-RQ					
25	Interstate Power Co	OS(1)	417	NA	NA	N
26	Iowa Elec Light & Pwr	OS(2)	321	NA	NA	NA
27	IA-IL Gas & Elec Co	OS(3)	417	NA	NA	NA
28	IES Utilities	OS(4)	417	NA	NA	NA
29	IA Southern Utility	OS(5)	417	NA	NA	NA
30	Kansas City Pwr & Lt	OS(6)	417	NA	NA	NA
31	Lincoln Elec System	OS(7)	417	NA	NA	NA
32	Midwest Pwr System	OS(8)	417	NA	NA	NA
33	Madison Gas & Elec	OS(9)	359	NA	NA	NA
34	Minn Power Co	OS(10)	417	NA	NA	NA
35	Missouri Basin	OS(11)	417	NA	NA	NA
36	Montana-Dakota	OS(12)	417	NA	NA	NA
37	Muni Agency of Nebraska	OS(13)	Co-Gen	NA	NA	N

SALES FOR RESALE (Account 447)(Continued)

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h + i + j) (k)	Line No.
67,710	1,216,941	1,471,620	43,587 (40)	2,732,148	15
4,030	79,254	87,616	1,080 (40)	167,950	16
			(1,935) (40)	(1,935)	17
122,462	1,914,736	2,662,369	118,175 (40)	4,695,280	18
24,597	363,662	533,511	(8,443) (40)	888,730	19
15,631	262,296	339,750	12,581 (40)	614,627	21
4,926,970			162,725,938	162,725,938 (43)	22
(43,107)		(1,526,499)		(1,526,499)	23
5,782,517	14,548,165	18,662,803	162,724,689	195,935,657	24
6,137		79,009		79,009	25
233,264		4,274,260		4,274,260	26
5,172		69,957		69,957	27
115,962		2,245,403		2,245,403	28
33,579		447,588		447,588	29
358,405		5,106,522		5,106,522	30
33,725		580,036		580,036	31
17,148		264,285		264,285	32
154,560	1,121,665	2,345,907		3,467,572	33
354,494		4,986,564		4,986,564	34
73,556		1,067,656		1,067,656	35
15,645		183,410		183,410	36
70		1,880		1,880	37

SALES FOR RESALE (Account 447)(Continued)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
38	Muscatine Pwr & Wtr	OS(14)	417	NA	NA	NA
39	Nebraska Pub Pwr Dist	OS(15)	417	NA	NA	NA
40	North Central Power	OS(16)	417	NA	NA	NA
41	NoWestern Pub Serv Co	OS(17)	417	NA	NA	NA
42	NoWestern Wis Electric	OS(18)	417	NA	NA	NA
43	Omaha Pub Pwr Dist	OS(19)	417	NA	NA	NA
44	Otter Tail Pwr Co	OS(20)	417	NA	NA	NA
45	St Joseph Lt & Pwr Co	OS(21)	351	NA	NA	NA
46	So Mn Mun Pwr Agency	OS(22)	417	NA	NA	NA
47	Union Electric Co	OS(23)	321	NA	NA	N
48	Wis Elec Pwr Co	OS(24)	319	NA	NA	NA
49	Wis Pub Pwr Inc Sys	OS(25)	447	NA	NA	NA
50	Wis Pub Serv Corp	OS(26)	346	NA	NA	NA
51	Wis Pwr & Lgt Co	OS(27)	410	NA	NA	NA
52	Basin Elec Coop	OS(28)	417	NA	NA	NA
53	Coop Pwr Assoc	OS(29)	417	NA	NA	NA
54	Dairyland Pwr Coop	OS(30)	417	NA	NA	NA
55	Minnkota Pwr Coop	OS(31)	417	NA	NA	NA
56	Manitoba Hydro	OS(32)	359	NA	NA	NA
57	United Power Assoc	OS(33)	417	NA	NA	NA
58	Western Area Pwr Admin	OS(34)	446	NA	NA	NA
59	City of Delano	OS(35)	470	NA	NA	N

SALES FOR RESALE (Account 447)(Continued)

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h + i + j) (k)	Line No.
2,535		27,289		27,289	38
108,487		1,682,444		1,682,444	39
15,896	198,205	310,870		509,075	40
13,829		203,165		203,165	41
127,297	880,000	2,702,534		3,582,534	42
14,747		230,025		230,025	43
56,814		804,434		804,434	44
53,346		680,694		680,694	45
4,960		62,366		62,366	46
1,740,534	1,158,150	24,584,689		25,742,839	47
321,290	4,200,000	4,848,742		9,048,742	48
163,094		2,033,706		2,033,706	49
1,383,994		22,500,476		22,500,476	50
307,945		3,609,234		3,609,234	51
201		6,720		6,720	52
7,970		129,252		129,252	53
15,715		211,040		211,040	54
29,510		487,373		487,373	55
268,193		2,988,450		2,988,450	56
122,653	800,000	2,007,259		2,807,259	57
319,726		4,086,176		4,086,176	58
25,361		482,877		482,877	59

SALES FOR RESALE (Account 447)(Continued)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
60	City of Janesville	OS(35)	470	NA	NA	NA
61	City of Lake Crystal	OS(35)	470	NA	NA	NA
62	City of Glencoe	OS(35)	470	NA	NA	NA
63	City of Mountain Lake	OS(35)	470	NA	NA	NA
64	City of Truman	OS(35)	470	NA	NA	NA
65	City of New Ulm	OS(36)	398	NA	NA	NA
66	City of Sleepy Eye	OS(37)	393	NA	NA	NA
67	City of Blue Earth	OS(38)	485	NA	NA	NA
68	City of East Grand Forks	OS(39)	476	NA	NA	NA
69	Subtotal-Non-RQ					
70	Corporate Level Adjustment					
71	Total					

SALES FOR RESALE (Account 447)(Continued)

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h + i + j) (k)	Line No.
9,234		174,789		174,789	60
12,750		243,537		243,537	61
58,053		1,089,786		1,089,786	62
10,151		200,556		200,556	63
13,044		259,238		259,238	64
126,623	678,328	1,993,711		2,672,039	65
25,666	84,953	401,401		486,354	66
923		20,099		20,099	67
4,292	49,735	85,840		135,575	68
6,766,550	9,171,036	100,801,249	0	109,972,285	69
			306,540 (42)	306,540	70
12,549,067 (43)	23,719,201	119,464,052	163,031,229	306,214,482 (43)	71

SALES FOR RESALE (Account 447)(Continued)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (pages 326-327).
2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate customers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)

Footnotes:

(1) Economy, Emergency, Schedule M
(2) Economy, Emergency, Schedule M, Scheduled Outage
(3) Economy, Emergency, Schedule M, Scheduled Outage
(4) Economy, Schedule M, Scheduled Outage
(5) Economy, Emergency, Schedule M, Scheduled Outage
(6) Scheduled Outage, Term
(7) Schedule M, Scheduled Outage
(8) Economy, Emergency, Schedule M, Scheduled Outage
(9) Economy, General Purpose, System Power, Short-Term
(10) Economy, Emergency, Schedule M, Scheduled Outage
(11) Schedule M, Scheduled Outage
(12) Economy, Schedule M, Scheduled Outage
(13) Schedule M
(14) Economy, Schedule M, Scheduled Outage
(15) Economy, Schedule M, Scheduled Outage, Emergency
(16) Peaking Power, System Power, Supplemental Power
(17) Economy, Schedule M, Emergency, Scheduled Outage
(18) System Power, Supplemental Power
(19) Economy, Emergency, Schedule M, Scheduled Outage
(20) Economy, Emergency, Firm, Schedule M, Scheduled Outage
(21) Scheduled Outage, Term
(22) Economy, Schedule M, Scheduled Outage
(23) Excess, Term, Participation Power
(24) Economy, General Purpose, Short-Term, System Power, General Purpose-Negotiated
(25) Economy, General Purpose, Schedule M, Scheduled Outage
(26) Economy, General Purpose-Negotiated, General Purpose, Reserve
(27) Economy, General Purpose - Negotiated, General Purpose
(28) Emergency
(29) Economy, Schedule M, Scheduled Outage
(30) Economy, Emergency, Scheduled Outage, Schedule M, Interruptible Replacement
(31) Economy, Participation Power, Schedule M, Interruptible Replacement
(32) Operational Control, Scheduled Outage
(33) Economy, Scheduled Outage, Schedule M, Firm
(34) Breakdown, Schedule M
(35) Economy
(36) Firm, Short-Term
(37) Peaking, Short-Term
(38) Supplemental
(39) Base Load
(40) Fuel Clause Adjustment; Customer Charge; Refund for Nuclear expenses, Option payments, and Highwall expenses that should not have flowed through the fuel clause per the 1986-1989 FERC Audit.
(41) 15 Minute Integration
(42) Customer refunds (see note 40) which were previously accrued through regulatory reserve.
(43) Total dollars and MWHs will not match page 300/301, line 11 due to differences in accounting classification associated with the interchange agreement of the Company and the Wisconsin Company (see Note 12 of Notes to the Financial Statements or page 450 for dollar amounts) and the classification on the bulk power transaction pages.

Northern States Power Company (Minnesota) Dec. 31, 1993

An Original

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnotes.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$8,903,359	$9,419,144
5	(501) Fuel	258,483,278	244,846,738
6	(502) Steam Expenses	15,567,795	15,788,318
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	4,302,626	4,658,652
10	(506) Miscellaneous Steam Power Expenses	20,918,664	18,452,916
11	(507) Rents	19,015	6,496
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	308,194,737	293,172,263
14	Maintenance		
15	(510) Maintenanee Supervision and Engineering	5,553,157	6,043,076
16	(511) Maintenance of Structures	2,505,822	3,307,385
17	(512) Maintenance of Boiler Plant	20,343,960	27,179,295
18	(513) Maintenance of Electric Plant	7,018,952	7,782,882
19	(514) Maintenance of Miscellaneous Steam Plant	3,511,743	3,769,096
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	38,933,634	48,081,733
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	347,128,371	341,253,996
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	28,040,150	39,444,422
25	(518) Fuel	52,518,597	51,955,560
26	(519) Coolants and Water	135,472	198,907
27	(520) Steam Expenses	18,693,691	18,416,562
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	7,393,344	4,821,956
31	(524) Miscellaneous Nuclear Power Expenses	41,867,356	46,295,195
32	(525) Rents	36,610	0
33	TOTAL Operation (Enter Total of lines 24 thru 32)	148,685,220	161,132,601
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	10,327,591	10,444,344
36	(529) Maintenanee of Structures	1,284,648	1,444,304
37	(530) Maintenance of Reactor Plant Equipment	8,274,531	11,107,061
38	(531) Maintenanee of Electric Plant	5,841,925	7,490,510
39	(532) Maintenance of Miscellaneous Nuclear Plant	7,807,429	7,349,616
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	33,536,124	37,835,834
41	TOTAL Power Production Expenses-Nuclear Power (Enter total of lines 33 and 40)	182,221,344	198,968,435
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	78,412	400,301
45	(536) Water for Power	108,114	84,216
46	(537) Hydraulic Expenses	59,059	37,501
47	(538) Electric Expenses	54,526	55,435
48	(539) Miscellaneous Hydraulic Power Generation Expenses	147,877	176,168
49	(540) Rents	1,000	2,000
50	TOTAL Operation (Enter Total of lines 44 thru 49)	448,988	755,620

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$43,761	$52,818
54	(542) Maintenance of Structures	7,826	70,270
55	(543) Maintenance of Reservoirs, Dams, and Waterways	13,890	7,165
56	(544) Maintenance of Electric Plant	54,908	56,884
57	(545) Maintenance of Miscellaneous Hydraulic Plant	9,648	13,840
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	130,033	200,977
59	TOTAL Power Production Expenses–Hydraulic Power (Enter total of lines 50 and 68)	579,021	956,597
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	162,759	411,893
63	(547) Fuel	1,065,124	386,921
64	(548) Generation Expenses	189,611	129,772
65	(549) Miscellaneous Other Power Generation Expenses	402,355	384,142
66	(550) Rents	6,912	9,862
67	TOTAL Operation (Enter Total of lines 62 thru 66)	1,826,761	1,322,590
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	210,141	205,124
70	(552) Maintenance of Structures	(17,071)	69,037
71	(553) Maintenance of Generating and Electric Plant	692,627	1,260,441
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	(187,677)	36,510
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	698,020	1,571,112
74	TOTAL Power Production Expenses–Other Power (Enter Total of lines 67 and 73)	2,524,781	2,893,702
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	208,845,457	154,875,468
77	(556) System Control and Load Dispatching	2,407,592	2,393,932
78	(557) Other Expenses (See Page 450)	48,358,824	48,518,697
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	259,611,873	205,788,096
80	TOTAL Power Production Expenses (Enter Total of lines 21,41,59,74, and 79)	792,065,390	749,860,827
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,286,844	1,581,285
84	(561) Load Dispatching	3,549,977	3,515,867
85	(562) Station Expenses	1,232,648	263,125
86	(563) Overhead Lines Expenses	580,206	604,477
87	(564) Underground Line Expenses	65,278	61,696
88	(565) Transmission of Electricity by Others	2,113,245	2,438,535
89	(566) Miscellaneous Transmission Expenses	27,294,742	26,037,838
90	(567) Rents	408,428	500,923
91	TOTAL Operation (Enter Total of lines 83 thru 90)	37,531,368	35,003,746
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	357,744	327,002
94	(569) Maintenance of Structures	19,786	6,157
95	(570) Maintenance of Station Equipment	6,382,237	8,409,444
96	(571) Maintenance of Overhead Lines	2,425,145	1,800,440
97	(572) Maintenance of Underground Lines	11,002	8,681
98	(573) Maintenance of Miscellaneous Transmission Plant	0	0
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	9,195,914	10,551,723
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	46,727,282	45,555,469
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	1,927,317	1,679,924

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	3,893,547	3,846,712
106	(582) Station Expenses	2,410,280	515,248
107	(583) Overhead Line Expenses	3,978,936	3,784,660
108	(584) Underground Line Expenses	3,496,093	3,375,005
109	(585) Street Lighting and Signal System Expenses	556,568	626,719
110	(586) Meter Expenses	2,924,350	3,134,578
111	(587) Customer Installations Expenses	659,357	523,099
112	(588) Miscellaneous Expenses	13,738,582	17,166,156
113	(589) Rents	576,302	584,863
114	TOTAL Operation (Enter Total of lines 103 thru 113)	34,161,332	35,236,964
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	1,257,826	1,263,660
117	(591) Maintenance of Structures	364,159	340,260
118	(592) Maintenance of Station Equipment	7,011,694	10,902,840
119	(593) Maintenance of Overhead Lines	27,725,459	30,109,430
120	(594) Maintenance of Underground Lines	4,874,823	5,216,376
121	(595) Maintenance of Line Transformers	975,843	1,060,483
122	(596) Maintenance of Street Lighting and Signal Systems	1,831,800	1,568,700
123	(597) Maintenance of Meters	231,709	153,904
124	(598) Maintenance of Miscellaneous Distribution Plant	209,595	223,025
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	44,482,908	50,838,676
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	78,644,240	86,075,640
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	1,853,741	2,071,338
130	(902) Meter Reading Expenses	8,295,361	8,315,669
131	(903) Customer Records and Collection Expenses	12,658,244	13,103,020
132	(904) Uncollectible Accounts	4,482,517	4,859,367
133	(905) Miscellaneous Customer Accounts Expenses	3,826,286	4,521,509
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	31,116,149	32,870,903
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	158,491	134,804
138	(908) Customer Assistance Expenses	23,417,560	13,748,519
139	(909) Informational and Instructional Expenses	943,716	1,758,908
140	(910) Miscellaneous Customer Service and Informational Expenses	6,821,226	9,722,210
141	TOTAL Cust. Service and Informational Exp. (Enter Total of lines 137 thru 140)	31,340,993	25,364,441
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision	17,930	46,980
145	(912) Demonstrating and Selling Expenses	1,108,564	835,216
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses	21,114	31,707
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	1,147,608	913,904
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	47,328,457	34,619,214
152	(921) Office Supplies and Expenses	24,988,390	31,850,871
153	(Less) (922) Administrative Expenses Transferred–Cr.	5,551,425	3,274,481

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	1,720,119	2,211,208
156	(924) Property Insurance	9,278,114	9,753,675
157	(925) Injuries and Damages	6,644,413	9,131,145
158	(926) Employee Pensions and Benefits	50,114,595	53,620,415
159	(927) Franchise Requirements	27,605	26,769
160	(928) Regulatory Commission Expenses	3,945,222	4,422,939
161	(929) Duplicate Charges-Cr.	970,067	994,817
162	(930.1) General Advertising Expenses	1,145,137	1,727,276
163	(930.2) Miscellaneous General Expenses	10,472,421	11,159,410
164	(931) Rents	14,949	7,969
165	TOTAL Operation (Enter Total of lines 151 thru 164)	149,157,930	154,261,592
166	Maintenance		
167	(935) Maintenance of General Plant	451,984	675,048
168	TOTAL Administrative and General Expenses (Enter Total of lines 165 thru 167)	149,609,914	154,936,640
169	TOTAL Electric Operation and Maintenance Expenses (Enter total of lines 80,100,126 134,141,148, and 168)	1,130,651,576	1,095,577,825

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.
3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	12-31-93
2. Total Regular Full-Time Employees	5,398
3. Total Part-Time and Temporary Employees	603
4. Total Employees	6,001

Estimated number of employees attributed to electric department from joint functions - 1,004.

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PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.

2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifieation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Basin Elec Pwr Coop	OS(1)	417	NA	NA	NA
2	Cooperative Pwr Assoc	OS(2)	417	NA	NA	NA
3	Dairyland Pwr Coop	OS(3)	417	NA	NA	NA
4	Heartland Consumers Pwr Dist	OS(4)	471	NA	NA	NA
5	Hutchinson Utilities	OS(4)	434	NA	NA	NA
6	Interstate Power Co	OS(5)	417	NA	NA	NA
7	Interstate Power Co	EX(40)	417	NA	NA	NA
8	IA Elec Light & Pwr Co	OS(6)	321	NA	NA	NA
9	IA IL Gas & Elec Co	OS(6)	417	NA	NA	NA
10	IA Southern Util Co	OS(6)	417	NA	NA	NA
11	Kansas City Pwr & Light	OS(7)	417	NA	NA	NA
12	Lincoln Electric Sys	OS(6)	417	NA	NA	NA
13	Madison Gas & Electric	OS(8)	359	NA	NA	NA
14	Manitoba Hydro	OS(9)	359	NA	NA	NA

PURCHASED POWER (Account 555)(Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.

5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (1) includes credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in columns (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on page 401, line 10. The total amount in column (h) must be reported as Exchange Received on page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on page 401, line 13.

9. Footnote entries as required and provide explanations following all required data.

Megawatthours Purchased (g)	POWER EXCHANGES Megawatthours Received (h)	Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
408,748			600,000	6,131,685		6,731,685	1
107,851				1,460,038		1,460,038	2
35,570				504,554		504,554	3
3				90		90	4
1				30		30	5
1,059				17,949		17,949	6
		74,675					7
3,624				66,433		66,433	8
89,513				1,760,348		1,760,348	9
1,910				24,240		24,240	10
73,697				1,441,209		1,441,209	11
107,766				1,608,904		1,608,904	12
25				472		472	13
5,368,872			45,343,629	79,496,109		124,839,738	14

PURCHASED POWER (Account 555)(Continued)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
15	Midwest Power Systems	OS(6)	417	NA	NA	NA
16	MN Power	OS(10)	417	NA	NA	NA
17	Minnkota Power Coop	OS(11)	417	NA	NA	NA
18	Minnkota Power Coop	EX(39)	417	NA	NA	NA
19	Missouri Basin Mun Pwr	OS(12)	417	NA	NA	NA
20	Montana-Dakota Util	OS(13)	417	NA	NA	NA
21	Muscatine Pwr & Water	OS(6)	417	NA	NA	NA
22	Nebraska Public Pwr Dist	OS(14)	417	NA	NA	NA
23	Northwestern Public Serv	OS(6)	417	NA	NA	NA
24	Northwestern WI Elec	OS(15)	417	NA	NA	NA
25	Omaha Public Pwr Dist	OS(6)	417	NA	NA	NA
26	Otter Tail Power	OS(16)	417	NA	NA	NA
27	Rochester Public Util	OS(17)	NA(17)	NA	NA	NA
28	St. Joseph Light & Pwr	OS(18)	351	NA	NA	NA
29	Southern MN Municipal Pwr	OS(19)	417	NA	NA	NA
30	Union Electric	OS(20)	321	NA	NA	NA
31	United Power Assoc	OS(21)	417	NA	NA	NA
32	Western Area Pwr Admin	OS(22)	446	NA	NA	NA
33	WI Electric Pwr Co	OS(23)	319	NA	NA	NA
34	WI Pwr & Light	OS(24)	410	NA	NA	NA
35	WI Public Pwr Inc Sys	OS(6)	447	NA	NA	NA
36	WI Public Service Corp	OS(25)	346	NA	NA	NA

PURCHASED POWER (Account 555)(Continued)
(Including power exchanges)

Megawatthours Purchased (g)	POWER EXCHANGES Megawatthours Received (h)	Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
8,878				126,292		126,292	15
41,217			4,022,664	782,056		4,804,720	16
606,397			14,834,341	6,455,216		21,289,557	17
	7,240						18
438,336				6,322,321		6,322,321	19
42,018				814,884		814,884	20
2,024				26,856		26,856	21
18,654			420,000	301,485		721,485	22
2,740				35,987		35,987	23
58				8,719		8,719	24
12,669				167,519		167,519	25
22,606				413,475		413,475	26
743				17,802		17,802	27
1,750				30,894		30,894	28
35,281				480,805		480,805	29
107,027			499,950	2,281,123		2,781,073	30
195,824			1,980,880	2,105,807		4,086,687	31
54,949				892,191		892,191	32
161,971				2,856,489		2,856,489	33
33,221				689,826		689,826	34
1,650				25,869		25,869	35
410				13,437		13,437	36

PURCHASED POWER (Account 555)(Continued)
(Including power exchanges)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifieation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
37	City of Blue Earth	OS(26)	485	NA	NA	NA
38	American Resource Recovery	OS(27)	IPP	NA	NA	NA
39	Barron County Waste	OS(27)	IPP	NA	NA	NA
40	Byllesby Dam	OS(27)	IPP	NA	NA	NA
41	Chippewa Reservoir Pwr	OS(28)	IPP	NA	NA	NA
42	Cypress Silver Bay Pwr Co	OS(27)	IPP	NA	NA	NA
43	Eau Galle Renew Energy Co	OS(27)	IPP	NA	NA	NA
44	Ford Motor Co	OS(29)	IPP	NA	NA	NA
45	Hastings Lock & Dam	OS(30)	IPP	NA	NA	NA
46	Hennepin Energy Resource Recov	OS(27)	IPP	NA	NA	NA
47	Neshkoro Power Assoc	OS(27)	IPP	NA	NA	NA
48	Actacon-Rapidan	OS(31)	IPP	NA	NA	NA
49	St. Cloud Hydro	OS(32)	IPP	NA	NA	NA
50	Alfred Jessen	OS(33)	IPP	NA	NA	NA
51	Lester Vandenberg	OS(33)	IPP	NA	NA	NA
52	John Youngdahl	OS(33)	IPP	NA	NA	NA
53	District Energy	OS(34)	Co-Gen	NA	NA	NA
54	Mun Energy Agency of Nebraska	OS(35)	Co-Gen	NA	NA	NA
55	Northwestern IA Pwr Coop	OS(36)	Co-Gen	NA	NA	NA
56	Northern States Power Co (WI)	RQ	154	NA	NA	NA
57	Mid-Continent Area Power Pool	EX(38)	MAPP	NA	NA	NA
58	Total					

PURCHASED POWER (Account 555)(Continued)
(Including power exchanges)

Megawatthours Purchased (g)	POWER EXCHANGES Megawatthours Received (h)	Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j + k + l) or Settlement ($) (m)	Line No.
414				3,942		3,942	37
1,569				44,524		44,524	38
3				78		78	39
14,979			412,315	278,712		691,027	40
4,605			465,594	250,185		715,779	41
110,093			6,082,800	1,961,778		8,044,578	42
1,594				98,313		98,313	43
15,820				192,189		192,189	44
15,372			594,023	171,511		765,534	45
207,261			8,092,907	2,502,729		10,595,636	46
3,055			77,298	69,586		146,884	47
31,337			474,240	383,842		858,082	48
52,419			1,348,558	261,795		1,610,353	49
26				1,576		1,576	50
3				202		202	51
11				664		664	52
1,068				12,858		12,858	53
64				600		600	54
2				60		60	55
378,853					46,631,573	46,631,573 (37)	56
	103,216						57
8,825,610	110,456	74,675	$85,249,199	$123,596,258	$46,631,573	$255,477,030 (37)	58

PURCHASED POWER (Account 555)(Continued)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity. Power exchanges must be reported on the Purchased Power schedule (pages 326-327).

2. Enter the name of the seller or other party in an exchange transactionin in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Footnotes:		(23) General Purpose, Economy			
2	(1) Emergency, Schedule M, Firm		(24) General Purpose, General Purpose-Negotiated			
3	(2) Economy, Schedule M, Emergency, Scheduled Outage		(25) General Purpose			
4	(3) Economy, Schedule M, Emergency, Class B		(26) Dump Energy			
5	(4) Emergency		(27) Base Load			
6	(5) Emergency, Schedule M		(28) Firm			
7	(6) Economy, Emergency, Schedule M		(29) Excess			
8	(7) Scheduled Outage, Term		(30) Base Load, Excess			
9	(8) General Purpose		(31) Peaking, Excess, Base Load			
10	(9) Operational Control, Scheduled Outage, Peaking, Firm,		(32) Base Load, Excess, High On-Peak. Energy Charges include a reversal			
11	Seasonal Diversity, Tertiary. Demand & Energy Charges		as a result of a resolution of a pending lawsuit.			
12	include an accrual for disagreement on payment to Manitoba.		(33) Windmill Energy			
13	(10) Economy, Operational Control, Firm, Emergency, Schedule M,		(34) Steam Driven Energy			
14	Scheduled Outage, Operating Reserve		(35) Emergency, Operational Control			
15	(11) Economy, Operational Control, Scheduled Outage, Firm,		(36) Emergency			
16	Coyote, Emergency, Schedule M, Participation Power		(37) Total dollars will not match page 321, line 75 due to differences			
17	(12) Emergency, Schedule M, Scheduled Outage		in accounting classification of dollars associated with the			
18	(13) Economy, Schedule M, Scheduled Outage, Emergency		interchange agreement of the Company and the Wisconsin			
19	(14) Economy, Scheduled Outage, Schedule M, Firm, Emergency		Company (see page 450 or Note 12 of the Notes to Financial			
20	(15) Operational Control		Statements for dollar amounts) and the classification of the			
21	(16) Economy, Firm, Emergency, Schedule M, Scheduled Outage		MWHs on the bulk power transaction pages.			
22	(17) Emergency, Schedule M; it was not necessary for NSP to file		(38) Due to MAPP Loss Repayment Procedure.			
23	this contract since NSP's only transactions with them were purchases		(39) Final contract loss resolution included energy payment by MPC to NSP			
24	(18) Scheduled Outage		(40) Compensation as a result of the difference between the point of			
25	(19) Economy, Emergency, Schedule M, Oper Control, Sched Outage		metering and point of system interconnection on the Wilmarth-			
26	(20) Economy, Term, Excess, Firm		Winnebago line.			
27	(21) Economy, Operational Control, Scheduled Outage, Emergency,					
28	Participation Power, Schedule M					
29	(22) Replacement, Emergency, Schedule M					

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e. wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in columns (a), (b), and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b), or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:

LF - for long-term firm transmission service. "Long-term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

Line No.	Payment By (Company or Public Authority) Footnote Affiliations) (a)	Energy Received From (Company or Public Authority) Footnote Affiliations) (b)	Energy Delivered To (Company or Public Authority) Footnote Affiliations) (c)	Statistical Classification (d)
1	Cooperative Power Assoc	United Power Assoc	Various	LF
2	Cooperative Power Assoc	Western Area Pwr Adm	Interstate Power	LF
3	Blue Earth L & W	Missouri Basin Mun Pwr Agency	Blue Earth	LF
4	Wisconsin P & L	Minnesota Power	Wisconsin Power & Light	OS (9)
5	Wisconsin P & L	Otter Tail Power	Wisconsin Power & Light	OS (9)
6	Wisconsin P & L	Minnesota Power	Wisconsin Power & Light	OS (8)
7	Dairyland Power Coop	Western Area Pwr Adm	Dairyland Power Coop	LF
8	Iowa Pub Serv Twin Cities– Iowa Omaha Kansas City 345 KV Inter	Iowa Public Service	St Joseph P & L	LF
9	So Mn Muni Pwr Agency	Sherco 3 Pwr Plant	Various	LF
10	City of Mountain Lake	West Area Pwr Adm	Interstate Power	LF
11	Wis Pub Pwr Inc System–West	Minnesota Power	Various	LF
12	Wis Pub Pwr Inc System–East	Minnesota Power	Various	LF
13	Nw Wis Electric Power	NW Wis Electric Power	Dairyland Power Coop	LF
14	City of Anoka	NSP	Anoka	LF
15	City of Shakopee	NSP	Shakopee	LF
16	Univ of North Dakota	Western Area Pwr Adm	Univ of North Dakota	LF
17	City of Hillsboro	Western Area Pwr Adm	Hillsboro	LF

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as "wheeling")

OS - for other transmission service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm transmission service, regardless of the length of the contract. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

5. In column (e), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

FERC Rate Schedule or Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)(1)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				Megawatthours Received (i)	Megawatthours Delivered (j)	
342	Various	Various		2,259,551	2,165,074	1
457	NSP-WAPA 345kv Sioux Falls Interconnection	NSP-IPW 161kv Luverne Interconnection	29.16			2
464	B	Blue Earth	10.1, 10.26, 4.395	43,133	41,859	3
NSP Tariff Volume 1	Minnesota Power	Wis P & L Interconn		13,410	13,070	4
NSP Tariff Volume 1	Otter Tail/MN Pwr	Wis P & L Interconn		61,398	59,182	5
NSP Tariff Volume 1	Minnesota Power	Wis P & L Interconn	20	11,340	11,064	6
407	Various	Various		9,843	9,843	7
351	Neal Pwr Plant	St Joseph P & L				8
415	Sherco 3	Various		595,672	552,304 (10)	9
453	NSP-WAPA 345kv Sioux Falls Interconnection	NSP-IPW 161kv Luverne Interconnection	1.308			10
466	Minnesota Power	Wis Pub Pwr Inc	45,50.3	334,857	334,857	11
465	Minnesota Power	Wis Elec Power, Wis Pub Serv, Wis Pwr & Lght	62			12
451	Black Brook Hydro (Dahlberg Interconnection)	NSP-DPC Point of Interconnection		2,111	1,900	13
420	Crooked Lake Substation	Crooked Lake Substation				14
431	Blue Lake Substation	Blue Lake Substation				15
440	A	Univ of North Dakota	8.113	45,207	44,122	16
414	A	Hillsboro	5.1	12,902	12,592	17

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as "wheeling")

8. Report in columns (i) and (j) the total megawatthours received and delivered.

9. In columns (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity listed in column (a).

If no monetary settlement was made, enter zero ("0") in column (n). Provide a footnote explaining the nature of the nonmonetary settlement, including the amount and type of energy or service rendered.

10. Provide total amounts in columns (i) through (n) as the last line. Enter "TOTAL" in column (a) as the last line. The total amounts in columns (i) and (j) must be reported as Transmission Receivod and Delivered on page 401, lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS				
Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k + l + m) (n)	Line No.
		53,971 (2)	53,971	1
0	0	0 (12)	0	2
136,315			136,315	3
	26,140		26,140	4
	118,364		118,364	5
141,709			141,709	6
	9,843		9,843	7
		326,484	326,484	8
		97,681 (3)	97,681	9
10,272			10,272	10
620,832		108,325 (4)	729,157	11
915,740		110 (4)	915,850	12
	6,895		6,895	13
		63,000 (6)	63,000	14
		20,000 (6)	20,000	15
34,561		93,365 (5)	127,926	16
75,519			75,519	17

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e. wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.

2. Use a separate line of data for each distinct type of transmission service involving the entities listed in columns (a), (b), and (c).

3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b), or (c).

4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:

LF - for long-term firm transmission service. "Long-term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

Line No.	Payment By (Company or Public Authority) Footnote Affiliations) (a)	Energy Received From (Company or Public Authority) Footnote Affiliations) (b)	Energy Delivered To (Company or Public Authority) Footnote Affiliations) (c)	Statistical Classification (d)
18	City of Ada	Western Area Pwr Adm	Ada	LF
19	City of East Grand Forks	Western Area Pwr Adm	East Grand Forks	LF
20	City of Fairfax	Western Area Pwr Adm	Fairfax	LF
21	City of Granite Falls	West Area Pwr Adm, Miss Basin	Granite Falls	LF
22	City of Marshall	West Area Pwr Adm, Heartland	Marshall	LF
23	City of Melrose	Western Area Pwr Adm	Melrose	LF
24	City of Olivia	Western Area Pwr Adm	Olivia	LF
25	City of St James	West Area Pwr Adm, Miss Basin	St James	LF
26	City of Sauk Centre	West Area Pwr Adm, Miss Basin	Sauk Centre	LF
27	City of Sleepy Eye	Western Area Pwr Adm	Sleepy Eye	LF
28	City of Sioux Falls	Western Area Pwr Adm	Sioux Falls	LF
29	SD State Penitentiary	Western Area Pwr Adm	SD State Penitentiary	LF
30	City of Springfield	Western Area Pwr Adm	Interstate Power	LF
31	City of Windom	Western Area Pwr Adm	Interstate Power	LF
32	Missouri Basin Mun Pwr Agency	Western Area Pwr Adm	Interstate Power	LF
33	Heartland Consumers Pwr Dist	Heartland Consumers Pwr Dist	United Power Assoc	LF
34	Wis Electric Pwr Co	Basin Elec Pwr Coop	Wis Elec Pwr	OS(8)
35	Wis Electric Pwr Co	Basin Elec Pwr Coop	Wis Elec Pwr	OS(8)
36	Wis Electric Pwr Co	Otter Tail Power	Wis Elec Pwr	OS(9)
37	Interstate Pwr Co	United Power Assoc	Interstate Power	OS(8)
38	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)

(Including transactions referred to as "wheeling")

OS - for other transmission service. Use this category only for those services which cannot be placod in the above-defined categories, such as all nonfirm transmission service, regardless of the length of the contract. Describe the nature of the service in a footnote.

AD - for out-of-poriod adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

5. In column (e), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (b) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

FERC Rate Schedule or Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)(1)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatthours Received (i)	TRANSFER OF ENERGY Megawatthours Delivered (j)	Line No.
390	A	Ada	2.8	13,972	13,637	18
483	A	East Grand Forks		76,237	74,407	19
400	A	Fairfax	1.9	9,269	9,047	20
436	A & B	Granite Falls	6.1,6.3	7,652	7,468	21
403	A	Marshall	49.6, 54.8	134,471	131,244	22
401	A	Melrose	6	36,494	35,618	23
388	A	Olivia	4.9	23,224	22,667	24
412	A & B	St James	11.5,12.4	36,487	35,611	25
449	A & B	Sauk Centre	7.9,8.3	25,515	24,903	26
393	A	Sleepy Eye	2.5	8,671	8,463	27
413 & 484 (11)	A	Sioux Falls	8.1,8.4	45,501	44,409	28
385	A	SD State Penitentiary	.616	2,956	2,885	29
454	NSP-WAPA 345kv Sioux Falls Intereonnection	NSP-IPW 161kv Luverne Interconnection	1.419	5,484	5,484	30
455	NSP-WAPA 345kv Sioux Falls Interconnection	NSP-IPW 161kv Luverne Interconnection	8.726	38,181	38,181	31
456	NSP-WAPA 345kv Sioux Falls Interconnection	NSP-IPW 161kv Luverne Interconnection	53	305,138	297,815	32
471	Marshall	United Power Assoc	13	42	42	33
NSP Tariff Volume 1	Basin Elec	Wis Elec Pwr	73	140,125	135,079	34
NSP Tariff Volume 1	Basin Elec	Wis Elec Pwr	98	380,725	369,552	35
NSP Tariff Volume 1	Otter Tail Power	Wis Elec Pwr		60,177	58,031	36
NSP Tariff Volume 1	United Power Assoc	Interstate Power	98	467,255	455,429	37
				5,207,000	5,015,839	38

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)

(Including transactions referred to as "wheeling")

8. Report in columns (i) and (j) the total megawatthours received and delivered.

9. In columns (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers reudered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity listed in column (a).

If no monetary settlement was made, enter zero ("0") in column (n). Provide a footnote explaining the nature of the nonmonetary settlement, including the amount and type of energy or service rendered.

10. Provide total amounts in columns (i) through (n) as the last line. Enter "TOTAL" in column (a) as the last line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered on page 401, lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS				
Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k + l + m) (n)	Line No.
42,066		13,360 (6)	55,426	18
32,370		29,151 (6)	61,521	19
27,723			27,723	20
26,472			26,472	21
794,262			794,262	22
88,531			88,531	23
71,974			71,974	24
178,372		28,056 (6)	206,428	25
121,080			121,080	26
37,486			37,486	27
35,411			35,411	28
2,624			2,624	29
11,136		1,582 (7)	12,718	30
68,496		8,894 (7)	77,390	31
416,052			416,052	32
14,214	42		14,256	33
470,108			470,108	34
1,263,049			1,263,049	35
	116,062		116,062	36
1,457,870			1,457,870	37
$7,094,244	$277,346	$843,979	$8,215,569	38

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e. wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in columns (a), (b), and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b), or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:

LF - for long-term firm transmission service. "Long-term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

Footnotes:

1) A = NSP-WAPA interconnection, B = Missouri Basin interconnections.
2) Settlement on the basis of $.018 mills for KWH's delivered to CPA loads from CPA-NSP integrated transmission system. Also includes an initial payment of $15,000 in consideration of NSP's initial costs of serving as a host control area for CPA.
3) Generation Control and Transmission Control-Transmission Agreement with SMMPA.
4) Non-firm power; meter service charge.
5) Facilities charge; transformation service @.0007/Kwh.
6) Facilities charge.
7) Transmission Losses.
8) Reserved Service.
9) Interruptible Service

This number is in dispute pending resolution of Docket #EL91-43-000.

Rate Schedule #484 replaced #413 on 4/12/93.

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e., wheeling, of electricity provided to respondent by other electric utilities, cooperatives, municipalities, or other public authorities during the year.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company; abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider.
3. Provide in column (a) subheadings and classify transmission service purchased from other utilities as: "Delivered Power to Wheeler" or "Received Power from Wheeler."
4. Report in columns (b) and (c) the total megawatthours received and delivered by the provider of the transmission service.
5. In columns (d) through (g), report expenses as shown on bills or vouchers rendered to the respondent. In column (d), provide demand charges. In column (e), provide energy charges related to the amount of energy transferred. In column (f), provide the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (f). Report in column (g) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") in column (g). Provide a footnote explaining the nature of the nonmonetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line. Provide a total amount in columns (b) through (g) as the last line. Energy provided by the respondent for the wheeler's transmission losses should be reported on the Electric Energy Account, page 401. If the respondent received power from the wheeler, energy provided to account for losses should be reported on line 19, Transmission By Other Losses, on page 401. Otherwise, losses should be reported on line 27, Total Energy Losses, page 401.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	TRANSFER OF ENERGY: Megawatthours Received (b)	TRANSFER OF ENERGY: Megawatthours Delivered (c)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (d)	Energy Charges ($) (e)	Other Charge ($) (f)	Total Cost of Transmission ($) (g)
1	Received Power from Wheeler East River Electric	417,200	413,069	149,482			149,482
2	Redwood Elec Coop	2,515	2,515	36,341 (1)			36,341
3	Stearns Coop Elec Assn	405	401		3,201 (2)		[illegible]01
4	McLeod Elec Coop	1,621	1,548	1,515 (3)			1,515
5	Minnkota Pwr Coop	18,492	18,492		18,492 (4)		18,492
7	NSP-WAPA-So Dakota State Pen	340,292	327,204	943,300 (5)			943,300
8	NW Wis Elec Pwr (Across DPC)	138,141	129,103		463,915 (6)		463,915
9	MN Pwr & Light - Phase Angle Regul Transf Cost Sharing Agreement					491,499	491,499
10	North Central Power					5,500 (7)	5,500
11	Otter Tail Power	1,717,842	1,645,136	0	0	0	0
12	WAPA-Mallard Logan Line	189,563	186,728	0	0	0	0
13	Total	2,826,071	2,724,196	$1,130,638	$485,608	$496,999	$2,113,245

Footnotes:

(1) Settled on a basis of $.75/Kw Jan-Mar; $.70/Kw Apr-Dec; plus basic monthly charge $1,950

(2) Settled on a basis of $.001/Kwh

(3) Settled on a basis of $.39/Kw

(4) Settled on a basis of $.001/Kwh

(5) WAPA transmission service @ $12.65/62,000 Kw. This number also includes an accrual made to reflect money due WAPA for 1993 for a revision to the wheeling charge from 62,000 KW to 112,000 KW. It also includes a credit for Oct-Dec 1992 for a revision to the wheeling charge from 117,000 Kw to 62,000 Kw.

(6) Transmission Service @ $3.44/Mwh Jan-Apr; $3.70/Mwh May-Dec

(7) NCP transmission services for LCO (Chippewa Reservoir Power)

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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (Electric)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	$847,928
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	7,066,111
4	Publishing and Distributing Information and Reports to Stockholders; Trustee, Registrar, and Transfer Agent Fces and Expenses, and Other Expenses of Servicing Outstanding Securities of the Respondent	1,794,399
5	Other Expenses (List items of $5000 or more in this column showing the (1) purpose, (2) recipient and (3) amount of such items. Group amounts of less than $5,000 by classes if the number of items so grouped is shown)	
6	Annual Shareholders Meeting	
7	Audio & Video	24,256
8	Brokers Expense	142,246
9	Proxy Statements	44,021
10	Company Postage	46,975
11	Other Items	22,696
12	Hall (Minneapolis Hilton)	23,291
13		303,485
14		
15		
16		
17	Directors Fees and Expenses	
18	H Lyman Bretting	32,019
19	David A Christensen	34,452
20	W John Driscoll	34,452
21	N Bud Grossman	18,906
22	Dale L Haakenstad	32,019
23	Allen F Jacobson	30,722
24	Richard M Kovacevich	29,980
25	Douglas W Leatherdale	28,683
26	Donald W McCarthy	18,906
27	John E Pearson	32,599
28	W G Phillips	18,906
29	G M Pieschel	32,599
30	Margaret R Preska	32,019
31	D B Reinhart	18,906
32	A Patricia Sampson	32,019
33		427,187
34		
35		
36		
37	Lobbying Expenses	32,412
38		
39	Other Expenses	899
40		
41		
42		
43		
44		
45		
46	Total	$10,472,421

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)
(Except amortization of acquisition adjustments)

1. Report in section A for the year the amounts for: (a) Depreciation Expense (Account 403); (b) Amortization of Limited-Term Electric Plant (Account 404); and (c) Amortization of Other Electric Plant (Account 405).

2. Report in section B the rates used to compute amortization charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of section C the type of plant included in any subaccount used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional classifications and showing a composite total. Indicate at the bottom of section C the manner in which column (b) balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant.

If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited-Term Electric Plant (Account 404) (c)	Amortization of Other Electric Plant (Account 405) (d)	Total (e)
1	Intangible Plant		136,555		136,555
2	Steam Production Plant	54,940,996			54,940,996
3	Nuclear Production Plant	86,603,922			86,603,922
4	Hydraulic Production Plant-Conventional	178,510		38,056	216,566
5	Hydraulic Production Plant-Pumped Storage				
6	Other Production Plant	2,382,866			2,382,866
7	Transmission Plant	14,850,923			14,850,923
8	Distribution Plant	43,868,210			43,868,210
9	General Plant	6,639,221			6,639,221
10	Common Plant-Electric	7,609,512	2,552,019		10,161,531
11	TOTAL	$217,074,160	$2,688,574	$38,056	$219,800,790

B. Basis for Amortization Charges

ACCOUNT 404

The total computer software amortization of $2,552,019 is based on 60 months (1.67%) on an average basis of $12,757,543.
New software has been capitalized and certain old has been fully amortized.

ACCOUNT 405

The annual $38,056 amortization charge for Mill-Powers is based on a plant balance of $1,235,057.41 and a life of 32 years, beginning Jan. 1, 1969. This basis for amortization was approved by Mr. A. L. Litke and Staff (FERC) in a letter to C.K. Larson, dated May 23, 1969.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rate(s) (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	311	280,970	N/A	-15	N/A	N/A	19.4
13	312	904,230	"	0	"	"	17.8
14	314	222,299	"	0	"	"	17.2
15	315	141,164	"	0	"	"	18.8
16	316	58,192	"	0	"	"	17.3
17		1,606,855					
18							
19							
20							
21	321	271,055	N/A	see note (4)	N/A	N/A	18.8
22	321	6,603	"	"	"	"	19.1
23	322	555,582	"	"	"	"	18.2
24	322	15,174	"	"	"	"	18.1
25	323	122,310	"	"	"	"	18.6
26	323	15,251	"	"	"	"	19.9
27	324	185,246	"	"	"	"	19.3
28	324	2,661	"	"	"	"	18.6
29	325	130,228	"	"	"	"	18.8
30		1,304,110					
31							
32							
33							
34	331	436	N/A	-10	N/A	N/A	7.1
35	332	2,674	"	-15	"	"	7.1
36	333	1,083	"	5	"	"	7.1
37	334	279	"	5	"	"	7.1
38	335	42	"	5	"	"	7.1
39		4,515					
40							
41							
42							
43	341	2,366	N/A	0	N/A	N/A	4.8
44	342	3,366	"	0	"	"	4.8
45	344	60,800	"	0.4	"	"	5.5
46	345	3,158	"	0	"	"	3.6
47	346	436	"	0	"	"	5.2
48		70,126					
49							
50							
51							
52	352	7,986					32.8
53	353	207,057					30.7
54	354	92,576					30.4
55	355	91,859					23.8
56	356	112,325					29.4
57	357	4,784					43.4
58	358	4,320					30.0
59		520,908					
60							
61							
62							
63							

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rate(s) (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
64	361	18,231					33.2
65	362	209,161					30.3
66	364	137,738					22.1
67	365	159,807					25.1
68	366	74,019					34.3
69	367	333,231					26.2
70	368	205,815					24.7
71	368	253					17.9
72	368	10,046					11.9
73	369	46,241					22.1
74	369	74,506					25.3
75	370	81,709					19.8
76	371	664					4.0
77	371	7,555					3.9
78	371	67					4.5
79	372	178					20.2
80	372	1					9.1
81	373	21,018					9.2
82	373	16					6.7
83		1,380,254					
84							
85	390	41,287					37.0
86	390	930					34.2
87	391	349					4.5
88	391	3,785					17.3
89	391	1,911					3.3
90	392	sep prov (3)					1.1
91	392	sep prov (3)					4.2
92	392	sep prov (3)					20.4
93	392	sep prov (3)					7.0
94	393	1,975					24.0
95	394	810					17.7
96	394	3,683					21.0
97	394	11,686					16.3
98	394	604					2.7
99	395	6,102					21.4
100	396	2					5.8
101	396	sep prov (3)					8.8
102	396	11					6.7
103	397	34,376					4.6
104	397	109					3.2
105	397	973					3.1
106	397	25					7.2
107	397	49					8.3
108	398	384					14.5
109		109,051					
110		4,995,819					
111							
112							
113							
114							
115							

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)
(Except amortization of acquisitions and adjustments)(Continued)

Description Section C

Line 21 Nuclear – Structures & Improvements
Line 23 Nuclear – Reactor Plant Equipment
Line 22, 24, 26, 28, 85, 103 – Leased
Line 69 Line Transformers
Line 70 Line Transformer – Trailers
Line 71 Line Capacitors
Line 72 Overhead Services
Line 73 Underground Services
Line 76 Leased Property on Customer's Premises
Line 79 Loaned Property on Customer's Premises
Line 80 Street Lighting and Signal Systems
Line 81 Street Lighting Transformers in Reserve
Line 85 Structures & Improvements
Line 87 Office Furniture & Equipment
Line 94 Garage Equipment
Line 95 Shop Equipment
Line 96 Other Tools and Work Equipment
Line 97 Hand Held Meters
Line 99 Power Operated Equipment – Mobile (Licensed)
Line 101 Power Operated Equipment – Other
Line 102 Communication Equipment
Line 103 Communication Equipment – Leased to Others

Separate Provision (3)	Charged to Clearing Accounts	Depreciable Plant Base (Thousands)
Line 90 Cars	$38,541	$876
Line 91 Vans & Light Trucks	548,193	6,021
Line 92 Licensed Trailers	71,387	2,481
Line 93 Heavy Trucks	2,015,934	26,264
Line 101 Trenchers, Loaders, Cranes & Other Power Operated Equipment	309,627	5,032
	$2,983,682	$40,673

Footnotes: Section C

(1) Column (b) Computation: (Average Jan + Average Feb + ... Average Dec)/12 = Column (b)
Average Month = (Beginning month + end month)/2
Column (b) Functional Classification Totals exclude Separate Provision (Sep Prov)

(2) Column (c) through (g):
Subaccounts 311-346: A remaining life technique is applied to each generating facility. Therefore, column (g) represents dollar weighted composites at the plant subaccount level and column (c), (e), and (f) do not apply.
Subaccounts 352-398: Changes requested from the MPUC in 1992 were approved during the past year.

(3) Separate Provision is charged to clearing accounts monthly, computed as described in Footnote (1).

(4) Effective Aug 1, 1981, Nuclear Plant Decommissioning Costs are recovered using an internal and external sinking fund calculation.

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PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425) - Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions - Report the nature, payee, and amount of other income deductions for the year as required by accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) - For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) accounts payable, (c) notes payable, (d) accounts payable, and (e) other debt and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) - Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	Miscellancous Amortization (Account 425)	
2	None	
3		
4	Other Income Deductions (Account 426)	
5	Donations (Subaccount 426.1)	
6	Sec Page 340A	$4,363,742
7		
8	Life Insurance (Subaccount 426.2)	
9	Wealth Op-Cash Surrender Value Earnings	(900,800)
10	Wealth Op-Premium Expense	235,391
11	Officer Survivor Benefits-Premium Expense	517,182
12	Officer Survivor Benefits-Cash Surrender Value Earnings	(517,182)
13	Total Subaccount 426.2	(665,409)
14		
15	Penalties (Subaccount 426.3)	1,553
16		
17	Expenditures for Certain Civic, Political & Related Activities	
18	(Subaccount 426.4)	
19	See Page 340A	726,470
20		
21	Other Deductions (Subaccount 426.5)	
22	Social and Service Club Dues (See Page 340A)	89,286
23	Employee Corporate Expenses	79,399
24	Pathfinder Decommissioning Costs	296,076
25	Settlements of Employment Complaints	589,879
26	Regulatory Reserve	100,000
27	Miscellaneous - Donations	62,939
28	Amortization of South Dakota AFUDC regulatory differences	268,000
29	Costs of investigating potential business acquisitions	101,525
30	Miscellaneous	9,121
31	Total Subaccount 426.5	1,596,225
32		
33	Total Account 426	$5,787,190
34		
35	Interest on Debt to Associated Companies (Account 430)	
36	Cormorant Corporation at an average effective rate of 3.18%	$9,174
37		
38	Other Interest Expense (Account 431)	
39	Commercial Paper	2,511,707
40	Customer Deposits	71,318
41	Tax Assessments Past Due	772,936
42	Coal Mine Reclamation	190,780
43	External Decommissioning Qualified Fund	3,464,642
44	External Decommissioning Non-Qualified Fund	260,366
45	Financing Cost for Wealth-Op Deferred Compensation Plan	317,219
46	Accrued Interest on 1993 MN Electric rate refund	133,000
47	Interest on wholesale rate refunds - 1985/89 FERC audit	168,630
48	Miscellaneous	40,612
49		
50	Total Account 431	$7,931,210

ANALYSIS OF DONATIONS - subaccount 426.1

United Way - 36 Items	$1,186,084
Civic/Cultural - 83 Items	469,466
Health & Human Services - 246 Items	1,676,932
Education - 206 Items	516,811
Environment - 16 Items	195,000
Miscellancous (Regional Grants) - 650 Items	319,449
Total All Donations	$4,363,742

EXPENDITURES FOR CERTAIN CIVIC, POLITICAL AND RELATED ACTIVITIES
(Account 426.4)

Minnesota Taxpayers Association	$3,506
Prairie Island Dry Cask Storage	162,985
Salaries & Expenses of Various Employees during 1993 Session of Minnesota Legislature & Committee Meetings	297,879
Confirmation Presentation	6,569
Congressional Reception	4,144
Congressional Presentation	28,000
Utility Working Group	12,000
Edison Electric Institute	15,316
Minnesota Utility Investors Group - Membership/Expenses	188,896
Professional Services - Miscellaneous	6,637
4 Minor Items	538
Total	$726,470

ANALYSIS OF SOCIAL AND SERVICE CLUB DUES
(See Other Deductions - Subaccount 426.5 on Page 340)

Decathlon Athletic Club	$2,294
Fargo Country Club	2,633
International Club	1,225
Kiwanis Club	3,122
Lions Club	3,138
Mankato Golf Club	1,720
Midland Hills Country Club	2,589
Minikahda Club	4,868
Minneapolis Athletic Club	13,853
Minneapolis Club	10,696
Minneapolis Rotary Club	1,060
Minnesota Club	9,885
Minot Country Club	1,250
Moorhead Country Club	16,357
St Cloud Rotary Club	2,402
Town & Country Club	4,403
Winona Country Club	2,520
16 Miscellancous Other Clubs	5,271
	$89,286

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REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such body was a party
2. In columns (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (Furnish name of regulatory commission or body, the docket or case number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 186 at Beginning of Year (e)
1	Expenses incurred preparing filings and attending				
2	conferences and hearings.				
3					
4	Minnesota				
5	Docket Nos.				
6	E-002/GR-91-001 (Rate)		$28,161	$28,161	
7	E-002/GR-92-1185 (Rate)		1,007,134	1,007,134	
8	E-002/RP-91-682 (Resource Plan)		157,203	157,203	
9	E-002/RP-93-630 (Resource Plan)		276,688	276,688	
10	GR-92-1186 (Rate)		474,841	474,841	
11	Various C.I.P. Filings (Elec)	$73,419		73,419	
12	Various C.I.P. Filings (Gas)	$18,574		18,574	
13	North Dakota				
14	PU-400-92-399 (Rate)		43,153	43,153	
15	South Dakota				
16					
17	Assessments by the State of Minnesota, Minnesota				
18	Public Service Commission and the Department				
19	of Public Service for rate and other expenses				
20	in accordance with provision of the 1974 utility	1,194,334		1,194,334	
21	regulation law.	287,577		287,577	
22					
23	State of South Dakota Public Utilities				
24	Commission special hearing fund assessment.	94,243		94,243	
25					
26	Expenses incurred preparing filing and				
27	attending conferences				
28	and hearings in connection with various				
29	FERC electric rate filings.				
30	ER93-385-000		5,860	5,860	
31	Various Misc		28,802	28,802	
32	FERC Annual Assessment	977,174		977,174	
33					
34	Expenses incurred in connection with various				
35	FERC Gas Rate Filing Applications and				
36	interventions.				
37	RP-92-1		41,708	41,708	
38	Various Misc		1,583	1,583	
39					
40	Various Miscellaneous Regulatory Expenses				
41	Electric		59,050	59,050	
42	Gas		3,079	3,079	
43					
44					
45					
46	Total	$2,645,321	$2,127,261	$4,772,583	

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. The totals of columns (e), (i), (k) and (l) must agree with the totals at the bottom of page 223 for Account 186.
5. List in column (f), (g) and (h) expenses incurred during years which were charged currently to income, plant, or other accounts.
6. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CHARGED CURRENTLY TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 186 (i)	Contra Account (j)	Amount (k)	Deferred in Account 186 End of Year (l)	Line No.
							1
							2
							3
							4
							5
Electric	928	$28,161					6
Electric	928	1,007,134					7
Electric	928	157,203					8
Electric	928	276,688					9
Gas	928	474,841					10
Electric	928	73,419					11
Gas	928	18,574					12
							13
Electric	928	43,153					14
							15
							16
							17
							18
							19
Electric	928	1,194,334					20
Gas	928	287,577					21
							22
							23
Electric	928	94,243					24
							25
							26
							27
							28
							29
Electric	928	5,860					30
Electric	928	28,802					31
Electric	928	977,174					32
							33
							34
							35
							36
Gas	928	41,708					37
Gas	928	1,583					38
							39
							40
Electric	928	59,050					41
Gas	928	3,079					42
							43
							44
							45
		$4,772,583					46

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development and demonstration (R,D&D) project initiated, continued, or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R,D&D work carried on by the respondent in which there is a sharing of costs with others, show separately the respondent's cost for the year and cost chargeable to others. (See definition of research, development and demonstration in Uniform System of Accounts.)

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

A. Electric R,D&D Performed Internally
- (1) Generation
  - a. Hydroelectric
    - i. Recreation, fish, and wildlife
    - ii. Other Hydroelectric
  - b. Fossil-fuel steam
  - c. Internal Combustion or gas turbine
  - d. Nuclear
  - e. Unconventional Generation
  - f. Siting and heat rejection
- (2) System Planning, Engineering and Operation
- (3) Transmission
  - a. Overhead
  - b. Underground
- (4) Distribution
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $5,000.)
- (7) Total Cost Incurred

B. Electric RD&D Performed Externally
- (1) Research Support to the Electrical Research Council or the Electric Power Research Institute.

Line No.	Classification (a)	Description (b)
1	(A) Electric RD&D Performed Internally	
2	(1) Generation	
3	A Hydropower	
4	None	
5	B Fossil Fuel - Steam	
6	Life Assessment & Ext High Temp Pressure Parts	
7	Advance Coal Characteristics	
8	Advanced Combustion	
9	Coal Qlty Impacts on Plant Perform	
10	Flue Gas Trace Element Removal	
11	Black Dog #2 FBC Optimization	
12	Cooling Tower Life Extension	
13	Coproduction of Liquid Fuels/Electricity from Coal	
14	Wet ESP Evaluation	
15	Misc (3)	
16		
17	C Internal Combustion or Gas Turbine	
18	Misc (2)	
19	D Nuclear	
20	None	
21	E Unconventional Generation	
22	Fuel Cells Users Group	
23	Misc (2)	
24	F Siting & Heat Rejection	
25	None	
26	(2) System Planning Engineering & Operation	
27	Assessment-Power Sys Stability	
28	Stability Benchmarking	
29	Misc (5)	
30	(3) Transmission	
31	A Overhead	
32	Misc (2)	
33	B Underground	
34	Underground Trans Cable Temp Monitor	
35	(4) Distribution	
36	Manufactured Wood Poles	
37	Misc (3)	
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others
(5) Total Cost Incurred

3. Include in column (c) all R,D&D items performed internally and in column (d) those items performed outside the company costing $5,000 of more, briefly describing the specific area of R,D&D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R,D&D activity.

4. Show in colum (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, lisiting Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged on column (e).

5. Show in column (g) the total unamortized accumulation of costs of projects. This total must equal the balance in Account 188, Research, Development and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R,D&D activities or projects, submit estimates for columns (c), (d) and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
					4
					5
$8,597		930.2	$8,597		6
31,198		930.2	31,198		7
7,671		930.2	7,671		8
11,142		930.2	11,142		9
38,108		930.2	38,108		10
25,999		930.2	25,999		11
6,289		930.2	6,289		12
5,590		930.2	5,590		13
7,184		930.2	7,184		14
5,515		930.2	5,515		15
					16
					17
963		930.2	963		18
					19
					20
					21
35,317		930.2	35,317		22
3,898		930.2	3,898		23
					24
					25
					26
22,509		930.2	22,509		27
58,843		930.2	58,843		28
325		930.2	325		29
					30
					31
168		930.2	168		32
					33
4,006		930.2	4,006		34
					35
22,145		930.2	22,145		36
1,595		930.2	1,595		37
					38

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

1. Describe and show below costs incurred and accounts charged during the year for technological research, development and demonstration (R,D&D) project initiated, continued, or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R,D&D work carried on by the respondent in which there is a sharing of costs with others, show separately the respondent's cost for the year and cost chargeable to others. (See definition of research, development and demonstration in Uniform System of Accounts.)

2. Indicate in column (a) the applicable classifieation, as shown below. Classifications:

A. Electric R,D&D Performed Internally
  (1) Generation
    a. Hydroelectric
      i. Recreation, fish, and wildlife
      ii. Other Hydroelectric
    b. Fossil-fuel steam
    c. Internal Combustion or gas turbine
    d. Nuclear
    e. Unconventional Generation
    f. Siting and heat rejection
  (2) System Planning, Engineering and Operation
  (3) Transmission
    a. Overhead
    b. Underground
  (4) Distribution
  (5) Environment (other than equipment)
  (6) Other (Classify and include items in excess of $5,000.)
  (7) Total Cost Incurred
B. Electric RD&D Performed Externally
  (1) Research Support to the Electrical Research Council or the Electric Power Research Institute.

Line No.	Classification (a)	Description (b)
1	(A) Elcctric RD&D Performed Internally (Cont'd)	
2		
3	(5) Environment - Other Than Equipment	
4	Electricmagnetic Field	
5	Misc (4)	
6	(6) Other	
7	A Alternative Energy	
8	Photovoltaic Demonstration	
9	Solar Energy Resource Assessment	
10	Photovoltaics	
11	Wind Technical Support	
12	North Dakota Wind Resource Assessment	
13	Misc (4)	
14	B By-Product Utilization	
15	Western Fly Ash Research	
16	UND Advisory Council	
17	Extending Life of Sherco 1&2 Scrubber	
18	Development of Wis Power Plant Ash	
19	Misc (3)	
20	C Conservation	
21	Misc (2)	
22	D Load Management	
23	Ice Slurry/District Cooling	
24	Thermal Storage in Ice Slurry	
25	Electric Vehicle Evaluation	
26	DSM Study	
27	Natural Gas Air Condition Study	
28	Misc (3)	
29	E Load Research	
30	Load Research Large C & I Customers Research Prog	
31	Load Research Small C & I Customers	
32	Residential Load Research Monitoring Program	
33	F Metering	
34	Jurisdictional Metering	
35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others
(5) Total Cost Incurred

3. Include in column (c) all R,D&D items performed internally and in column (d) those items performed outside the company costing $5,000 of more, briefly describing the specific area of R,D&D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R,D&D activity.

4. Show in colum (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, lisiting Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged on eolumn (e).

5. Show in column (g) the total unamortized accumulation of costs of projects. This total must equal the balance in Account 188, Research, Development and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R,D&D activities or projects, submit estimates for columns (c), (d) and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
12,591		930.2	12,591		4
5,098		930.2	5,098		5
					6
					7
25,372		930.2	25,372		8
5,324		930.2	5,324		9
7,602		930.2	7,602		10
10,653		930.2	10,653		11
7,425		930.2	7,425		12
5,378		930.2	5,378		13
					14
9,673		930.2	9,673		15
7,761		930.2	7,761		16
13,042		930.2	13,042		17
31,600		930.2	31,600		18
4,023		930.2	4,023		19
					20
1,045		930.2	1,045		21
					22
17,112		107.0	17,112		23
12,482		930.2	12,482		24
9,446		930.2	9,446		25
9,232		930.2	9,232		26
33,627		930.2	33,627		27
6,227		930.2	6,227		28
					29
28,878		930.2	28,878		30
5,570		930.2	5,570		31
14,716		930.2	14,716		32
					33
17,507		930.2	17,507		34
					35
					36
					37
					38

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

1. Describe and show below costs incurred and accounts charged during the year for technological research, development and demonstration (R,D&D) project initiated, continued, or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R,D&D work carried on by the respondent in which there is a sharing of costs with others, show separately the respondent's cost for the year and cost chargeable to others. (See definition of research, development and demonstration in Uniform System of Accounts.)
2. Indicate in column (a) the applicable classification, as shown below. Classifications:

A. Electric R,D&D Performed Internally
- (1) Generation
  - a. Hydroeleetric
    - i. Recreation, fish, and wildlife
    - ii. Other Hydroelectric
  - b. Fossil-fuel steam
  - e. Internal Combustion or gas turbine
  - d. Nuclear
  - e. Unconventional Generation
  - f. Siting and heat rejection
- (2) System Planning, Engineering and Operation
- (3) Transmission
  - a. Overhead
  - b. Underground
- (4) Distribution
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $5,000.)
- (7) Total Cost Incurred

B. Electric RD&D Performed Externally
- (1) Research Support to the Electrical Research Council or the Electric Power Research Institute.

Line No.	Classification (a)	Description (b)
1	(A) Electric RD&D Performed Internally (Cont'd)	
2		
3	G Research - General	
4	Research - General	
5	EPRI Projects Review and Evaluations	
6	Training	
7	Emerging Technology-Misc Costs	
8	Center For Hardy Landscape Plants	
9	Polymer Burn Treatment	
10	EPRI RP 2568-25 Chargeback	
11		
12		
13	(7) Total Cost Incurred - Internal	
14		
15		
16	(B) Electric RD&D Performed Externally	
17	(1) Research Support to EPRI	
18	EPRI Membership	
19	EPRI Advisory Group Participation	
20	(2) Research Support to Edison Electric Institute	
21	None	
22	(3) Research Support to Nuclear Power Groups	
23	None	
24	(4) Research Support to Others	
25	By-Products Utilization - Wis	
26	U M CNT EL EN R87052	
27	Misc (2)	
28		
29		
30	(5) Total Cost Incurred - External	
31		
32		
33	GRAND TOTAL	
34		
35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others
(5) Total Cost Incurred

3. Include in column (c) all R,D&D items performed internally and in column (d) those items performed outside the company costing $5,000 of more, briefly describing the specific area of R,D&D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R,D&D activity.

4. Show in colum (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, lisiting Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged on column (e).

5. Show in column (g) the total unamortized accumulation of costs of projects. This total must equal the balance in Account 188, Research, Development and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R,D&D activities or projects, submit estimates for columns (c), (d) and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
340,965		930.2	340,965		4
65,019		930.2	65,019		5
6,940		930.2	6,940		6
3,204		930.2	3,204		7
9,170		930.2	9,170		8
15,111		930.2	15,111		9
6,923		930.2	6,923		10
					11
					12
$1,045,779			$1,045,779		13
					14
					15
					16
					17
	5,918,535	930.2	5,918,535		18
	46,704	930.2	46,704		19
					20
					21
					22
					23
					24
	8,131	930.2	8,131		25
	60,151	930.2	60,151		26
	3,924	930.2	3,924		27
					28
					29
	$6,037,445		$6,037,445		30
					31
					32
	$7,083,224		$7,083,224		33
					34
					35
					36
					37
					38

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	$87,372,657		
4	Transmission	4,563,658		
5	Distribution	21,687,484		
6	Customer Accounts	17,735,466		
7	Customer Service and Informational	5,233,515		
8	Sales	546,504		
9	Administrative and General	52,184,630		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	189,323,914		
11	Maintenance			
12	Production	38,445,919		
13	Transmission	821,747		
14	Distribution	14,275,303		
15	Administrative and General	75,225		
16	TOTAL Maintenance (Enter Total of lines 12 thru 15)	53,618,194		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	125,818,576		
19	Transmission (Enter Total of lines 4 and 13)	5,385,405		
20	Distribution (Enter Total of lines 5 and 14)	35,962,787		
21	Customer Accounts (Transcribe from line 6)	17,735,466		
22	Customer Service and Information (Transcribe from line 7)	5,233,515		
23	Sales (Transcribe from line 8)	546,504		
24	Administrative and General (Enter Total of lines 9 and 15)	52,259,855		
25	TOTAL Operation and Maintenance (Total of lines 18 thru 24)	242,942,108	$4,645,226	$247,587,334
26	Gas			
27	Operation			
28	Production - Manufactured Gas	313,860		
29	Production - Natural Gas (Including Expl. and Dev.)			
30	Other Gas Supply	674,692		
31	Storage, LNG Terminaling and Processing	227,834		
32	Transmission	705,521		
33	Distribution	7,576,077		
34	Customer Accounts	3,762,998		
35	Customer Service and Informational	1,081,144		
36	Sales	284,056		
37	Administrative and General	5,333,132		
38	TOTAL Operation (Enter Total of lines 28 thru 37)	19,959,314		
39	Maintenance			
40	Production - Manufactured Gas	103,647		
41	Production - Natural Gas			
42	Other Gas Supply	3,370		
43	Storage, LNG Terminaling and Processing	265,299		
44	Transmission	79,121		
45	Distribution	3,978,085		
46	Administrative and General	63,788		
47	TOTAL Maintenance (Enter Total of lines 40 thru 46)	$4,493,310		

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
	Gas (Continued)			
48	Total Operation and Maintenance			
49	Production - Manufactured Gas (Enter Total of lines 28 and 40)	$417,507		
50	Production - Natural Gas (Including Expl. and Dev.) (Total of lines 29 and 41)			
51	Other Gas Supply (Enter Total of lines 30 and 42)	678,062		
52	Storage, LNG, Terminaling and Processing (Total of lines 31 and 43)	493,133		
53	Transmission (Enter Total of lines 32 and 44)	784,642		
54	Distribution (Enter Total of lines 33 and 45)	11,554,162		
55	Customer Accounts (Transcribe from line 34)	3,762,998		
56	Customer Service and Informational (Transcribe from line 35)	1,081,144		
57	Sales (Transcribe from line 36)	284,056		
58	Administrative and General (Enter Total of lines 37 and 46)	5,396,920		
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)	24,452,624	$560,995	$25,013,619
60	Other Utility Departments			
61	Operation and Maintenance	0	0	0
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	267,394,732	5,206,221	272,600,953
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	45,451,333	3,561,538	49,012,871
66	Gas Plant	7,485,353	250,332	7,735,685
67	Other	0	0	0
68	TOTAL Construction (Enter Total of lines 65 thru 67)	52,936,686	3,811,870	56,748,556
69	Plant Removal (By Utility Department)			
70	Electric Plant	2,168,856	187,674	2,356,530
71	Gas Plant	154,303	13,817	168,120
72	Other	0		0
73	TOTAL Plant Removal (Enter Total of lines 70 thru 72)	2,323,159	201,491	2,524,650
74	Other Accounts (Specify):			
75	Non Operating and Non Utility Income Accounts	8,297,730	37,884	8,335,614
76	Accounts Receivable	5,079,382	376,070	5,455,452
77	Materials & Supplies	6,129,114	1,002,481	7,131,595
78	Temporary Facilities	88,451	111,097	199,548
79	Other Deferred Debits	2,976,416	155,409	3,131,825
80	Conservation Programs	4,139,618		4,139,618
81	Hazardous Waste Disposal	327,482		327,482
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	27,038,193	1,682,941	28,721,134
96	TOTAL SALARIES AND WAGES	$349,692,770	$10,902,523	$360,595,293

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using common utility plant and explain the basis of allocation used, giving the allocation factors.

2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation factors used.

3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.

4. Give date of approval by the Commission for the use of the common utility plant classification and reference to order of the Commission or other authorization.

1 - See page 356A

2 - See page 356A

3 - See page 356B

Basis of Allocation of Common Utility Plant Expenses

Accounts	
902,903,909,	Number of customers bills of the various utilities to average total customers at year-end 1992.
920 to 935 Incl. 408	Composite percentage of gross operating revenues as adjusted for appropriate revenue accounts for year ended December 31, 1992 and original cost of fixed capital at December 31, 1992 adjusted to give effect to the allocation of a portion of investment in general office buildings and to transfer from electric utility to gas utility a portion of investment in joint use communication equipment.
403, 404	Common Depreciation Expense has been allocated to various utilities on the basis of a study that considers customers, revenues, plant and labor.
	Pension costs on labor affecting operating accounts were charged to Account 926.

4 - The use of common utility plant classification was recommended by commission letter dated 8-14-69.

COMMON UTILITY PLANT IN SERVICE

ACCOUNT (a)	COST AT DEC 31, 1993 (b)	ALLOCATED TO UTILITY DEPARTMENTS ELECTRIC (c)	GAS (d)
INTANGIBLE PLANT			
301 Organization	$100,608	$93,465	$7,143
303 Computer Software	34,778,675	32,309,390	2,469,285
Total Intangible Plant	$34,879,283	$32,402,855	$2,476,428
GENERAL PLANT			
389 Land and Land Rights	$1,896,648	$1,412,299	$484,349
390 Structures and Improvements	38,164,018	30,832,178	7,331,840
391 Office furniture and equipment	77,600,965	70,607,935	6,993,030
392 Transportation equipment	373,561	257,565	115,996
393 Stores equipment	947,447	596,439	351,008
394 Tools, shop and garage equipment	2,706,410	1,852,373	854,037
395 Laboratory equipment	35,984	32,847	3,137
396 Power operated equipment	6,446	4,378	2,068
397 Communication equipment	8,846,042	7,453,311	1,392,731
398 Miscellaneous equipment	641,503	548,179	93,324
Total General Plant	$131,219,024	$113,597,504	$17,621,520
Total Common Utility Plant – In Service	$166,098,307	$146,000,359	$20,097,948

COMMON UTILITY PLANT COMPLETED CONSTRUCTION NOT CLASSIFIED

GENERAL PLANT	$0	$0	$0

COMMON UTILITY PLANT HELD FOR FUTURE USE

GENERAL PLANT			
389 Land and land rights	$3,961,053	$3,679,818	$281,235

COMMON UTILITY PLANT CONSTRUCTION WORK IN PROGRESS

GENERAL PLANT	$23,954,175	$21,809,797	$2,144,378

COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION

GENERAL PLANT	$97,454,509	$87,972,523	$9,481,986

METHOD OF ALLOCATION

The above items of Common Utility Plant and Accumulated Provision for Depreciation have been allocated to various utilities on the basis of a study that considers customers, revenues, plant and labor.

COMMON UTILITY PLANT EXPENSES

ACCOUNT (a)	TOTAL (b)	ALLOCATED TO UTILITY DEPARTMENTS ELECTRIC (c)	GAS (d)
CUSTOMER ACCOUNTS EXPENSES			
902 Meter reading expenses	$131	$98	$33
903 Customer records and collection expenses	3,140	2,270	870
Total Customer Accounts Expenses	$3,271	$2,368	$903
CUSTOMER SERVICE AND INFORMATIONAL EXPENSES			
909 Informational and instructional advertising expenses	$135,973	$113,218	$22,755
Total Customer Service and Informational Expenses	$135,973	$113,218	$22,755
ADMINISTRATIVE AND GENERAL EXPENSES			
920 Administrative and general salaries	$25,081,952	$23,361,362	$1,720,590
921 Office supplies and expenses	15,751,161	14,670,606	1,080,555
922 Administrative expenses transferred - Cr.	(2,536,255)	(2,362,268)	(173,987)
923 Outside services employed	963,401	897,196	66,205
924 Property insurance	100,133	93,264	6,869
925 Injuries and damages	678,110	631,520	46,590
926 Employee pensions and benefits	14,512,824	13,516,219	996,605
930.1 Miscellancous general expenscs	4,892	4,518	374
930.2 Miscellaneous general expenses	2,094,752	1,951,029	143,723
931 Rents	(7,808)	(7,272)	(536)
935 Maintenance of general plant	648	617	31
Total Administrative and General Expenses	$56,643,810	$52,756,791	$3,887,019
403 Depreciation Expense	$8,494,744	$7,609,512	$885,232
404 Amortization of limited term common plant	$2,747,060	$2,552,019	$195,041
408.1 Taxes other than income taxes	$2,005,455	$1,867,885	$137,570
Total Common Utility Plant Expenses	$70,030,313	$64,901,793	$5,128,520

Next Page is 401

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	Megawatt Hours (b)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	27,187,988
3	Steam	20,900,904			
4	Nuclear	11,985,953	23	Requirements Sales For Resale (See instruction 4, page 311.)	5,782,517
5	Hydro-Conventional	80,612			
6	Hydro-Pumped Storage		24	Non-Requirements Sales For Resale (See instruction 4, page 311.)	6,766,550
7	Other	8,785			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	1,341
9	Net Generation (Enter Total of lines 3 thru 8)	32,976,254	26	Energy Used by the Company (Electric Department Only, Excluding Station Use)	47,129
10	Purchases	8,825,610	27	Total Energy Losses	2,141,406
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27)(MUST EQUAL LINE 20)	41,926,931
12	Received	110,456			
13	Delivered	74,675			
14	Net Exchanges (Lines 12 & 13)	35,781			
15	Transmission For Other (Wheeling)				
16	Received	5,207,000			
17	Delivered	5,015,839			
18	Net Transmission for Other (Line 16 minus line 17)	191,161			
19	Transmission By Others Losses	(101,875)			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	41,926,931			

MONTHLY PEAKS AND OUTPUT

1. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.

2. Report in column (b) the system's energy output for each month such that the total on line 41 matches the total on line 20.

3. Report in column (c) a monthly breakdown of the Non-Requirements Sales For Resale reported on line 24. Include in the monthly amounts any energy losses associated with the sales so that the total on line 41 exceeds the amount on line 24 by the amount of losses incurred (or estimated) in making the Non-Requirements Sales For Resale.

4. Report in column (d) the system's monthly maximum megawatt load (60-minute integration) associated with the net energy for the system defined as the difference between columns (b) and (c).

5. Report in columns (e) and (f) the specified information for each monthly peak load reported in column (d).

SEE PAGE 401A FOR SCHEDULE OF MONTHLY PEAKS AND OUTPUT

MONTHLY PEAKS AND OUTPUT

Name of System: Northern States Power Company (Minnesota)

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales For Resale & Associated Losses (c)(2)	MONTHLY PEAK Megawatt (See Instruction 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
	Interconnected System (respondent)					
29	January	3,181,507	255,396	4,197	6	1800
30	February	2,910,731	313,434	4,104	17	1900
31	March	3,141,353	350,159	3,890	17	1100
32	April	2,864,369	426,918	3,810	14	1200
33	May	3,162,407	656,951	3,998	27	1400
34	June	3,348,521	707,360	4,991	23	1400
35	July	3,702,897	669,692	5,234	27	1600
36	August	3,755,927	542,056	5,776	26	1600
37	September	3,331,583	708,619	4,388	2	1400
38	October	3,740,487	979,989	4,068	7	1200
39	November	3,363,296	616,261	4,195	30	1800
40	December	3,509,598	539,715	4,317	28	1800
41	TOTAL	40,012,676	6,766,550			
	Fargo-Grand Forks North Dakota System					
42	January	180,327		309	8	900
43	February	154,683		313	17	800
44	March	153,068		283	18	900
45	April	123,109		236	1	[illegible]
46	May	114,305		211	13	1700
47	June	113,152		258	21	1700
48	July	121,775		243	27	1400
49	August	117,208		273	25	1600
50	September	112,999		279	30	1900
51	October	131,314		244	29	900
52	November	150,740		290	22	1800
53	December	172,455		316	28	1100
54	TOTAL	1,645,135				
	Minot North Dakota System					
55	January	25,859		49	5	2100
56	February	22,449		44	16	1900
57	March	22,711		41	9	1600
58	April	20,347		39	6	1200
59	May	20,497		46	13	1600
60	June	20,608		53	21	1700
61	July	21,795		52	30	1700
62	August	23,002		54	11	1400
63	September	20,934		42	8	1700
64	October	22,031		40	28	2000
65	November	23,345		47	22	1800
66	December	25,542		47	21	1800
67	TOTAL	269,120				
	Total 3 Systems	41,926,931	6,766,550			

MONTHLY PEAKS AND OUTPUT (Continued)

1. Certain parts of the system of the respondent are connected or interconnected with the systems or parts of the systems of the Northern States Power Company (Wisconsin), which is a subsidiary of Northern States Power Company (Minnesota).

2. Regarding column (c), Non-Requirements Sales for Resale and Associated Losses, Northern States Power does not supply losses for any particular sale. Rather, the value of the energy to supply the sale is reflected in the price. Consequently, NSP has no separate accounting for losses due to sales.

3. Sales to other utilities at time of the Interconnected System monthly peaks and not included in column (d).

Month	MW Sales to Other Utilities
January	200
February	250
March	225
April	900
May	865
June	577
July	370
August	555
September	570
October	1,098
November	625
December	830

STEAM-ELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS)

1. Report data for Plant in Service Only
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report on this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis, report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as shown on line 21.
8. If more than one fuel is burned in a plant, furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Black Dog (b)			Plant Name: MN Valley (c)		
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Steam			Steam		
2	Type of Plant Construction (Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Conventional			Conventional		
3	Year Originally Constructed	1952			1932		
4	Year Last Unit was Installed	1960			1953		
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	504.2			46.0		
6	Net Peak Demand on Plant - MW (60 Minutes)						
7	Plant Hours Connected to Load	7,260			2,699		
8	Net Continuous Plant Capability (Megawatts)						
9	When Not Limited by Condenser Water	436			47		
10	When Limited by Condenser Water	462			47		
11	Average Number of Employees	127			20		
12	Net Generation, Exclusive of Plant Use - KWH	1,524,223,000			85,855,000		
13	Cost of Plant						
14	Land and Land Rights	$952,692			$20,492		
15	Structures and Improvements	23,158,153			2,842,917		
16	Equipment Costs	153,979,002			9,006,7[illegible]		
17	Total Cost	$178,089,847			$11,870,1[illegible]		
18	Cost per KW of Installed Capacity (Line 5)	$353			$258		
19	Production Expenses:						
20	Operation Supervision and Engineering	$1,178,566			$334,138		
21	Fuel	19,902,417			1,474,987		
22	Coolants and Water (Nuclear Plants Only)						
23	Steam Expenses	1,862,551			398,976		
24	Steam From Other Sources						
25	Steam Transferred (Cr.)						
26	Electric Expenses	824,818			185,128		
27	Misc. Steam (or Nuclear) Power Expenses	2,710,728			153,320		
28	Rents	7,029					
29	Maintenance Supervision and Engineering	826,986			155,210		
30	Maintenance of Structures	433,009			90,275		
31	Maintenance of Boiler (or Reactor) Plant	2,582,012			110,483		
32	Maintenance of Electric Plant	437,812			42,458		
33	Maintenance of Misc. Steam (or Nuclear) Plant	840,324			67,685		
34	Total Production Expenses	$31,606,252			$3,012,660		
35	Expenses per Net KWh	$0.021			$0.035		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Gas	Oil	Coal	Gas	Oil
37	Unit: (Coal-tons of 2,000lb.) (Oil-barrels of 42 gals.) (Gas-Mcf) (Nuclear-indicate)	Tons	MCF	Bbls	Tons	MCF	Bbls
38	Quantity (Units) of Fuel Burned	992,031	350,177	0	56,795	25,758	445
39	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)	8,684	1,018	0	9,798	1,017	139,328
40	Average Cost of Fuel per Unit, As Delivered f.o.b. Plant During Year	$17.98	$2.53	$0.00	$19.14	$2.61	$27.06
41	Average Cost of Fuel per Unit Burned	$19.16	$2.55	$0.00	$24.56	$2.64	$27.7[illegible]
42	Avg. Cost of Fuel Burned per Million Btu (cents)	$1.10	$2.51	$0.00	$1.25	$2.59	$4.[illegible]
43	Avg. Cost of Fuel Burned per KWh Net Gen.		$13.06*			$17.18*	
44	Average Btu per KWh Net Generation		11.54*			13.30*	

* All Fuels - reported per MWh

STEAM-ELECTRIC GENERATING PLANT STATISTICS(Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A. accounts. Production expenses do not include purchased power, System Control and Load Dispatching, and Other Expenses classified as Other Power Supply Expenses.

10. For IC and GT plants, report Operating Expenses, Account No. 548 and 549 on line 26 "Electric Expenses," and Maintenance Account No. 553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.

11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.

12. If a nuclear power generating plant, briefly explain by a footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of costs units used for the various components of fuel cost; and (c) any other informative data concerning plant type, fuel used, fuel enrichment by type and quantity for the report period, and other physical and operating characteristics of the plant.

Plant Name: Wilmarth (d)			Plant Name: High Bridge (e)			Plant Name: Riverside (f)			Line No.
		Steam			Steam			Steam	1
		Conventional			Conventional			Conventional	2
		1948			1924			1911	3
		1951			1959			1964	4
		25.0			396.8			381.9	5
									6
		7,677			6,229			7,884	7
									8
		23			263			372	9
		22			261			334	10
		28			128			136	11
		102,454,000			910,835,000			1,768,646,000	12
									13
		$368,323			$528,150			$397,485	14
		4,515,129			18,213,369			25,376,768	15
		28,283,633			62,140,651			131,865,634	16
		$33,167,085			$80,882,170			$157,639,887	17
		$1,327			$204			$413	18
									19
		$295,466			$865,871			$873,165	20
		1,843,498			12,499,969			22,463,836	21
									22
		117,390			2,091,979			3,026,773	23
									24
									25
		5,964			540,863			342,276	26
		1,247,377			1,489,104			2,435,249	27
		130							28
		291,166			820,749			876,101	29
		56,406			358,160			503,782	30
		787,187			2,090,493			3,214,539	31
		31,439			365,618			2,040,271	32
		253,964			226,149			250,151	33
		$4,929,987			$21,348,955			$36,026,143	34
		$0.048			$0.023			$0.020	35
RDF	Gas	Wood	Coal	Gas	Oil	Coal	Gas	Oil	36
Tons	MCF	Tons	Tons	MCF	Bbls	Tons	MCF	Bbls	37
171,948	16,719	293	606,769	243,018	14	1,069,228	64,087	3,318	38
5,711	1,017	6,976	8,612	1,042	138,462	8,704	1,016	139,574	39
$4.55	$2.83	$7.55	$18.85	$2.62	$17.76	$19.16	$2.84	$24.53	40
$10.43	$2.85	$7.72	$19.54	$2.64	$18.33	$20.76	$2.86	$25.60	41
$0.09	$2.80	$0.55	$1.13	$2.53	$3.17	$1.19	$2.82	$4.37	42
	$17.99*			$13.72*			$12.70*		43
	19.38*			11.75*			10.57*		44

* All Fuels – reported per MWh

STEAM-ELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS) (Continued)

1. Report data for Plant in Service Only
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report on this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis, report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as shown on line 21.
8. If more than one fuel is burned in a plant, furnish only the composite heat rate for all fuels burned.

Linc No.	Item (a)	Plant Name: West Faribault (b)	Plant Name: Pathfindcr (c)
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Gas Turbine	Steam
2	Type of Plant Construction (Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Ind Enclosures	Conventional
3	Year Originally Constructed	1965	1969
4	Year Last Unit was Installed	1965	1969
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	32.3	75.0
6	Net Peak Demand on Plant - MW (60 Minutes)		
7	Plant Hours Connected to Load	24	147
8	Net Continuous Plant Capability (Megawatts)	15	
9	When Not Limited by Condenser Water		64
10	When Limited by Condenser Water		64
11	Average Number of Employees	0	4
12	Net Generation, Exclusive of Plant Use - KWH	(200,000)	1,888,000
13	Cost of Plant		
14	Land and Land Rights	$19,874	$292,140
15	Structures and Improvements	117,231	3,535,234
16	Equipment Costs	3,357,551	11,931,2[illegible]
17	Total Cost	$3,494,656	$15,758,62[illegible]
18	Cost per KW of Installed Capacity (Line 5)	$108	$210
19	Production Expenses:		
20	Operation Supervision and Engineering	$9,364	$53,204
21	Fuel	577	131,531
22	Coolants and Water (Nuclear Plants Only)		
23	Steam Expenses		39,984
24	Steam From Other Sources		
25	Steam Transferred (Cr.)		
26	Electric Expenses	1,741	55,636
27	Misc. Steam (or Nuclear) Power Expenses	6,911	239,406
28	Rents	6,696	
29	Maintenance Supervision and Engineering	26,720	60,170
30	Maintenance of Structures	423	21,005
31	Maintenance of Boiler (or Reactor) Plant		45,022
32	Maintenance of Electric Plant	17,335	48,632
33	Maintenance of Misc. Steam (or Nuclear) Plant	1,898	24,358
34	Total Production Expenses	$71,665	$718,948
35	Expenses per Net KWh	($0.36)	$0.38

Linc No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Gas			Gas	
37	Unit: (Coal-tons of 2,000lb.) (Oil-barrels of 42 gals.) (Gas-Mcf) (Nuclear-indicate)		MCF			MCF	
38	Quantity (Units) of Fuel Burned		202			51,682	
39	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)		1,000			1,014	
40	Average Cost of Fuel per Unit, As Delivered f.o.b. Plant During Year		$2.86			$2.47	
41	Average Cost of Fuel per Unit Burned		$2.86			$2.51	
42	Avg. Cost of Fuel Burned per Million Btu (cents)		$2.84			$2.51	
43	Avg. Cost of Fuel Burned per KWh Net Gen.					$69.67*	
44	Average Btu per KWh Net Generation					$27.76*	

* All Fuels - reported per MWh

STEAM-ELECTRIC GENERATING PLANT STATISTICS(Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A. accounts. Production expenses do not include purchased power, System Control and Load Dispatching, and Other Expenses classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account No. 548 and 549 on line 26 "Electric Expenses," and Maintenance Account No. 553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbinc equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by a footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of costs units used for the various components of fuel cost; and (c) any other informative data concerning plant type, fuel used, fuel enrichment by type and quantity for the report period, and other physical and operating characteristics of the plant.

Plant Name: Allen S King (d)	Plant Name: Sherburne County (e)	Plant Name: Blue Lake (f)	Line No.
Steam	Stcam	Gas Turbine	1
Conventional	Conventional	Ind Enclosures	2
1968	1976	1974	3
1968	1987	1974	4
598.4	1,947.4	226.8	5
			6
7,507	8,759	33	7
		190	8
581	2,295		9
567	2,295		10
108	491	6	11
3,524,901,000	12,865,629,000	(324,000)	12
			13
$666,605	$4,668,175	$190,323	14
19,691,212	177,626,893	847,172	15
101,740,550	805,222,257	19,772,952	16
$122,098,367	$987,517,325	$20,810,447	17
$204	$507	$92	18
			19
$692,056	$4,263,565	$61,771	20
34,570,514	167,433,977	132,741	21
			22
2,209,242	5,357,995		23
			24
			25
601,670	1,350,063	67,299	26
1,971,007	7,101,486	148,884	27
11,856			28
883,370	1,323,645	101,336	29
233,329	748,757	13,160	30
3,345,055	7,432,428		31
436,364	3,299,613	422,170	32
626,947	997,313	(199,215)	33
$45,581,410	$199,308,842	$748,146	34
$0.01	$0.02	($2.31)	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Gas	Wood	Coal		Oil			Oil	36
Tons	MCF	Tons	Tons		Bbls			Bbls	37
1,809,503	19,670	13,688	7,595,489		9,831			6,583	38
9,161	1,018	8,027	8,632		139,110			138,004	39
** $17.35	$2.65	$16.43	** $22.16		$26.02			$20.16	40
$18.55	$2.73	$16.62	$21.68		$27.91			$20.16	41
$1.01	$2.68	$1.04	$1.26		$4.78			$3.48	42
	$9.60*				$12.82*				43
	9.47*				10.20*				44

*All Fuels-reported per MWH
** Includes Option Payments

STEAM-ELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS) (Continued)

1. Report data for Plant in Service Only
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report on this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis, report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as shown on line 21.
8. If more than one fuel is burned in a plant, furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Granite City (b)			Plant Name: Key City (c)		
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Gas Turbine			Gas Turbine		
2	Type of Plant Construction (Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Ind Enclosures			Ind Enclosures		
3	Year Originally Constructed	1969			1970		
4	Year Last Unit was Installed	1969			1970		
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	72.0			72.0		
6	Net Peak Demand on Plant - MW (60 Minutes)						
7	Plant Hours Connected to Load	63			81		
8	Net Continuous Plant Capability (Megawatts)	61			65		
9	When Not Limited by Condenser Water						
10	When Limited by Condenser Water						
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWH	2,078,000			1,004,000		
13	Cost of Plant						
14	Land and Land Rights	$40,240			$67,495		
15	Structures and Improvements	474,772			93,931		
16	Equipment Costs	6,280,705			7,056,7[illegible]		
17	Total Cost	$6,795,717			$7,218,1[illegible]		
18	Cost per KW of Installed Capacity (Line 5)	$94			$100		
19	Production Expenses:						
20	Operation Supervision and Engineering	$8,495			$17,534		
21	Fuel	334,368			76,571		
22	Coolants and Water (Nuclear Plants Only)						
23	Steam Expenses						
24	Steam From Other Sources						
25	Steam Transferred (Cr.)						
26	Electric Expenses	21,511			9,426		
27	Misc. Steam (or Nuclear) Power Expenses	26,825			30,543		
28	Rents	96					
29	Maintenance Supervision and Engineering	12,888			28,414		
30	Maintenance of Structures	(11,000)			(10,379)		
31	Maintenance of Boiler (or Reactor) Plant						
32	Maintenance of Electric Plant	35,028			77,089		
33	Maintenance of Misc. Steam (or Nuclear) Plant	5,024			2,277		
34	Total Production Expenses	$433,235			$231,475		
35	Expenses per Net KWh	$0.21			$0.23		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Gas	Oil		Gas	
37	Unit: (Coal-tons of 2,000lb.) (Oil-barrels of 42 gals.) (Gas-Mcf) (Nuclear-indicate)		MCF	Bbls		MCF	
38	Quantity (Units) of Fuel Burned		145,910	0		28,230	
39	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)		1,017	0		1,016	
40	Average Cost of Fuel per Unit, As Delivered f.o.b. Plant During Year		$2.29			$2.65	
41	Average Cost of Fuel per Unit Burned		$2.29	$0.00		$2.65	
42	Avg. Cost of Fuel Burned per Million Btu (cents)		$2.25	$0.00		$2.61	
43	Avg. Cost of Fuel Burned per KWh Net Gen.						
44	Average Btu per KWh Net Generation						

* All Fuels - reported per MWh

STEAM-ELECTRIC GENERATING PLANT STATISTICS(Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A. accounts. Production expenses do not include purchased power, System Control and Load Dispatching, and Other Expenses classified as Other Power Supply Expenses.

10. For IC and GT plants, report Operating Expenses, Account No. 548 and 549 on line 26 "Electric Expenses," and Maintenance Account No. 553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.

11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.

12. If a nuclear power generating plant, briefly explain by a footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of costs units used for the various components of fuel cost; and (c) any other informative data concerning plant type, fuel used, fuel enrichment by type and quantity for the report period, and other physical and operating characteristics of the plant.

Plant Name: Monticello (d)	Plant Name: Inver Hills (e)	Plant Name: Prairie Island (f)	Line No.
Nuclear	Gas Turbine	Nuclear	1
Conventional	Ind Enclosures	Conventional	2
1971	1972	1973	3
1971	1972	1974	4
568.8	326.4	1,186.2	5
			6
7,311	152	8,508	7
	323		8
553		1,064	9
539		1,017	10
443	6	581	11
3,862,905,000	6,273,000	8,123,048,000	12
			13
$767,317	$221,371	$377,794	14
100,644,644	843,220	178,295,057	15
371,816,766	29,270,936	660,503,676	16
$473,228,727	$30,335,527	$839,176,527	17
$832	$93	$707	18
			19
$12,830,962	$54,245	$15,208,763	20
17,738,743	519,950	35,161,577	21
105,760		29,712	22
11,723,646		6,696,318	23
			24
			25
1,550,381	89,263	5,842,963	26
17,938,964	187,508	23,928,393	27 **
36,610	120		28
4,096,205	40,646	6,231,386	29
103,860	(9,275)	1,180,788	30
4,083,931		4,190,600	31
2,218,670	130,974	3,623,255	32
5,048,564	2,209	2,758,864	33
$77,476,296	$1,015,640	$104,852,619	34
$0.02	$0.16	$0.01	35
Nuclear	Oil	Nuclear	36
Grams U-235	Bbls	Grams U-235	37
321,900	21,559	770,273	38
125,883	139,182	113,577	39
	$24.12		40
$55.11	$24.12	$45.65	41
$0.44	$4.13	$0.40	42
$4.59	$82.89*	$4.33	43
10.49	20.09*	10.77	44

* All Fuels - reported per MWh

**Includes NRC Fees

Instruction 3 – Sherburne County Generating Plant (p. 403A)

Sherburne County Generating Plant Unit 3 is jointly owned by the Company (59%) and Southern Minnesota Municipal Power Agency (41%). See Note 13 on page 123H for further discussion.

Instruction 12 – Monticello Nuclear Generating Plant (p. 403B)

(a) Operating and maintenance costs of the Monticello Plant are charged to expenses as incurred.

(b) Northern States Power Company buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.

(c) The Monticello Plant is a General Electric BWR3 Nuclear Power Plant. Fuel material is UO2 contained in Zircaloy tube cladding. The equilibrium cycle has approximately 86 metric tons of Uranium metal with a nominal U-235 enrichment of 2.8%. The reactor is licensed to allow operation of 1670 MWT.

Instruction 12 – Prairie Island Nuclear Generating Plant (p. 403B)

(a) Operating and maintenance costs of the Prairie Island Plant are charged to expenses as incurred.

(b) Northern States Power Company buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.

(c) The Prairie Island Plant is a 2 loop pressurized water reactor nuclear power plant of Westinghouse design. Fuel material is UO2 contained in Zircaloy-4 tube cladding. The equilibrium cycle has approximately 44 metric tons of Uranium metal enriched at three different levels, the average of which is 3.5 weight percent of U-235. The reactor is licensed to operate at 1650 MWT. There are two identical units at the Prairie Island site.

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large Plants are hydro plants of 10,000 Kw or more of installed capacity (Name Plate).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC No. 2056 Plant Name: Henn Is & Upper Dam (b)	FERC No. Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run of River	
2	Type of Plant Construction (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1908	
4	Year Last Unit was Installed	1955	
5	Total Installed Capacity (Generator Name Plate Ratings in MW)	20.4	
6	Net Peak Demand on Plant – Megawatts (60 Minutes)		
7	Plant Hours Connected to Load	N/A	
8	Net Plant Capability (In megawatts)	12	
9	(a) Under the Most Favorable Oper. Conditions	20	
10	(b) Under to Most Adverse Oper. Conditions	2	
11	Average Number of Employees	4	
12	Net Generation, Exclusive of Plant Use – KWh	80,612,000	
13	Cost of Plant:		
14	Land and Land Rights	$1,548,707	
15	Structures and Improvements	402,364	
16	Reservoirs, Dams, and Waterways	1,862,346	
17	Equipment Costs	1,485,068	
18	Roads, Railroads, and Bridges		
19	TOTAL Cost (Enter Total of lines 14 thru 18)	$5,298,485	
20	Cost per KW of Installed Capacity (Line 5)	$260	
21	Production Expenses:		
22	Operation Supervision and Engineering	$43,891	
23	Water for Power	108,114	
24	Hydraulic Expenses	59,059	
25	Electric Expenses	54,526	
26	Misc. Hydraulic Power Generation Expense	140,860	
27	Rents		
28	Maintenance Supervision and Engineering	29,642	
29	Maimtenance of Structures	7,827	
30	Maintenance of Reservoirs, Dams, and Waterways	13,890	
31	Maintenance of Electric Plant	26,991	
32	Maintenance of Misc. Hydraulic Plant	9,648	
33	Total Production Expenses (Total lines 22 thru 32)	$494,448	
34	Expense per net KWh (cents)	$0.01	

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GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of less than 25,000 Kw; internal combustion and gas-turbine plants, conventional hydro plants and pumped storage of less than 10,000 Kw installed capacity (name plate rating).

2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If a licensed project, give project number in a footnote.

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas-

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (c)	Net Peak Demand MW (60 Min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	STEAM PLANT					
2						
3	Red Wing	1949	23.0	28.6	116,476	$31,308,572
4						
5						
6	INTERNAL COMBUSTION					
7						
8	Disbursed Generation - United Hospital				(233)	2,107,717
9						
10						
11	HYDRO PLANTS					
12						
13	Lower Dam	1887	8.0		0	612,506
14	St Croix Falls	1908	23.2		116,209	427,898
15						
16						
17	WIND TURBINE PLANT					
18						
19	Holland	1986	.195		187	636,245
20						
21						
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28						
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GENERATING PLANT STATISTICS (Small Plants)(Continued)

turbine plants. For nuclear, see instruction 11, page 403.

4. If net peak demand for 60 min. is not available, give that which is available, specifying period.

5. If any plant is equipped with combinations of steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas-turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost Per MW Inst Capacity (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind Of Fuel (k)	Fuel Cost (In Cents per million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
						2
	$1,483,948	$1,516,422	$1,655,198	RDF, Gas	149.51	3
						4
						5
						6
						7
	2,769	916	826	Oil	57.00	8
						9
						10
						11
						12
	42,539		42,035	Hydro		13
						14
						15
						16
						17
						18
	1,659		9,335	Wind		19
						20
						21
						22
						23
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						27
						28
						29
						30
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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a state commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood or steel; (2) H-frame, wood or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting strueture, indicate mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another Iine. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole Miles) On Structures of Line Designated (f)	LENGTH (Pole Miles) On Structures of Another Line (g)	Number of Circuits (h)
1	Overhead Transmission	Lines:						
2	Forbes (MPC)	Manitoba Hydro						
3		Interconn	500,000	500,000	Tower	203.79		1
4	Chisago Co	MP&L	500,000	500,000	Tower	61.56		1
5								
6	Total					265.35		
7								
8	King	Red Rock	345,000	345,000	Tower	18.85		1
9					2 Pole K	6.12		1
10	Parkers Lake	Prairie Island	345,000	345,000	Tower	31.29		1
11					Tower	5.93		1
12					Steel Pole	4.13		1
13					Steel Pole	0.11		1
14					Steel Pole			
15					on 0976		0.11	1
16					2 Pole K	25.91		1
17	King	Terminal	345,000	345,000	Tower	19.77		1
18					Steel Pole	3.23		1
19	Monticello	Parkers Lake	345,000	345,000	Tower	16.72		1
20					2 Pole K	20.33		1
21	Prairie Island	Adams	345,000	345,000	Tower	2.42		1
22					Tower	0.87		1
23					2 Pole K	72.88		1
24	Chisago Co	Coon Creek	345,000	345,000	Twr on 0977		11.19	1
25					Steel Pole			
26					on 0977		3.23	1
27					Tower	6.78		1
28					Steel Pole	4.98		1
29					Steel Pole	31.56		1
30	King	St Croix River	345,000	345,000	Twr on 0975		14.80	1
31					Tower	0:62		1
32					2 Pole K	3.84		1
33	Blue Lake	Lakefield Junction	345,000	345,000	Tower	14.95		
34					2 Pole K	112.24		1
35								
36								

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give the name of lessee, date and terms of lease, annual rent for the year, and how determined. Specify whether leasee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

	COST OF LINE (Include in column (j) land, land rights and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				
Size of Conductor and Material (i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line no.
								1
								2
3-1192ACSR	1,723,334	60,178,984	61,902,318					3
3-1192ACSR	2,562,359	16,301,260	18,863,619					4
								5
	4,285,693	76,480,244	80,765,937	71,949	161,501	1,072	234,522	6
								7
2-795ACSR								8
2-795ACSR	401,465	2,382,525	2,783,990					9
2-795ACSR								10
2-954ACSR								11
2-795ACSR								12
2-312ACSR								13
								14
2-312ACSR								15
2-954ACSR	2,224,390	9,216,147	11,440,537					16
2-795ACSR								17
2-795ACSR	1,525,272	4,033,144	5,558,416					18
2-954ACSR								19
2-954ACSR	882,297	4,162,510	5,044,807					20
2-954ACSR								21
2-795ACSR								22
2-795ACSR	187,240	9,969,720	10,156,960					23
2-795ACSR								24
								25
2-795ACSR								26
2-795ACSR								27
2-795ACSR								28
2-954ACSR	4,858,601	12,978,573	17,837,174					29
2-795ACSR								30
2-795ACSR								31
2-795ACSR	24,099	595,168	619,267					32
2-795ACSR								33
2-795ACSR	1,308,883	14,167,091	15,475,974					34
								35
								36

TRANSMISSION LINE STATISTICS (Continued)

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a state commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood or steel; (2) H-frame, wood or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pele miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such struetures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	To (b)	VOLTAGE (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole Miles) On Structures of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	Overhead Transmission Lines (Continued)							
2	Sherburne Co	Terminal	345,000	345,000	Tower	12.24		1
3					2 Pole K	16.21		1
4					Twr on 0977		1.97	1
5					Steel Pole	15.07		1
6					Steel Pole			
7					on 0980		5.11	
8					Twr on 0980		6.65	1
9	Sherburne Co	CU Conn	345,000	345,000	Tower	5.82		1
10					2 Pole K	20.33		1
11					Twr on 0978		7.00	1
12	Prairie Island	Red Rock	345,000	345,000	Tower	3.05		1
13					Twr on 0979		2.42	1
14					2 Pole K	19.91		1
15					Steel Pole	6.48		1
16	Prairie Island	Red Rock	345,000	345,000	Steel Pole			
17					on 0986		6.48	1
18					2 Pole K	19.52		1
19					Twr on 0986		2.16	1
20					Tower	1.28		1
21					Twr on 0976		2.57	1
22	Parkers Lake	Blue Lake	345,000	345,000	Tower		11.56	1
23					Steel Pole		3.30	1
24	Blue Lake	Red Rock	345,000	345,000	Tower	7.62		1
25					Twr on 0976		19.10	1
26					Steel Pole	0.58		
27					on 0976		0.83	
28					2 Pole K	3.03		1
29	Sherburne Co	Monticello	345,000	345,000	Twr on 0985		5.78	1
30								
31								
32								
33								
34								
35								
36								

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respendent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give the name of lessee, date and terms of lease, annual rent for the year, and how determined. Specify whether leasee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) land, land rights and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line no.
								1
2-954ACSR								2
2-954ACSR								3
2-795ACSR								4
2-795ACSR								5
								6
2-795ACSR								7
2-795ACSR	667,056	8,096,993	8,764,049					8
2-954ACSR								9
2-954ACSR								10
2-954ACSR	8,733	3,704,319	3,713,052					11
2-795ACSR								12
2-954ACSR								13
2-795ACSR								14
2-795ACSR	661,692	2,927,358	3,589,050					15
								16
2-795ACSR								17
2-795ACSR								18
2-795ACSR								19
2-795ACSR								20
2-954ACSR		2,190,036	2,190,036					21
2-795ACSR								22
2-795ACSR		478,209	478,209					23
2-795ACSR								24
2-795ACSR								25
								26
2-795ACSR								27
2-795ACSR	353,005	2,932,822	3,285,827					28
2-954ACSR		196,978	196,978					29
								30
								31
								32
								33
								34
								35
								36

TRANSMISSION LINE STATISTICS (Continued)

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a state commission.

4. Exclude from this page any transmission lines for which plant costs arc included in Account 121, Nonutility Property.

5. Indieate whether the type of supporting structure reported in column (e) is: (1) single pole, wood or steel; (2) H-frame, wood or steel poles; (3) tower; or (4) underground construction. If a transmission Iine has more than one type of supporting structure, indicatc mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole Miles) On Structures of Line Designated (f)	LENGTH (Pole Miles) On Structures of Another Line (g)	Number of Circuits (h)
1	Overhead Transmission Lines (Continued)							
2	Sherburne Co.	Coon Creek	345,000	345,000	Tower	0.88		1
3					2 Pole K	16.21		1
4					Steel Pole			
5					on 0984		15.07	1
6					Twr on 0984		11.34	
7	Sherburne Co.	CPA Interconn	345,000	345,000	Steel Pole	10.55		
8	Chisago Co.	King	345,000	345,000	Twr on 0977		6.61	1
9					Steel Pole			
10					on 0980		31.56	1
11	Parkers Lake	CU Conn	345,000	345,000	Twr on 0978		9.64	1
12	Split Rock	WAPA (Watertwn)	345,000	345,000	Steel Pole	5.10		
13	Split Rock	WAPA (Sioux Cty)	345,000	345,000	Steel Pole		5.10	
14								
15	Total					567.41	183.58	
16								
17	Black Dog	WAPA	230,000	230,000	Tower	115.45		1
18					2 Pole K	1.19		1
19	Red Rock-Lake	James-MP&L Co	230,000	230,000	2 Pole K	66.55		1
20					2 Pole K	9.77		1
21					Tower	4.05		1
22	Audobon	Badura	230,000	230,000	2 Pole H	44.95		1
23	Maple River	Minnkota Conn	230,000	230,000	Tower	3.66		1
24	Maple River	OTP CO	230,000	230,000	Twr on 0910		3.61	1
25		Interconn	230,000	230,000	2 Pole H	4.36		1
26	Drayton	Manitoba Hydro						
27		Interconn	230,000	230,000	2 Pole H	28.69		
28	Sheyenne	WAPA	230,000	230,000	2 Pole H	4.26		1
29			230,000	230,000				
30								
31	Total					282.93	3.61	
32								
33								
34								
35								
36								

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give the name of lessee, date and terms of lease, annual rent for the year, and how determined. Specify whether leasee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) land, land rights and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line no.
								1
2-954ACSR								2
2-954ACSR								3
								4
2-954ACSR								5
2-954ACSR	472,774	3,331,070	3,803,844					6
2-1192ACSR	958,866	3,456,198	4,415,064					7
2-795ACSR								8
								9
2-954ACSR		1,648,291	1,648,291					10
2-954ACSR		491,361	491,361					11
2-954ACSR	139,860	2,945,436	3,085,296					12
2-954ACSR		446,776	446,776					13
								14
	14,674,233	90,350,725	105,024,958	81,664	422,994	184,270	688,928	15
								16
795ACSR								17
795ACSR	450,318	4,503,751	4,954,069					18
795ACSR								19
1272ACSR								20
1272ACSR	437,738	2,598,558	3,036,296					21
795ACSR	57,863	1,210,723	1,268,586					22
795ACSR	55,625	283,964	339,589					23
795ACSR								24
795ACSR	31,735	674,935	706,670					25
								26
954ACSR	57,281	758,399	815,680					27
795ACSR	21,223	519,990	541,213					28
	3,103	1,000,985	1,004,088					29
								30
	1,114,886	11,551,305	12,666,191	15,219	22,382	103	37,704	31
								32
								33
								34
								35
								36

TRANSMISSION LINE STATISTICS (Continued)

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a state commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood or steel; (2) H-frame, wood or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole Miles) On Structures of Line Designated (f)	LENGTH (Pole Miles) On Structures of Another Line (g)	Number of Circuits (h)
1	Mankato	Winnebago	161,000	161,000	2 Pole H	38.86		
2	Split Rock	Heron Lake	161,000	161,000	2 Pole H	18.98		
3	Split Rock	Heron Lake	161,000	161,000	Steel Pole	0.99		
4								
5	Total					58.83		
6								
7	Various		115,000			1122.23	83.24	
8	Various		69,000			1782.53	38.65	
9	Various		34,500			67.30	0.70	
10	Various		23,000			5.55	1.20	
11								
12	Total Overhead Lines					4,152.13	310.98	
13								
14								Cir Mi.
15	Underground Transmission Lines							
16	Various		115,000					6.02
17	Various		69,000					1.59
18	Various		13,800					0.32
19								
20	Total Underground Lines							7.93
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36								

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give the name of lessee, date and terms of lease, annual rent for the year, and how determined. Specify whether leasee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

	COST OF LINE (Include in column (j) land, land rights and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				
Size of Conductor and Material (i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line no.
477ACSR	112,192	629,463	741,655					1
477ACSR	56,236	971,716	1,027,952					2
2312ACSR								3
								4
	168,428	1,601,179	1,769,607	3,213	22,208	94	25,515	5
								6
	10,333,932	71,476,706	81,810,638	142,324	637,481	198,010	977,815	7
	3,428,843	48,812,024	52,240,867	261,645	1,107,064	20,490	1,389,199	8
	242	981,960	982,202	3,575	4,535	268	8,378	9
		363,854	363,854	617	46,980	4,121	51,718	10
								11
	34,006,257	301,617,997	335,624,254	580,206	2,425,145	408,428	3,413,779	12
								13
								14
								15
		8,271,851	8,271,851					16
		798,244	798,244					17
		34,380	34,380					18
								19
		9,104,475	9,104,475	65,278	11,002		76,280	20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.

2. Provide separate subheadings for overhead and underground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the estimated final completion costs. Designate, however, if estimated amounts are reported.

Line No.	LINE DESIGNATION From (a)	To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	Ultimate (g)
1	Paynesville	Lowry	0.04	Pole	19	1	1
2	Black Oak	Douglas Co.	(0.04)	Pole	24	1	1
3	High Bridge	Terminal	0.11	Pole	22	1	1
4	Pipestone	Minnesota Valley	1.26	Pole	8	1	1
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
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39							
40							
41							
42							
43							
44							

* Estimated

TRANSMISSION LINES ADDED DURING YEAR (Continued)

Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle 3 phase, indicate such other characteristic.

CONDUCTORS				LINE COST				
Size (h)	Specification (i)	Configuration and Spacing (j)	Voltage KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Total (o)	Line No.
2/0	ACSR		69		6,215	565,312	$571,527 *	1
2/0	ACSR		69		137,825	91,001	$228,826 *	2
795	SSAC		115		69,834	21,888	$91,722 *	3
447	ACSR		115		168,285	164,437	$332,722 *	4
								5
					$382,159	$842,638	$1,224,797	6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
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								32
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SUBSTATIONS

1. Report below the information called for concerning substations for the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Paynesville-Stearns County, MN	Trans U	110.00	36.20	
2		Trans U	110.00	69.00	13.80
3		Trans U	66.00	13.20	
4	Franklin-Birch Cooley Twp, MN	Trans U	110.00	70.60	13.80
5		Trans U	69.00	25.00	
6		Trans U	69.00	4.00	
7	Lincoln Co-So Souix Falls, SD	Trans U	110.00	70.60	13.80
8	Prairie, SW of Grand Forks, ND	Trans U	230.00	118.00	13.80
9		Trans U	110.00	70.60	13.80
10	West Coon Rapids-Brkyln Pk, MN	Trans U	112.50	78.75	2.45
11		Trans U	104.30	66.00	2.40
12		Trans U	67.00	13.09	
13		Trans U	68.80	13.09	
14	Douglas County-Osakis, MN	Trans U	110.00	70.60	35.30
15	King-Oak Park Heights, MN	Trans A	345.00	118.00	13.80
16		Trans A	345.00	20.00	
17	Grant-Grant Twsp, SD	Trans U	115.00	72.00	2.40
18	Westgate-Eden Prairie, MN	Trans U	110.00	70.60	13.80
19		Trans U	116.00	70.60	13.80
20		Trans U	118.00	14.40	
21		Trans U	110.00	13.80	
22	Parkers Lake-Plymouth, MN	Trans U	345.00	115.00	13.80
23		Trans U	110.00	13.80	
24		Trans U	118.00	14.40	83.00
25	West Faribault-Warsaw Twp, MN	Trans U	68.80	13.80	
26		Trans U	68.80	13.80	
27		Trans U	110.00	70.60	2.50
28		Trans U	110.00	70.60	2.50
29	Monticello Nuclear-Monticello, MN	Trans A	345.00	22.00	
30		Trans A	345.00	230.00	13.80
31		Trans A	345.00	118.00	13.80
32	Facilities at Maple River, ND	Trans U	230.00	118.00	13.80
33	Rogers Lake-Mendota Heights, MN	Trans U	118.00	14.40	
34		Trans U	110.00	70.60	
35	Cannon Falls-Dakota County, MN	Trans A	68.80	13.80	
36		Trans A	110.00	70.60	
37		Trans A	161.00	118.00	13.80
38		Trans A	110.00	70.60	
39	St Cloud #1-St Cloud, MN	Trans A	34.50	4.36	
40		Trans A	110.00	36.20	

SUBSTATIONS(Continued)

5. Show in columns (i), (j), and (k) special equipment such as rotary converters, reactifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by sold ownership or leaso, give name of co-owner or other party, explain basis of sharing expenses or other accounting betwcen the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)	Line No.
12.5 3P	2		Regulators	1-3P	1,000	1
37.5 3P	2		Capacitor Bank	1-3P	14,400	2
9.4 1P	3	1	Regulators	1-3P	750	3
93.3 3P	2		Regulators	3-1P	864	4
4.5 1P	3					5
1.0 3P	3		Regulators	3-1P	144	6
70.0 3P	1		Capacitor Bank	2-3P	28,800	7
374.0 3P	2					8
140.0 3P	2					9
24.0 1P	3					10
23.4 1P	3	2				11
12.5 3P	2		Regulators	1-3P	750	12
6.3 3P	1		Regulators	3-3P	999	13
46.7 3P	1		Capacitor Bank	1-3P	14,400	14
336.0 3P	1		Grounding Bank	3-1P	30	15
784.0 3P	1					16
18.8 3P	1					17
46.7 3P	1					18
46.7 3P	1					19
46.7 3P	1					20
46.7 3P	1					21
900.0 1P	6					22
93.3 3P	2		Grounding Bank	3-1P	30	23
46.7 3P	1					24
6.3 3P	1		Regulators	2-3P	1,874	25
44.8 3P	2					26
70.0 3P	1					27
50.0 3P	2					28
728.0 3P	1					29
336.0 3P	1					30
280.0 3P	1					31
186.7 3P	1					32
93.3 3P	2					33
46.7 3P	1					34
10.5 3P	1					35
46.6 3P	1					36
186.7 3P	1					37
46.7 3P	1					38
3.7 3P	1					39
83.3 3P	2		Regulators	1-3P	500	40

SUBSTATIONS(Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	St Cloud #1-St Cloud, MN	Trans A	33.00	2.42	
2		Trans A	33.00	19.03	
3		Trans A			
4		Trans A			
5	Red Rock-Newport, MN	Trans U	110.00	13.80	
6		Trans U	345.00	118.00	13.80
7		Trans U	345.00	230.00	13.80
8	Adams (Interstate Power), MN	Trans U	345.00	165.00	13.80
9	Lake Yankton-Lyon County, SD	Trans U	115.00	72.00	2.30
10		Trans U	115.00	72.00	13.80
11		Trans U	69.00	24.90	2.45
12	Crow River-Wright County, MN	Trans U	110.00	70.60	13.80
13	Scott County-Jackson Twsp, MN	Trans U	110.00	70.60	13.80
14	Carver County-Benton Twsp, MN	Trans U	110.00	70.60	2.50
15	Inver Grove, Inver Grove Twsp, MN	Trans U	110.00	70.60	13.80
16	Wakefield-Wakefield Twsp, MN	Trans U	118.00	65.50	
17		Trans U	69.00	23.90	
18		Trans U	110.00	69.00	
19		Trans U	63.00	13.20	
20	Chisago Co-Lent Twsp, MN	Trans U	500.00	345.00	
21		Trans U	500.00	345.00	
22		Trans U	500.00	345.00	
23		Trans U			
24	Riverside-Mpls, MN	Trans A	118.00	14.40	
25		Trans A	118.00	14.40	
26		Trans A	115.00	22.00	
27		Trans A	115.00	66.57	
28	High Bridge-St Paul, MN	Trans A	118.80	15.40	
29		Trans A	118.00	14.40	
30		Trans A	115.00	13.80	
31		Trans A	115.00	18.00	
32		Trans A	13.70	4.24	
33	Black Dog - Bloomington, MN	Trans A	115.00	13.80	
34		Trans A	115.00	13.80	
35		Trans A	115.00	13.80	
36		Trans A	230.00	118.00	13.80
37	Wilmarth-Mankato, MN	Trans A	69.00	13.80	
38		Trans A	161.00	118.00	13.80
39		Trans A	68.80	13.80	
40		Trans A	110.00	70.60	13.80
41		Trans A	110.00	70.60	13.80
42		Trans A	345.00	188.00	13.80
43	Minn Valley-Granite Falls, MN	Trans A	69.00	13.80	
44		Trans A	115.00	13.80	
45		Trans A	230.00	115.00	
46		Trans A	23.90	13.80	
47		Trans A	110.00	70.60	13.80
48		Trans A	115.00	72.00	
49		Trans A	230.00	115.00	
50	Lawrence-Mapleton Twsp, SD	Trans A	110.00	70.60	13.80

SUBSTATIONS(Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)	Line No.
4.7 1P	3		Regulators	1-3P	500	1
3.0 1P	3		Regulators	1-3P	500	2
P			Grounding Bank	1-3P	10,000	3
P			Grounding Bank	1-3P	7,500	4
40.0 3P	2		Regulators	1-3P	937	5
896.0 3P	2					6
336.0 3P	1		Capacitor Bank	3-3P	248,400	7
300.0 3P	1		Grounding Bank	3-1P	30	8
15.0 3P	1					9
15.0 3P	1					10
2.5 1P	3	1	Grounding Bank	1-3P	40,000	11
112.0 3P	1					12
132.5 3P	2					13
41.7 3P	1					14
125.0 3P	2					15
18.8 1P	3		Grounding Bank	1-3P	6,250	16
0.7 1P	1		Regulators	1-3P	18,750	17
10.0 3P	1					18
1.8 1P	3					19
401.0 1P	1	1	Capacitor Bank	4-3P	96,000	20
401.0 1P	1		Grounding Bank	3-1P	300	21
401.0 1P	1		Grounding Bank	3-1P	30	22
P			Capacitor Bank	1-3P	164,680	23
47.0 3P	1					24
47.0 3P	1					25
275.0 3P	1					26
185.0 3P	1					27
100.0 3P	2					28
140.0 3P	2		Regulators	8-1P	3,981	29
133.0 3P	1		Grounding Bank	2-3P	95,600	30
192.0 3P	1					31
15.0 1P	6					32
100.0 3P	2					33
266.0 3P	2					34
192.0 3P	1					35
187.0 3P	1					36
37.5 3P	4		Grounding Bank	2-3P	159,400	37
112.0 3P	1		Regulators	6-3P	5,435	38
93.3 3P	2					39
140.0 3P	2					40
70.0 3P	1					41
448.0 3P	1					42
25.0 1P	6	1				43
50.0 3P	1					44
100.0 3P	2					45
7.5 1P	6		Regulators	2-3P	750	46
46.7 3P	1					47
41.7 3P	1					48
112.0 3P	1					49
93.3 3P	2					50

SUBSTATIONS(Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Lawrence-Mapleton Twsp, SD	Trans A	68.80	13.80	
2		Trans A	110.00	70.60	13.80
3	Benton County-St Cloud, MN	Trans U	230.00	118.00	13.80
4		Trans U	230.00	118.00	13.80
5	Pathfinder-Brandon Twsp, SD	Trans A	115.00	66.40	13.80
6	Red Wing-Red Wing, MN	Trans A	69.00	13.80	
7	Granite City-St Cloud, MN	Trans U	118.00	14.40	
8		Trans U	118.00	36.20	
9	Lake Pulaski-Buffalo, MN	Trans U	116.00	70.60	
10		Trans U	118.00	36.20	
11	Prairie Island-Red Wing, MN	Trans A	345.00	20.00	
12		Trans A	345.00	20.00	
13		Trans A	345.00	161.00	13.80
14	Coon Creek-Coon Rapids, MN	Trans U	345.00	118.00	13.80
15		Trans U	345.00	118.00	13.80
16	Inver Hills-Inver Grove Heights, MN	Trans A	124.00	14.40	
17		Trans A	124.00	14.40	
18		Trans A	345.00	118.00	13.80
19		Trans A	124.00	14.40	
20	Blue Lake-Shakopee, MN	Trans U	345.00	118.00	13.80
21		Trans U	110.00	13.80	
22		Trans U	127.00	14.40	
23	Kohlman Lake-Maplewood, MN	Trans U	345.00	118.00	13.80
24		Trans U	345.00	115.00	
25		Trans U	118.00	14.40	
26	Sherburne County-Becker, MN	Trans U	345.00	24.00	
27		Trans U	345.00	24.00	
28	Fort Ridgley-New Ulm, MN	Trans U	116.00	92.95	
29	Split Rock-Brandon Twsp, SD	Trans U	345.00	118.00	13.80
30		Trans U	161.00	118.00	13.80
31	Eden Prairie-Eden Prairie, MN	Trans U	345.00	118.00	13.80
32		Trans U	118.00	14.40	8.31
33	Sheyenne Sub-Fargo, ND	Trans U	230.00	115.00	13.80
34	Roseau County-MN	Trans U			
35	Buffalo Ridge-Benton Lk, SD	Trans U	118.00	36.20	
36	Gopher-Mpls, MN	Distr U	118.00	14.40	
37		Distr U	118.00	14.40	
38	Garfield-Mpls, MN	Distr U	13.70	4.24	
39	Elm Creek, MN	Distr U	110.00	13.80	
40	Main Street-Mpls, MN	Distr A	118.00	14.40	
41	Nicollet-Mpls, MN	Distr U	13.80	4.24	
42	Oakland-Mpls, MN	Distr U	13.70	4.24	
43	Osseo-Maple Grove, MN	Distr U	118.00	14.40	
44	Quincy-Mpls, MN	Distr U	13.70	4.24	
45	St Louis Park-St Louis Park, MN	Distr U	110.00	13.80	
46		Distr U	110.00	13.80	
47		Distr U	110.00	13.80	
48		Distr U	118.00	14.40	
49		Distr U	15.00	13.80	
50	Elliot Park-Mpls, MN	Distr U	118.00	14.40	

SUBSTATIONS(Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)	Line No.
10.5 3P	1					1
112.0 3P	1					2
186.7 3P	1					3
186.0 3P	1					4
85.0 3P	1					5
40.0 3P	4		Regulators	5-3P	4,124	6
93.3 3P	2		Regulators	3-3P	2,811	7
70.0 3P	1					8
70.0 3P	1					9
28.0 3P	1					10
672.0 3P	1					11
672.0 3P	1					12
224.0 3P	1					13
448.0 3P	1					14
448.0 3P	1					15
140.0 3P	1					16
140.0 3P	1					17
550.0 3P	1					18
140.0 3P	1					19
336.0 3P	1					20
50.0 3P	2					21
246.0 3P	2		Regulators	2-3P	7,900	22
448.0 3P	1					23
450.0 3P	1		Capacitor Bank	3-3P	248,400	24
46.7 3P	1		Grounding Bank	1-3P	40,000	25
800.0 3P	1					26
800.0 3P	1					27
70.0 3P	1					28
896.0 3P	2					29
93.3 3P	2		Capacitor Bank	1-3P	40,500	30
448.0 3P	1					31
93.3 3P	2					32
187.0 3P	1					33
P			Capacitor Bank	2-3P	329,360	34
28.0 3P	1					35
46.7 3P	1					36
46.7 3P	1					37
15.0 1P	6		Regulators	30-1P	2,106	38
25.0 3P	1					39
140.0 3P	2					40
15.0 3P	3					41
15.0 1P	6		Regulators	21-1P	1,329	42
140.0 3P	1					43
15.0 1P	6		Regulators	13-1P	957	44
16.7 3P		1				45
25.0 3P	2		Grounding Bank	1-3P	2,000	46
20.0 3P	1					47
140.0 3P	2					48
8.3 3P	3					49
46.7 3P	1					50

SUBSTATIONS(Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Elliot Park-Mpls, MN	Distr U	115.00	13.80	
2	Wold-Chamberlain-Mpls, MN	Distr U	13.20	4.36	
3	Twin Lakes-Brooklyn Ctr, MN	Distr U	118.00	14.40	
4	Aldrich-Mpls, MN	Distr U	121.00	14.40	
5		Distr U	118.00	14.40	
6		Distr U	110.00	4.38	
7		Distr U	118.00	14.40	
8	Southtown-Mpls, MN	Distr U	110.00	14.00	
9	Wilson-Bloomington, MN	Distr U	112.00	13.80	
10		Distr U	118.00	14.40	
11	Terminal-Lauderdale	Distr U	345.00	118.00	
12		Distr U	345.00	118.00	
13		Distr U	115.00	13.80	
14		Distr U	13.20	4.36	
15	Nine Mile Creek, MN	Distr U	115.00	13.80	
16	Edina-Edina, MN	Distr U	118.00	14.40	
17	Medicine Lake-Golden Valley, MN	Distr U	118.00	14.40	
18	Savage-Dakota County, MN	Distr U	110.00	13.80	
19	Moore Lake-Fridley, MN	Distr U	118.00	14.40	
20		Distr U	108.00	13.69	
21	Airport-Mpls, MN	Distr U	118.00	14.40	
22	Bloomington-Bloomington, MN	Distr U	115.00	13.80	
23	Riverwood-Burnsville, MN	Distr U	110.00	63.50	13.80
24	Brooklyn Park-Brooklyn Park, MN	Distr U	110.00	13.80	
25	Apache-St Anthony, MN	Distr U	118.00	14.40	
26	Indiana-Robbinsdale, MN	Distr U	110.00	13.80	
27		Distr U	118.00	14.40	
28	Fifth Street-Mpls, MN	Distr U	110.00	13.80	
29	Crooked Lake-Coon Rapids, MN	Distr U	119.00	13.80	
30		Distr U	13.80	12.47	
31	Hyland Lake-Edina, MN	Distr U	118.00	14.40	
32		Distr U	118.00	14.40	
33	Dodge Center-Dodge Center, MN	Distr U	69.00	13.80	
34	Faribault-Faribault, MN	Distr U	69.00	39.83	2.30
35		Distr U	69.00	13.09	
36	Farmington-Farmington, MN	Distr U	68.80	13.80	
37		Distr U	68.80	13.80	
38	Hastings-Hastings, MN	Distr U	68.80	13.80	
39	Waseca-Waseca, MN	Distr U	69.00	4.33	
40		Distr U	68.00	26.18	
41		Distr U			
42		Distr U	68.80	13.80	
43	Zumbrota-Zumbrota, MN	Distr U	68.80	13.09	
44		Distr U			
45		Distr U	70.70	25.00	2.40
46	Pine Island-Pine Island, MN	Distr U	68.80	13.09	
47		Distr U			
48	Airlake-Lakeville, MN	Distr U	68.80	13.80	
49	Northfield-Northfield, MN	Distr U	68.80	13.80	
50		Distr U	68.80	13.80	

SUBSTATIONS(Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)	Line No.
46.7 3P	1					1
10.0 3P	2					2
210.0 3P	3					3
46.7 3P	1		Grounding Bank	1-3P	79,600	4
140.0 3P	2					5
50.0 3P	2					6
46.7 3P	1					7
195.0 3P	3					8
70.0 1P	6		Grounding Bank	2-3P	10,333	9
140.0 3P	2					10
448.0 3P	1					11
448.0 3P	1					12
100.0 3P	4					13
15.0 3P	2		Regulators	18-1P	1,251	14
28.0 3P	1					15
210.0 3P	3					16
210.0 3P	3					17
53.0 3P	2		Regulators	6-3P	3,882	18
140.0 3P	2					19
50.0 3P	1					20
93.3 3P	2					21
93.3 3P	2					22
25.0 3P	1					23
50.0 3P	2					24
140.0 3P	2					25
39.2 3P	1					26
28.0 3P	1					27
336.0 3P	4					28
93.3 3P	2					29
10.0 3P	3					30
46.7 3P	1					31
46.7 3P	1					32
10.5 3P	1		Capacitor Bank	1-3P	5,400	33
7.9 1P	3		Regulators	12-1P	876	34
14.0 3P	1		Capacitor Bank	1-3P	7,200	35
14.0 3P	1					36
10.5 3P	1					37
56.0 3P	2					38
7.8 3P	2		Regulators	3-1P	864	39
14.0 3P	1					40
P	3	1	Regulators	2-3P	1,300	41
12.5 3P	1		Regulators	3-1P	864	42
7.0 3P	1		Regulators	3-1P	216	43
P			Capacitor Bank	1-3P	7,200	44
1.5 1P	3		Regulators	2-3P	1,125	45
5.6 3P	1		Regulators	2-3P	1,000	46
P			Capacitor Bank	1-3P	5,400	47
28.0 3P	2					48
28.0 3P	1		Grounding Bank	3-1P	750	49
28.0 3P	1					50

SUBSTATIONS(Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Waterville-Waterville, MN	Distr U	68.80	26.18	
2		Distr U	68.80	4.36	
3		Distr U	65.43	14.70	
4	Fair Park-Faribault, MN	Distr U	68.80	13.80	
5	Kasson-Kasson, MN	Distr U	68.80	13.80	
6	Becker, MN	Distr U	67.00	35.30	
7		Distr U	118.00	36.20	
8	Cold Spring, MN	Distr U	68.80	13.09	
9		Distr U	34.73	2.42	
10	Glenwood, MN	Distr U	69.00	4.16	
11		Distr U	68.80	13.09	
12	Industrial-St Cloud, MN	Distr U	34.50	12.52	
13		Distr U	34.50	4.33	
14	Linn Street, MN	Distr U	68.80	13.09	
15		Distr U	68.80	13.09	
16	St Joseph, MN	Distr U	68.80	13.09	
17		Distr U			
18	Albany Substation-Albany, MN	Distr U	68.80	12.47	
19		Distr U	13.20	4.36	
20	New Avon, MN	Distr U	68.80	13.09	
21		Distr U			
22	Empire Park, MN	Distr U	34.40	4.36	
23	Southside, MN	Distr U	68.80	13.09	
24	Mei, MN	Distr U	100.00	13.80	
25		Distr U	15.00	8.66	
26	Crossroads, MN	Distr U	110.00	13.80	
27		Distr U	115.00	13.80	
28	Pipestone-Pipestone, MN	Distr U	69.00	4.33	
29		Distr U	69.00	24.25	
30		Distr U	115.00	72.00	13.80
31	Cherry Creek, SD	Distr U	118.00	14.40	
32		Distr U	69.00	7.50	
33	Cliff Avenue-Sioux Falls, SD	Distr U	69.00	4.16	
34		Distr U	68.80	13.09	
35	Dell Rapids-Dell Rapids, SD	Distr U	68.80	13.80	
36		Distr U			
37	Silver Creek-Sioux Falls, SD	Distr U	68.80	13.80	
38		Distr U	68.80	13.80	
39	Sioux Falls, Sioux Falls, SD	Distr U	68.80	13.80	
40	So Sioux Falls-Sioux Falls, SD	Distr U	68.80	13.80	
41		Distr U	69.00	4.33	
42		Distr U			
43	Tracy SW Station-Tracy, MN	Distr U	69.00	13.80	
44		Distr U			
45	West Sioux Falls-Sioux Falls, SD	Distr U	67.00	4.36	
46		Distr U	110.00	70.60	13.80
47		Distr U	118.00	14.40	
48	Minnehaha, SD	Distr U	118.00	14.40	8.31
49	Canistota Jnct-Grand Twsp, SD	Distr U	68.80	24.10	
50		Distr U			

SUBSTATIONS(Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)	Line No.
5.6 3P	1		Regulators	6-1P	660	1
1.5 3P	1		Capacitor Bank	1-3P	7,200	2
1.9 1P	3		Regulators	1-3P	225	3
21.0 3P	2		Capacitor Bank	1-3P	7,200	4
9.4 3P	1		Regulators	6-1P	1,002	5
4.7 3P	1		Regulators	1-3P	750	6
7.0 3P	1					7
7.0 3P	1		Regulators	2-3P	1,000	8
3.8 1P	3		Regulators	3-1P	216	9
7.5 1P	3	1	Regulators	9-1P	933	10
5.3 3P	1					11
12.5 3P	2					12
1.5 1P	3		Regulators	3-1P	225	13
10.5 3P	1		Regulators	6-1P	1,002	14
10.5 3P	1		Regulators	6-1P	1,002	15
4.2 3P	1		Regulators	6-1P	432	16
P			Capacitor Bank	1-3P	10,800	17
10.5 3P	1		Regulators	6-1P	1,002	18
6.3 3P	1					19
3.5 3P	1		Regulators	3-1P	501	20
P			Capacitor Bank	1-3P	10,800	21
14.0 3P	2					22
10.5 3P	1		Regulators	1-3P	937	23
16.7 3P	1					24
2.8 3P	1					25
50.0 3P	2					26
22.4 3P	1					27
18.8 3P	2		Regulators	15-1P	1,380	28
3.0 3P	2					29
25.0 3P	1					30
37.3 3P	1		Regulators	3-1P	999	31
0.2 1P	1		Regulators	3-1P	1,998	32
6.7 3P	1		Regulators	6-1P	432	33
10.5 3P	1		Regulators	2-3P	450	34
9.4 3P	1		Regulators	3-1P	501	35
P			Regulators	3-1P	501	36
10.5 3P	1					37
10.5 3P	1					38
56.0 3P	2					39
56.0 3P	2					40
12.9 3P	2		Regulators	3-3P	725	41
P			Regulators	6-1P	438	42
5.3 3P	1		Regulators	3-1P	501	43
P			Capacitor Bank	1-3P	5,400	44
6.3 3P	1		Regulators	3-1P	216	45
70.0 3P	1		Regulators	1-3P	225	46
140.0 3P	2					47
28.0 3P	1					48
6.2 3P	1		Regulators	1-3P	500	49
P			Capacitor Bank	1-3P	5,400	50

SUBSTATIONS(Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Lester Prairie, MN	Distr U	68.80	13.09	
2		Distr U			
3	Montevideo, MN	Distr U	69.00	4.33	
4		Distr U	68.80	13.09	
5		Distr U	13.20	4.36	
6	Winsted, MN	Distr U	68.80	4.36	
7	Young America, MN	Distr U	69.00	12.50	
8		Distr U			
9	Credit River-Prior Lake, MN	Distr U	68.80	13.09	
10	Wyoming-Wyoming Twsp, MN	Distr U	68.80	13.09	
11		Distr U	68.80	13.09	
12		Distr U			
13	Cleveland-St Paul, MN	Distr U	13.20	4.36	
14	Forest Sub-St Paul, MN	Distr U	14.00	4.33	
15		Distr U			
16		Distr U			
17	Prior - St Paul, MN	Distr U	118.00	14.40	
18	Afton Sub-Afton, MN	Distr U	118.00	36.20	
19	Roseplace-Roseville, MN	Distr U	118.00	14.40	
20	Battle Creek, MN	Distr U	118.00	14.40	
21	St Clair-St Paul, MN	Distr U	13.80	4.24	
22	Oakdale-Oakdale, MN	Distr U	118.00	14.40	
23	Baytown-Baytown, MN	Distr U	118.00	14.40	
24	Birch-Birch, MN	Distr U	68.80	36.20	
25	Ramsey-Little Canada, MN	Distr U	108.90	13.69	
26		Distr U			
27		Distr U			
28	Merriam Park-St Paul, MN	Distr U	110.00	14.00	
29	Western-St Paul, MN	Distr U	118.00	14.40	
30	Koch Refinery-Rosemount, MN	Distr U	68.80	4.36	
31		Distr U	68.80	4.36	
32		Distr U	68.80	13.80	
33		Distr U	118.00	14.40	
34		Distr U	13.80	4.16	
35	Williams Bros-Apple Valley, MN	Distr U	110.00	14.00	
36		Distr U	15.00	13.80	
37		Distr U	14.00	4.33	
38	Stockyards-So St Paul, MN	Distr U	110.00	13.80	
39	Daytons Bluff-St Paul, MN	Distr U	110.00	14.00	
40	Pine Bend-Rosemount, MN	Distr U	68.80	4.36	
41		Distr U	67.00	13.50	
42	Tanners Lake-Maplewood, MN	Distr U	118.00	14.40	
43		Distr U	14.40	12.47	
44	Upper Levee-St Paul, MN	Distr U	115.00	13.80	
45	Chemolite-Cottage Grove, MN	Distr U	110.00	13.09	
46		Distr U	110.00	70.60	13.80
47	Rondo-St Paul, MN	Distr U	13.20	4.36	
48	Linde-Inver Grove Heights, MN	Distr U	115.00	13.20	
49		Distr U	14.00	12.99	
50	Arden Hills-Arden Hills, MN	Distr U	110.00	70.60	13.80

SUBSTATIONS(Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)	Line No.
7.5 3P	1		Regulators	2-3P	1,125	1
P			Grounding Bank	1-3P	10,000	2
6.0 3P	1		Grounding Bank	1-3P	5,000	3
5.2 3P	1		Regulators	1-3P	625	4
P			Regulators	9-1P	657	5
10.7 3P	1		Regulators	3-1P	501	6
9.4 3P	1		Regulators	3-1P	750	7
P			Regulators	3-1P	1,248	8
14.0 3P	1					9
17.6 3P	1		Regulators	2-3P	1,687	10
30.1 3P	1		Capacitor Bank	3-3P	16,200	11
P			Regulators	6-1P	2,496	12
10.0 3P	2		Regulators	2-3P	1,000	13
20.0 3P	2		Grounding Bank	3-1P	1,875	14
P			Regulators	1-3P	225	15
P			Regulators	18-1P	1,305	16
28.0 3P	1					17
93.3 3P	2					18
93.3 3P	2					19
93.3 3P	2					20
10.0 3P	2		Regulators	18-1P	1,296	21
93.3 3P	2					22
28.0 3P	1					23
16.8 3P	1		Regulators	3-1P	1,200	24
100.0 3P	2		Regulators	5-3P	4,498	25
P			Regulators	6-3P	1,998	26
P			Grounding Bank	2-3P	6,772	27
187.5 3P	3					28
140.0 3P	2					29
25.0 3P	4					30
18.7 3P	2					31
56.0 3P	2					32
140.1 3P	3		Capacitor Bank	2-3P	28,800	33
28.0 3P	1					34
9.4 3P	1		Regulators	1-3P	937	35
2.8 3P	1					36
7.5 3P	1					37
93.3 3P	2					38
187.5 3P	3					39
10.0 3P	2		Regulators	1-3P	937	40
9.4 3P	1					41
140.0 3P	2					42
70.0 1P	21	1				43
210.0 3P	3					44
50.0 3P	2					45
46.7 3P	1					46
10.0 3P	2		Regulators	2-3P	1,000	47
50.0 3P	1					48
2.0 3P	1					49
140.0 3P	2		Regulators	4-3P	3,748	50

SUBSTATIONS(Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Arden Hills–Arden Hills, MN	Distr U			
2	Shepard–St Paul, MN	Distr U	110.00	13.80	
3	North Star Steel–St Paul, MN	Distr U	110.00	13.80	
4	Cottage Grove–Cottage Grove, MN	Distr U	118.00	14.40	
5	Lexington–Arden Hills, MN	Distr U	110.00	13.80	
6		Distr U	118.00	36.20	
7		Distr U	36.20	14.40	
8	Cedarvale–St Paul, MN	Distr U	110.00	13.80	
9		Distr U			
10	Rich Valley–Inver Grove Heights, MN	Distr U	118.00	14.40	
11	Maxwell–St Paul, MN	Distr U	118.00	4.16	
12	Lone Oak, MN	Distr U	68.80	13.80	
13	Eastwood–Mankato, MN	Distr U	68.80	13.80	
14	Sibley Park–Mankato, MN	Distr U	68.80	13.80	
15		Distr U	68.80	13.80	
16	St James Municipal–St James, MN	Distr U	68.80	13.09	
17	Hugo–Hugo, MN	Distr U	68.80	13.09	
18	Oak Park–Oak Park Heights, MN	Distr U	118.00	68.60	
19		Distr U	118.00	68.60	
20		Distr U	118.00	14.40	64.70
21	Goose Lake–Ramsey County, MN	Distr U	118.00	14.40	
22		Distr U	110.00	70.60	13.80
23	Minnesota Pipeline–Ramsey County, MN	Distr U	68.80	13.09	
24	Lindstrom–Lindstrom, MN	Distr U	68.80	13.80	
25	Long Lake–Northdale Twsp, MN	Distr U	115.00	13.80	
26		Distr U			
27	North Broadway–Fargo Twsp, ND	Distr U	22.90	4.36	
28	Barnes–Barnes Twsp, ND	Distr U	22.90	4.36	
29	Woodrow–Fargo, ND	Distr U	22.90	4.36	
30	Red River–Fargo, ND	Distr U	110.00	63.50	13.80
31		Distr U	118.00	68.13	13.80
32		Distr U	118.00	68.10	13.80
33	Cass County–Barnes Twsp, ND	Distr U	110.00	24.10	2.40
34		Distr U	118.00	68.12	13.80
35	Nordic Sub–Grand Forks, ND	Distr U	119.00	13.80	
36	Park Substation, MN	Distr U	68.80	4.36	
37	Water Plant–Grand Forks, ND	Distr U	68.80	4.36	
38	Mayville–Mayville, ND	Distr U	68.80	4.36	
39		Distr U	68.80	13.09	
40		Distr U			
41	Gateway–Grand Forks, ND	Distr U	68.80	13.80	
42		Distr U	68.80	13.80	
43	Portal Pipeline–Minot, ND	Distr U	14.00	4.30	
44	Souris–Minot, ND	Distr U	110.00	13.80	
45		Distr U	110.00	13.80	
46	Hollydale, MN	Distr U	68.80	14.40	
47	Waconia Switching–Waconia, MN	Distr U	68.80	13.80	
48	Bluff Creek, MN	Distr U	118.00	14.40	
49	Chaska, MN	Distr U	68.80	13.80	
50		Distr U	67.00	13.80	

SUBSTATIONS(Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)	Line No.
P			Grounding Bank	2-3P	4,800	1
50.0 3P	2					2
93.3 3P	2					3
93.3 3P	2					4
93.3 3P	2					5
46.7 3P	1					6
46.7 3P	1					7
42.5 3P	2		Regulators	5-3P	4,685	8
P			Regulators	1-3P	750	9
28.0 3P	1					10
28.0 3P	1					11
56.0 3P	2					12
56.0 3P	2					13
26.2 3P	1					14
26.8 3P	1					15
14.0 3P	1					16
14.0 3P	1		Regulators	2-3P	1,422	17
28.0 3P	1					18
7.2 1P	3	1				19
93.3 3P	2					20
93.3 3P	2					21
41.7 3P	1					22
10.5 3P	1					23
21.0 3P	2					24
22.4 3P	1		Regulators	2-3P	2,187	25
P			Regulators	3-1P	999	26
10.5 3P	2		Regulators	2-3P	1,000	27
10.3 3P	2		Regulators	15-1P	1,098	28
12.5 3P	2		Regulators	15-1P	1,062	29
46.7 3P	1					30
90.5 3P	1					31
90.5 3P	1					32
50.0 3P	2					33
46.7 3P	1					34
93.3 3P	2					35
10.5 3P	1					36
10.5 3P	1					37
6.2 3P	1		Regulators	12-1P	1,578	38
6.2 3P	1					39
P			Capacitor Bank	1-3P	5,400	40
25.0 3P	1					41
28.0 3P	1					42
10.0 3P	2					43
50.0 3P	2					44
25.0 3P	1					45
28.0 3P	1					46
22.4 3P	1					47
46.7 3P	1					48
10.5 3P	1		Regulators	3-1P	501	49
12.5 3P	1					50

SUBSTATIONS(Continued)

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Excelsior, MN	Distr U	68.80	13.80	
2		Distr U			
3	Deephaven, MN	Distr U	68.80	13.80	
4	Gleason Lake, MN	Distr U	118.00	14.40	
5		Distr U	110.00	13.80	
6		Distr U	110.00	70.60	13.80
7	Glen Lake, MN	Distr U	68.80	13.80	
8	Shakopee, MN	Distr U	68.80	13.80	
9		Distr U	13.70	4.24	
10	Orono, MN	Distr U	68.80	13.80	
11	Mound, MN	Distr U	68.80	13.80	
12	Watertown, MN	Distr U	72.40	13.80	
13	Winona-Winona, MN	Distr U	68.80	13.80	
14	Goodview-Goodview, MN	Distr U	68.80	13.09	
15	LaCrescent-LaCrescent, MN	Distr U	68.80	13.80	
16	Wabasha-Wabasha, MN	Distr U	69.00	13.09	
17		Distr U	69.00	12.99	
18		Distr U			
19	Burnside-Red Wing, MN	Distr U	68.80	13.09	
20		Distr U	68.80	13.80	
21					
22					
23	188 Substations with capacities over 10,000 KVA				
24	147 Substations with capacities under 10,000 KVA				
25	aggregated capacity 465,183 KVA				
26	2 transmission sub				
27	145 distribution subs				
28					
29	Total 147				
30					
31	p = Phase				
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SUBSTATIONS(Continued)

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (k)	
19.0 3P	1		Capacitor Bank	1–3P	14,400	1
P			Regulators	6–1P	1,998	2
56.0 3P	2					3
47.0 3P	1					4
46.6 3P	1					5
112.0 3P	1					6
56.0 3P	2		Regulators	6–3P	4,937	7
56.0 3P	2					8
6.0 1P	3					9
22.4 3P	1					10
56.0 3P	2					11
10.5 3P	1		Regulators	6–1P	1,002	12
56.0 3P	2		Capacitor Bank	1–3P	7,200	13
56.0 3P	2		Capacitor Bank	1–3P	7,200	14
10.5 3P	1					15
10.5 3P	1		Capacitor Bank	1–3P	7,200	16
2.0 3P	1		Regulators	2–1P	144	17
P			Regulators	1–3P		18
7.0 3P	1		Regulators	1–3P	750	19
10.5 3P	1					20
						21
						22
31,378.8						23
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ELECTRIC DISTRIBUTION METERS AND LINE TRANSFORMERS

1. Report below the information called for concerning distribution watt-hour meters and line transformers.
2. Include watt-hour demand distribution meters, but not external demand meters.
3. Show in a footnote the number of distribution watt-hour meters or line transformers held by the respondent under lease from others, jointly owned with others, or held otherwise than by reason of sole ownership by the respondent. If 500 or more meters or line transformers are held under a lease, give name of lessor, date and period of lease, and annual rent. If 500 or more meters or line transformers are held other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of accounting for expenses between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Item (a)	Number of Watt-Hour Meters (b)	LINE TRANSFORMERS Number (c)	LINE TRANSFORMERS Total Capacity (In MVa) (d)
1	Number at Beginning of Year	1,382,272	206,019	11,975
2	Additions During Year			
3	Purchases	65,948	3,317	203
4	Associated with Utility Plant Acquired			
5	Total Additions (Enter total as of lines 3 and 4)	65,948	3,317	203
6	Reductions During Year			
7	Retirements	34,498	2,263	107
8	Associated with Utiltiy Plant Sold			
9	Total Reductions (Enter total of lines 7 and 8)	34,498	2,263	107
10	Number at End of Year (Lines 1+5-9)	1,413,722	207,073	12,071
11	In Stock	9,354	7,460	777
12	Locked Meters on Customers' Premises	36,198		
13	Inactive Transformers on System			
14	In Customers' Use	1,367,786	199,613	11,294
15	In Company's Use	384		
16	Total End of Year (Enter Total of Lines 11 to 15. This line should equal line 10.)	1,413,722	207,073	12,071

ENVIRONMENTAL PROTECTION FACILITIES

1. For purposes of this response, environmental protection facilities shall be defined as any building, structure, equipment, facility or improvement designed and constructed solely for control, reduction, prevention or abatement of discharges or releases into the environment of gaseous, liquid, or solid substances, heat, noise or for the control, reduction, prevention, or abatement of any other adverse impact of an activity on the environment.

2. Report the differences in cost of facilities installed for environmental considerations over the cost of alternative facilities which would otherwise be used without environmental considerations. Use the best engineering design achievable without environmental restrictions as the basis for determining costs without environmental considerations. It is not intended that special design studies be made for purposes of this response. Base the response on the best engineering judgement where direct comparisons are not available.

Include in these differences in costs the cost or estimated cost of environmental protection facilities in service, constructed or modified in connection with the production, transmission, and distribution of electrical energy and shall be reported herein for all such environmental facilities placed in service on or after January 1, 1969, so long as it is readily determinable that such facilities were constructed or modified for environmental rather than operational purposes. Report similar expenditures for environmental plant included in construction work in progress. Estimate the cost of facilities when the original cost is not available or facilities are jointly owned with another utility, provided the respondent explains the basis of such estimations. Examples of these costs would include a portion of the costs of tall smokestacks, underground lines, and landscaped substations. Explain such costs in a footnote.

3. In the cost of facilities reported in this page, include as estimated portion of the cost of plant that is or will be used to provide power to operate associated environmental protection facilities. These costs may be estimated on a percentage of plant basis. Explain such estimations in a footnote.

4. Report all costs under the major classifications provided below and include, as a minimum, the items listed hereunder:

A. Air pollution control facilities
(1) Scrubbers, precipitators, tall smokestacks etc.
(2) Changes necessary to accomodate use of environmentally clean fuels such as low ash or low sulfur fuels including storage and handling equipment

B. Water pollution control facilities:
(1) Cooling towers, ponds, piping, pumps, etc.
(2) Waste water treatment equipment
(3) Sanitary waste disposal equipment
(4) oil interceptors
(5) Sediment control facilities
(6) Monitoring equipment
(7) Other

C. Solid waste disposal costs:
(1) Ash handling and disposal equipment
(2) Land
(3) Settling ponds
(4) Other

D. Noise abatement equipment
(1) Structures
(2) Mufflers
(3) Sound proofing equipment
(4) Monitoring equipment
(5) Other

5. In those instances when costs are composites of both actual supportable costs and estimates of costs, specify in column (g) the actual costs that are included in column (f).

6. Report construction work in progress relating to environmental facilities at line 9.

Line No.	Classification of Cost (a)	CHANGES DURING YEAR Additions (c)	Retirements (d)	Adjustments (e)	Balance at End of Year (f)	Actual Cost (g)
1	Air Pollution Control Facilities	$772,939	$0	$0	$449,419,520	$449,419,520
2	Water Pollution Control Facilities	128,861			126,203,443	126,203,443
3	Solid Waste Disposal Costs	3,544			52,219,485	52,219,485
4	Noise Abatement Equipment				7,095,661	7,095,661
5	Aesthetic Costs	0			22,255,402	22,255,402
6	Additional Plant Capacity				84,600,000	84,600,000
7	Misc. (Identify significant)				0	0
8	TOTAL (Total of lines 1 thru 7)	$905,344	0	0	$741,793,511	$741,793,511
9	Construction Work in Progress				24,006,518	24,006,518

ENVIRONMENTAL PROTECTION EXPENSES

1. Show below expenses incurred in connection with the use of environmental protection facilities the cost of which are reported on page 430. Where it is necessary that allocations and/or estimates of costs be made, state the basis of method used.

2. Include below the costs incurred due to the operation of environmental protection equipment, facilities, and programs.

3. Report expenses under subheadings listed below.

4. Under item 6 report the difference in cost between environmentally clean fuels and the alternative fuels that would otherwise be used and are available for use.

5. Under item 7 include the cost of replacement power purchased or generated to componsate for the deficiency in output from existing plants due to the addition of pollution control equipment,use of alternative environmentally preferable fuels or environmental regulations of governmental bodies. Base the price of replacement power purchased on the average system price of purchsed power if the actual cost of such replacement power is not known. Price internally generated replacement power at the system average cost of pewer generated if the actual cost of replacement generation is not known.

6. Under item 8 include ad valorem and other taxes assessed directly on or directly relatable to environmental facilities. Also include under item 8 licensing and similar fees on such facilities.

7. In those instances where expenses are composed of both actual supportable data and estimates of costs, specify in column (c) the actual expenses that are ineluded in column (b).

Line No.	Classification of Expense (a)	Amount (b)	Actual Expenses (c)
1	Depreciation	$22,383,961	$22,383,961
2	Labor, Maintenance, Materials and Supplies at		
	Cost, Related to Env. Facilities and Programs	9,623,474	9,623,474
3	Fuel Related Costs		
4	Operation of Facilities	626,069	626,069
5	Fly Ash and Sulfur Sludge Removal	10,589,839	10,589,839
6	Difference in Cost of Environmentally Clean Fuels	0	0
7	Replacement Power Costs	12,500,224	12,500,224
8	Taxes and Fees	5,804,480	5,804,480
9	Administrative and General	1,058,526	1,058,526
10	Other (Identify significant)	12,750,602	12,750,602
11	TOTAL	$75,337,175	$75,337,175
	Footnote:		
	Line #10 Includes the following:		
	Reclamation Costs	10,688,615	
	Rescarch & Development	2,061,987	
	Total	12,750,602	

FOOTNOTE DATA

Page Number (a)	Item Number (b)	Column Number (c)	Comments (d)
300	21	b	Includes reimbursement from Northern States Power Co. (Wi) for production and transmission costs shared under an interchange agreement between the companies dated Sept. 17, 1984. Fixed Production Expense $100,260,598 Variable Production Expense $62,465,340 Transmission Expense $12,514,239
321	78	b	Include $39,630,323 of Fixed Costs and $7,001,251 of Variable Costs reimbursed to Northern States Power Company (Wisconsin), a subsidiary company, for production costs shared through an Interchange Agreement.
321	89	b	Include $25,530,913 of fixed costs reimbursed to Northern States Power Company (Wisconsin), a subsidiary company, for transmission costs shared through an Interchange Agreement.

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