This annual report contains amendments. Amendments and their corresponding letters are appended to the end of the report.

4220

Classes A and B

PRIVATE UTILITY ANNUAL REPORT

OF

NAME	NORTHERN STATES POWER COMPANY (WISCONSIN)
PRINCIPAL OFFICE	1414 WEST HAMILTON AVENUE, P. O. BOX 8 EAU CLAIRE, WI 54702-0008
FOR THE YEAR ENDED	DECEMBER 31, 2002

ELECTRIC, WATER, OR GAS UTILITY
TO
PUBLIC SERVICE COMMISSION OF WISCONSIN

P.O. Box 7854
Madison, WI 53707-7854
(608) 266-3766

This form is required under Section 196.07, Wis. Stats. Failure to file the form by the statutory filing date can result in the imposition of a penalty under Section 196.66, Wis. Stats. The penalty which can be imposed by this section of the statutes is a forfeiture of not less than $25 nor more than $5,000 for each violation. Each day subsequent to the filing date constitutes a separate and distinct violation. The filed form is available to the public and personally identifiable information may be used for purposes other than those related to public utility regulation.

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 nonconfidential 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, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus Losses).

III. What and Where to Submit

(a) Submit this form electronically through the Form 1 Submission Software and an original and six (6) conformed paper copies, properly filed in and attested, to:

Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, NE.
Room 1A
Washington, DC 20426

Retain one copy of this report for your files.

Include with the original and each conformed paper copy of this form the subscription statement required by 18 C.F.R. 385.2011(c)(5). Paragraph (c)(5) of 18 C.F.R. 385.2011 requires each respondent submitting data electronically to file a subscription stating that the paper copies contain the same information as the electronic filing, that the signer knows the contents of the paper copies and electronic filing, and that the contents as stated in the copies and electronic filing are true to the best knowledge and belief of the signer.

(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
888 First Street, NE.
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.)

III. What and Where to Submit (Continued)

(c) Continued

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 office of the Secretary at the address indicated at III (a).

Use the following format 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 statements 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:

Public Reference and Files Maintenance Branch
Federal Energy Regulatory Commission
888 First Street, NE. Room 2A ES-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 1,217 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, 888 First Street N.E., Washington, DC 20426 (Attention: Mr. Michael Miller, CI-1); 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). No person shall be subject to any penalty if this collection of information does not display a valid control number. (44 U.S.C. 3512(a)).

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.

IV. For any page(s) that is not applicable to the respondent, 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. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below). The date of the resubmission must be reported in the header for all form pages, whether or not they are changed from the previous filing.

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, submit the electronic filing using the Form 1 Submission Software and an original and six (6) conformed paper copies of the entire form, as well as the appropriate number of copies of the subscription statement indicated at instruction III (a). Resubmissions must be numbered sequentially on the cover page of the paper copies of the form. In addition, the cover page of each paper copy must indicate that the filing is a resubmission. Send the resubmissions to the address indicated at instruction III (a).

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

IX. 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.

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.

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 shalt 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 an the business of developing, transmitting, unitizing, 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 my prescribe the manner and form in which such reports shalt 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, 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 of 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 OTHER

IDENTIFICATION	
01 Exact Legal Name of Respondent Northern States Power Company (Wisconsin)	02 Year of Report Dec. 31, 2002
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Year *(Street, City, State, Zip Code)* 1414 W. Hamilton Avenue, Eau Claire, WI 54701	
05 Name of Contact Person David W. Sears	06 Title of Contact Person Accounting Analyst
07 Address of Contact Person *(Street, City, State, Zip Code)* 1414 W. Hamilton Avenue, Eau Claire, WI 54701	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(715) 839-2418	(1) ☒ An Original (2) ☐ A Resubmission	03/27/2003

ATTESTATION

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.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Michael L. Swenson	Michael L. Swenson	03/27/2003
02 Title President & CEO		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	NONE
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	
17	Electric Plant Held for Future Use	214	
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	
21	Materials and Supplies	227	
22	Allowances	228-229	NONE
23	Extraordinary Property Losses	230	NONE
24	Unrecovered Plant and Regulatory Study Costs	230	NONE
25	Other Regulatory Assets	232	
26	Miscellaneous Deferred Debits	233	
27	Accumulated Deferred Income Taxes	234	
28	Capital Stock	250-251	
29	Other Paid-in Capital	253	
30	Capital Stock Expense	254	
31	Long-Term Debit	256-257	
32	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
33	Taxes Accrued, Prepaid and Charged During the Year	262-263	
34	Accumulated Deferred Investment Tax Credits	266-267	
35	Other Deferred Credits	269	
36	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Other Property	274-275	
38	Accumulated Deferred Income Taxes-Other	276-277	
39	Other Regulatory Liabilities	278	
40	Electric Operating Revenues	300-301	
41	Sales of Electricity by Rate Schedules	304	
42	Sales for Resale	310-311	
43	Electric Operation and Maintenance Expenses	320-323	
44	Purchased Power	326-327	
45	Transmission of Electricity for Others	328-330	NONE
46	Transmission of Electricity by Others	332	NONE
47	Miscellaneous General Expenses-Electric	335	
48	Depreciation and Amortization of Electric Plant	336-337	
49	Regulatory Commission Expenses	350-351	
50	Research, Development and Demonstration Activities	352-353	
51	Distribution of Salaries and Wages	354-355	
52	Common Utility Plant and Expenses	356	
53	Electric Energy Account	401	
54	Monthly Peaks and Output	401	
55	Steam Electric Generating Plant Statistics (Large Plants)	402-403	
56	Hydroelectric Generating Plant Statistics (Large Plants)	406-407	
57	Pumped Storage Generating Plant Statistics (Large Plants)	408-409	NONE
58	Generating Plant Statistics (Small Plants)	410-411	
59	Transmission Line Statistics	422-423	
60	Transmission Lines Added During Year	424-425	NONE
61	Substations	426-427	
62	Footnote Data	450	
63	Stockholders Rpts Check Approp box: Four copies... No annual report...		
	Stockholders' Reports Check appropriate box: [ ] Four copies will be submitted [X] No annual report to stockholders is prepared		

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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.

David E. Ripka
1414 W. Hamilton Avenue
P.O. Box 8
Eau Claire, WI 54702-0008

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 Wisconsin on November 21, 1901.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or 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.

Not Applicable.

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

Electric Service - Wisconsin
Electric Service - Michigan
Gas Service - Wisconsin
Gas Service - Michigan

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) [X] Yes...Enter the date when such independent accountant was initially engaged: 04/30/2002
(2) [ ] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the 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 beneficiearies for whom trust was maintained, and purpose of the trust.

100% of the voting stock of Northern States Power Company (Wisconsin) is held by Xcel Energy Inc. a publicly owned company.

Northern States Power Company (Wisconsin) is a first tier subsidiary of Xcel Energy Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect 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 the consent of the other, as where the voting control is 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.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Chippewa and Flambeau Improvement Company	Operate hydro reservoirs	75.86	
2	Clearwater Investments, Inc.	Affordable housing	100.00	
3	NSP Lands, Inc	Real estate holdings	100.00	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 policy making 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 the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman of the Board/President/CEO	Wayne H. Brunetti	53,907
2	State Vice President WI & MI	Michael Swenson	155,833
3	State Vice President WI & MI *	Jerome L. Larson	
4	Vice President-Regulatory Affairs & General Counsel	John D. Wilson	159,000
5	Vice President & General Counsel *	Gary R. Johnson	
6	Vice President & Chief Financial Officer *	Edward J McIntyre	
7	Vice President & Chief Financial Officer *	Richard Kelly	
8	Vice President *	Paul J Bonavia	
9	Vice President *	Cynthia Lesher	
10	Vice President *	J. Tom Petillo	
11	Vice President *	Patricia Vincent	
12	Vice President *	David Wilks	
13	Vice President & Secretary *	Cathy Hart	
14	Vice President & Treasurer *	Ben Fowke	
15	Vice President & Treasurer *	Paul Pender	
16	Vice President & Controller *	David E. Ripka	
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19	* Less than $50,000 allocated to NSP-Wisconsin		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	M. L. Swenson	1414 W. Hamilton Ave.
2	President and CEO	Eau Claire, WI 54701
3		
4	W. H. Brunetti	800 Nicollet Mall, Suite 3000
5	Chairman	Minneapolis, MN 55402
6		
7	R. C. Kelly	800 Nicollet Mall, Suite 3000
8	V P & CFO & Principal Financial Officer	Minneapolis, MN 55402
9		
10	G. R. Johnson	800 Nicollet Mall, Suite 3000
11	V P & General Counsel	Minneapolis, MN 55402
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FOOTNOTE DATA

Schedule Page: 104 Line No.: 3 Column: b

Jerome L. Larson left the company 2/1/02.

Schedule Page: 104 Line No.: 6 Column: b

Left the company August 20, 2002

Schedule Page: 104 Line No.: 14 Column: b

Promoted to officer level position November 12, 2002.

Schedule Page: 104 Line No.: 15 Column: b

Left the company November 22, 2002

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 therefore and state from whom the franchise rights were acquired. If acquired without the payment of 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 leaseholds (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 condition. 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, development, 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 included on this page.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

IMPORTANT CHANGES DURING THE YEAR (Continued)

ITEM NUMBER 1 - None

ITEM NUMBER 2 - On August 18, 2000, following receipt of all required regulatory approvals, Northern States Power Company (NSP) and New Century Energies Inc. merged and formed Xcel Energy. NSP-Wisconsin is one of six utility subsidiaries owned by Xcel Energy.

ITEM NUMBER 3 - None

ITEM NUMBER 4 - None

ITEM NUMBER 5 - None

ITEM NUMBER 6 - Note 3 in the Notes to the Financial Statements contains information relevant to the Company's short-term borrowings. (page 123.3) Note 7 in the Notes to the Financial Statements contins information on guarantees outstanding. (page 123.9)

ITEM NUMBER 7 - None

ITEM NUMBER 8 - Bargaining employees received a 4.3 percent wage increase in 2002. Average non-union increase across all companies of Xcel Energy, which includes NSP-Wisconsin, was 4.3%.

ITEM NUMBER 9 - Note 9 in the Notes to the Financial Statements discusses significant legal proceedings pending against the company at the close of 2002. (pages 123.13 and 123.14)

ITEM NUMBER 10 - None

ITEM NUMBER 11 - Not applicable

ITEM NUMBER 12 - Not applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	1,346,446,882	1,386,673,294
3	Construction Work in Progress (107)	200-201	24,503,056	18,039,955
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,370,949,938	1,404,713,249
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	552,521,741	591,241,015
6	Net Utility Plant (Enter Total of line 4 less 5)		818,428,197	813,472,234
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	0	0
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
9	Net Nuclear Fuel (Enter Total of line 7 less 8)		0	0
10	Net Utility Plant (Enter Total of lines 6 and 9)		818,428,197	813,472,234
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored Underground - Noncurrent (117)		0	0
13	**OTHER PROPERTY AND INVESTMENTS**			
14	Nonutility Property (121)	221	4,983,423	2,826,846
15	(Less) Accum. Prov. for Depr. and Amort. (122)		945,411	680,676
16	Investments in Associated Companies (123)		0	0
17	Investment in Subsidiary Companies (123.1)	224-225	3,317,229	3,544,177
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
19	Noncurrent Portion of Allowances	228-229	0	0
20	Other Investments (124)		6,506,467	6,272,584
21	Special Funds (125-128)		0	0
22	TOTAL Other Property and Investments (Total of lines 14-17,19-21)		13,861,708	11,962,931
23	**CURRENT AND ACCRUED ASSETS**			
24	Cash (131)		30,102	98,000
25	Special Deposits (132-134)		0	0
26	Working Fund (135)		5,150	3,250
27	Temporary Cash Investments (136)		0	0
28	Notes Receivable (141)		0	0
29	Customer Accounts Receivable (142)		34,972,100	42,932,652
30	Other Accounts Receivable (143)		-354,657	6,612,548
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		969,461	1,373,114
32	Notes Receivable from Associated Companies (145)		0	0
33	Accounts Receivable from Assoc. Companies (146)		8,854,001	1,459,656
34	Fuel Stock (151)	227	5,641,235	5,753,062
35	Fuel Stock Expenses Undistributed (152)	227	302,412	328,850
36	Residuals (Elec) and Extracted Products (153)	227	0	0
37	Plant Materials and Operating Supplies (154)	227	5,918,689	5,945,257
38	Merchandise (155)	227	66,608	-43,002
39	Other Materials and Supplies (156)	227	0	0
40	Nuclear Materials Held for Sale (157)	202-203/227	0	0
41	Allowances (158.1 and 158.2)	228-229	0	0
42	(Less) Noncurrent Portion of Allowances		0	0
43	Stores Expense Undistributed (163)	227	-100,362	91,405
44	Gas Stored Underground - Current (164.1)		3,119,450	3,989,849
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		102,343	197,576
46	Prepayments (165)		14,372,169	15,415,799
47	Advances for Gas (166-167)		0	0
48	Interest and Dividends Receivable (171)		0	0
49	Rents Receivable (172)		22,499	0
50	Accrued Utility Revenues (173)		20,595,934	20,073,854
51	Miscellaneous Current and Accrued Assets (174)		0	0
52	Derivative Instrument Assets (175)		0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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	Derivative Instrument Assets - Hedges (176)		0	0
54	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 53)		92,578,212	101,485,642
55	**DEFERRED DEBITS**			
56	Unamortized Debt Expenses (181)		1,895,008	1,726,649
57	Extraordinary Property Losses (182.1)	230	-279,100	0
58	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
59	Other Regulatory Assets (182.3)	232	27,433,986	38,784,411
60	Prelim. Survey and Investigation Charges (Electric) (183)		1,162,969	1,188,592
61	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)		0	0
62	Clearing Accounts (184)		-2,821,858	1,600
63	Temporary Facilities (185)		2,565	0
64	Miscellaneous Deferred Debits (186)	233	32,565,039	43,215,801
65	Def. Losses from Disposition of Utility Plt. (187)		0	0
66	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
67	Unamortized Loss on Reaquired Debt (189)		9,967,835	9,327,952
68	Accumulated Deferred Income Taxes (190)	234	7,308,455	16,756,909
69	Unrecovered Purchased Gas Costs (191)		0	0
70	TOTAL Deferred Debits (Enter Total of lines 56 thru 69)		77,234,899	111,001,914
71	TOTAL Assets and Other Debits (Enter Total of lines 10,11,12,22,54,70)		1,002,103,016	1,037,922,721

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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	93,300,000	93,300,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	59,691,288	33,337,651
7	Other Paid-In Capital (208-211)	253	80,000	29,643,577
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	253,906,330	259,663,956
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	2,567,903	2,794,851
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	-1,726
15	TOTAL Proprietary Capital (Enter Total of lines 2 thru 13)		409,545,521	418,738,309
16	**LONG-TERM DEBT**			
17	Bonds (221)	256-257	215,000,000	215,000,000
18	(Less) Reaquired Bonds (222)	256-257	0	0
19	Advances from Associated Companies (223)	256-257	0	0
20	Other Long-Term Debt (224)	256-257	99,562,870	99,529,085
21	Unamortized Premium on Long-Term Debt (225)		-1,475,084	-1,387,712
22	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
23	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)		313,087,786	313,141,373
24	**OTHER NONCURRENT LIABILITIES**			
25	Obligations Under Capital Leases - Noncurrent (227)		0	0
26	Accumulated Provision for Property Insurance (228.1)		0	0
27	Accumulated Provision for Injuries and Damages (228.2)		1,150,000	2,398,221
28	Accumulated Provision for Pensions and Benefits (228.3)		6,423,802	1,532,180
29	Accumulated Miscellaneous Operating Provisions (228.4)		821,000	406,000
30	Accumulated Provision for Rate Refunds (229)		0	0
31	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)		8,394,802	4,336,401
32	**CURRENT AND ACCRUED LIABILITIES**			
33	Notes Payable (231)		0	0
34	Accounts Payable (232)		20,275,097	26,820,833
35	Notes Payable to Associated Companies (233)		34,300,000	6,880,000
36	Accounts Payable to Associated Companies (234)		4,521,069	7,119,487
37	Customer Deposits (235)		1,228,926	1,280,913
38	Taxes Accrued (236)	262-263	-2,603,241	-196,005
39	Interest Accrued (237)		5,620,559	5,547,412
40	Dividends Declared (238)		10,987,668	12,259,735
41	Matured Long-Term Debt (239)		0	0
42	Matured Interest (240)		0	0
43	Tax Collections Payable (241)		1,142,063	1,112,179
44	Miscellaneous Current and Accrued Liabilities (242)		2,355,000	2,027,000
45	Obligations Under Capital Leases-Current (243)		0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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	Derivative Instrument Liabilities (244)		0	0
47	Derivative Instrument Liabilities - Hedges (245)		0	0
48	TOTAL Current & Accrued Liabilities (Enter Total of lines 32 thru 44)		77,827,141	62,851,554
49	**DEFERRED CREDITS**			
50	Customer Advances for Construction (252)		14,617,483	16,363,009
51	Accumulated Deferred Investment Tax Credits (255)	266-267	15,628,356	14,819,917
52	Deferred Gains from Disposition of Utility Plant (256)		0	0
53	Other Deferred Credits (253)	269	13,062,829	27,724,843
54	Other Regulatory Liabilities (254)	278	20,361,352	13,866,238
55	Unamortized Gain on Reaquired Debt (257)		0	0
56	Accumulated Deferred Income Taxes (281-283)	272-277	129,577,746	166,081,077
57	TOTAL Deferred Credits (Enter Total of lines 47 thru 53)		193,247,766	238,855,084
58			0	0
59			0	0
60			0	0
61			0	0
62			0	0
63			0	0
64			0	0
65			0	0
66			0	0
67			0	0
68			0	0
69			0	0
70			0	0
71	TOTAL Liab and Other Credits (Enter Total of lines 14,22,30,45,54)		1,002,103,016	1,037,922,721

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 account 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 pages 122-123 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 revenues or costs to which the contingency relates and the tax effects together 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

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	481,654,650	488,052,710
3	Operating Expenses			
4	Operation Expenses (401)	320-323	287,336,046	329,781,458
5	Maintenance Expenses (402)	320-323	18,484,176	20,608,658
6	Depreciation Expense (403)	336-337	44,182,635	41,374,220
7	Amort. & Depl. of Utility Plant (404-405)	336-337	142,386	107,081
8	Amort. of Utility Plant Acq. Adj. (406)	336-337		31,792
9	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		90,949	131,256
10	Amort. of Conversion Expenses (407)			
11	Regulatory Debits (407.3)			
12	(Less) Regulatory Credits (407.4)			
13	Taxes Other Than Income Taxes (408.1)	262-263	15,968,676	15,881,472
14	Income Taxes - Federal (409.1)	262-263	13,789,843	16,731,095
15	- Other (409.1)	262-263	3,084,966	3,374,216
16	Provision for Deferred Income Taxes (410.1)	234, 272-277	39,171,677	10,291,581
17	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	17,477,727	7,219,546
18	Investment Tax Credit Adj. - Net (411.4)	266	-806,769	-819,397
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)		403,966,858	430,273,886
24	Net Util Oper Inc (Enter Tot line 2 less 23) Carry fwd to P117,line 25		77,687,792	57,778,824

STATEMENT OF INCOME FOR THE YEAR (Continued)

resulting from 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, income, and expense accounts.

7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be included on pages 122-123.

B. Enter on pages 122-123 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 pages.122-123 or in a footnote.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	
						1
378,461,900	364,726,320	102,951,824	123,052,900	240,926	273,490	2
						3
203,401,355	221,118,579	83,934,691	108,662,879			4
17,561,728	19,662,377	922,448	946,281			5
38,788,167	35,975,740	5,356,011	5,360,022	38,457	38,458	6
108,540	107,081	33,846				7
			31,792			8
90,949	131,256					9
						10
						11
						12
14,340,131	14,189,644	1,628,545	1,691,828			13
12,608,407	15,389,818	1,140,543	1,290,224	40,893	51,053	14
2,720,498	3,070,062	358,239	296,344	6,229	7,810	15
30,625,850	8,620,779	8,551,856	1,693,634	-6,029	-22,832	16
10,817,976	4,291,071	6,659,751	2,928,475			17
-747,982	-759,740	-56,033	-56,906	-2,754	-2,751	18
						19
						20
						21
						22
308,679,667	313,214,525	95,210,395	116,987,623	76,796	71,738	23
69,782,233	51,511,795	7,741,429	6,065,277	164,130	201,752	24

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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)		77,687,792	57,778,824
26	Other Income and Deductions			
27	Other Income			
28	Nonutilty Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)		1,308	100,563
30	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		388,958	13,008
31	Revenues From Nonutility Operations (417)		494,792	
32	(Less) Expenses of Nonutility Operations (417.1)		661,798	446,010
33	Nonoperating Rental Income (418)		6,788	61,236
34	Equity in Earnings of Subsidiary Companies (418.1)	119	265,001	591,626
35	Interest and Dividend Income (419)		876,044	207,987
36	Allowance for Other Funds Used During Construction (419.1)		357,489	1,229,773
37	Miscellaneous Nonoperating Income (421)		280,112	118,628
38	Gain on Disposition of Property (421.1)		-414,712	-456,516
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		816,066	1,394,279
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)			
42	Miscellaneous Amortization (425)	340		
43	Miscellaneous Income Deductions (426.1-426.5)	340	1,752,743	1,816,529
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		1,752,743	1,816,529
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263	98,222	94,971
47	Income Taxes-Federal (409.2)	262-263	-647,216	-1,039,741
48	Income Taxes-Other (409.2)	262-263	-177,970	-137,175
49	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-12,071	-23,051
50	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277		
51	Investment Tax Credit Adj.-Net (411.5)			
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Income and Deduct. (Total of 46 thru 52)		-739,035	-1,104,996
54	Net Other Income and Deductions (Enter Total lines 39, 44, 53)		-197,642	682,746
55	Interest Charges			
56	Interest on Long-Term Debt (427)		22,346,239	22,366,504
57	Amort. of Debt Disc. and Expense (428)		255,731	255,732
58	Amortization of Loss on Reaquired Debt (428.1)		639,883	639,888
59	(Less) Amort. of Premium on Debt-Credit (429)			
60	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)			
61	Interest on Debt to Assoc. Companies (430)	340	162,751	459,376
62	Other Interest Expense (431)	340	62,439	-582,832
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		350,139	1,069,583
64	Net Interest Charges (Enter Total of lines 56 thru 63)		23,116,904	22,069,085
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		54,373,246	36,392,485
66	Extraordinary Items			
67	Extraordinary Income (434)			
68	(Less) Extraordinary Deductions (435)			
69	Net Extraordinary Items (Enter Total of line 67 less line 68)			
70	Income Taxes-Federal and Other (409.3)	262-263		
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)			
72	Net Income (Enter Total of lines 65 and 71)		54,373,246	36,392,485

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 of 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 the State and Federal income tax effect of 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 appropriated as well as the totals eventually to be accumulated.
8. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance-Beginning of Year		248,515,110
2	Changes		
3	Adjustments to Retained Earnings (Account 439)		
4	Prior year reclassification of Other Comprehensive Income to FERC 219		959
5			
6			
7			
8			
9	TOTAL Credits to Retained Earnings (Acct. 439)		959
10			-1
11			
12			
13			
14			
15	TOTAL Debits to Retained Earnings (Acct. 439)		-1
16	Balance Transferred from Income (Account 433 less Account 418.1)		54,108,245
17	Appropriations of Retained Earnings (Acct. 436)		
18	Excess Earnings Amortization of Hydro Reserve		-1,853,135
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-1,853,135
23	Dividends Declared-Preferred Stock (Account 437)		
24			
25			
26			
27			
28			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		
30	Dividends Declared-Common Stock (Account 438)		
31			-48,389,630
32			
33			
34			
35			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-48,389,630
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		38,053
38	Balance - End of Year (Total 1,9,15,16,22,29,36,37)		252,419,601

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 of 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 the State and Federal income tax effect of 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 appropriated as well as the totals eventually to be accumulated.
8. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	APPROPRIATED RETAINED EARNINGS (Account 215)		
39			
40			
41			
42			
43			
44			
45	TOTAL Appropriated Retained Earnings (Account 215)		
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)		
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		7,244,355
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		7,244,355
48	TOTAL Retained Earnings (Account 215, 215.1, 216) (Total 38, 47)		259,663,956
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)		
49	Balance-Beginning of Year (Debit or Credit)		2,567,903
50	Equity in Earnings for Year (Credit) (Account 418.1)		265,001
51	(Less) Dividends Received (Debit)		38,053
52			
53	Balance-End of Year (Total lines 49 thru 52)		2,794,851

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 included in page 122-123. Information about non-cash investing and financing activities should be provided on Page 122-123. Provide also on pages 122-123 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 and financing activities should be reported in those activities. Show on Page 122-123 the amount of interest paid (net of amounts capitalized) and income taxes paid.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
1	Net Cash Flow from Operating Activities:	
2	Net Income	54,373,246
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	45,641,192
5	Amortization of	
6		
7	Deferred Debitd/Credits	3,898,894
8	Deferred Income Taxes (Net)	21,681,877
9	Investment Tax Credit Adjustment (Net)	-806,769
10	Net (Increase) Decrease in Receivables	-14,524,104
11	Net (Increase) Decrease in Inventory	-1,212,622
12	Net (Increase) Decrease in Allowances Inventory	
13	Net Increase (Decrease) in Payables and Accrued Expenses	8,849,941
14	Net (Increase) Decrease in Other Regulatory Assets	-1,287,373
15	Net Increase (Decrease) in Other Regulatory Liabilities	-1,021,114
16	(Less) Allowance for Other Funds Used During Construction	357,489
17	(Less) Undistributed Earnings from Subsidiary Companies	226,949
18	(Gain) Loss on sale of assets	970,712
19	(Increase)/Decrease in Accrued Utility Revenues	522,080
20	Miscellaneous Changes in Working Capital	-1,252,242
21	Changes in Other Assets and Liabilities	-16,053,373
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	99,195,907
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (including land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	-40,079,767
27	Gross Additions to Nuclear Fuel	
28	Gross Additions to Common Utility Plant	
29	Gross Additions to Nonutility Plant	637,511
30	(Less) Allowance for Other Funds Used During Construction	-357,489
31	Proceeds from disposition of Plant	1,090,722
32		
33		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-37,994,045
35		
36	Acquisition of Other Noncurrent Assets (d)	
37	Proceeds from Disposal of Noncurrent Assets (d)	
38		
39	Investments in and Advances to Assoc. and Subsidiary Companies	
40	Contributions and Advances from Assoc. and Subsidiary Companies	13,202,703
41	Disposition of Investments in (and Advances to)	
42	Associated and Subsidiary Companies	
43		
44	Purchase of Investment Securities (a)	
45	Proceeds from Sales of Investment Securities (a)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

STATEMENT OF CASH FLOWS

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 pages 122-123. Do not include on this statement the dollar amount of Leases capitalized per US of A General Instruction 20; instead provide a reconciliation of the dollar amount of Leases capitalized with the plant cost on pages 122-123.
5. Codes used:
(a) Net proceeds or payments. (c) Include commercial paper.
(b) Bonds, debentures and other long-term debt. (d) Identify separately such items as investments, fixed assets, intangibles, etc.
6. Enter on pages 122-123 clarifications and explanations.

Line No.	Description (See Instruction No. 5 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	Net (Increase) Decrease in Allowances Held for Speculation	
52	Net Increase (Decrease) in Payables and Accrued Expenses	
53	Other Miscellaneous Other Investing Activities	232,781
54		
55		
56	Net Cash Provided by (Used in) Investing Activities	
57	Total of lines 34 thru 55)	-24,558,561
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long-Term Debt (b)	
62	Preferred Stock	
63	Common Stock	
64	Other (provide details in footnote):	
65		
66	Net Increase in Short-Term Debt (c)	
67	Other (provide details in footnote):	
68		
69		
70	Cash Provided by Outside Sources (Total 61 thru 69)	
71		
72	Payments for Retirement of:	
73	Long-term Debt (b)	-33,785
74	Preferred Stock	
75	Common Stock	
76	Other (provide details in footnote):	
77		
78	Net Decrease in Short-Term Debt (c)	-27,420,000
79		
80	Dividends on Preferred Stock	
81	Dividends on Common Stock	-47,117,563
82	Net Cash Provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	-74,571,348
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22,57 and 83)	65,998
87		
88	Cash and Cash Equivalents at Beginning of Year	35,252
89		
90	Cash and Cash Equivalents at End of Year	101,250

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 Commmission 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 included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Merger and Basis of Presentation — On Aug. 18, 2000, Northern States Power Co. (NSP) and New Century Energy, Inc. (NCE) merged and formed Xcel Energy, Inc. Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. Cash was paid in lieu of any fractional shares of Xcel Energy common stock. The merger was structured as a tax-free, stock-for-stock exchange for shareholders of both companies (except for fractional shares) and accounted for as a pooling-of-interests. At the time of the merger, Xcel Energy registered as a holding company under the PUHCA.

Pursuant to the merger agreement, NCE was merged with and into NSP. NSP, as the surviving legal corporation, changed its name to Xcel Energy. Also, as part of the merger, NSP transferred its existing utility operations that were being conducted directly by NSP at the parent company level to a newly formed wholly owned subsidiary of Xcel Energy, which was renamed NSP-Minnesota.

Consistent with pooling accounting requirements, results and disclosures for all periods prior to the merger have been restated for consistent reporting with post-merger organization and operations.

Business and System of Accounts — NSP-Wisconsin was incorporated in 1901 under the laws of Wisconsin. NSP-Wisconsin, a wholly owned subsidiary of Xcel Energy, is an operating utility engaged in the generation, transmission and distribution of electricity to approximately 230,000 retail customers in northwestern Wisconsin and in the western portion of the Upper Peninsula of Michigan. NSP-Wisconsin is also engaged in the distribution and sale of natural gas in the same service territory to approximately 90,000 customers in Wisconsin and Michigan.

NSP-Wisconsin owns the following direct subsidiaries: Chippewa and Flambeau Improvement Company, which operates hydro reserves; Clearwater Investments Inc., which owns interests in affordable housing; and NSP Lands, Inc., which holds real estate.

NSP-Wisconsin is subject to regulation by the Federal Energy Regulatory Commission (FERC), the Public Service Commission of Wisconsin (PSCW), and the Michigan Public Service Commission (MPSC). All of the utility companies' accounting records conform to the FERC uniform system of accounts or to systems required by state regulatory commissions, which are the same in all material aspects.

Principles of Consolidation — NSP-Wisconsin uses the equity method of accounting for its investments in subsidiaries and records its portion of earnings from such investments after subtracting income taxes. Chippewa and Flambeau Improvement Company is 75.86 percent owned; NSP Lands, Inc. is 100 percent owned; and Clearwater Investments, Inc. is 100 percent owned. The impact of consolidating these subsidiaries would be immaterial.

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based of the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated.

NSP-Wisconsin has various rate adjustment mechanisms in place that currently provide for the recovery of certain purchased natural gas and electric energy costs. These cost adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred.

NSP-Wisconsin's rates include a cost-of-energy adjustment clause for purchased natural gas, but not for purchased electricity or electric fuel. NSP-Wisconsin can request recovery of those electric costs prospectively through the rate review process, which normally occurs every two years, and an interim fuel-cost hearing process.

Property, Plant, Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and applicable interest expense. The cost of plant retired, plus net removal cost is charged to accumulated depreciation and amortization. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance are charged to expense as incurred. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses.

NSP-Wisconsin determines the depreciation of their plant by using the straight-line method, which spreads the original cost equally over the plant's useful life. Depreciation expense for NSP-Wisconsin, expressed as a percentage of average depreciable property, for the years ended December 31, is listed in the following table:

	2002	2001
NSP-Wisconsin	3.3%	3.1%

Allowance for Funds Used During Construction (AFDC) and Capitalized Interest — AFDC, a noncash item, represents the cost of capital used to finance utility construction activity. AFDC is computed by applying a composite pretax rate to qualified construction work in progress. The amount of AFDC capitalized as a utility construction cost is credited to other income and deductions (for equity capital) and interest charges (for debt capital). AFDC amounts capitalized are included in NSP-Wisconsin's rate base for establishing utility service rates. Interest capitalized as AFDC for NSP-Wisconsin is listed in the following table:

	2002	2001
	(Millions of dollars)	
NSP-Wisconsin	$ 0.4	$ 1.1

Environmental Costs — We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset based on our expectation that we will recover these costs from customers in future rates. Otherwise, we expense the costs. If an environmental expense is related to facilities we currently use, such as pollution-control equipment, we capitalize and depreciate the costs over the life of the plant, assuming the costs are recoverable in future rates or future cash flow.

We record estimated remediation costs, excluding inflationary increases and possible reductions for insurance coverage and rate recovery. The estimates are based on our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, we estimate and record only our share of the cost. We treat any future costs of restoring sites where operation may extend indefinitely as a capitalized cost of plant retirement. The depreciation expense levels we can recover in rates include a provision for these estimated removal costs.

Income Taxes — NSP-Wisconsin files consolidated federal (as part of Xcel Energy) and separate state income tax returns. Income taxes from the consolidated federal return are allocated to NSP-Wisconsin based on separate company computations of taxable income or loss. In accordance with the PUHCA requirements, the holding company also allocates its own net income tax benefits to its direct subsidiaries, with NSP-Wisconsin being one of the direct subsidiaries, based on the positive taxable income of each company in the consolidated federal or combined state returns. NSP-Wisconsin defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. We use the tax rates that are scheduled to be in effect when the temporary differences are expected to turn around, or reverse.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, we account for the reversal of some temporary differences as current income tax expense. We defer investment tax credits and spread their benefits over the estimated lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes, which we summarize in Note 10 to the Financial Statements. For more information on income taxes, see Note 5 to the Financial Statements.

Derivative Financial Instruments — On Jan. 1, 2001, NSP-Wisconsin adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activity," as amended by SFAS No. 137 and SFAS No. 138 (collectively referred to as SFAS No. 133). For more information on the impact of SFAS No. 133, see Notes 7 and 8 to the Financial Statements.

Use of Estimates — In recording transactions and balances resulting from business operations, NSP-Wisconsin uses estimates based on the best information available. We use estimates for such items as plant depreciable lives, tax provisions, uncollectible amounts, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we get better information or when we can determine actual amounts. Those revisions can affect operating results. Each year we also review the depreciable lives of certain plant assets and revise them, if appropriate.

Cash Items — NSP-Wisconsin considers investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. Excess funds are invested primarily in money market funds. NSP-Wisconsin had $0 of temporary cash investments at Dec. 31, 2002 and 2001.

Inventory — All inventories are recorded at average cost.

Regulatory Accounting — NSP-Wisconsin accounts for certain income and expense items using SFAS No. 71. Under SFAS No. 71:

- we defer certain costs, which would otherwise be charged to expense, as regulatory assets based on our expected ability to recover them in future rates; and
- we defer certain credits, which would otherwise be reflected as income, as regulatory liabilities based on our expectation they will be returned to customers in future rates.

We base our estimates of recovering deferred costs and returning deferred credits on specific ratemaking decisions or precedent for each item. We amortize regulatory assets and liabilities consistent with the period of expected regulatory treatment.

Intangible Assets and Deferred Financing Costs — Effective Jan. 1, 2002, NSP-Wisconsin implemented SFAS No. 142, "Goodwill and Other Intangible Assets," which requires different accounting for intangible assets as compared to goodwill. Intangible assets are amortized over their economic useful life and reviewed for impairment in accordance with SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of." Goodwill is no longer amortized after adoption of SFAS No. 142. Non-amortized intangible assets and goodwill are tested for impairment annually and on an interim basis if an event or circumstance occurs between annual tests that might reduce the fair value of that asset.

NSP-Wisconsin has an immaterial amount of unamortized intangible assets and no amounts of goodwill as of Dec. 31, 2002 and 2001.

Other assets include deferred financing costs, which we are amortizing over the remaining maturity periods of the related debt. NSP-Wisconsin's deferred financing costs, net of amortization at Dec. 31, is listed in the following table:

	2002	2001
	(Millions of dollars)	
NSP-Wisconsin	$ 1.7	$ 1.9

2. Special Charges

2002 and 2001 — Restaffing — During the fourth quarter of 2001, Xcel Energy expensed pretax special charges of $39 million for

expected staff consolidation costs for an estimated 500 employees in several utility operating and corporate support areas of Xcel Energy. Approximately $36 million of these restaffing costs were allocated to Xcel Energy's utility subsidiaries consistent with service company cost allocation methodologies utilized under the requirements of the PUHCA. In the first quarter of 2002, the identification of affected employees was completed and additional pretax special charges of $9 million were expensed for the final costs of staff consolidations. Approximately $6 million of these restaffing costs were allocated to Xcel Energy's utility subsidiaries. All 564 of accrued staff terminations have occurred. See the summary of costs for NSP-Wisconsin below.

2000 — Merger Costs — Upon consummation of the merger in 2000, Xcel Energy expensed pretax special charges related to its regulated operations totaling $199 million. During 2000, an allocation of approximately $188 million of merger costs was made to Xcel Energy's utility subsidiaries consistent with prior regulatory filings, in proportion to expected merger savings by the Company and consistent with service company cost allocation methodologies utilized under the requirements of the PUHCA. These costs are reported on the accompanying consolidated financial statements as special charges.

Of the total pretax special charges recorded by Xcel Energy that related to its regulated operations, $159 million was recorded during the third quarter of 2000 and $40 million was recorded during the fourth quarter of 2000. See Note 13 to the Financial Statements for the quarterly impacts on NSP-Wisconsin.

The total pretax charges included $52 million related to one-time transaction related costs incurred in connection with the merger of NSP and NCE. These transaction costs included investment banker fees, legal and regulatory approval costs, and expenses for support of and assistance with planning and completing the merger transaction.

Also included in the total were $147 million of pretax charges pertaining to incremental costs of transition and integration activities associated with merging operations. These transition costs included approximately $77 million for severance and related expenses associated with staff reductions. All 721 of accrued staff terminations have occurred. The staff reductions were non-bargaining positions mainly in corporate and operations support areas. Other transition and integration costs included amounts incurred for facility consolidation, systems integration, regulatory transition, merger communications and operations integration assistance.

Accrued Special Charges — The following table summarizes activity related to accrued special charges in 2002 and 2001:

	Dec. 31, 2000 Liability*	Expensed 2001	Payments 2001	Dec. 31, 2001 Liability*	Expensed 2002	Payments 2002	Dec. 31, 2002 Liability*
	(Millions of dollars)						
NSP-Wisconsin	3	2	(3)	2	1	(3)	—

* Reported on the balance sheets in other current liabilities.

3. Short-Term Borrowings

NSP-Wisconsin has an intercompany borrowing arrangement with NSP-Minnesota, with interest charged at NSP-Minnesota's short-term borrowing rate. At Dec. 31, 2002 and 2001, NSP-Wisconsin had $6.9 million and $34.3 million, respectively, in short-term borrowings. The weighted average interest rate for NSP-Wisconsin was 4.40 percent at Dec. 31, 2002 and 2.16 percent at Dec. 31, 2001.

4. Long-Term Debt

All property of NSP-Wisconsin is subject to the liens of its first mortgage indentures, which are contracts between the companies

and their bondholders.

The annual sinking-fund requirements of first mortgage indentures are the amounts necessary to redeem 1 percent of the highest principal amount of each series of first mortgage bonds at any time outstanding, excluding resource recovery financing. NSP-Wisconsin expects to satisfy substantially all of its sinking fund obligations in accordance with the terms of their respective indentures through the application of property additions.

Maturities and sinking fund requirements for long-term debt for NSP-Wisconsin is listed in the following table:

	NSP-Wisconsin (Millions of dollars)
2003	$ 41
2004	1
2005	1
2006	1
2007	1

5. Income Taxes

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The reasons for the difference are:

	2002	2001
Federal statutory rate	35.0%	35.0%
Increases (decreases) in tax from:		
State income taxes, net of federal income tax benefit	5.7%	4.4%
Life insurance policies	(0.1)%	—
Tax credits recognized	(0.9)%	(1.4)%
Equity income from unconsolidated affiliates	(0.1)%	(0.4)%
Regulatory differences — utility plant items	0.6%	(1.1)%
Non-deductibility of merger costs	—	—
Other — net	0.2%	0.3%
Effective income tax rate	40.4%	36.8%

Income taxes comprise the following expense (benefit) items (Thousands of dollars):

	2002	2001
Current federal tax expense	$ 13,143	$ 15,691
Current state tax expense	2,907	3,237
Deferred federal tax expense	16,569	2,462
Deferred state tax expense	5,113	587
Deferred investment tax credits	(807)	(819)
Total income tax expense	$ 36,925	$ 21,158

The components of net deferred tax liability (current and noncurrent portions) at Dec. 31 were:

	2002	2001
	(Thousands of dollars)	
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 132,044	$ 113,039

Regulatory assets	21,744	17,583
Other	20,048	14,777
Total deferred tax liabilities	$ 173,836	$ 145,399
Deferred tax assets:		
Regulatory liabilities	$ 5,040	$ 6,877
Deferred investment tax credits	6,019	6,284
Employee benefits and other accrued liabilities	12,773	8,786
Other	680	1,183
Total deferred tax assets	$ 24,512	$ 23,130
Net deferred tax liability	$ 149,324	$ 122,269

6. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its benefit employees, including those of NSP-Wisconsin. NSP-Wisconsin had 419 union employees , or approximately 70 percent of total benefit employees, covered under a collective bargaining agreement which expires at the end of 2004.

Pension Benefits — Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all utility employees, including those of NSP-Wisconsin. Benefits are based on a combination of years of service, the employee's average pay and Social Security benefits.

Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws. Plan assets principally consist of the common stock of public companies, corporate bonds and U.S. government securities.

A comparison of the actuarially computed pension benefit obligation and plan assets for Xcel Energy plans which benefit utility subsidiary employees, including those of NSP-Wisconsin, on a combined basis, is presented in the following table:

	2002	2001
	(Thousands of dollars)	
Change in Benefit Obligation		
Obligation at January 1	$ 2,409,186	$ 2,254,138
Service cost	65,649	57,521
Interest cost	172,377	172,159
Acquisitions	7,848	—
Plan amendments	3,903	2,284
Actuarial loss	65,763	108,754
Settlements	(994)	—
Special termination benefits	4,445	—
Benefit payments	(222,601)	(185,670)
Obligation at December 31	$ 2,505,576	$ 2,409,186
Change in Fair Value of Plan Assets		
Fair value of plan assets at January 1	$ 3,267,586	$ 3,689,157
Actual return on plan assets	(404,940)	(235,901)
Employer contributions — acquisitions	912	—
Settlements	(994)	—
Benefit payments	(222,601)	(185,670)
Fair value of plan assets at December 31	$ 2,639,963	$ 3,267,586
Funded Status of Plans at December 31		
Net asset	$ 134,387	$ 858,400
Unrecognized transition asset	(2,003)	(9,317)

Unrecognized prior service cost	224,651	242,313
Unrecognized (gain) loss	165,927	(712,571)
Xcel Energy net pension amounts recognized on balance sheet	$ 522,962	$ 378,825
NSP-Wisconsin prepaid pension asset recorded	38,557	28,563
Significant Assumptions		
Discount rate for year end valuation	6.75%	7.25%
Expected average long term increase in compensation level	4.00%	4.50%
Expected average long term rate of return on assets	9.50%	9.50%

The components of net periodic pension cost (credit) for Xcel Energy plans which benefit employees of its utility subsidiaries, including those of NSP-Wisconsin, are:

Xcel Energy	2002	2001
	(Thousands of dollars)	
Service cost	$ 65,649	$ 57,521
Interest cost	172,377	172,159
Expected return on plan assets	(339,932)	(325,635)
Curtailment	—	1,121
Amortization of transition asset	(7,314)	(7,314)
Amortization of prior service cost	22,663	20,835
Amortization of net gain	(69,264)	(72,413)
Net periodic pension credit under SFAS No. 87	$ (155,821)	$ (153,726)
NSP-Wisconsin		
Net SFAS No. 87 benefit credit recognized for reporting	$ (9,994)	$ (10,002)

Xcel Energy also maintains noncontributory defined benefit supplemental retirement income plans for certain qualifying executive personnel. Benefits for these unfunded plans are paid out of Xcel Energy's operating cash flows.

Defined Contribution Plans — Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees, including those of NSP-Wisconsin. Total contributions to these plans, which benefit employees of the utility subsidiaries, were approximately $19 million in 2002 and $23 million in 2001. The total contribution for 2002 included $0.7 million for NSP-Wisconsin.

Until May 6, 2002 Xcel Energy had a leveraged employee stock ownership plan (ESOP) that covered substantially all employees of NSP-Minnesota and NSP-Wisconsin. Xcel Energy made contributions to this noncontributory, defined contribution plan to the extent it realized tax savings from dividends paid on certain ESOP shares. ESOP contributions had no material effect on Xcel Energy earnings because the tax savings provided by the dividends paid on ESOP shares essentially offset the contributions. Xcel Energy allocated leveraged ESOP shares to participants when it repaid ESOP loans with dividends on stock held by the ESOP.

In May 2002 the ESOP was merged into the Xcel Retirement Savings 401(k) Plan. Starting with the 2003 plan year, the ESOP component of the 401(k) will no longer be leveraged.

Xcel Energy's leveraged ESOP held no shares of Xcel Energy common stock at the end of 2002, 10.7 million shares of Xcel Energy common stock at May 6, 2002, 10.5 million shares of Xcel Energy common stock at the end of 2001, and 12.0 million shares of Xcel Energy common stock at the end of 2000. Xcel Energy excluded the following average number of uncommitted leveraged ESOP shares from earnings per share calculations: 0.7 million in 2002, 0.9 million in 2001, and 0.7 million in 2000. On Nov. 19, 2002, Xcel Energy paid off all of the ESOP loans. All uncommitted ESOP shares were released and will be used by Xcel Energy for its

employer matching contribution to its 401(k) plan.

Postretirement Health Care Benefits — Xcel Energy has contributory health and welfare benefit plans that provide health care and death benefits to most Xcel Energy retirees, including those of NSP-Wisconsin. The former NSP discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees of NSP-Minnesota and NSP-Wisconsin who retired after 1999. However, employees of the former NCE who retired in 2002 continue to receive employer subsidized health care benefits. Employees of the former NSP who retired after 1998 are eligible to participate in the Xcel Energy health care program with no employer subsidy.

In conjunction with the 1993 adoption of SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pension," Xcel Energy elected to amortize the unrecognized accumulated postretirement benefit obligation (APBO) on a straight-line basis over 20 years.

Regulatory agencies for nearly all of Xcel Energy's retail and wholesale utility customers have allowed rate recovery of accrued benefit costs under SFAS No. 106. Additionally, certain state agencies, which regulate Xcel Energy's utility subsidiaries, have also issued guidelines related to the funding of SFAS No. 106 costs. Wisconsin retail regulators required external funding of accrued SFAS No. 106 costs to the extent such funding is tax advantaged. Plan assets held in external funding trusts principally consist of investments in equity mutual funds, fixed-income securities and cash equivalents.

A comparison of the actuarially computed benefit obligation and plan assets for Xcel Energy postretirement health care plans that benefit employees of its utility subsidiaries, including those of NSP-Wisconsin, is presented in the following table:

	2002	2001
	(Thousands of dollars)	
Change in Benefit Obligation		
Obligation at January 1	$ 662,853	$ 558,994
Service cost	5,967	5,258
Interest cost	48,304	45,177
Acquisitions	773	—
Plan amendments	—	—
Plan participants' contributions	5,755	3,517
Actuarial loss	57,175	98,655
Special termination benefits	(173)	—
Benefit payments	(44,263)	(48,748)
Obligation at December 31	$ 736,391	$ 662,853
Change in Fair Value of Plan Assets		
Fair value of plan assets at January 1	$ 242,803	$ 223,266
Actual return on plan assets	(13,632)	(3,701)
Plan participants' contributions	5,755	3,517
Employer contributions	60,320	68,469
Benefit payments	(44,263)	(48,748)
Fair value of plan assets at December 31	$ 250,983	$ 242,803
Funded Status of Plan at December 31		
Net obligation	$ 485,408	$ 420,050
Unrecognized transition asset (obligation)	(169,328)	(186,099)
Unrecognized prior service cost	10,675	12,559
Unrecognized gain (loss)	(200,634)	(132,354)
Total accrued benefit liability recorded	$ 126,121	$ 114,156
NSP-Wisconsin accrued benefit liability recorded	$ 4,899	$ 5,052
Significant Assumptions		
Discount rate for year end valuation	6.75%	7.25%
Expected average long term rate of return on assets	8.0 - 9.0%	9.0%

The assumed health care cost trend rate for 2002 is approximately 8 percent, decreasing gradually to 5.5 percent in 2007 and remaining level thereafter. A 1 percent change in the assumed health care cost trend rate would have the following effects:

	Xcel Energy	NSP-Wisconsin
	(Thousands of dollars)	
Effect of changes in the assumed health care cost trend rate		
1 percent increase in APBO components at Dec. 31, 2002	$ 79,028	$ 2,181
1 percent decrease in APBO components at Dec. 31, 2002	(65,755)	(1,889)
1 percent increase in service and interest components of the net periodic cost	6,285	142
1 percent decrease in service and interest components of the net periodic cost	(5,181)	(124)

The components of net periodic postretirement benefit cost of Xcel Energy's plans are:

	2002	2001
	(Thousands of dollars)	
Xcel Energy		
Service cost	$ 5,967	$ 6,160
Interest cost	48,304	46,579
Expected return on plan assets	(21,011)	(18,920)
Amortization of transition obligation	16,771	16,771
Amortization of prior service credit	(1,130)	(1,235)
Amortization of net loss	5,380	1,457
Net periodic postretirement benefit cost under SFAS No. 106	54,281	50,812
Additional cost recognized due to effects of regulation	4,043	3,738
Net cost recognized for financial reporting	$ 58,324	$ 54,550
NSP-Wisconsin		
Net periodic postretirement benefit cost recognized — SFAS No. 106	$ 1,531	$ 1,155

7. Financial Instruments

Fair Values

The estimated December 31 fair values of NSP-Wisconsin's recorded financial instruments are as follows:

2002		2001	
Carrying Amount	Fair Value	Carrying Amount	Fair Value
(Thousands of dollars)			

Long-term investments	$ 10	$ 10	$ 9	$ 9
Long-term debt, including current portion	313,142	320,884	313,088	317,490

The carrying amount of cash, cash equivalents, short-term investments and other financial instruments approximates fair value because of the short maturity of those instruments. The fair value of NSP-Wisconsin's long-term debt is estimated based on the quoted market prices for the same or similar issues, or the current rates for debt of the same remaining maturities and credit quality.

The fair value estimates presented are based on information available to management as of Dec. 31, 2002 and 2001. These fair value estimates have not been comprehensively revalued for purposes of these financial statements since that date and current estimates of fair values may differ significantly from the amounts presented herein.

Guarantees

NSP-Wisconsin had the following guarantees outstanding on Dec. 31, 2002:

Guarantor	**NSP-Wisconsin**
Guarantee amount	$1.4 million
Exposure under guarantee	$0.1 million
Nature of guarantee	NSP-Wisconsin guarantees customer loans to encourage business growth and expansion.
Term of guarantee	Latest expiration in 2006.
Triggering events or circumstances requiring performance under the guarantee	Non-timely payment of the obligations or at the time the Debtor becomes the subject of bankruptcy or other insolvency proceedings.
Current carrying amount of the liability	n/a
Nature of any recourse provisions	None
Any assets held as collateral	None

8. Derivative Valuation and Financial Impacts

Use of Derivatives to Manage Risk

Business and Operational Risk — NSP-Wisconsin is exposed to commodity price risk in its generation and retail distribution operations. NSP-Wisconsin generally recovers natural gas costs in its jurisdictions on a dollar-for-dollar basis. NSP-Wisconsin has limited exposure to market price risk for the purchase of electric energy.

Interest Rate Risk — With the exception of short-term borrowings, NSP-Wisconsin does not have variable interest rates; therefore there is limited interest rate risk.

Derivatives as Hedges

2001 Accounting Change — On Jan. 1, 2001, Xcel Energy and its utility subsidiaries adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." This statement requires that all derivative instruments as defined by SFAS No. 133 be

recorded on the balance sheet at fair value unless exempted. Changes in a derivative instrument's fair value must be recognized currently in earnings unless the derivative has been designated in a qualifying hedging relationship. The application of hedge accounting allows a derivative instrument's gains and losses to offset related results of the hedged item in the income statement, to the extent effective. SFAS No. 133 requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship to apply hedge accounting.

A fair value hedge requires that the effective portion of the change in the fair value of a derivative instrument be offset against the change in the fair value of the underlying asset, liability, or firm commitment being hedged. That is, fair value hedge accounting allows the gain or loss on the hedged item to offset the gain or loss on the derivative instrument in the same period. A cash flow hedge requires that the effective portion of the change in the fair value of a derivative instrument be recognized in Other Comprehensive Income, and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. The ineffective portion of a derivative instrument's change in fair value is recognized currently in earnings.

Xcel Energy's utility subsidiaries formally document hedge relationships, including, among other things, the identification of the hedging instrument and the hedged transaction, as well as the risk management objectives and strategies for undertaking the hedged transaction. Derivatives are recorded in the balance sheet at fair value. Xcel Energy's utility subsidiaries also formally assess, both at inception and at least quarterly thereafter, whether the derivative instruments being used are highly effective in offsetting changes in either the fair value or cash flows of the hedged items.

Financial Impacts of Derivatives

SFAS No. 133 had no impact on Other Comprehensive Income for 2002 and 2001, included in Stockholder's Equity, for NSP-Wisconsin.

9. Commitments and Contingent Liabilities

Leases — NSP-Wisconsin leases a variety of equipment and facilities used in the normal course of business. The leases are primarily for trucks, cars and power-operated equipment and are accounted for as operating leases. The amounts paid under operating leases during 2002 NSP-Wisconsin are listed in the following table:

Rental expense under operating leases was:

	2002	2001
	(Millions of dollars)	
NSP-Wisconsin	4.8	4.7

Future commitments under operating leases are:

	2003	2004	2005	2006	2007
	(Millions of dollars)				
NSP-Wisconsin	3.7	3.7	3.7	3.7	3.7

Nuclear Insurance — Although NSP-Wisconsin does not own a nuclear facility, any assessment made against NSP-Minnesota under the Price-Anderson liability provisions of the Atomic Energy Act of 1954 would be a cost included under the Interchange Agreement (see note 12) and NSP-Wisconsin would be charged its proportion of the assessment. NSP-Minnesota'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. NSP-Minnesota 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 case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $88 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.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $1.5 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $7.5 million for business interruption insurance and $21.6 million for property damage insurance if losses exceed accumulated reserve funds.

Fuel Contracts — The utility subsidiaries of Xcel Energy have contracts providing for the purchase and delivery of a significant portion of their current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2003 and 2025. In addition, the utility subsidiaries of Xcel Energy are required to pay additional amounts depending on actual quantities shipped under these agreements. The potential risk of loss for the utility subsidiaries of Xcel Energy, 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 most fuel costs.

The minimum purchase for NSP-Minnesota and NSP-Wisconsin are as follows:

	Coal	Nuclear Fuel	Natural Gas	Gas Storage & Transportation
		(Millions of dollars)		
NSP-Minnesota and NSP-Wisconsin (combined)	$ 219	$ 122	$ 284	$ 268

Purchased Power Agreements — NSP-Minnesota has entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. NSP-Minnesota has various pay-for-performance contracts with expiration dates through the year 2050. In general, these contracts provide for capacity payments, subject to meeting certain contract obligations and energy payments based on actual power taken under the contracts. Most of the capacity and energy costs are recovered through base rates and other cost recovery mechanisms.

NSP-Minnesota has a 500-megawatt participation power purchase commitment with the Manitoba Hydro Electric Board, which expires in April 2005. The current cost of this agreement is based on 80 percent of the costs of owning and operating NSP-Minnesota's Sherco 3 generating plant, adjusted to 1993 dollars. This agreement was extended during 2002 to include the period starting May 2005 through April 2015. The cost of the agreement for this extended period is based on a base price, which was established from May 2001 through April 2002 and will be escalated by the change in the United States Gross National Product to reflect the current year. In addition, NSP-Minnesota and Manitoba Hydro have seasonal diversity exchange agreements, and there are no capacity payments for the diversity exchanges. These commitments represent about 17 percent of Manitoba Hydro's system capacity and account for approximately 9 percent of NSP- Minnesota's 2002 electric system capability. The risk of loss from nonperformance by Manitoba Hydro is not considered significant, and the risk of loss from market price changes is mitigated through cost-of-energy rate adjustments.

At Dec. 31, 2002, the estimated future payments for capacity that NSP-Minnesota is obligated to purchase, subject to availability, are as follows (Thousands of dollars):

	NSP-Minnesota*
2003	$ 133,688
2004	129,578
2005	108,828
2006	108,129
2007 and thereafter	1,442,140
Total	$ 1,922,363

* Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Environmental Contingencies

We are subject to regulations covering air and water quality, the storage of natural gas and the storage and disposal of hazardous or toxic wastes. We continuously assess our compliance. Regulations, interpretations and enforcement policies can change, which may impact the cost of building and operating our facilities.

Site Remediation — We must pay all or a portion of the cost to remediate sites where past activities of our subsidiaries and some other parties have caused environmental contamination. At Dec. 31, 2002 there were two categories of sites for NSP-Wisconsin:

- third party sites, such as landfills, to which we are alleged to be a potentially responsible party (PRP) that sent hazardous materials and wastes, and
- sites of former manufactured gas plants (MGP's) operated by our subsidiaries or predecessors.

We record a liability when we have enough information to develop an estimate of the cost of remediating a site and revise the estimate as information is received. The estimated remediation cost may vary materially.

To estimate the cost to remediate these sites, we may have to make assumptions where facts are not fully known. For instance, we might make assumptions about the nature and extent of site contamination, the extent of required cleanup efforts, costs of alternative cleanup methods and pollution control technologies, the period over which remediation will be performed and paid for, changes in environmental remediation and pollution control requirements, the potential effect of technological improvements, the number and financial strength of other PRPs and the identification of new environmental cleanup sites.

We revise our estimates as facts become known, but at Dec. 31, 2002 our estimated liability for the cost of remediating sites was:

	Total Liability	Current Portion of Liability
	(Millions of dollars)	
NSP-Wisconsin	23.1	2.0

Some of the cost of remediation may be recovered from:

- insurance coverage;
- other parties that have contributed to the contamination; and
- customers.

Neither the total remediation cost nor the final method of cost allocation among all PRPs of the unremediated sites has been determined. We have recorded estimates of our share of future costs for these sites. We are not aware of any other parties' inability to pay, nor do we know if responsibility for any of the sites is in dispute.

Asbestos Removal — Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Since we intend to operate most of these facilities indefinitely, we cannot estimate the amount or timing of payments for its final removal. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Ashland MGP Site — NSP-Wisconsin was named as one of three PRPs for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland site includes property owned by NSP-Wisconsin and two other properties: an adjacent city lakeshore park area and a small area of Lake Superior's Chequemegon Bay adjoining the park.

The Wisconsin Department of Natural Resources (WDNR) and NSP-Wisconsin have each developed several estimates of the ultimate cost to remediate the Ashland site. The estimates vary significantly, between $4 million and $93 million, because different methods of remediation and different results are assumed in each. The Environmental Protection Agency (EPA) and WDNR have not yet selected the method of remediation to use at the site. Until the EPA and the WDNR select a remediation strategy for all operable units at the site and determine the level of responsibility of each PRP, we are not able to accurately determine our share of the ultimate cost of remediating the Ashland site.

In the interim, NSP-Wisconsin has recorded a liability for an estimate of its share of the cost of remediating the portion of the Ashland site that it owns, estimated using information available to date and using reasonably effective remedial methods. NSP-Wisconsin has deferred, as a regulatory asset, the remediation costs accrued for the Ashland site because we expect that the Public Service Commission of Wisconsin (PSCW) will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site, and has authorized recovery of similar remediation costs for other Wisconsin utilities.

We proposed, and the EPA and WDNR have approved, an interim action (a coal tar removal/ groundwater treatment system) for one operable unit at the site for which NSP-Wisconsin has accepted responsibility. The groundwater treatment system began operating in the fall of 2000. In 2002 NSP-Wisconsin installed additional monitoring wells in the deep aquifer to better characterize the extent and degree of contaminants in that aquifer while the coal tar removal system is operational. In 2002 a second interim response action was also implemented. As approved by the WDNR, this interim response action involved the removal and capping of a seep area in a city park. Surface soils in the area of the seep were contaminated with tar residues. The interim action also included the diversion and ongoing treatment of groundwater that contributed to the formation of the seep.

On Sept. 5, 2002, the Ashland site was placed on the National Priorities List (NPL). The NPL is intended primarily to guide the EPA in determining which sites require further investigation. Resolution of Ashland remediation issues is not expected until 2004 or 2005.

NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to the ultimate remediation cost of the entire site.

Plant Emissions — NSP-Wisconsin's French Island plant generates electricity by burning a mixture of wood waste and refuse derived fuel. The fuel is derived from municipal solid waste furnished under a contract with La Crosse County, Wisconsin. In late 2000, the EPA reversed a prior decision and found that the plant was subject to the federal large combustor regulations. Those regulations became effective on Dec. 19, 2000. NSP-Wisconsin did not have adequate time to install the emission controls necessary to come into compliance with the large combustor regulations by the compliance date. As a result, in early 2001, the EPA issued a finding of violation to NSP-Wisconsin. NSP-Wisconsin is engaged in ongoing settlement discussions with the EPA regarding the finding of violation. In April 2001, a conservation group sent NSP-Wisconsin a notice of intent to sue under the citizen suit provisions of the Clean Air Act. NSP-Wisconsin could be fined up to $27,500 per day for each violation.

In July 2001, the state of Wisconsin filed a lawsuit against NSP-Wisconsin in the Wisconsin Circuit Court for La Crosse County, contending that NSP-Wisconsin exceeded dioxin emission limits on numerous occasions between July 1995 and December 2000 at French Island. In September 2002, the Court approved a settlement in the case requiring NSP-Wisconsin to pay penalties of $167,579 and contribute $300,000 in installments through 2005 to help fund a household hazardous waste project in the La Crosse area.

In August 2001, NSP-Wisconsin received a Certificate of Authority to install control equipment necessary to bring the French Island plant into compliance with both the federal large combustor regulations and state dioxin standard. NSP-Wisconsin began construction of the new air quality equipment in late 2001 and completed construction in 2002. NSP-Wisconsin has reached an agreement with La Crosse County through which La Crosse County will pay for the extra emissions equipment required to comply with the regulations.

Legal Contingencies

In the normal course of business, Xcel Energy's utility subsidiaries are party to routine claims and litigation arising from prior and current operations. Xcel Energy's utility subsidiaries are actively defending these matters and have recorded an estimate of the probable cost of settlement or other disposition.

NSP-Wisconsin is the defendant in suits claiming electricity and/or stray voltage from NSP-Wisconsin's system has harmed plaintiffs' dairy herds and caused other damage and injuries. Total damages claimed in these proceedings are approximately $17.5 million. The ultimate outcome of these claims is not determinable at this time, and NSP-Wisconsin has recorded an estimate of costs necessary to settle or otherwise resolve these matters.

10. Regulatory Assets and Liabilities

NSP-Wisconsin prepares its financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 1 to the Financial Statements. Under SFAS No. 71, regulatory assets and liabilities can be created for amounts that regulators allow us to collect from, or require us to pay back to, customers in future electric and natural gas rates.

Any portion of our business that is not rate regulated cannot use SFAS No. 71 accounting. Efforts to restructure and deregulate the utility industry may further reduce or end our ability to apply SFAS No. 71 in the future. Write-offs and material changes to our balance sheet, income and cash flows may result in such circumstances.

The components of unamortized regulatory assets and liabilities on the balance sheets of NSP-Wisconsin at December 31 are:

	Note Ref.	Remaining Amortization Period	December 31, 2002	December 31, 2001
		(Thousands of dollars)		
AFDC recorded in plant(a)		Plant lives	$ 7,290	$ 7,391
Conservation programs(a)		Through 2003	1,296	1,597
Losses on reacquired debt	1	Term of Related Debt	9,328	9,968
Environmental costs	9	To be determined	26,833	14,803
State commission accounting adjustments(a)		Plant lives	2,858	2,718
Other		Various	507	646
Total regulatory assets			$ 48,112	$ 37,123
Investment tax credit deferrals			$ 10,134	$ 10,510
Interest on income tax refunds			603	—
Deferred income tax adjustments			474	5,572
Fuel costs, refunds and other			739	809
Total regulatory liabilities			$ 11,950	$ 16,891

(a) Earns a return on investment in the ratemaking process. These amounts are amortized consistent with recovery in rates.

The adoption of SFAS No. 143 in 2003 will also affect NSP-Wisconsin's accrued plant removal costs for other generation, transmission and distribution facilities. Although SFAS No. 143 does not recognize the future accrual of removal costs as a Generally Accepted Accounting Principles liability, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long periods over which the amounts were accrued and the changing of rates through time, we have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Accordingly, the estimated amounts of future removal costs, which are considered regulatory liabilities under SFAS No. 143 that are accrued in accumulated depreciation, are as follows at Dec. 31, 2002:

	(Millions of Dollars)
NSP-Wisconsin	$ 70

11. Segment and Related Information

NSP-Wisconsin has two reportable segments: Electric Utility and Gas Utility.

- NSP-Wisconsin's Electric Utility generates, transmits and distributes electricity in Wisconsin and Michigan. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities.
- NSP-Wisconsin's Gas Utility transmits, transports, stores and distributes natural gas and propane primarily in portions of Wisconsin and Michigan.

Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the All Other category.

To report net income for electric and natural gas utility segments, NSP-Wisconsin must assign or allocate all costs and certain other income. In general, costs are:

- directly assigned wherever applicable;
- allocated based on cost causation allocators wherever applicable; or
- allocated based on a general allocator for all other costs not assigned by the above two methods.

The accounting policies of the segments are the same as those described in Note 1 to the Financial Statements. Xcel Energy evaluates performance by each legal entity based on profit or loss.

Business Segments

NSP-Wisconsin

	Electric Utility	Gas Utility	All Other	Reconciling Eliminations	Consolidated Total
			(Thousands of dollars)		
2002					
Operating revenues from					

external customers	$458,571	$101,335	$ 761	$ —	$560,667
Intersegment revenues	166	808	—	—	974
Total revenues	458,737	102,143	761	—	561,641
Depreciation and amortization	39,026	5,390	50	—	44,466
Financing costs, mainly interest expense	20,770	2,333	14	—	23,117
Income tax expense	34,427	3,335	(837)	—	36,925
Segment net income	$ 48,580	$ 5,433	$ 360	$ —	$ 54,373

	Electric Utility	Gas Utility	All Other	Reconciling Eliminations	Consolidated Total
			(Thousands of dollars)		
2001					
Operating revenues from external customers	$450,723	$120,951	$ 692	$ —	$572,366
Intersegment revenues	172	2,102	—	—	2,274
Total revenues	450,895	123,053	692	—	574,640
Depreciation and amortization	36,713	4,932	—	—	41,645
Financing costs, mainly interest expense	19,871	2,198	—	—	22,069
Income tax expense	20,475	683	—	—	21,158
Segment net income	$ 32,258	$ 4,134	$ —	$ —	$ 36,392

12. Related Party Transactions

NSP-Wisconsin receives various administrative, management, environmental and other support services from Xcel Energy Services Inc., which began operations in August 2000. Prior to this, all of these support services resided in former NSP for NSP-Minnesota and NSP-Wisconsin and were allocated to the former NSP subsidiaries, as appropriate.

Viking Gas Transmission Co. (Viking), a subsidiary of Xcel Energy through 2002, transports gas purchased by NSP-Wisconsin from various suppliers. NSP Wisconsin purchased $1.6 million of transportation service from Viking during 2002.

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

	2002	2001
	(Thousands of dollars)	
NSP-Wisconsin		
Operating revenues:		
Electric	$ 80,200	$ 85,895
Operating expenses:		

Purchased and interchange power	205,174	218,534
Gas purchased for resale	95	244
Other operations*	50,449	46,371

* Other operations expense includes $36,695 and $28,816 paid to Xcel Energy Services Inc. in 2002 and 2001.

NSP-Wisconsin obtains short-term borrowings from NSP-Minnesota at NSP-Minnesota's average daily interest rate, including the cost of NSP-Minnesota's compensating balance requirements. Corresponding interest charges on NSP-Wisconsin's statement of income include $0.2 million and $0.4 million for 2002 and 2001.

NSP-Wisconsin's receivable from affiliates primarily represents amounts receivable from NSP-Minnesota for the Interchange Agreement. NSP-Wisconsin's notes payable to affiliates represents amounts payable to NSP-Minnesota.

13. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
	March 31, 2002	June 30, 2002	Sept. 30, 2002	Dec. 31, 2002
	(Thousands of dollars)			
Revenue	$ 157,402	$ 129,059	$ 130,232	$ 144,948
Operating income	34,682	24,917	27,562	26,337
Net income	17,951	12,418	12,496	11,508

	Quarter Ended			
	March 31, 2001	June 30, 2001	Sept. 30, 2001	Dec. 31, 2001(a)
	(Thousands of dollars)			
Revenue	$ 183,567	$ 122,005	$ 132,111	$ 136,957
Operating income	26,565	9,928	19,431	22,858
Net income	13,092	3,414	8,627	11,259

(a) 2001 results include special charges as discussed in Note 2 to the Financial Statements. Fourth quarter results were decreased by $2 million for a pretax special charge related to employee restaffing costs.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b) (c) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceeding Year				
2	Preceding yr. Reclassification from Account 219 Net Income				
3	Preceding Year Changes in Fair Value	-959.0000			
4	Total (lines 2 and 3)	-959.0000			
5	Balance of Account 219 at End of Preceding Yr/Beginning of Current Yr	-959.0000			
6	Current Year Reclassification From Account 219 to Net Income				
7	Current Year Changes in Fair Value	-767.0000			
8	Total (lines 6 and 7)	-767.0000			
9	Balance of Account 219 at End of Current Year	-1726.0000			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges [Specify] (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 72) (i)	Total Comprehensive Income (j)
1					
2					
3			-959.0000		
4			-959.0000	36392485.0000	
5			-959.0000		
6					
7			-767.0000		
8			-767.0000	54373246.0000	
9			-1726.0000		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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

Line No.	Classification (a)	Total (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	1,383,807,682	1,160,522,075
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,383,807,682	1,160,522,075
9	Leased to Others	2,832,049	2,832,049
10	Held for Future Use	33,563	33,563
11	Construction Work in Progress	18,039,955	14,034,979
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	1,404,713,249	1,177,422,666
14	Accum Prov for Depr, Amort, & Depl	591,241,015	476,944,921
15	Net Utility Plant (13 less 14)	813,472,234	700,477,745
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	588,851,356	474,555,262
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	1,685,503	1,685,503
22	Total In Service (18 thru 21)	590,536,859	476,240,765
23	Leased to Others		
24	Depreciation	704,156	704,156
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)	704,156	704,156
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	591,241,015	476,944,921

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
131,950,950				91,334,657	3
					4
					5
					6
					7
131,950,950				91,334,657	8
					9
					10
2,941,487				1,063,489	11
					12
134,892,437				92,398,146	13
66,050,194				48,245,900	14
68,842,243				44,152,246	15
					16
					17
66,050,194				48,245,900	18
					19
					20
					21
66,050,194				48,245,900	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
66,050,194				48,245,900	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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

1. Report below the original cost of electric plant in service according to the 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 which have not been classified to primary accounts 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. Show in a footnote the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		429,644
4	(303) Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)		429,644
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	74,018	
9	(311) Structures and Improvements	12,901,316	166,836
10	(312) Boiler Plant Equipment	54,049,224	11,731,143
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	6,714,308	1,054,763
13	(315) Accessory Electric Equipment	5,089,111	147,281
14	(316) Misc. Power Plant Equipment	1,065,044	63,375
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	79,893,021	13,163,398
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights		
18	(321) Structures and Improvements		
19	(322) Reactor Plant Equipment		
20	(323) Turbogenerator Units		
21	(324) Accessory Electric Equipment		
22	(325) Misc. Power Plant Equipment		
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)		
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights	2,437,593	
26	(331) Structures and Improvements	16,291,735	64,962
27	(332) Reservoirs, Dams, and Waterways	123,431,166	118,052
28	(333) Water Wheels, Turbines, and Generators	35,535,155	27,931
29	(334) Accessory Electric Equipment	22,979,360	572,091
30	(335) Misc. Power PLant Equipment	3,527,692	
31	(336) Roads, Railroads, and Bridges		
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	204,202,701	783,036
33	D. Other Production Plant		
34	(340) Land and Land Rights	192,347	
35	(341) Structures and Improvements	2,180,086	7,671
36	(342) Fuel Holders, Products, and Accessories	2,308,281	
37	(343) Prime Movers	31,479,330	152,631
38	(344) Generators	17,936,636	
39	(345) Accessory Electric Equipment	5,807,784	70,374

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

instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in 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 requirement 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 purchase, 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
					2
			429,644		3
					4
			429,644		5
					6
					7
			74,018		8
			13,068,152		9
			65,780,367		10
					11
			7,769,071		12
			5,236,392		13
			1,128,419		14
			93,056,419		15
					16
					17
					18
					19
					20
					21
					22
					23
					24
			2,437,593		25
			16,356,697		26
			123,549,218		27
			35,563,086		28
			23,551,451		29
			3,527,692		30
					31
			204,985,737		32
					33
			192,347		34
			2,187,757		35
			2,308,281		36
			31,631,961		37
			17,936,636		38
			5,878,158		39

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
40	(346) Misc. Power Plant Equipment	602,208	
41	TOTAL Other Prod. Plant (Enter Total of lines 34 thru 40)	60,506,672	230,676
42	TOTAL Prod. Plant (Enter Total of lines 15, 23, 32, and 41)	344,602,394	14,177,110
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	12,608,062	10,408
45	(352) Structures and Improvements	1,457,720	
46	(353) Station Equipment	122,653,291	3,444,997
47	(354) Towers and Fixtures	2,473,482	66,339
48	(355) Poles and Fixtures	85,782,206	800,047
49	(356) Overhead Conductors and Devices	95,825,950	737,493
50	(357) Underground Conduit	65,524	
51	(358) Underground Conductors and Devices	217,962	
52	(359) Roads and Trails	104,023	
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	321,188,220	5,059,284
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	1,019,591	-7,362
56	(361) Structures and Improvements	1,145,649	
57	(362) Station Equipment	78,917,504	552,832
58	(363) Storage Battery Equipment		
59	(364) Poles, Towers, and Fixtures	65,972,467	1,032,232
60	(365) Overhead Conductors and Devices	78,437,867	1,497,766
61	(366) Underground Conduit	9,706,779	159,559
62	(367) Underground Conductors and Devices	49,148,632	7,879,379
63	(368) Line Transformers	69,548,436	1,007,175
64	(369) Services	53,663,047	3,209,441
65	(370) Meters	18,909,711	132,153
66	(371) Installations on Customer Premises	7,027,772	26,865
67	(372) Leased Property on Customer Premises		226,148
68	(373) Street Lighting and Signal Systems	5,387,170	
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	438,884,625	15,716,188
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	166,403	
72	(390) Structures and Improvements	3,903,595	1,079,596
73	(391) Office Furniture and Equipment	2,582,435	92,189
74	(392) Transportation Equipment	1,871,774	
75	(393) Stores Equipment	136,653	
76	(394) Tools, Shop and Garage Equipment	4,712,131	173,292
77	(395) Laboratory Equipment	2,772,322	36,652
78	(396) Power Operated Equipment	1,023,580	
79	(397) Communication Equipment	5,547,279	677
80	(398) Miscellaneous Equipment	15,393	2,338
81	SUBTOTAL (Enter Total of lines 71 thru 80)	22,731,565	1,384,744
82	(399) Other Tangible Property		
83	TOTAL General Plant (Enter Total of lines 81 and 82)	22,731,565	1,384,744
84	TOTAL (Accounts 101 and 106)	1,127,406,804	36,766,970
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 (Enter Total of lines 84 thru 87)	1,127,406,804	36,766,970

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
			602,208		40
			60,737,348		41
			358,779,504		42
					43
			12,618,470		44
			1,457,720		45
37,733		207,657	126,268,212		46
			2,539,821		47
21,082			86,561,171		48
			96,563,443		49
			65,524		50
			217,962		51
			104,023		52
58,815		207,657	326,396,346		53
					54
			1,012,229		55
7,468		77,404	1,215,585		56
119,150		-285,061	79,066,125		57
					58
366,265			66,638,434		59
228,998			79,706,635		60
6,421			9,859,917		61
2,457,754			54,570,257		62
19,262			70,536,349		63
288,898			56,583,590		64
			19,041,864		65
32,690			7,021,947		66
27,857			198,291		67
			5,387,170		68
3,554,763		-207,657	450,838,393		69
					70
			166,403		71
			4,983,191		72
			2,674,624		73
31,639			1,840,135		74
			136,653		75
			4,885,423		76
			2,808,974		77
6,483			1,017,097		78
			5,547,956		79
			17,731		80
38,122			24,078,187		81
					82
38,122			24,078,187		83
3,651,700			1,160,522,074		84
					85
					86
					87
3,651,700			1,160,522,074		88

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	**CHIPPEWA AND FLAMBEAU	CHIPPEWA RESERVOIR LOCATED			
2	IMPROVEMENT COMPANY	ON CHIPPEWA RIVER NEAR			
3		WINTER, WI.			
4					
5		EXEMPT LICENSED	11/26/1921		2,832,049
6		PROJECT NO. 8286			
7					
8					
9					
10					
11					
12					
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41					
42					
43					
44					
45					
46					
47	TOTAL				2,832,049

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 Rights:			
2	FUTURE SITE OF MERCER SUBSTATION (6 ACRES)			
3	IN MERCER IN IRON COUNTY, WI	6/1/77		2,285
4	FUTURE SITE FOR 115/69KV SUBSTATION (40 ACRES)			
5	IN TWN OF FLAMBEAU, PRICE COUNTY, WI.	4/1/77		8,103
6	FUTURE SITE FOR EAU CLAIRE WEST SUBSTATION			
7	(2 ACRES) CITY OF EAU CLAIRE, EAU CLAIRE CO., WI.	7/1/95		23,175
8				
9				
10				
11				
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14				
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16				
17				
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20				
21	Other Property:			
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42				
43				
44				
45				
46				
47	Total			33,563

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (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	T-CORNERS SUB-115KV (4) 25 MVAR CAP BANK	2,420,847
2	T-CORNERS SUB-INSTALL CAP BANKS	1,189,560
3	LADYSMITH TORNADO DAMAGE	1,003,202
4	HURLEY SUB-INSTALL INFRASTRUCTURE	771,734
5	WISSOTA HYDRO RELICENSING	600,332
6	HAYWARD COUNTY B 3 PHASE SYSTEM	466,309
7	PLUM CITY-COUNTY ROAD CC\REBUILD 3 PHASE	407,934
8	3432 T-LINE RELOCATE TO UG LACROSSE	387,531
9	WHEATON-U3 BUCKETS 1ST STAGE	372,008
10	FI SUB-REPLACE LAX LINE RELAYS	354,598
11	PURCHASE DISTR LINE TRANSFORMERS	346,686
12	WHEATON-U3 TRANSITION PIECES	305,935
13	PURCH CUST ELEC METER EQUIPMENT	278,603
14	DELLS HYDRO-RELICENSING	250,000
15	HYDRO MAINTENANCE BLDG-BLASTING/PAINTING	216,566
16	CAMERON SUB-REPLACE TRANSFORMER	214,460
17	VIROQUA SUB-UPGRADE 69KV BUS	364,011
18	FI STEAM-FEN WOOD DUST COLLECTION SYSTEM	194,434
19	PASSPORT WMS ACCOUNT VALIDATION	185,639
20	SOMERSET-NEW SUBSTATION	160,413
21	ATHENS STH29/97 HIWAY BILLING	158,835
22	COULEE SUB-COUO72 FEEDER BAY	153,016
23	CASHTON SUB-REPL CAP BANK SWITCH	131,002
24	INDEPENDENCE-NEW BUGLE LAKE SUBSTATION	108,903
25	MW/MERCER/PI STORM PROJECT	102,462
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39	MINOR PROJECTS-NONE OF WHICH EXCEED $100,000	2,889,959
40		
41		
42		
43	TOTAL	14,034,979

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

CONSTRUCTION OVERHEADS - ELECTRIC

1. List in column (a) to kinds of overheads according to the titles used by the 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 the 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		
2		
3		
4		
5		
6		
7		
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10		
11		
12		
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39		
40		
41		
42		
43		
44		
45		
46	TOTAL	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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

1. Explain in a footnote any important adjustments during 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 9d), 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	443,723,356	443,057,657		665,699
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	35,144,660	35,144,660		
4	(413) Exp. of Elec. Plt. Leas. to Others	38,457			38,457
5	Transportation Expenses-Clearing	211,341	211,341		
6	Other Clearing Accounts				
7	Other Accounts (Specify, details in footnote):				
8					
9	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 8)	35,394,458	35,356,001		38,457
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	3,651,700	3,651,700		
12	Cost of Removal	922,894	922,894		
13	Salvage (Credit)	735,696	735,696		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	3,838,898	3,838,898		
15	Other Debit or Cr. Items (Describe, details in footnote):	-19,498	-19,498		
16					
17	Balance End of Year (Enter Totals of lines 1, 9, 14, 15, and 16)	475,259,418	474,555,262		704,156
	Section B. Balances at End of Year According to Functional Classification				
18	Steam Production	53,737,709	53,737,709		
19	Nuclear Production				
20	Hydraulic Production-Conventional	76,474,647	76,474,647		
21	Hydraulic Production-Pumped Storage				
22	Other Production	53,383,329	53,383,329		
23	Transmission	99,441,865	99,441,865		
24	Distribution	177,741,868	177,741,868		
25	General	13,775,844	13,775,844		
26	TOTAL (Enter Total of lines 18 thru 25)	474,555,262	474,555,262		

FOOTNOTE DATA

Schedule Page: 219 Line No.: 15 Column: c

Figures Include:	
Changes in Retirement Work in Progress	-19,498
Miscellaneous Transfers	0
Total	-19,498

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL 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 open account. List each note giving date of issuance, maturity date, and specifying whether 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	Chippewa & Flambeau Improvement Company (a)(b)			
2				
3	Capital Stock, Par Value $76	12/24/94		
4	Per Share 6%	10/15/92		549,326
5	Equity in undistributed earnings			143,556
6	SUBTOTAL			692,882
7				
8	Clearwater Investments, Inc			
9	Capital Stock	6/1/92		150,000
10	Equity in undistributed earnings			2,021,375
11	SUBTOTAL			2,171,375
12				
13	NSP lands, Inc.			
14	Capital Stock	6/1/92		50,000
15	Equity in undristibuted earnings			402,972
16	SUBTOTAL			452,972
17				
18	(a) Includes $204,817.55 par value of 204,831,755			
19	shares received as stock dividends			
20	Includes 2,124 shares, par value $212,400			
21	and book value of $131,392 acquired in			
22	merger of LSDP effective Jan. 1, 1987			
23				
24	(b) Cost to respondent was $550,114;			
25	Difference of $788.32 represents excess of			
26	cost over par value of 27 shares acquired in			
27	September 1929 through open account of			
28	$3,488.23 from Chippewa River Power and			
29	Fibre Company, an associated company.			
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42	Total Cost of Account 123.1 $ 749,326		TOTAL	3,317,229

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

INVESTMENTS 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 column (f) interest and dividend revenues form investments, including such revenues form 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 cost of the investment (or the other amount at which carried in the books of account if difference 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 of 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
				3
		549,326		4
39,259	38,053	144,762		5
39,259	38,053	694,088		6
				7
				8
		150,000		9
230,839		2,252,214		10
230,839		2,402,214		11
				12
				13
		50,000		14
-5,097		397,875		15
-5,097		447,875		16
				17
				18
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265,001	38,053	3,544,177		42

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	5,641,235	5,753,062	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	302,412	328,850	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	3,591,114	2,928,332	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	750,255	1,022,583	Electric
8	Transmission Plant (Estimated)	230,623	237,461	Electric
9	Distribution Plant (Estimated)	1,346,697	1,756,881	Electric & Gas
10	Assigned to - Other (provide details in footnote)			
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	5,918,689	5,945,257	
12	Merchandise (Account 155)	66,608	-43,002	Electric
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
15	Stores Expense Undistributed (Account 163)	-100,362	91,405	Electric
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	11,828,582	12,075,572	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the rate making actions of regulatory agencies (and not includable in other accounts)
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	AFC in Excess of FERC-Carrying Charges-Electric	200,678	404 & 421	98,406	2,122,421
2					
3	AFC in Excess of FERC-Carrying Charges-Gas	49,493	404 & 421	31,204	429,839
4					
5	AFC in Excess of FERC-Carrying Charges-Common	32,927	404 & 421	13,289	305,831
6					
7	AFC in Plant on a Net of Tax Basis Pre 88 Debt	29,000	283	106,000	727,000
8					
9	AFC in Plant on a Net of Tax Basis Pre 87 Equity	171,000	283	195,000	6,563,000
10					
11	Capitalized DSM Expenses		910	901,066	901,066
12			254	74,004	
13					
14	Pension Transition Liability		186	90,000	448,000
15					
16	Environmental Clean-up	12,333,897	735	304,042	26,833,339
17					
18	Public Benefits	48,414	908	52,914	14,389
19					
20	Network Transmission Service	2,418	557	46,710	44,292
21					
22	Conservation Programs	395,234			395,234
23					
24					
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44	TOTAL	13,263,061		1,912,635	38,784,411

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (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	Misc Debits Under $50,000	21,923	34,610	426	13,811	42,722
2						
3	Est. Reimbursement-Orienta Dam	204,388	3,245			207,633
4						
5	Pensions Accrued-SFAS 87	28,563,000	10,164,667	184	170,667	38,557,000
6						
7	Contracts Receivable	3,775,728	888,383	various	255,665	4,408,446
8						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	32,565,039				43,215,801

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Vacation Reserve	743,026	591,414
3	Conservation Expenditures	-25,551	-243,579
4	Customer Advances	4,225,627	4,832,970
5	Deferred Compensation	1,117,060	1,436,813
6	Plant Related	3,462,901	9,953,938
7	Other	-6,955,989	-10,323,530
8	TOTAL Electric (Enter Total of lines 2 thru 7)	2,567,074	6,248,026
9	Gas		
10	Vacation Reserve	112,500	90,404
11	Conservation Expenditures	435,954	730,842
12	Customer Advances	260,022	403,204
13	Deferred Compensation	162,802	209,401
14	Plant Related	35,656	1,377,692
15	Other	3,734,447	7,697,340
16	TOTAL Gas (Enter Total of lines 10 thru 15	4,741,381	10,508,883
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	7,308,455	16,756,909

Notes

Electric "Other" Includes:

	Beginning	Ending
Lawsuits	462,415	973,921
Medical	0	155,416
Uncollectibles	489,438	403,349
Exec Incent Plan	81,349	25,227
Early Retirement	521,277	526,462
Lower Cost/Market	0	0
Reg Res/Emission	(92,953)	15,289
Pension Liabil	(9,033,470)	(12,060,439)
Post Retire Liab	231,052	(430,919)
Severence	243,115	2,770
Post Employment	107,840	(1,689)
Ashland & Others	33,948	(156,827)
Interest Reg. Pay	0	223,910
Total	(6,955,989)	(10,323,530)

Gas "Other" Includes:

	Beginning	Ending
	0	0
	0	22,650
	(7,114)	(11,274)
	11,854	3,674
	76,244	77,003
	26,837	49,593
	(44)	0
	(1,463,243)	(1,953,551)
	33,670	(62,804)
	39,379	447
	15,716	(247)
	5,001,148	9,550,835
	0	21,014
Total	3,734,447	7,697,340

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

CAPITAL STOCKS (Account 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 end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	1,000,000	100.00	
2				
3	Total Common	1,000,000		
4				
5				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

CAPITAL STOCKS (Account 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 non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
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 purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
933,000	93,300,000					1
						2
933,000	93,300,000					3
						4
						5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 necessary. Explain changes made in any account during the year and give the accounting 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 or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change 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 the 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	Acquisition of Natural Gas, Inc. common stock	80,000
3		
4	Contribution of capital by parent company in 2001	26,353,637
5		
6	Contribution of capital by parent company in 2002	3,209,940
7		
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40	TOTAL	29,643,577

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

LONG-TERM DEBT (Account 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 authorization 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 the principal amount of bonds 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. For 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. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

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 Bonds		
2			
3	First Mortgage Bonds, 7 3/8%	65,000,000	493,150
4			268,450 D
5			
6	First Mortgage Bonds, 7 1/4%	110,000,000	1,151,265
7			1,722,600 D
8			
9	First Mortgage Bonds, 5 3/4%	40,000,000	329,513
10			209,600 D
11			
12	Account 222 Reacquired Bonds		
13	None		
14			
15	Account 223 Advance from Associated Compnaies		
16	None		
17			
18	Account 224 Other Long Term Debt		
19	Senior Note 7.64% - DOCKET 4220-SB-118 ORDER EFFECTIVE 10/6/99	80,000,000	581,441
20	Other Long Term Debt-Fort McCoy 7% - ISSUED IN CONJUNCTION WITH TARIFF FILING,	996,655	
21	LETTER ORDER DATED SEPTEMBER 29, 2000.		
22	Resource Recovery Revenue Bonds 6%	18,600,000	248,410
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	314,596,655	5,004,429

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (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) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including 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 end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of 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)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
12/1/96	12/1/26	12/1/96	11/30/26	65,000,000	4,793,750	3
						4
						5
3/1/93	3/1/23	3/1/93	2/28/23	110,000,000	7,975,000	6
						7
						8
10/1/93	10/1/03	10/1/93	9/30/03	40,000,000	2,300,046	9
						10
						11
						12
						13
						14
						15
						16
						17
						18
10/1/00	10/1/08	10/1/00	9/30/08	80,000,000	6,095,027	19
10/15/00	10/15/30	10/15/00	10/14/30	929,085	66,416	20
						21
11/1/96	11/1/21	11/1/96	10/31/21	18,600,000	1,116,000	22
						23
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				314,529,085	22,346,239	33

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 detail as furnished on Schedule M-1 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 taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, 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. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	54,373,246
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	91,297,979
28	Show Computation of Tax:	
29	Pre Tax Income	91,297,979
30	2002 Effective Composite Tax Rate .4133	
31	Expected Tax on Pretax Income	37,731,503
32		
33	Federal Tax	29,711,178
34	Wisconsin Tax	7,217,249
35	Michigan Tax	803,076
36		
37	TOTAL	37,731,503
38		
39	Income After Taxes	53,566,476
40	Investment Tax Credit	806,769
41	Misc. Difference	1
42	NET INCOME	54,373,246
43		
44		

Schedule Page: 261 Line No.: 44 Column: a

BOOK INCOME TO TAXABLE INCOME
FORECASTED PRETAX INC (from ETR) & PERM M-1s(from ETR)

PRETAX BOOK INCOME	91,297,979
SCHEDULE M-1 ADJUSTMENTS	
PLANT TEMPORARY M-1'S	
BOOK DEPRECIATION	44,232,474
AMORTIZATION-COMPUTER SOFTWARE	261,103
CLEARING ACCOUNT BOOK EXPENSE	1,845,606
SUBTOTAL BOOK DEPRECIATION	46,339,183
TAX DEPRECIATION	(47,153,719)
JOB CREATION ACT	(7,221,424)
SUBTOTAL DEPRECIATION ADJUSTMENTS	(8,035,960)
ADR REPAIR ALLOWANCE	(995,792)
AFDC DEBT	(277,886)
AVOIDED COST INTEREST	760,765
BOOK CAPITALIZED COSTS	(4,000,000)
CONTRIBUTIOS IN AID OF CONSTRUCTION	4,830,274
INTEREST EXPENSE-VEHICLE LEASES	(192,963)
INTERNALLY DEVELOPED SOFTWARE	(463,708)
LOSS ON DISPOSITIONS-TAX	(915,047)
REUSEABLE MATERIAL PRICING ADJUST	20,368
SAVER SWITCH EXPENDITURES	(26,796)
TAX REMOVAL COST OVER BOOK	(976,506)
SUBTOTAL OTHER PLANT ADJUSTMENTS	(2,237,291)
TOTAL PLANT TEMPORARY M-1'S	(10,273,251)
NONPLANT TEMPORARY M-1'S	
BAD DEBTS	(3,993)
BOOK UNAMORT. COST OF REACQUIRED DBT	639,883
DEFERRED COMPENSATION PLAN RESERVE	879,208
ENVIRONMENTAL REMEDIATION	10,121,000
EXECUTIVE INCENTIVE PLANS	(64,052)
INTEREST INC/EXP ON DISPUTED TAX (audit)	603,098
LITIGATION RESERVE	1,248,221
PENSION EXPENSE	(8,418,400)
POST EMPLOYMENT BENEFITS-FAS 106	(1,518,028)
POST EMPLOYMENT BENEFITS-FAS 112	(182,040)
PREPAID EXPENSES	(590,051)
PREPAID INSURANCE	(205,410)
PUCIP ADJ	651,840
REGULATORY ASSET-NETWORK TRANS SRV	38,183
REGULATORY RESERVE	667,961
REGULATORY RESERVE-ENVIRONMENTAL	(11,573,387)
SALE OF EMISSION ALLOWANCES	9,802
SEVERANCE ACCRUAL	(1,658,423)
SUBTOTAL NONPLANT TEMPORARY M-1'S	(9,354,588)
PERMANENT M-1'S	
AFDC-EQUITY	(497,688)
EQUITY EARNINGS IN SUBS	(265,002)
INSURANCE FUND INCOME (CASH VALUE)	(150,000)

FOOTNOTE DATA

LOBBYING EXPENSES	50,000
MEALS & ENTERTAINMENT	120,000
STOCK OPTIONS	(176,214)
SUBTOTAL PERMANENT M-1'S	(918,904)
TOTAL SCHEDULE M-1 ADJUSTMENTS	(20,546,743)
FEDERAL TAXABLE INCOME BEFORE STATE TAXES	70,751,236

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the 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 know, 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 direct 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 proportions 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 manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL					
2	Income	-1,475,751		12,646,521	10,312,339	41,343
3	Unemploymnet-01	3,718			3,718	
4	Unemployment-02			38,844	35,418	
5	FICA-01	12,958			12,958	
6	FICA-02			3,047,529	2,913,520	
7						
8	WISCONSIN					
9	Income	-1,224,968		2,568,453	4,938,982	-1,924,995
10	Unemployment-01	1,592			1,592	
11	Unemployment-02		12,500	19,773	20,160	
12	Gross Recipts		13,144,510	12,469,660	13,059,711	
13	Real Estate-01	62,760			62,760	
14	Real Estate-02			134,007	598	
15	Use-01	49,519			49,519	
16	Use-02			233,253	212,688	
17	Remainder Assessment		300,739			-300,739
18						
19	MICHIGAN					
20	Income	-33,607		338,544	125,000	
21	Unemployment-01	133			133	
22	Unemployment-02			3,596	3,385	
23	Real Estate-01					
24	Real Estate-02			117,044	80,686	
25	Personal Property-01					
26	Personal Property-02			466,035	316,270	
27	Use-01	405			405	
28	Use-02			2,201	2,084	
29	Remainder Assessment		3,959			-3,959
30						
31	Service Company Allocation			11,278	11,278	
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-2,603,241	13,461,708	32,096,738	32,163,204	-2,188,350

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then 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 foot- note. 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. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
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				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
817,088		14,386,029			-1,739,508	2
						3
3,427		32,408			6,436	4
						5
134,009		2,460,521			587,008	6
						7
						8
-1,670,502		3,067,419			-498,966	9
						10
-387	12,500	16,330			3,443	11
	13,734,561	11,346,516			1,123,144	12
						13
133,409		-4,088			138,095	14
						15
20,564					233,253	16
						17
						18
						19
179,937		287,201			51,343	20
						21
210		3,015			581	22
						23
36,358		110,300			6,745	24
						25
149,765		365,303			100,732	26
						27
117					2,201	28
						29
						30
		9,825			1,453	31
						32
						33
						34
						35
						36
						37
						38
						39
						40
-196,005	13,747,061	32,080,779			15,960	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	100,108				22,571	
4	7%						
5	10%	14,971,392				728,165	
6							
7							
8	TOTAL	15,071,500				750,736	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Gas Utility						
12	4%	11,129				2,177	
13	10%	540,975				53,856	
14							
15							
16	Total Gas	552,104				56,033	
17							
18							
19							
20							
21							
22							
23							
24							
25	Non Utility						
26	10%	4,752					-1,670
27							
28							
29							
30							
31	Total Non Utility	4,752					-1,670
32							
33	Utility & Non Utili	15,628,356				806,769	-1,670
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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
			2
77,537			3
			4
14,243,227			5
			6
			7
14,320,764			8
			9
			10
			11
8,952			12
487,119			13
			14
			15
496,071			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
3,082			26
			27
			28
			29
			30
3,082			31
			32
14,819,917			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

OTHER DEFFERED 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 and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Line Extension Projects	605,246	various	2,359,127	1,812,547	58,666
2						
3	Deferred Comp. Liability	1,801,583	various	1,640,476	657,476	818,583
4						
5	Ashland & Other Remediation Costs	10,100,000			11,005,000	21,105,000
6						
7	Downtown Building Valuation	556,000	101 &121	906,000	350,000	
8						
9	SFAS 106 Benefits Liability		184	2,931,037	7,829,979	4,898,942
10						
11	Deferred Comp. Wealth Option		various	1,471,411	2,296,491	825,080
12						
13	Other Deferred Liability				18,572	18,572
14						
15						
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						
42						
43						
44						
45						
46						
47	TOTAL	13,062,829		9,308,051	23,970,065	27,724,843

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (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	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	25,958		9,579
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	25,958		9,579
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	25,958		9,579
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax	25,958		9,579
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
						16,379	4
							5
							6
							7
						16,379	8
							9
							10
							11
							12
							13
							14
							15
							16
						16,379	17
							18
							19
						16,379	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (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	118,881,996	22,958,345	588,449
3	Gas	4,965,814	2,119,933	-107,587
4				
5	TOTAL (Enter Total of lines 2 thru 4)	123,847,810	25,078,278	480,862
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	123,847,810	25,078,278	480,862
10	Classification of TOTAL			
11	Federal Income Tax	104,111,768	15,419,805	295,666
12	State Income Tax	19,736,042	9,658,473	185,196
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						141,251,892	2
						7,193,334	3
							4
						148,445,226	5
							6
							7
							8
						148,445,226	9
							10
						119,235,907	11
						29,209,319	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

ACCUMULATED DEFFERED 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 (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	Electric			
3	Bond Reacquistion	3,690,247	36,639	238,777
4	Capitalized DSM	590,711	5,881	298,296
5	Prepaid Insurance			
6	Deferred Transmission & Nuclea	35,618	354	15,505
7	Prepaid Gross Receipts Tax	3,871,059	1,323,399	
8	Other	64,088	298,759	-10,026
9	TOTAL Electric (Total of lines 3 thru 8)	8,251,723	1,665,032	542,552
10	Gas			
11	Bond Reacquistion	317,819	3,234	21,083
12	Capitalized DSM	133,927	1,334	67,636
13	Prepaid Insurance			
14	Unbilled Revenue Purchased Gas	-558,913	576,097	
15	Prepaid Gross Receipts Tax	258,941	124,206	
16	Other	5,950,760	4,815,061	-873
17	TOTAL Gas (Total of lines 11 thru 16)	6,102,534	5,519,932	87,846
18	Non Utility	-8,650,279		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	5,703,978	7,184,964	630,398
20	Classification of TOTAL			
21	Federal Income Tax	5,497,911	5,194,904	496,278
22	State Income Tax	206,067	1,990,060	134,120
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						3,488,109	3
						298,296	4
							5
						20,467	6
						5,194,458	7
						372,873	8
						9,374,203	9
							10
						299,970	11
						67,625	12
							13
						17,184	14
						383,147	15
						10,766,694	16
						11,534,620	17
	12,071				5,372,999	-3,289,351	18
	12,071				5,372,999	17,619,472	19
							20
	12,071				4,352,999	14,537,465	21
					1,020,000	3,082,007	22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

OTHER REGULATORY LIABILITIES (Account 254)

1. Reporting below the particulars (Details) called for concerning other regulatory liabilities which are created through the rate-making 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	Excess Deferred Income Taxes Collected	283	5,098,000		474,000
2					
3	ITC Gross Up	283	408,000	32,000	10,134,000
4					
5	Fuel and Other Refunds	431	4,747	1,011,180	266,264
6					
7	Emission Alowances	557	29,049	36,433	107,431
8					
9	Conservation Programs	908	7,657,014	6,207,943	
10					
11	Interest on Wis Income Tax Refund			603,098	603,098
12					
13	Purchased Gas Over/Under Recovery	805.1	8,106,820	6,552,848	1,916,432
14					
15	Retirement and Removal of Orienta Falls Dam	182.1	5,036	370,049	365,013
16	Authorized Under PSCW Docket 4220-UR-110				
17					
18					
19					
20					
21					
22					
23					
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39					
40					
41	TOTAL		21,308,666	14,813,551	13,866,238

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	142,521,843	135,350,441
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	70,180,426	68,549,093
5	Large (or Ind.) (See Instr. 4)	138,284,125	134,149,835
6	(444) Public Street and Highway Lighting	3,463,075	3,393,213
7	(445) Other Sales to Public Authorities	1,020,882	1,011,297
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	165,849	171,679
10	TOTAL Sales to Ultimate Consumers	355,636,200	342,625,558
11	(447) Sales for Resale	20,404,138	18,705,908
12	TOTAL Sales of Electricity	376,040,338	361,331,466
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	376,040,338	361,331,466
15	Other Operating Revenues		
16	(450) Forfeited Discounts	518,153	565,074
17	(451) Miscellaneous Service Revenues	725,089	457,507
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	640,090	734,082
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	538,230	1,638,191
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	2,421,562	3,394,854
27	TOTAL Electric Operating Revenues	378,461,900	364,726,320

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

ELECTRIC OPERATING REVENUES (Account 400)

4. Commercial 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 pages 108-109, Important Changes During Year, for important new territory added and important rate increase 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		AVG.NO. CUSTOMERS PER MONTH		Line No.
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
				1
1,874,118	1,779,853	196,639	193,223	2
				3
1,057,115	1,031,060	32,315	31,717	4
2,788,770	2,723,561	1,591	1,534	5
23,790	23,376	654	635	6
13,888	13,911	439	435	7
				8
2,122	2,271	10	10	9
5,759,803	5,574,032	231,648	227,554	10
563,829	518,295	10	10	11
6,323,632	6,092,327	231,658	227,564	12
				13
6,323,632	6,092,327	231,658	227,564	14

Line 12, column (b) includes $ -1,811,214 of unbilled revenues.

Line 12, column (d) includes -6,841 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 26 Column: b

Dec-2002

ELECTRIC OPERATING REVENUES
(Accounts 450-456)

Detail of Other Operating Revenues by Jurisdiction

	Total Co.	Wis	Mich
(450) Forfeited Discounts	**518,153**	**507,574**	**10,579**
(451) Misc. Service Revenues			
Service Connections	585,324	577,684	7,640
Returned Check Charges	18,150	17,810	340
Tariff Based-firm PTP	106,723	106,723	0
Misc. Work Performed	14,892	14,538	354
Total (451)	**725,089**	**716,755**	**8,334**
(454) Rent from Electric Property			
Rental E-Leases	220,376	215,131	5,245
Various Telephone & Cable TV Co.'s	419,714	391,037	28,677
Total (454)	**640,090**	**606,168**	**33,922**
(456) Other Electric Revenues			
Sales & Use Tax Handling	62,964	61,308	1,656
Michigan Power Supply Recovery	-1,011,179		-1,011,179
Regul. Freq. Resp. Service**	5,678	5,678	
Interchange Agreement NSP MN			
Wisconsin Power & Light Company	294,996	287,967	7,029
Other Interconnections	2,367	2,311	56
Wholesale Facility Charge**	167,355	163,372	3,983
Energy Imbalance Service**	674,269	674,269	
Network Integration Trans. Service**	297,082	297,082	
Miscellaneous Materials Sold	44,698	43,634	1,064
Total (456)	**538,230**	**1,535,621**	**-997,391**

**Amounts are included in Resale revenues at present rates (item RV01) on page 14 of 34 in the cost of service study.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule 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 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 schedule 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 (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Wisconsin Residential W/O Sp Htg					
2	==========					
3	Water Heating B00	1,792	126,270	667	2,687	0.0705
4	Residential B01	1,334,247	103,379,168	154,081	8,659	0.0775
5	Residential TOD B02	55,077	3,539,585	3,770	14,609	0.0643
6	Residential Managed Serv B03	12	835	1	12,000	0.0696
7	Farm Service B04	120,433	8,751,945	4,359	27,629	0.0727
8	Farm Service B08	145	10,187	21	6,905	0.0703
9	Optional Off Peak B11	146	5,713	19	7,684	0.0391
10	Automatic Protective B30					
11	Controlled Water Heating B37	28	2,075	10	2,800	0.0741
12	Unbilled	-1,590	-342,513			0.2154
13	Total Wi Res. W/O Space Heating	1,510,290	115,473,265	162,928	9,270	0.0765
14						
15	Wisconsin Residential With Sp Htg					
16	==========					
17	Residential Service B01	223,247	17,131,507	21,281	10,490	0.0767
18	Residential TOD B02	83,576	5,157,811	4,561	18,324	0.0617
19	Residential Managed Service B03					
20	Farm Service B04	372	27,388	18	20,667	0.0736
21	Optional Off Peak B11	100	3,647	11	9,091	0.0365
22	Automatic Protect Ltg. B30	3,600	397,502	5,550	649	0.1104
23	Unbilled	-2,523	-320,659			0.1271
24	Total Wi Res With Space Heating	308,372	22,397,196	31,421	9,814	0.0726
25						
26	Michigan Residential W/O Sp Htg					
27	==========					
28	Water Heating C03					
29	Residential C01	53,781	4,526,544	7,737	6,951	0.0842
30	Residential TOD C02	1,681	115,415	124	13,556	0.0687
31	Automatic Outdoor C04	143	19,962	227	630	0.1396
32	Unbilled	-149	-10,539			0.0707
33	Total Mi Res. W/O Space Heating	55,456	4,651,382	8,088	6,857	0.0839
34						
35	Wisconsin Small Comm. and Indust.					
36	==========					
37	Small General TOD B05	4,537	286,751	182	24,929	0.0632
38	Small General Service B06	347,724	26,901,317	24,522	14,180	0.0774
39	Small General Service B07	140	10,085	22	6,364	0.0720
40	Small General Service B09	8,940	757,421	1,423	6,283	0.0847
41	TOTAL Billed	5,766,644	357,447,414	241,393	23,889	0.0620
42	Total Unbilled Rev.(See Instr. 6)	-6,841	-1,811,214	0	0	0.2648
43	TOTAL	5,759,803	355,636,200	241,393	23,861	0.0617

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule 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 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 schedule 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 (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	General Service B10	593,667	36,152,493	4,711	126,017	0.0609
2	Optional Off Service B11	3,413	126,321	107	31,897	0.0370
3	Peak Controlled General B12	10,119	499,909	32	316,219	0.0494
4	Large TOD B13	52,288	2,728,497	104	502,769	0.0522
5	Automatic Protective B30	4,958	439,850	3,766	1,317	0.0887
6	Controlled Water Heating B37		3			
7	Underground Area Lighting B38	91	24,799	31	2,935	0.2725
8	Unbilled	-662	-255,900			0.3866
9	Total Wi Small Comm & Industria	1,025,215	67,671,546	34,900	29,376	0.0660
10						
11	Michigan Small Comm & Industrial					
12	==========					
13	Controlled Water Heating C03					
14	Small Commercial Unmtred C9	339	31,814	58	5,845	0.0938
15	Small Commercial C10	14,154	1,214,835	1,035	13,675	0.0858
16	Time of Day	12	1,020	1	12,000	0.0850
17	Commercial/Industrial C12	14,483	1,080,142	112	129,313	0.0746
18	Industrial Rate Schedule C13	1,173	75,641	5	234,600	0.0645
19	Peak Controlled TOD C20	1,396	76,609	1	1,396,000	0.0549
20	Peak Controlled General C21	248	14,792	1	248,000	0.0596
21	Automatic Outdoor Lighting C04	201	21,247	143	1,406	0.1057
22	Unbilled	-106	-7,220			0.0681
23	Total Mi Small Comm & Industrial	31,900	2,508,880	1,356	23,525	0.0786
24						
25	Wisconsin Large Comm & Industrial					
26	==========					
27	General Service B10	298,378	17,412,526	708	421,438	0.0584
28	Optional Off Peak B11	66	2,517	2	33,000	0.0381
29	Peak Controlled General B12	14,799	759,869	34	435,265	0.0513
30	Large TOD	904,650	48,850,628	603	1,500,249	0.0540
31	Peak Controlled Time B14	159,997	8,001,834	111	1,441,414	0.0500
32	Power Supply Req W01	98,378	3,879,525	3	32,792,667	0.0394
33	Bundles Requirements W16	134,284	5,236,467	9	14,920,444	0.0390
34	>1000 TOD	761,720	36,239,042	78	9,765,641	0.0476
35	>1000 Peak Contrld TOD B14	370,808	15,974,870	18	20,600,444	0.0431
36	Unbilled	-1,694	-856,796			0.5058
37	Total Wi Large Comm & Industrial	2,741,386	135,500,482	1,566	1,750,566	0.0494
38						
39	Michigan Large Comm & Industrial					
40	==========					
41	TOTAL Billed	5,766,644	357,447,414	241,393	23,889	0.0620
42	Total Unbilled Rev.(See Instr. 6)	-6,841	-1,811,214	0	0	0.2648
43	TOTAL	5,759,803	355,636,200	241,393	23,861	0.0617

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule 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 (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Commercial/Industrial C12	3,911	302,664	16	244,438	0.0774
2	Industrial Rate	18,641	1,160,120	11	1,694,636	0.0622
3	Peak Controlled Time C20	24,678	1,310,794	3	8,226,000	0.0531
4	Peak Controlled Gen C21	257	23,741	1	257,000	0.0924
5	Unbilled	-103	-13,676			0.1328
6	Total Mi Large Comm & Industrial	47,384	2,783,643	31	1,528,516	0.0587
7						
8	Wisconsin Public Street & Hwy Ltg					
9	==========					
10	Company Owned Street Lighting B31	13,319	2,638,763	419	31,788	0.1981
11	Customer Owned Street Lightg B32	71	5,451	4	17,750	0.0768
12	Customer Owned Street Lightg B33	8,044	405,878	105	76,610	0.0505
13	Customer Owned Street Lightg B34	220	29,690	9	24,444	0.1350
14	Underground Area Lighting B35	699	191,680	74	9,446	0.2742
15	Street Lighting Service B36	571	23,333	25	22,840	0.0409
16	Unbilled	-2	-60			0.0300
17	Total Wi Pub Street & Hwy Lightg	22,922	3,294,735	636	36,041	0.1437
18						
19	Michigan Public Street & Hwy Ltg					
20	==========					
21	Street Lighting C30	871	168,340	18	48,389	0.1933
22	Unbilled	-3				
23	Total Mi Public Street & Hwy Ltg	868	168,340	18	48,222	0.1939
24						
25	Wiconsin Other Sales to Pub. Auth					
26	==========					
27	Fire Siren Service B20		2,090	84		
28	Municipal Water Pumping B22	12,807	940,018	317	40,401	0.0734
29	Unbilled	-10	-3,798			0.3798
30	Total Wi Other Sales to Pub Auth	12,797	938,310	401	31,913	0.0733
31						
32	Michigan Other Sales to Pub. Auth					
33	==========					
34	Municipal Pumping Service	1,090	82,625	38	28,684	0.0758
35	Unbilled	1	-53			-0.0530
36	Total Mi Other Sales to Pub Auth	1,091	82,572	38	28,711	0.0757
37						
38	Interdepartmental - Wisconsin	2,068	160,900	9	229,778	0.0778
39	Interdepartmental - Michigan	54	4,949	1	54,000	0.0916
40	Total Interdepartmental	2,122	165,849	10	212,200	0.0782
41	TOTAL Billed	5,766,644	357,447,414	241,393	23,889	0.0620
42	Total Unbilled Rev.(See Instr. 6)	-6,841	-1,811,214	0	0	0.2648
43	TOTAL	5,759,803	355,636,200	241,393	23,861	0.0617

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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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 customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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5. For any rate schedule 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 (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3	Duplicate Customers in Col (d)					
4	Wisconsin - 9353					
5	Michigan - 371					
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
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40						
41	TOTAL Billed	5,766,644	357,447,414	241,393	23,889	0.0620
42	Total Unbilled Rev.(See Instr. 6)	-6,841	-1,811,214	0	0	0.2648
43	TOTAL	5,759,803	355,636,200	241,393	23,861	0.0617

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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 (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note 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 tong-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 setter 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 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.

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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Bangor	RQ	93	6	7	
2	Barron	RQ	71	11	0	
3	Bloomer	RQ	91	8	9	
4	Cadott	RQ	81	2	3	
5	Cornell	RQ	59	2	3	
6	Medford	RQ	74			
7	Rice Lake	RQ	92	28	32	
8	Spooner	RQ	64	5	0	
9	Trempealeau	RQ	94	2	4	
10	Wakefield	RQ	75	2	2	
11	Unbilled	RQ				
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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.
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. 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 (9) 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 megawatt hours 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 column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
33,852	508,524	797,550	39,692	1,345,766	1
80,039	895,407	1,874,284	15,880	2,785,571	2
48,493	665,961	1,117,975	50,640	1,834,576	3
13,892	199,648	320,642	16,977	537,267	4
13,311	188,419	309,701	15,607	513,727	5
142,689	1,395,002	3,425,576	107,249	4,927,827	6
166,410	1,705,561	4,005,663	128,121	5,839,345	7
32,815	453,382	766,031	36,411	1,255,824	8
13,116	200,059	304,010	17,027	521,096	9
13,433	177,173	307,940	15,152	500,265	10
5,778		342,874		342,874	11
					12
					13
					14
563,828	6,389,136	13,572,246	442,756	20,404,138	
0	0	0	0	0	
563,828	**6,389,136**	**13,572,246**	**442,756**	**20,404,138**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

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	264,536	327,032
5	(501) Fuel	4,726,554	7,134,401
6	(502) Steam Expenses	772,493	681,323
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	403,598	284,927
10	(506) Miscellaneous Steam Power Expenses	1,552,807	1,542,543
11	(507) Rents	4,549	
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	7,724,537	9,970,226
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	179,020	192,080
16	(511) Maintenance of Structures	11,192	9,941
17	(512) Maintenance of Boiler Plant	1,335,910	1,097,358
18	(513) Maintenance of Electric Plant	788,364	1,360,994
19	(514) Maintenance of Miscellaneous Steam Plant	446,273	685,082
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	2,760,759	3,345,455
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	10,485,296	13,315,681
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	373,847	370,375
45	(536) Water for Power	727,849	631,165
46	(537) Hydraulic Expenses	96,025	92,381
47	(538) Electric Expenses	1,983,460	1,832,744
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,809,327	1,187,758
49	(540) Rents	85,443	64,959
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	5,075,951	4,179,382

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	244,875	213,849
54	(542) Maintenance of Structures	20,553	17,525
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,018,834	1,410,214
56	(544) Maintenance of Electric Plant	849,310	939,237
57	(545) Maintenance of Miscellaneous Hydraulic Plant	149,961	219,618
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	2,283,533	2,800,443
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	7,359,484	6,979,825
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	34,894	104,453
63	(547) Fuel	2,448,947	7,503,825
64	(548) Generation Expenses	116,607	162,333
65	(549) Miscellaneous Other Power Generation Expenses	331,358	346,665
66	(550) Rents	80	
67	TOTAL Operation (Enter Total of lines 62 thru 66)	2,931,886	8,117,276
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	34,006	15,818
70	(552) Maintenance of Structures	2,417	17,725
71	(553) Maintenance of Generating and Electric Plant	351,430	375,882
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	156,651	211,271
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	544,504	620,696
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	3,476,390	8,737,972
75	E. Other Power Supply Expenses		
76	(555) Purchased Power		
77	(556) System Control and Load Dispatching		224,057
78	(557) Other Expenses	161,662,921	168,505,699
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	161,662,921	168,729,756
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	182,984,091	197,763,234
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	270,474	314,124
84	(561) Load Dispatching	755,481	610,027
85	(562) Station Expenses	81,545	409,928
86	(563) Overhead Lines Expenses	429,889	110,456
87	(564) Underground Lines Expenses		
88	(565) Transmission of Electricity by Others		
89	(566) Miscellaneous Transmission Expenses	-21,109,617	-17,895,263
90	(567) Rents	142	
91	TOTAL Operation (Enter Total of lines 83 thru 90)	-19,572,086	-16,450,728
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	6,546	267,766
94	(569) Maintenance of Structures		
95	(570) Maintenance of Station Equipment	948,431	699,730
96	(571) Maintenance of Overhead Lines	1,244,836	1,806,263
97	(572) Maintenance of Underground Lines		35,190
98	(573) Maintenance of Miscellaneous Transmission Plant	5,456	
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	2,205,269	2,808,949
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	-17,366,817	-13,641,779
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	495,220	595,062

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Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	547,720	523,196
106	(582) Station Expenses	218,354	621,059
107	(583) Overhead Line Expenses	1,847,147	2,122,199
108	(584) Underground Line Expenses	1,685,729	1,427,403
109	(585) Street Lighting and Signal System Expenses	26,044	22,850
110	(586) Meter Expenses	832,116	574,184
111	(587) Customer Installations Expenses	52,944	221,081
112	(588) Miscellaneous Expenses	4,365,826	5,197,177
113	(589) Rents	135,875	217,768
114	TOTAL Operation (Enter Total of lines 103 thru 113)	10,206,975	11,521,979
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	940,884	618,424
117	(591) Maintenance of Structures		
118	(592) Maintenance of Station Equipment	755,127	754,468
119	(593) Maintenance of Overhead Lines	6,534,514	7,491,699
120	(594) Maintenance of Underground Lines	1,237,096	925,745
121	(595) Maintenance of Line Transformers		64
122	(596) Maintenance of Street Lighting and Signal Systems	71,221	22,291
123	(597) Maintenance of Meters	215,115	263,540
124	(598) Maintenance of Miscellaneous Distribution Plant	4,802	3,134
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	9,758,759	10,079,365
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	19,965,734	21,601,344
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	19,275	11,862
130	(902) Meter Reading Expenses	1,992,879	1,965,445
131	(903) Customer Records and Collection Expenses	5,752,134	4,026,610
132	(904) Uncollectible Accounts	1,527,103	1,275,156
133	(905) Miscellaneous Customer Accounts Expenses	221,921	248,396
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	9,513,312	7,527,469
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision		16,261
138	(908) Customer Assistance Expenses	4,186,225	7,151,018
139	(909) Informational and Instructional Expenses	181,949	316,296
140	(910) Miscellaneous Customer Service and Informational Expenses	734,523	20,999
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	5,102,697	7,504,574
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses	265,876	308,921
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	265,876	308,921
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	6,827,379	7,411,073
152	(921) Office Supplies and Expenses	7,873,910	10,372,966
153	(Less) (922) Administrative Expenses Transferred-Credit	2,051,103	1,842,448

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

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	2,988,565	2,026,733
156	(924) Property Insurance	1,139,174	611,935
157	(925) Injuries and Damages	2,327,667	903,721
158	(926) Employee Pensions and Benefits	-2,025,177	-1,363,221
159	(927) Franchise Requirements		
160	(928) Regulatory Commission Expenses	541,080	505,354
161	(929) (Less) Duplicate Charges-Cr.		
162	(930.1) General Advertising Expenses	288,744	382,949
163	(930.2) Miscellaneous General Expenses	2,047,153	349,238
164	(931) Rents	531,893	351,425
165	TOTAL Operation (Enter Total of lines 151 thru 164)	20,489,285	19,709,725
166	Maintenance		
167	(935) Maintenance of General Plant	8,905	7,468
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	20,498,190	19,717,193
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	220,963,083	240,780,956

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm 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 firm service which meets the definition of RQ service. For all transaction 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 expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term 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 expect 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 for each adjustment.

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	Northern States Power Co (MN) 1					
2	Northern States Power Co (MN) 1	AD				
3						
4						
5						
6	All transactions involving Purchased					
7	Power and Sales to Other Utilities					
8	are included in and shared through the					
9	Interchange Areement with the Parent					
10	Company (NSP Minnesota)					
11						
12						
13						
14						
	Total					

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 monnthly (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 (l) include 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 column (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.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,530,052					161,662,787	161,662,787	1
					-336,271	-336,271	2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
5,530,052					161,326,516	161,326,516	

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: a

Total dollars and MWH's will not match page 321, line 76, due to differences in accounting classification associated with the NSP Minnesota and Wisconsin Company Interchange Agreement. (see Note 6 of Notes to the Financial Statements).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	100,410
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	417,753
6	Directors Fees	111,760
7	Shared Costs	1,263,081
8	Professional Association Dues	10,231
9	IT Expenses	143,918
10		
11		
12		
13		
14		
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20		
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46	TOTAL	2,047,153

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition 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 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute 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 sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column 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 (Acc 404) (c)	Amortization of Other Electric Plant (Acc 405) (d)	Total (e)
1	Intangible Plant				
2	Steam Production Plant	1,873,849			1,873,849
3	Nuclear Production Plant				
4	Hydraulic Production Plant-Conventional	6,146,871			6,146,871
5	Hydraulic Production Plant-Pumped Storage				
6	Other Production Plant	599,954			599,954
7	Transmission Plant	9,358,272			9,358,272
8	Distribution Plant	16,076,193		94,241	16,170,434
9	General Plant	1,089,521		4,165	1,093,686
10	Common Plant-Electric	3,643,507		10,134	3,653,641
11	TOTAL	38,788,167		108,540	38,896,707

B. Basis for Amortization Charges

A. (d) EXCESS AFUDC AMORTIZED OVER AVERAGE LIFE OF PROPERTY.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	311	12,985					
13	312	59,914					
14	314	7,242					
15	315	5,163					
16	316	1,097					
17	SUBTOTAL STEAM	86,401					
18							
19	331	16,324					
20	332	123,490					
21	333	35,549					
22	334	23,265					
23	335	3,528					
24	SUBTOTAL HYDRO	202,156					
25							
26	341	2,184					
27	342	2,308					
28	343	31,556					
29	344	17,937					
30	345	5,843					
31	346	602					
32	SUBTOTAL PEAKING	60,430					
33							
34	352	1,458					
35	353	124,460					
36	354	2,507					
37	355	86,172					
38	356	96,194					
39	357	66					
40	358	218					
41	359	104					
42	SUBTOTAL	311,179					
43							
44	361	1,181					
45	362	78,993					
46	364	66,305					
47	365	79,073					
48	366	9,783					
49	367	51,859					
50	368	70,042					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	369	55,123					
13	370	18,976					
14	371	7,025					
15	373	5,486					
16	SUBTOTAL	443,846					
17							
18	390	4,442					
19	391	960					
20	391	1,669					
21	392	4					
22	392	1,852					
23	393	137					
24	394	4,798					
25	395	2,791					
26	396	1,020					
27	397	5,548					
28	398	17					
29	SUBTOTAL	23,238					
30	302	215					
31	303	17,779					
32	390	27,686					
33	391	5,266					
34	391	13,576					
35	392						
36	392	463					
37	393	810					
38	394	1,150					
39	395	31					
40	396	164					
41	397	20,926					
42	398	67					
43	SUBTOTAL COMMON	88,133					
44							
45	GRAND TOTAL	1,215,383					
46	DEPRECIABLE PLANT						
47	BASE IN COLUMN (B)						
48	IS DETERMINED BY BEG						
49	END OF YEAR AVE BAL.						
50							

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

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 Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	PUBLIC SERVICE COMMISION OF WISCONSIN				
2	----------				
3	Miscellaneous Regulatory Expenses	1,291	8,713	10,004	
4					
5	Remainder Assessment	370,746		370,746	
6	----------				
7					
8	----------				
9	MICHIGAN PUBLIC SERVICE COMMISSION				
10					
11	Public Utility Assessment	15,597		15,597	
12	----------				
13	FFEDERAL ENERGY REGULATORY COMMISSION				
14					
15	FERC Assessment	144,733		144,733	
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
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36					
37					
38					
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40					
41					
42					
43					
44					
45					
46	TOTAL	532,367	8,713	541,080	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
							2
ELECTRIC	928	10,004					3
							4
ELECTRIC	928	370,746					5
							6
							7
							8
							9
							10
ELECTRIC	928	15,597					11
							12
							13
							14
ELECTRIC	928	144,733					15
							16
							17
							18
							19
							20
							21
							22
							23
							24
							25
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							40
							41
							42
							43
							44
							45
		541,080					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 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
(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, R, D & 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 Utility RD&D Performed Internally	
2	(1) Generation	
3	a. Hydroelectric	None
4	b. Fossil-Fuel Steam	None
5	c. Internal Combustion or Gas Turbine	None
6	d. Nuclear	None
7	e. Unconventional	None
8	f. Siting and Heat Rejection	None
9	(2) System Planning, Engineering &	
10	and Operation	None
11	(3) Transmission	None
12	(4) Distribution	None
13	(5) Enviroment	None
14	(6) Other	RESEARCH GENERAL
15		
16		
17	B. Electric Utility, RD&D Performed External	
18	(1) Research Support to ERC and EPRI	EPRI
19		EPRI
20	(2) Research Support to EEI	None
21	(3) Research Support to Nuclear Power Grps	None
22	(4) Research Cost Incurred	None
23		
24	Total of Internal and External Incurred	
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 (Classify)
(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 or 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 column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating 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		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
5,847		920	5,847		14
					15
					16
					17
	44,240	921	44,240		18
	90,995	923	90,995		19
					20
					21
					22
					23
5,847	135,235		141,082		24
					25
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					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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	5,544,710		
4	Transmission	1,132,229		
5	Distribution	6,183,667		
6	Customer Accounts	4,222,551		
7	Customer Service and Informational	246,840		
8	Sales	231,739		
9	Administrative and General	6,704,667		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	24,266,403		
11	Maintenance			
12	Production	2,989,172		
13	Transmission	1,160,729		
14	Distribution	4,726,027		
15	Administrative and General	20,858		
16	TOTAL Maint. (Total of lines 12 thru 15)	8,896,786		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	8,533,882		
19	Transmission (Enter Total of lines 4 and 13)	2,292,958		
20	Distribution (Enter Total of lines 5 and 14)	10,909,694		
21	Customer Accounts (Transcribe from line 6)	4,222,551		
22	Customer Service and Informational (Transcribe from line 7)	246,840		
23	Sales (Transcribe from line 8)	231,739		
24	Administrative and General (Enter Total of lines 9 and 15)	6,725,525		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	33,163,189	2,040,647	35,203,836
26	Gas			
27	Operation			
28	Production-Manufactured Gas	427		
29	Production-Nat. Gas (Including Expl. and Dev.)			
30	Other Gas Supply	92,202		
31	Storage, LNG Terminaling and Processing	58,478		
32	Transmission			
33	Distribution	2,294,355		
34	Customer Accounts	1,427,103		
35	Customer Service and Informational	37,730		
36	Sales	49		
37	Administrative and General	1,377,148		
38	TOTAL Operation (Enter Total of lines 28 thru 37)	5,287,492		
39	Maintenance			
40	Production-Manufactured Gas			
41	Production-Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
45	Distribution	555,542		
46	Administrative and General	3,205		
47	TOTAL Maint. (Enter Total of lines 40 thru 46)	558,747		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Total Operation and Maintenance			
49	Production-Manufactured Gas (Enter Total of lines 28 and 40)	427		
50	Production-Natural Gas (Including Expl. and Dev.) (Total lines 29,			
51	Other Gas Supply (Enter Total of lines 30 and 42)	92,202		
52	Storage, LNG Terminaling and Processing (Total of lines 31 thru	58,478		
53	Transmission (Lines 32 and 44)			
54	Distribution (Lines 33 and 45)	2,849,897		
55	Customer Accounts (Line 34)	1,427,103		
56	Customer Service and Informational (Line 35)	37,730		
57	Sales (Line 36)	49		
58	Administrative and General (Lines 37 and 46)	1,380,353		
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)	5,846,239	125,611	5,971,850
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	39,009,428	2,166,258	41,175,686
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	6,837,243	846,810	7,684,053
66	Gas Plant	1,935,505	176,323	2,111,828
67	Other (provide details in footnote):	-278		-278
68	TOTAL Construction (Total of lines 65 thru 67)	8,772,470	1,023,133	9,795,603
69	Plant Removal (By Utility Departments)			
70	Electric Plant	66,695	4,207	70,902
71	Gas Plant	5,460	237	5,697
72	Other (provide details in footnote):			
73	TOTAL Plant Removal (Total of lines 70 thru 72)	72,155	4,444	76,599
74	Other Accounts (Specify, provide details in footnote):			
75	Temporary Facilities	1,636		1,636
76	Accounts Receivable	2,772		2,772
77	Nonoperating Expenses	325,239	2,439	327,678
78	Regulatory Asset	-10,002		-10,002
79	Regulatory Liability-Conservation	1,259,888	13,285	1,273,173
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	1,579,533	15,724	1,595,257
96	TOTAL SALARIES AND WAGES	49,433,586	3,209,559	52,643,145

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Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 the 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 and 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 use of the common utility plant classification and reference to order of the Commission or other authorization.

SEE INSERT PAGES 356.1 AND 356.2 FOR COMMON UTILITY PLANT AND ACCUMULATED PROVISIONS.

Common Utility Plant classification was included in original cost and reclassification studies filed with the Federal Power Commission on March 30, 1940.

GENERAL BASIS USED IN ALLOCATING TO UTILITY DEPARTMENTS, COMMON UTILITY PLANT AND DEPRECIATION.

COMMON UTILITY PLANT AND DEPRECIATION
Plant and Depreciation provisions are allocated on the basis of average percentages of utility plant in service, gross revenue and operating expenses (exclusive of joint utility administrative and general expenses, depreciation and taxes) of each department to the total. (Electric 82.33% and Gas 17.67%)

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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 the 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 and 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 use of the common utility plant classification and reference to order of the Commission or other authorization.

COMMON UTILITY PLANT IN SERVICE

Account (a)	Cost at Dec 31, 2002 (b)	Allocated to Utility Departments: Electric (c)	Allocated to Utility Departments: Gas (d)
301 Organization			
303 Misc.Intangible Plant	18,907,605	15,566,631	3,340,974
389 Land and Land Rights	2,018,779	1,662,061	356,718
390 Structures and Improvements	27,772,076	22,864,750	4,907,326
391 Office Furniture & Equipment	18,919,850	15,576,713	3,343,137
392 Transportation Equipment	462,891	381,098	81,793
393 Stores Equipment	810,058	666,921	143,137
394 Tools, Shop & Garage Equipment	1,211,215	997,193	214,022
395 Laboratory Equipment	31,019	25,538	5,481
396 Power Operated Equipment	164,280	135,252	29,028
397 Communication Equipment	20,959,331	17,255,817	3,703,514
398 Miscellaneous Equipment	77,553	63,849	13,704
Total	91,334,657	75,195,823	16,138,834
COMMON UTILITY HELD FOR FUTURE USE			
389 Land and Land Rights	000	000	000
COMMON UTILITY CONSTRUCTION WORK IN PROGRESS			
General Plant	1,063,489	875,571	187,918

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 the 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 and 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 use of the common utility plant classification and reference to order of the Commission or other authorization.

ACCUMULATED PROVISION FOR DEPRECIATION

Item (a)	Common Utility Plant in Service (b)
Balance Beginning of Year	45,373,126
Depreciation accruals for year charged to:	
Common utility plant expense (Acct 403)	4,093,628
Transportation expense - clearing	40,602
Total Depreciation accruals	4,134,230
Net charges for plant retired	
Book cost of plant retired	000
Cost of Removal	(6,048)
Salvage (credit)	643,200
Net charges for plant retired	637,152
Transfers	(624,304)
Balance end of year	48,245,900

COMMON UTILITY ACCUMULATED PROVISION FOR DEPRECIATION
ALLOCATION TO UTILITY DEPARTMENTS

	Electric	Gas	Total
Accumulated Provision	39,720,849	8,525,051	48,245,900

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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)	5,759,803
3	Steam	314,711	23	Requirements Sales for Resale (See instruction 4, page 311.)	563,828
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	1,075,536	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	6,897
7	Other	39,884	27	Total Energy Losses	629,655
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	6,960,183
9	Net Generation (Enter Total of lines 3 through 8)	1,430,131			
10	Purchases	5,530,052			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	6,960,183			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31. 2002

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).

NAME OF SYSTEM: Northern States Power Company (Wisconsin)

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	595,711		1,013	2	1900
30	February	535,083		983	4	0800
31	March	581,242		1,015	4	0900
32	April	534,945		1,051	17	1100
33	May	538,502		1,032	31	0900
34	June	585,350		1,178	24	1500
35	July	657,968		1,240	30	1600
36	August	628,008		1,102	1	1400
37	September	575,786		1,240	9	1500
38	October	566,420		946	1	1200
39	November	553,491		972	26	1800
40	December	607,677		1,057	16	1800
41	TOTAL	6,960,183				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 in 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 average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 37) and average cost per unit of fuel burned (Line 40) must be consistent with charges to expense accounts 501 and 547 (Line 41) as show on Line 19. 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: *French Island* (b)			Plant Name: *Wheaton* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Gas Turbine			Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Heated Individually			Heated Individually
3	Year Originally Constructed			1973			1973
4	Year Last Unit was Installed			1974			1974
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			175.00			322.00
6	Net Peak Demand on Plant - MW (60 minutes)			0			0
7	Plant Hours Connected to Load			0			0
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			0			0
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			4
12	Net Generation, Exclusive of Plant Use - KWh			3819100			34855500
13	Cost of Plant: Land and Land Rights			451024			182549
14	Structures and Improvements			720598			1341630
15	Equipment Costs			15163871			38415859
16	Total Cost			16335493			39940038
17	Cost per KW of Installed Capacity (line 5)			93.3457			124.0374
18	Production Expenses: Oper, Supv, & Engr			10004			19175
19	Fuel			457339			1188131
20	Coolants and Water (Nuclear Plants Only)			0			0
21	Steam Expenses			0			0
22	Steam From Other Sources			0			0
23	Steam Transferred (Cr)			0			0
24	Electric Expenses			37275			63737
25	Misc Steam (or Nuclear) Power Expenses			92142			192826
26	Rents			6			74
27	Allowances			0			0
28	Maintenance Supervision and Engineering			2443			28268
29	Maintenance of Structures			828			1420
30	Maintenance of Boiler (or reactor) Plant			0			0
31	Maintenance of Electric Plant			24836			292971
32	Maintenance of Misc Steam (or Nuclear) Plant			15071			122585
33	Total Production Expenses			639944			1909187
34	Expenses per Net KWh			0.1676			0.0548
35	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		OIL		GAS	OIL	Composite
36	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		BARREL		MCF	BARREL	
37	Quantity (units) of Fuel Burned	0	12905	0	497732	8406	0
38	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	140000	0	1003	139806	0
39	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	40.879	0.000	3.195	0.000	0.000
40	Average Cost of Fuel per Unit Burned	0.000	34.665	0.000	3.195	35.328	0.000
41	Average Cost of Fuel Burned per Million BTU	0.000	5.895	0.000	3.187	6.016	3.442
42	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.117	0.000	0.000	0.000	0.054
43	Average BTU per KWh Net Generation	0.000	19868.660	0.000	0.000	0.000	15732.572

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 Nos. 547 and 549 on Line 24 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 31, "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 footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Bay Front* (d)	Plant Name: *Flambeau Station* (e)	Plant Name: *French Island* (f)	Line No.
Steam	Gas Turbine	Steam	1
Conventional	Conventional	Conventional	2
1917	1969	1940	3
1958	1969	1948	4
68.00	19.30	35.00	5
0	0	0	6
0	0	0	7
55	0	24	8
75	0	24	9
68	14	24	10
38	2	29	11
260728030	1210240	53983200	12
67165	9798	6853	13
6477835	395093	6590317	14
37440134	3747129	42474115	15
43985134	4152020	49071285	16
646.8402	215.1306	1402.0367	17
136769	10004	127828	18
5572351	457339	-845797	19
0	0	0	20
429307	0	343249	21
0	0	0	22
0	0	0	23
220900	37275	182743	24
733478	92142	820061	25
4548	6	0	26
0	0	0	27
122609	2443	56410	28
7263	828	3928	29
880871	0	455040	30
517889	24836	270476	31
298903	15071	147371	32
8924888	639944	1561309	33
0.0342	0.5288	0.0289	34

WOOD	COAL	GAS	COMPOSITE	OIL	GAS	WOOD	RDF	GAS	35
TON	TON	MCF		BARREL	MCF	TON	TON	MCF	36
202412	82047	180307	0	0	25791	41842	39519	0	37
5628	10150	1004	0	0	1003	6439	5602	0	38
8.848	34.381	3.807	0.000	0.000	4.012	8.282	-40.195	0.000	39
8.722	33.645	3.807	0.000	0.000	4.012	8.685	-39.675	0.000	40
0.775	1.657	3.791	0.000	0.000	4.001	0.674	-3.541	0.000	41
0.000	0.022	0.000	0.000	0.000	0.086	0.000	-0.022	0.000	42
0.000	15820.852	0.000	0.000	0.000	21370.224	0.000	18228.391	0.000	43

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
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 plan, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2440 Plant Name: Chippewa Falls (b)	FERC Licensed Project No. 2639 Plant Name: Cornell (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1928	1976
4	Year Last Unit was Installed	1928	1977
5	Total installed cap (Gen name plate Rating in MW)	21.60	30.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	23	30
10	(b) Under the Most Adverse Oper Conditions	19	30
11	Average Number of Employees	0	1
12	Net Generation, Exclusive of Plant Use - Kwh	89,742,400	100,682,400
13	Cost of Plant		
14	Land and Land Rights	112,909	54,115
15	Structures and Improvements	513,954	2,429,414
16	Reservoirs, Dams, and Waterways	3,174,178	12,831,957
17	Equipment Costs	9,361,539	4,609,079
18	Roads, Railroads, and Bridges	0	0
19	TOTAL cost (Total of 14 thru 18)	13,162,580	19,924,565
20	Cost per KW of Installed Capacity (line 5)	609.3787	664.1522
21	Production Expenses		
22	Operation Supervision and Engineering	9,840	15,675
23	Water for Power	77,413	98,082
24	Hydraulic Expenses	2,896	4,368
25	Electric Expenses	45,211	76,689
26	Misc Hydraulic Power Generation Expenses	74,241	100,954
27	Rents	5	6,068
28	Maintenance Supervision and Engineering	2,885	15,030
29	Maintenance of Structures	589	771
30	Maintenance of Reservoirs, Dams, and Waterways	19,363	52,132
31	Maintenance of Electric Plant	16,755	44,653
32	Maintenance of Misc Hydraulic Plant	1,991	8,889
33	Total Production Expenses (total 22 thru 32)	251,189	423,311
34	Expenses per net KWh	0.0028	0.0042

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 1982 Plant Name: Holcombe (d)	FERC Licensed Project No. 2491 Plant Name: Jim Falls (e)	FERC Licensed Project No. 0 Plant Name: St. Croix Falls (f)	Line No.
Run-of-River	Run-of-River	Run-of-River	1
Conventional	Conventional	Conventional	2
1950	1923	1907	3
1950	1988	1923	4
33.90	50.20	23.15	5
0	0	0	6
0	0	0	7
			8
35	57	25	9
35	57	25	10
1	1	5	11
128,944,850	181,614,420	135,923,482	12
			13
230,831	851,120	87,546	14
717,531	9,689,885	567,678	15
7,034,162	69,534,015	1,451,658	16
3,592,603	26,248,141	2,477,584	17
0	0	0	18
11,575,127	106,323,161	4,584,466	19
341.4492	2,117.9913	198.0331	20
			21
13,423	13,282	32,409	22
104,363	137,003	0	23
3,898	4,222	7,185	24
62,662	55,075	193,552	25
119,983	125,244	60,106	26
0	0	0	27
2,748	4,307	11,052	28
218	401	1,409	29
11,153	18,766	56,246	30
9,329	15,545	45,709	31
1,674	2,663	7,082	32
329,451	376,508	414,750	33
0.0026	0.0021	0.0031	34

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Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
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 plan, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	TOTAL cost (Total of 14 thru 18)	0	0
20	Cost per KW of Installed Capacity (line 5)	0.0000	0.0000
21	Production Expenses		
22	Operation Supervision and Engineering	0	0
23	Water for Power	0	0
24	Hydraulic Expenses	0	0
25	Electric Expenses	0	0
26	Misc Hydraulic Power Generation Expenses	0	0
27	Rents	0	0
28	Maintenance Supervision and Engineering	0	0
29	Maintenance of Structures	0	0
30	Maintenance of Reservoirs, Dams, and Waterways	0	0
31	Maintenance of Electric Plant	0	0
32	Maintenance of Misc Hydraulic Plant	0	0
33	Total Production Expenses (total 22 thru 32)	0	0
34	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2567 Plant Name: Wissota (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1917			3
1917			4
36.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
37	0	0	9
37	0	0	10
7	0	0	11
182,675,263	0	0	12
			13
283,370	0	0	14
712,729	0	0	15
14,490,023	0	0	16
4,607,556	0	0	17
0	0	0	18
20,093,678	0	0	19
558.1577	0.0000	0.0000	20
			21
62,293	0	0	22
141,253	0	0	23
15,269	0	0	24
344,358	0	0	25
228,451	0	0	26
0	0	0	27
22,584	0	0	28
1,663	0	0	29
89,060	0	0	30
74,805	0	0	31
13,680	0	0	32
993,416	0	0	33
0.0054	0.0000	0.0000	34

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 plants 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 licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro					
2	Apple River	1907	2.40		18,898,542	2,187,437
3						
4	Cedar Falls	1910	6.00		46,720,673	3,872,555
5						
6	Eau Claire Dells	1907	9.50		52,913,600	2,781,604
7						
8	Menomonie	1958	5.40		31,373,200	4,163,800
9						
10	Riverdale	1905	0.60		3,941,672	792,846
11						
12	Trego	1927	1.20		5,853,092	1,034,955
13						
14	Big Falls	1922	9.00		42,616,303	2,692,842
15						
16	Hayward	1923	0.20		1,548,980	250,780
17						
18	Ladysmith	1940	3.90		13,264,500	4,724,134
19						
20	Saxon Falls	1913	1.20		12,447,290	1,325,743
21						
22	Superior Falls	1917	2.00		13,939,650	1,741,302
23						
24	Thornapple	1929	1.40		7,850,400	2,282,057
25						
26	White River	1907	1.00		4,585,360	1,013,326
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the 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 Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
911,432	66,247		49,881			2
						3
645,426	93,383		48,721			4
						5
292,800	573,000		113,442			6
						7
771,074	38,810		22,871			8
						9
1,321,410	32,927		5,073			10
						11
862,463	65,712		67,782			12
						13
299,205	139,410		40,914			14
						15
1,253,900	43,248		5,045			16
						17
1,211,316	69,012		30,798			18
						19
1,104,786	49,681		4,685			20
						21
870,651	92,205		17,563			22
						23
1,630,041	51,688		117,295			24
						25
1,013,326	67,160		25,189			26
						27
						28
						29
						30
						31
						32
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 the 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 the 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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	ST CROIX RIVER	EAU CLAIRE	345.00		K-FRAME	61.06		1
2			345.00			2.82		1
3	EAU CLAIRE	STEVENS POINT	345.00		K-FRAME	99.38		1
4			345.00		TOWER	2.59		1
5	LA CROSSE	DPC TIE	161.00		H-FRAME	4.03		1
6	EAU CLAIRE	DPS TIE	161.00		H-FRAME	1.02		1
7	EAU CLAIRE	LA CROSSE	161.00		H-FRAME	80.28		1
8	TREMVAL	JACKSON COUNTY	161.00		H-FRAME	23.66		1
9	LA CROSSE	COULEE	161.00		H-FRAME	8.30		1
10	DPC	COULEE	161.00		H-FRAME	0.79	0.97	1
11	LA CROSSE	MONROE	161.00		H-FRAME	26.71		1
12	CRYSTAL CAVE	APPLE RIVER	161.00		1 POLE WD	38.97	1.04	1
13	EAU CLAIRE	ELK MOUND	161.00		H-FRAME	8.01		1
14	EAU CLAIRE	PRESTO	161.00		1POLE WD	3.28		1
15	EAU CLAIRE	CRYSTAL CAVE	161.00		H-FRAME	50.60		1
16	HYDRO LANE	LINE 3213	161.00		1 POLE WD	10.16		1
17	RED CEDAR	LINE 3213	161.00		1 POLE WD	1.52		2
18	STONE LAKE	MINONG	161.00		H-FRAME	20.38		1
19	STONE LAKE	GINGLES	161.00		1 POLE WD	63.31		1
20			115.00		H-FRAME	384.54	11.92	1
21			115.00		TOWER	52.97		1
22			88.00		H-FRAME	72.78		1
23			69.00		WOOD POLE	991.89	13.49	1
24			69.00		TOWER	27.50	1.58	1
25			34.50		1 POLE WD	363.68	2.83	1
26			23.00		1 POLE WD	6.84		1
27	LA CROSSE	COULEE	69.00		UNDERGROU	0.34		1
28								
29	EXPENSES APPLICABLE TO							
30								
31								
32								
33								
34								
35								
36					TOTAL	2,407.41	31.83	28

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 transmission line 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 name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee 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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795AS	382,010	5,156,614	5,538,624					1
795AS								2
795AS	361,191	6,257,333	6,618,524					3
795AS								4
795AS	25,111	593,402	618,513					5
477AS		25,977	25,977					6
477AS	420,171	2,297,782	2,717,953					7
795AS	174,415	941,056	1,115,471					8
477AS	96,279	370,336	466,615					9
636AS		82,611	82,611					10
705AS	158,582	1,241,773	1,400,355					11
954AS	276,200	3,792,140	4,068,340					12
795AS	12,527	563,791	576,318					13
4/0 AS	44,366		44,366					14
795AS	352,275	4,780,341	5,132,616					15
795AS	105,718	1,350,908	1,456,626					16
795AS	35,141	447,294	482,435					17
636AS	30,345	694,262	724,607					18
795AS	607,153	19,888,388	20,495,541					19
VARIOUS	2,348,874	43,676,389	46,025,263					20
VARIOUS	255,115	5,075,148	5,330,263					21
4/0 AS	135,679	2,649,415	2,785,094					22
VARIOUS	5,288,815	71,740,345	77,029,160					23
VARIOUS	99,449	1,897,599	1,997,048					24
VARIOUS	802,445	11,509,751	12,312,196					25
1250AL	7,931	501,349	509,280					26
	152,786	517,939	670,725					27
								28
				-19,653,773	1,256,838	142	-18,396,793	29
								30
								31
								32
								33
								34
								35
	12,172,578	186,051,943	198,224,521	-19,653,773	1,256,838	142	-18,396,793	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

SUBSTATIONS

1. Report below the information called for concerning substations of 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 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such 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	Bay Front	Transmission A	88.00	34.50	
2	Bay Front	Transmission A	88.00	13.80	
3	Bay Front	Transmission A	34.50	13.80	
4	Bay Front	Transmission A	88.00	13.80	
5	Bay Front	Transmission A	88.00	69.00	
6	Bay Front	Transmission A	115.00	88.00	
7	Big Falls	Transmission A	69.00	2.40	
8	Cedar Falls	Transmission A	69.00	2.40	
9	Cedar Falls	Transmission A	69.00	23.90	
10	Chippewa Falls	Transmission U	69.00	4.00	
11	Cornell Hydro	Transmission A	115.00	7.20	
12	Crystal Cave	Transmission U	161.00	115.00	13.80
13	Eau Claire	Transmission U	161.00	69.00	13.80
14	Eau Claire	Transmission U	345.00	161.00	13.80
15	Eau Claire Dells	Transmission A	69.00	2.40	
16	Farmers Inn	Transmission U	69.00	12.50	
17	Farmers Inn	Transmission U	161.00	69.00	
18	Flambeau	Transmission U	34.50	13.80	
19	French Island	Transmission A	69.00	13.80	
20	Gingles	Transmission U	161.00	115.00	
21	Gingles	Transmission U	115.00	69.00	
22	Gingles	Transmission U	115.00	34.50	
23	Holcombe	Transmission A	115.00	7.20	
24	Hydro Lane	Transmission U	161.00	115.00	
25	Hydro Lane	Transmission U	115.00	69.00	
26	Hydro Lane	Transmission U	115.00	23.90	
27	Hydro Lane	Transmission U	115.00	12.50	
28	Jackson County	Transmission U	161.00	69.00	13.50
29	Jim Falls	Transmission A	115.00	69.00	
30	Jim Falls	Transmission A	115.00	7.20	
31	Jim Falls	Transmission A	69.00	12.50	
32	Jim Falls	Transmission A	12.50	7.20	
33	La Crosse	Transmission U	161.00	69.00	13.80
34	La Crosse	Transmission U	69.00	13.80	
35	Marshland	Transmission U	161.00	69.00	13.80
36	Monroe County	Transmission U	161.00	69.00	
37	Osprey	Transmission U	69.00	23.90	
38	Osprey	Transmission U	115.00	69.00	
39	Park Falls 115KV	Transmission U	115.00	34.50	
40	Pine Lake	Transmission U	115.00	69.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, 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 reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting 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.

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 (In MVa) (k)	Line No.
20	1					1
27	6	1				2
13	2		Capacitor Bank	2	12	3
52	2					4
20	1					5
50	1		Capacitor Bank	1	11	6
10	2	1				7
7	1					8
11	1					9
46	2					10
40	1					11
187	1					12
224	2		Capacitor Bank	4	356	13
600	2					14
12	3					15
14	1		Capacitor Bank	1	5	16
50	1					17
20	1					18
213	3		Capacitor Bank	1	5	19
187	1					20
42	1					21
94	2		Capacitor Bank	2	12	22
38	3					23
187	1					24
42	1					25
47	1					26
28	1					27
46	1					28
112	1					29
67	2					30
11	1					31
1	3					32
140	2					33
93	2		Capacitor Bank	1	5	34
224	2					35
70	1		Capacitor Bank	1	14	36
11	1					37
25	1					38
50	2		Capacitor Bank	1	6	39
224	2					40

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SUBSTATIONS

1. Report below the information called for concerning substations of 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 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such 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	Pine Lake	Transmission U	161.00	115.00	
2	Prentice	Transmission U	115.00	69.00	
3	Prentice	Transmission U	115.00	12.50	
4	Red Cedar	Transmission U	161.00	69.00	
5	Red Cedar	Transmission U	69.00	12.50	
6	River Falls	Transmission U	115.00	69.00	
7	St. Croix Falls	Transmission A	69.00	12.50	
8	St. Croix Falls	Transmission A	12.50	2.40	
9	Seven Mile	Transmission U	161.00	69.00	13.80
10	Stone Lake	Transmission U	161.00	69.00	
11	T-Corners	Transmission U	115.00	69.00	13.80
12	T-Corners	Transmission U	69.00	23.90	
13	Trails End	Transmission U	69.00	23.90	
14	Tremval	Transmission U	161.00	69.00	13.80
15	Wheaton	Transmission A	161.00	13.80	
16	Whitetail	Transmission U	69.00	34.50	7.20
17	Whitetail	Transmission U	69.00	13.80	
18	Wissota	Transmission A	69.00	13.80	
19	Ironwood (MI)	Transmission U	34.50	4.16	
20	Ironwood (MI)	Transmission U	115.00	34.50	
21	Ironwood (MI)	Transmission U	88.00	34.50	
22					
23	Total Transmission Substations 35		6571.50	2592.26	131.10
24	Above 10 MVA Capacity				
25					
26	11 Transmission Substations				
27	Under 10 MVA Capacity				
28					
29	Transmission Substation Total 46				
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, 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 reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting 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.

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 (In MVa) (k)	Line No.
112	1	1				1
50	1					2
11	1		Capacitor Bank	1	13	3
70	1					4
56	2					5
70	1		Capacitor Bank	1	5	6
28	1					7
29	5	1				8
112	1					9
70	1		Capacitor Bank	3	47	10
93	2		Capacitor Bank	2	29	11
56	2		Capacitor Bank	1	5	12
11	1					13
70	1	1				14
435	3					15
20	1	1	Capacitor Bank	1	5	16
11	1					17
50	6	1				18
6	4	1				19
97	2		Capacitor Bank	1	11	20
25	1					21
						22
4837	105	8		24	541	23
4837	105	8		24	541	24
						25
						26
55	21	3	Capacitor Bank	1	5	27
						28
4892	126	11		25	546	29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1					
2					
3					
4					
5					
6	Arkansaw	Distribution U	69.00	23.90	
7	Bangor	Distribution U	69.00	12.50	
8	Blair	Distribution U	69.00	12.50	
9	Bloomer	Distribution U	69.00	12.50	
10	Bloomer	Distribution U	69.00	4.00	
11	Camp McCoy	Distribution U	69.00	6.90	
12	Chippewa Falls	Distribution U	69.00	12.50	
13	Cornell	Distribution U	115.00	2.40	
14	Cornell	Distribution U	2.40	4.16	
15	Coulee Ave	Distribution U	69.00	13.80	
16	Coulee Ave	Distribution U	161.00	69.00	13.80
17	Doughty Road	Distribution U	69.00	23.90	
18	Eagle Point	Distribution U	115.00	23.90	
19	Ellis	Distribution U	69.00	12.50	
20	Ellsworth Area	Distribution U	69.00	12.50	
21	Galesville	Distribution U	69.00	12.50	
22	Griffin Street	Distribution U	69.00	12.50	
23	Hallie	Distribution U	69.00	12.50	
24	Hay River	Distribution U	69.00	23.90	
25	Holmen Area	Distribution U	69.00	13.80	
26	Hurley	Distribution U	115.00	12.50	
27	Hurley	Distribution U	115.00	13.80	
28	Jeffers Road	Distribution U	161.00	23.90	
29	Lake Camelia	Distribution U	69.00	23.00	
30	London	Distribution U	69.00	12.50	
31	Loyal	Distribution U	69.00	12.50	
32	Madison Street	Distribution U	69.00	12.50	
33	Mayfair	Distribution U	161.00	13.80	
34	Menomonie	Distribution U	69.00	4.16	
35	Menomonie	Distribution U	69.00	12.50	
36	Naples	Distribution U	69.00	12.50	
37	Neillsville	Distribution U	69.00	4.16	
38	Neillsville	Distribution U	69.00	12.50	
39	New Richmond	Distribution U	69.00	12.50	2.40
40	North Fork	Distribution U	34.50	12.50	

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SUBSTATIONS (Continued)

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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 (In MVa) (k)	Line No.
						1
						2
						3
						4
						5
11	1					6
11	1					7
11	1					8
11	1					9
		1				10
11	1	1				11
44	2					12
8	1					13
6	1	1				14
93	2					15
182	2		Capacitor Bank	1	5	16
14	1					17
47	1					18
56	2					19
11	1					20
11	1					21
11	1					22
56	2					23
11	1					24
25	2		Capacitor Bank	1	5	25
7	1					26
37	1					27
94	2					28
11	1					29
56	2					30
11	1					31
28	1					32
93	2					33
6	1		Capacitor Bank	1	5	34
56	2					35
11	1					36
5	1					37
11	1		Capacitor Bank	1	5	38
11	1		Capacitor Bank	1	5	39
21	2					40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Onalaska	Distribution U	69.00	13.80	
2	Osceola	Distribution U	69.00	12.50	
3	Otter Creek	Distribution U	69.00	12.50	
4	Phillips	Distribution U	115.00	12.50	
5	Pokegama	Distribution U	69.00	13.80	
6	Prescott	Distribution U	69.00	12.50	
7	Rice Lake	Distribution U	69.00	12.50	
8	Rush River	Distribution U	69.00	23.00	
9	Rusk	Distribution U	69.00	12.50	
10	Second Street	Distribution U	34.50	13.80	
11	Sparta	Distribution U	69.00	12.50	
12	Spencer	Distribution U	69.00	12.50	
13	Stanley Area	Distribution U	69.00	23.90	
14	Strum	Distribution U	69.00	12.50	
15	Sumner	Distribution U	69.00	23.90	
16	Swift Creek	Distribution U	69.00	13.80	
17	Truax	Distribution U	69.00	12.50	
18	Turtle Lake	Distribution U	69.00	12.50	
19	U.S. Rubber	Distribution U	69.00	2.40	
20	U.S. Rubber	Distribution U	69.00	4.16	
21	Viroqua	Distribution U	69.00	13.80	
22	Viroqua	Distribution U	69.00	4.16	
23	Waumandee	Distribution U	69.00	23.90	
24	West Salem	Distribution U	69.00	23.90	
25	Willow River	Distribution U	115.00	23.00	
26	Woodmohr	Distribution U	69.00	23.00	
27					
28	Total Distribution Substations 53		4625.40	899.30	16.20
29	Above 10 MVA Capacity				
30					
31	98 Distribution Substations				
32	Under 10 MVA Capacity				
33					
34	16 Distribution Serving One				
35	Industrial Customer				
36					
37					
38					
39	Distribution Substation Totals 166				
40					

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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 (In MVa) (k)	Line No.
14	1		Capacitor Bank	1	5	1
25	2		Capacitor Bank	1	7	2
56	2					3
25	2					4
7	1					5
11	1					6
56	2		Capacitor Bank	1	5	7
30	2					8
11	1					9
14	1					10
56	2					11
11	1		Capacitor Bank	1	5	12
14	1					13
11	1		Capacitor Bank	1	5	14
14	1					15
56	2		Capacitor Bank	1	5	16
56	2					17
11	1					18
9	3	1				19
12	4					20
13	1					21
5	1		Capacitor Bank	1	5	22
11	1					23
56	2		Capacitor Bank	1	5	24
98	2					25
11	1		Capacitor Bank	1	5	26
						27
1781	86	4		14	72	28
1781	86	4	Capacitor Bank	14	72	29
						30
						31
372	136	8	Capacitor Bank	10	52	32
						33
						34
140	24	1	Capacitor Bank	1	5	35
						36
						37
						38
2293	246	13		25	129	39
						40

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INDEX

Schedule	Page No.
Accrued and prepaid taxes	262-263
Accumulated Deferred Income Taxes	234
	272-277
Accumulated provisions for depreciation of	
common utility plant	356
utility plant	219
utility plant (summary)	200-201
Advances	
from associated companies	256-257
Allowances	228-229
Amortization	
miscellaneous	340
of nuclear fuel	202-203
Appropriations of Retained Earnings	118-119
Associated Companies	
advances from	256-257
corporations controlled by respondent	103
control over respondent	102
interest on debt to	256-257
Attestation	i
Balance sheet	
comparative	110-113
notes to	122-123
Bonds	256-257
Capital Stock	251
expense	254
premiums	252
reacquired	251
subscribed	252
Cash flows, statement of	120-121
Changes	
important during year	108-109
Construction	
work in progress - common utility plant	356
work in progress - electric	216
work in progress - other utility departments	200-201
Control	
corporations controlled by respondent	103
over respondent	102
Corporation	
controlled by	103
incorporated	101
CPA, background information on	101
CPA Certification, this report form	i-ii

Schedule	Page No.
Deferred	
credits, other	269
debits, miscellaneous	233
income taxes accumulated - accelerated amortization property	272-273
income taxes accumulated - other property	274-275
income taxes accumulated - other	276-277
income taxes accumulated - pollution control facilities	234
Definitions, this report form	iii
Depreciation and amortization	
of common utility plant	356
of electric plant	219 336-337
Directors	105
Discount - premium on long-term debt	256-257
Distribution of salaries and wages	354-355
Dividend appropriations	118-119
Earnings, Retained	118-119
Electric energy account	401
Expenses	
electric operation and maintenance	320-323
electric operation and maintenance, summary	323
unamortized debt	256
Extraordinary property losses	230
Filing requirements, this report form	
General information	101
Instructions for filing the FERC Form 1	i-iv
Generating plant statistics	
hydroelectric (large)	406-407
pumped storage (large)	408-409
small plants	410-411
steam-electric (large)	402-403
Hydro-electric generating plant statistics	406-407
Identification	101
Important changes during year	108-109
Income	
statement of, by departments	114-117
statement of, for the year (see also revenues)	114-117
deductions, miscellaneous amortization	340
deductions, other income deduction	340
deductions, other interest charges	340
Incorporation information	101

Schedule | Page No.

Interest
charges, paid on long-term debt, advances, etc 256-257
Investments
nonutility property 221
subsidiary companies 224-225
Investment tax credits, accumulated deferred 266-267
Law, excerpts applicable to this report form iv
List of schedules, this report form 2-4
Long-term debt 256-257
Losses-Extraordinary property 230
Materials and supplies 227
Miscellaneous general expenses 335
Notes
to balance sheet 122-123
to statement of changes in financial position 122-123
to statement of income 122-123
to statement of retained earnings 122-123
Nonutility property 221
Nuclear fuel materials 202-203
Nuclear generating plant, statistics 402-403
Officers and officers' salaries 104
Operating
expenses-electric 320-323
expenses-electric (summary) 323
Other
paid-in capital 253
donations received from stockholders 253
gains on resale or cancellation of reacquired
capital stock 253
miscellaneous paid-in capital 253
reduction in par or stated value of capital stock 253
regulatory assets 232
regulatory liabilities 278
Peaks, monthly, and output 401
Plant, Common utility
accumulated provision for depreciation 356
acquisition adjustments 356
allocated to utility departments 356
completed construction not classified 356
construction work in progress 356
expenses 356
held for future use 356
in service 356
leased to others 356
Plant data 336-337
401-429

Schedule	Page No.
Plant - electric	
accumulated provision for depreciation	219
construction work in progress	216
held for future use	214
in service	204-207
leased to others	213
Plant - utility and accumulated provisions for depreciation amortization and depletion (summary)	201
Pollution control facilities, accumulated deferred income taxes	234
Power Exchanges	326-327
Premium and discount on long-term debt	256
Premium on capital stock	251
Prepaid taxes	262-263
Property - losses, extraordinary	230
Pumped storage generating plant statistics	408-409
Purchased power (including power exchanges)	326-327
Reacquired capital stock	250
Reacquired long-term debt	256-257
Receivers' certificates	256-257
Reconciliation of reported net income with taxable income from Federal income taxes	261
Regulatory commission expenses deferred	233
Regulatory commission expenses for year	350-351
Research, development and demonstration activities	352-353
Retained Earnings	
amortization reserve Federal	119
appropriated	118-119
statement of, for the year	118-119
unappropriated	118-119
Revenues - electric operating	300-301
Salaries and wages	
directors fees	105
distribution of	354-355
officers'	104
Sales of electricity by rate schedules	304
Sales - for resale	310-311
Salvage - nuclear fuel	202-203
Schedules, this report form	2-4
Securities	
exchange registration	250-251
Statement of Cash Flows	120-121
Statement of income for the year	114-117
Statement of retained earnings for the year	118-119
Steam-electric generating plant statistics	402-403
Substations	426
Supplies - materials and	227

Schedule	Page No.
Taxes	
accrued and prepaid	262-263
charged during year	262-263
on income, deferred and accumulated	234 272-277
reconciliation of net income with taxable income for	261
Transformers, line - electric	429
Transmission	
lines added during year	424-425
lines statistics	422-423
of electricity for others	328-330
of electricity by others	332
Unamortized	
debt discount	256-257
debt expense	256-257
premium on debt	256-257
Unrecovered Plant and Regulatory Study Costs	230

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Utility No. 4220 Year Ended December 31, 2002 Form AFP Copy 1

LIST OF SUPPLEMENTARY SCHEDULES

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".

Title of Schedule	Reference Page No. (b)	Date Revised ©	Remarks (d)
Security Holders and Voting Powers	FERC 106-107		
Construction Overheads-Electric	FERC 217		
General Description of Construction Overhead Procedure	FERC 218		
Nonutility Property	FERC 221		
Capital Stock Subscribed, Capital Stock Liability for Conversion			
Premium on Capital Stock and Installments Received on Capital Stock	FERC 252		
Discount on Capital Stock	FERC 254		
Number of Electric Department Employees	FERC 323		
Particulars Concerning Certain Income Deductions and Interest Charges	FERC 340		
Electric Distribution Meters and Line Transformers	FERC 429		
Summary of Affiliated Transactions with Xcel Energy Services	-		
Summary of Affiliated Transactions with Regulated Operating Companies			
Summary of Affiliated Transactions with E-Prime	-		
Return on Common Equity and Common Equity Plus ITC Computations	F-9		
Return on Rate Base Computation	F-10		
Revenues Subject to Wisconsin Remainder Assessment	F-10		
Construction Overheads & Completed Construction Cleared	F-16 & F-17		
Additional Construction Overhead			
& Completed Construction Cleared Pages (if needed)	F-16a, F-16b, F-17a & F-17b		
Investments and Funds (Accounts 123-128)	F-18		
Accounts Receivable (Accounts 142-143)	F-19		
Accumulated Provision for Uncollectible Accounts	F-20		
Miscellaneous Current and Accrued Assets	F-22		
Unamortized Debt Discount and Expense	F-24		
Unamortized Premium on Debt	F-25		
Additional Unamortized Debt Discount & Premium on Debt Pages	F-24a & F-25a		
Retained Earnings and Notes Payable	F-33		
Misc. Current and Accrued Liabilities	F-34		
Distribution of Taxes to Accounts	F-36 & F-37		
Interest and Dividend Income	F-43		
Detail of Certain General Expense Accounts	F-50 & F-51		
Common Utility Plant and Accumulated Depreciation	F-52 & F-53		
Map of Service Territory		-	-
ELECTRIC OPERATION SECTION			
Electric Expenses	E-1		
Sales to Ultimate Customers	E-2		
Power Adjustment Clause	E-5		
Accumulated Provision for Depreciation of Plant	E-24		
Monthly Peaks & Output	E-29		
Unit Fuel Statistics - Steam Plant	E-36		
Coal Contract Information	E-40		
Electric Distribution Lines	E-63		
Electric Distribution Meters	E-63		
Names of Cities, Villages, Towns	E-66		
GAS OPERATING SECTION			
Names of Cities, Villages and Towns	G-1 & G-2		
Gas Operating Expenses	G-3		
Revenues From Sales Of Gas and Other Gas Revenues	G-4 & G-5		
Gas Operation And Maintenance Expenses	G-7, G-8 & G-9		
Detail of Natural Gas City Gate Purchases (Account 804)	G-8 Supplement		
Gas Plant In Service	204, 205, 206, & 207		
Accum. Provision For Depreciation (Account 108)	G-12, G-13,G-12A, & G-13A		
Gas Production Statistics	G-14		
Gas Holders	G-14		
Liquid Petroleum Gas Storage	G-14		
Liquified Natural Gas Stored (Account 164)	G-15		
Liquefied Natural Gas Storage Statistics	G-15		
Summary of Gas Account	G-16 & G-17		
Summary of System Load Statistics	G-16 & G-17		
Purchased Gas	G-18 & G-19		
Gas Mains By Types And Sizes	G-20		
Gas Services (Located In Wisconsin)	G-21		
Gas Services (Located Outside Wisconsin)	G-21		
Gas Meters	G-22		
Hirschman-Herfindahl Index Form			
Gas Stored (Accounts 117, 164.1, 164.2, & 164.3)	G-220		
Detail of Stored Gas Account (Account 164.1)	G-220 Supplement		

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 that 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 titles 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 footnote the circumstances whereby such security became vested with voting rights give other important particulars (details) concerning voting rights of each security. State whether voting right 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 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 right the amount of such securities or assets so entitled to purchased by any officer, director, associated company, 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 public where the options, warrants, or rights were issued prorata basis.

1. Give the 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 at the latest general meeting prior to 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
	Total			
	By Proxy			

Line		Voting Securities			
		Number of Votes as of (date)			
1	Name (Title) of all voting securities		Voting Securities		
2	Holder	Total Votes	Common Stock	Preferred Stock	Other
3					
4	(a)	(b)	(c)	(d)	(e)
5					
6	Total votes of all voting securities				
7	Total number of securities				
8	Total votes of security holders listed below				
9	Xcel Energy Inc.				
10	(a Minnesota corporation)				
11	800 Nicollet Mall, Suite 2900				
12	Minneapolis, MN 55402-2024	933,000	933,000		
13					
14					
15					
16					
17					
18					

SECURITY HOLDERS AND VOTING POWERS (Continued)

Line	Name (Title) of all voting securities Holder	Total Votes	Voting Securities Common Stock	Preferred Stock	Other
	(a)	(b)	(c)	(d)	(e)
19	See page 106				
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
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41					
42					
43					
44					
45					
46					
47					
48					
49					
50					
51					
52					
53					

CONSTRUCTION OVERHEADS - ELECTRIC

1. List in column (a) the kinds of overheads according to the titles used by the respondent. Charges for outside professional services for engineering fees and management or superv ision 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 the 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.

Description of overhead (a)	Amount (b)
CONSTRUCTION ENGINEERING/SUPERVISION	2,097,137
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	569,440
ADMINISTRATIVE AND GENERAL EXPENSE	390,865
BARR ENGINEERING COMPANY	1,217
BRADCAD	4,316
EAGLE MOUNTAIN SCIENTIFIC INC.	6,757
GME CONSULTANTS INC.	1,533
LIESCH ASSOCIATES,INC.	11,600
MECHANICAL SYSTEMS, INC.	20,200
TECH SOURCE DESIGN INC.	13,788
UTILITY ENGINEERING CORP.	338,368
WUNDERLICH-MALEC ENGINEERING	17,687
TOTAL	**3,472,908**

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GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the natureand 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, (e) basis of differentaiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the compputation of allowance for funds used during construction rates, in accordance with the provisions of Electric Plant. instructions 3(17) of the U.S. of A.
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.

* (1) and (2) SEE FOOTNOTES

AFUDC COMPUTATION

2. BORROWED FUNDS - SEE (2A)
3. OTHER FUNDS - SEE (2B)
4. WEIGHTED RATE - SEE (2)

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.

Line No.	Title (a)	Amount (b)	Capitalization/Ratio(Percent) (c	Cost Rate Percentage (d)
1	Average Short-Term Debt & computation of Allowan	5,390,000		
2	Short-term Interest			2.43
3	Long-term Debt	304,595,000	42.65%	7.64
4	Preferred Stock			
5	Common Equity	409,546,000	57.35%	11.90
6	Total Capitalization	714,141,000	100.00%	
7	Average Construction Work in Progress Balance	22,345,000		

2. Gross Rate for Borrowed Funds **s(S/W) + d(D/D+P+C) (1 - S/W)** 3.06%

3. Rate of Other Funds **[1 - S/W] [p(P/D+P+C) + c(C/D+P+C)]** 5.18%

Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 3.23%

b. Rate for Other Funds - 5.31%

FOOTNOTE DATA

Schedule Page: 218 Line No. 1 Column: OH exp

CONSTRUCTION ENGINEERING

(1) This overhead covers (1) overhead charges originating in the Engineering Department, which costs represent direct expenditures incurred in engineering and supervision pertaining to construction projects and (2) certain expenses incurred in accounting for construction. Engineering labor is charged to this account on the basis of actual time devoted to construction projects. Other expenses pertaining to the operation of the Engineering Departments are also charged direct to this account when they pertain to engineering or construction. Miscellaneous engineering office department expenses are allocated between this overhead, and operation and maintenance and supervision and engineering on the basis of time devoted by the Engineering Department to each of these classes of engineering. This overhead also includes the cost of labor and expenses incurred by superintendents and others in the distribution , transmission and plant organization which pertain to construction work. Since all engineering expenditures included in this account pertain to construction, no portion of the costs is cleared to other than construction accounts of the various utility departments. Engineering expenses applicable to major specific projects are charged on the basis of actual amounts applicable thereto, and to other construction projects on a functional basis by a percentage applied to direct work order costs.

(2) During 2002, the Company capitalized AFUDC on production and transmission plant at a 8.54% rate. Because the Interchange Agreement between NSP(M) and NSP(W) requires the FERC method of accounting, the company recorded AFUDC at the estimated FERC formula rate for the FERC jurisdictional property. By order dated March 11, 1986 the Public Service Commission of Wisconsin authorized the company to capitalize AFUDC on production and transmission property effective January 1, 1985 at the FERC formula rate.

AFDC at 8.54% rate was capitalized on distribution, general and common electric plant and gas plant effective January 1, 2002. By order dated December 22, 1988, the Public Service Commission of Wisconsin instructed the Company to capitalize AFUDC at the adjusted weighted cost of capital. The Company has recorded carrying charges for the amounts allowed by the PSCW in excess of that in the above formula to Account 182.3 Regulatory Assets.

(2.a) 2.43% (5,390,000/22,345,000) + 7.64% (304,595,000)
(304,595,000 + 409,546,000) [1-(5,390,000/22,345,000)]
= 0.59% + 2.47%
= 3.06% (BORROWED FUNDS)

(2.b) [1 - 5,390,000] [11.94% 409,546,000]
---------- ----------
22,345,000 (304,595,000 + 409,546,000)
= .75878 * 6.824%
= 5.18% (OTHER FUNDS)

NON-UTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of Nonutility property included in Account 121.
2. Designate with a double 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)	alance of Beginning of ye (b)	Purchases, Sales, Transfers, et (c.)	Balance at End of Year (d)	
1	Hydraulic production plant located at Cornell, WI				1
2	on the Chippewa River	1,056		1,056	2
3	Misc hydraulic lands owned in excess of requirement			-	3
4	for developed project	14,655		14,655	4
5	Hydraulic lands at undeveloped locations	1,015		1,015	5
6	Dunnville lands on Chippewa River	26,353		26,353	6
7	Miscellaneous lands	25,550		25,550	7
8	Abandoned sub lands	11,735		11,735	8
9	Miscellaneous lands	216,767		216,767	9
10	Dunn County site lands	2,438,666		2,438,666	10
11	Bake site	17,862		17,862	11
12	Mathews site	2,675		2,675	12
13	City of Ashland	5,549		5,549	13
14	Town of Gingles-tank farm land	7,053		7,053	14
15	Ogema sub	472		472	15
16	Clear lake diesel	35,076		35,076	16
17	Chippewa Reservoir land	23		23	17
18	Oriental Falls lands	22,339		22,339	18
19	Eau Claire Operations Bldg (1)	2,156,577	(2,156,577)	-	19
20					20
21					21
22	(1) Sale of E.C. Oper Bldg.				22
23					23
24					24
25					25
26					26
27					27
28					28
29					29
30					30
31					31
32					32
33	Minor Item Previously Devoted to Public Service				33
34	Minor Items-Other Nonutility Property				34
35	**TOTAL**	**4,983,423**	**(2,156,577)**	**2,826,846**	35

CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL AND INSTALLMENTS RECEIVED ON CAPITAL STOCK (Accounts 202 and 205, 203 and 206, 207, 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, Common stock Subscribed, and Account 205, Preferred Stock Subscribed, show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a 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 on Account 207, Capital Stock, designate with a double asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Name of Account and Description of Item	Number of Shares	Amount
(a)	(b)	(c.)
ACCOUNT 207 - PREMIUM ON CAPITAL STOCK		
Excess of consideration received over par value of common stock		
issued in conversion on 2,132 shares of 5% Cumulative Preferred Stock		
on the basis of 1.5 shares of Preferred Stock for each share of Common Stock	1,855	27,825
Premium over book value on 162,000 shares of Common Stock issued in		
Lake Superior District Power Company from parent company		10,432,916
Premium over book value on 71,000 shares of Common Stock issued in		
Northern States Power Company-Wisconsin from parent company		22,876,910
Contribution of Capital by Parent - 2001		26,353,637
Reclassification of prior year contribution of capital by parent company to Ferc 211		(26,353,637)
TOTAL	**1,855**	**33,337,651**

DISCOUNT ON CAPITAL STOCK

1. Report the balance at end of the uear 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.

Class and Series of Stock (a)	Balance at End of Year (b)
TOTAL	**$0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) ☐ An Original (2) ☐ A Resubmission	/ /	Dec. 31, 2002

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the 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 in 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		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported fro 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	1. Payroll Period Ended (Date)	12/31/2002	1
2	2. Total Regular Full-Time Employees	519	2
3	3. Total Part-time and Temporary Employees	44	3
4	4. Total Employees	563	4
5			5
6			6
7			7
8			8
9			9
10			10
11			11
12			12
13			13
14			14
15			15
16			16
17			17
18			18
19			19
20			20
21			21
22			22
23			23
24			24
25			25
26			26
27			27
28			28
29			29
30			30
31			31
32			32
33			33
34			34
35			35

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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 account. 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 theis 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) advances on open account, (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.

Item (a)	Amount (b)
ANALYSIS OF DONATIONS - ACCOUNT 426.1	
CIVIC ORGANIZATIONS	
GOGEBIC COUNTY ECONOMIC DEVELOPMENT	2,000
CADOTT SPEC BUILDING	14,490
IRON COUNTY DEVELOPMENT	2,000
CHIPPEWA COUNTY ECONOMIC DEVELOPMENT	2,000
CLARK COUNTY ECONOMIC DEVELOPMENT	2,000
VILLAGE OF OSCEOLA	5,000
CITY OF LADYSMITH	5,000
WESTERN DAIRYLAND FRESH START	3,000
CHIPPEWA FALLS MAIN STREET	4,500
WEDA	2,500
DUNN COUNTY ECONOMIC DEVELOPMENT	3,000
ST CROIX ECONOMIC DEVELOPMENT	2,500
RIVER COUNTY RC&D CNCLCOMMUNITY GRANT	2,250
MISCELLANEOUS	20,994
SUBTOTAL 426.1 - CIVIC	71,234
CULTURAL ORGANIZATIONS	
MISCELLANEOUS	5,900
SUBTOTAL 426.1 - CULTURAL	5,900
EDUCATION, COLLEGES, HIGH SCHOOLS	
UNIVERSITY OF WISCONSIN-EXTENS	5,000
WISCONSIN PUBLIC UTILITY INST	6,500
BAYFIELD COUNTY EDC	2,000
STOUT UNIVERSITY FOUNDATION IN	2,000
UNIVERSITY OF WISCONSIN-EXTENS	5,000
UNIVERSITY OF WISCONSIN-STOUT	4,000
UNIVERSITY OF WISCONSIN-MULTI-YEAR SCHOLORSHIP	10,000
MUELLER COMMUNICATIONS-ENERGY	6,000
ENERGY SYMPOSIUM	3,000
MISCELLANEOUS	6,800
SUBTOTAL 426.1 - EDUCATION, COLLEGES, HIGH SCHOOLS	50,300

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 account. 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) advances on open account, (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.

Item (a)	Amount (b)
HOSPITAL AND MEDICAL RESEARCH PROGRAMS	
MISCELLANEOUS	1,300
SUBTOTAL 426.1-HOSPITAL AND MEDICAL RESEARCH	1,300
YOUTH ORGANIZATIONS AND ACTIVITIES, FRATERNAL AND BUSINESS ORGANIZATIONS, CHAMBER OF COMMERCE, LOCAL CELEBRATIONS AND VETERANS ORGANIZATIONS	
CITY OF BAYFIELD	2,500
OSCEOLA COMMUNITY HEALTH FNDTN	7,000
EAU CLAIRE AREA CHAMBER OF COM	2,500
WISCONSIN CHAMBER OF COMMERCE	6,000
BOOK ACROSS THE BAY INC	2,500
LAKE SUPERIOR BIG TOP CHAUTAUQ	5,000
FRIENDS OF BEAVER CREEK	2,000
MISCELLANEOUS	15,527
SUBTOTAL 426.1 - ORGANIZATIONS	43,027
COMMUNITY WELFARE ORGANIZATIONS	
SALVATION ARMY	6,000
UWF-BADGER FUND	2,500
GOLDSTEIN'S	2,267
MISCELLANEOUS	9,500
SUBTOTAL 426.1 - COMMUNITY WELFARE	20,267
MISCELLANEOUS	
XCEL FOUNDATION DONATIONS	243,538
TOTAL 426.1	435,566
LIFE INSURANCE - ACCOUNT 426.2	
WEALTH OPTION AND OFFICER SURVIVOR BENEFITS	188,650
TOTAL 426.2	188,650
PENALTIES - ACCOUNT 426.3	
WDNR PENALTY FOR FRENCH ISLAND STEAM PLANT	250,800
TOTAL 426.3	250,800

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 account. 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) advances on open account, (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.

Item (a)	Amount (b)
INC DED - CIVIC, POLITICAL AND RELATED - ACCOUNT 426.4	
GEORGE CARR PROFESSIONAL SERVICES	1,212
EISENHOWER CENTER BUILDING FUND	10,000
ELECTRIC UTILITY ASSOCIATION	1,899
FRANKIN & ASSOCIATES	71,898
HAMILTON CONSULTING GROUP	20,263
HOUGH, FASSBENDER, OSBORNE AND ASSOCIATES	40,548
LEGISLATIVE DAY	5,607
NSP(W) INTERNAL CHARGES	6,682
XCEL CHARGES	69,071
WISCONSIN UTILITY ASSOCIATION	447
TOTAL 426.4	227,627
INCOME DEDUCTIONS-MISCELLANEOUS-ACCOUNT 426.5	
SERVICE CLUB DUES	30,788
DEFAULTED ECONOMIC DEVELOPMENT LOANS AND/OR GUARANTEES	600,383
XCEL CHARGES	19,526
NSP(W) INTERNAL CHARGES	(597)
TOTAL 426.5	650,100
INTEREST ON DEBT TO ASSOCIATED COMPANY - ACCOUNT 430	
SHORT-TERM LOAN FROM NSP-MN	162,751
TOTAL 430	162,751
OTHER INTEREST EXPENSE - ACCOUNT 431	
INTEREST ON CUSTOMER DEPOSITS	49,194
MISCELLANEOUS	13,245
TOTAL 431	62,439

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 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	Number of Watt-hour Meters	LINE TRANSFORMERS Number	Total capacity (in Mva)
	(a)	(b)	(c.)	(d.)
1	Number at Beginning of Year	241,871	75,761	2,978
2	Additions During Year		121	5
3	Purchases	4,627	2,127	84
4	Associated with Utilitiy Plant Acquired			
5	TOTAL Additions (Enter Total of lines 3 and 4)	4,627	2,127	84
6	Reductions During Year			
7	Retirements	7,107	779	30
8	Associated with Utilitiy Plant Sold			
9	TOTAL Reductions (Enter Total of lines 7 and 8)	7,107	779	30
10	Number at End of Year (Lines 1+5-9)	239,391	77,109	3,032
11	In Stock	7,171	2,311	91
12	Locked Meters on Customers' Premises	848		
13	Inactive Transformers on System	-	-	
14	In Customers' Use	231,257	74,798	2,941
15	In Company's Use	115		
16	TOTAL End of Year (Total Lines 11 to 15. This should equal line 10)	239,391	77,109	3,032
17				
18				

Intercompany charges from Xcel Energy Services, Inc.
to Northern States Power Company (Wisconsin)
for Calendar Year 2002 *

Service Function	Allocation Method	Total
Accounting, Fin Rptg & Taxes	Direct Assigned	2,404,883
Accounting, Fin Rptg & Taxes		-15,483
Accounting, Fin Rptg & Taxes		32,896
Accounting, Fin Rptg & Taxes	SEC approved allocator	1,127,923
Aviation Services	Direct Assigned	168,302
Aviation Services	SEC approved allocator	6
Bus Unit Acctg&Budgeting-DE	Direct Assigned	3,613,926
Bus Unit Acctg&Budgeting-DE	SEC approved allocator	137,637
Bus Unit Acctg&Budgeting-EM	Direct Assigned	59,246
Bus Unit Acctg&Budgeting-EM	SEC approved allocator	145,827
Bus Unit Acctg&Budgeting-ES	Direct Assigned	228,516
Bus Unit Acctg&Budgeting-ES	SEC approved allocator	65,642
Bus Unit Acctg&Budgeting-RE	Direct Assigned	319,119
Bus Unit Acctg&Budgeting-RE	SEC approved allocator	12,559
Bus Unit Acctg&Budgeting-SS	Direct Assigned	16,057
Bus Unit Acctg&Budgeting-SS	SEC approved allocator	74,336
Bus Unit Acctg-CO Juris Ldr	SEC approved allocator	576
Claims Services	Direct Assigned	77,892
Claims Services	SEC approved allocator	15,657
Corp Strategy & Bus Dev	Direct Assigned	3,401
Corp Strategy & Bus Dev	SEC approved allocator	660,924
Corporate Communications	Direct Assigned	225,906
Corporate Communications	SEC approved allocator	765,970
Customer Service	Direct Assigned	5,559,441
Customer Service	SEC approved allocator	865,500
ED Construction, O&M	Direct Assigned	659,038
ED Construction, O&M	SEC approved allocator	46,909
ED Engineering/Design	Direct Assigned	2,492,132
ED Engineering/Design	SEC approved allocator	119,529
EM - Fuel Procurement	Direct Assigned	261,895
EM - Fuel Procurement	SEC approved allocator	1,821
EM Reg Trdg-Resource Planning	Direct Assigned	15,024
EM Reg Trdg-Resource Planning	SEC approved allocator	39
EM Regulated Trading & Mktg	Direct Assigned	324,085
EM Regulated Trading & Mktg	SEC approved allocator	150,137
Energy Delivery Marketing	Direct Assigned	41,814
Energy Delivery Marketing	SEC approved allocator	26,743

Intercompany charges from Xcel Energy Services, Inc.
to Northern States Power Company (Wisconsin)
for Calendar Year 2002 *

Service Function	Allocation Method	Total
ES Bus Res-Hayden	Direct Assigned	760,766
ES Bus Res-Hayden	SEC approved allocator	8,385
ES Business Resources	Direct Assigned	165,994
ES Business Resources	SEC approved allocator	6,572
ES Engineering & Environmental	Direct Assigned	823,851
ES Engineering & Environmental	SEC approved allocator	13,290
Executive Management Services	Direct Assigned	15,517
Executive Management Services	SEC approved allocator	353,435
Facilities & Real Estate	Direct Assigned	1,662,469
Facilities & Real Estate	SEC approved allocator	548,728
Facilities Admin Services	Direct Assigned	334,102
Facilities Admin Services	SEC approved allocator	71,212
Finance & Treasury	Direct Assigned	65,369
Finance & Treasury	SEC approved allocator	367,776
Fleet	Direct Assigned	58,303
Fleet	SEC approved allocator	604
Government Affairs	Direct Assigned	824
Government Affairs	SEC approved allocator	115,872
Human Resources-DE	Direct Assigned	55,817
Human Resources-DE	SEC approved allocator	91,584
Human Resources-ES	Direct Assigned	48,552
Human Resources-ES	SEC approved allocator	30,674
Human Resources-RE	Direct Assigned	157,491
Human Resources-RE	SEC approved allocator	28,076
Human Resources-SS	Direct Assigned	218,077
Human Resources-SS	SEC approved allocator	905,952
Information Technology - ET	Direct Assigned	406,915
Information Technology - ET	SEC approved allocator	16
Information Technology-EM	Direct Assigned	18,842
Information Technology-EM	SEC approved allocator	176,358
Information Technology-ES	Direct Assigned	37,833
Information Technology-ES	SEC approved allocator	12,211
Information Technology-RE	Direct Assigned	3,179,460
Information Technology-RE	SEC approved allocator	97,657
Information Technology-SS	SEC approved allocator	0
Internal Audit	Direct Assigned	47,169
Internal Audit	SEC approved allocator	60,168

Intercompany charges from Xcel Energy Services, Inc.
to Northern States Power Company (Wisconsin)
for Calendar Year 2002 *

Service Function	Allocation Method	Total
Investor Relations	SEC approved allocator	225,779
Legal	Direct Assigned	812,621
Legal	SEC approved allocator	504,011
Marketing & Sales	Direct Assigned	2,058,316
Marketing & Sales	SEC approved allocator	123,025
Payment & Reporting	Direct Assigned	117,132
Payment & Reporting	SEC approved allocator	15,438
Payroll	Direct Assigned	35,200
Payroll	SEC approved allocator	92,051
Rates & Regulation	Direct Assigned	648,757
Rates & Regulation	SEC approved allocator	74,975
Receipts Processing	Direct Assigned	238
Receipts Processing	SEC approved allocator	147,545
Supply Chain - DE	Direct Assigned	175,578
Supply Chain - DE	SEC approved allocator	2,156
Supply Chain - SS	Direct Assigned	31,986
Supply Chain - SS	SEC approved allocator	-1,885
Supply Chain Special Programs	Direct Assigned	1,016
Supply Chain Special Programs	SEC approved allocator	381
Supply Chain-ES(910 Alloc)	Direct Assigned	62,447
Supply Chain-ES(910 Alloc)	SEC approved allocator	4,759
Other		-1,118,312
Total		$35,664,960

* Excludes convenience payments

This report is prepared in accordance with Docket 4220-AU-125. Additional information is available upon request.

See Appendix A for a description of the services and methods of allocation for each Service Function.

APPENDIX A

DESCRIPTION OF SERVICES TO BE PROVIDED BY XCEL ENERGY SERVICES INC. AND DETERMINATION OF CHARGES FOR SUCH SERVICES TO THE OPERATING COMPANIES AND OTHER AFFILIATES

Description of Services Provided

A description of the services provided by Xcel Energy Services is detailed below. Identifiable costs will be directly assigned to the Operating Companies and other affiliates. For costs that are for services of a general nature and cannot be directly assigned, the method of allocation is described below for each service provided. If specific conditions are met (as outlined in the Xcel Energy Services Policies and Procedures Manual), an alternative Labor Dollars Ratio may be used to allocate non-labor costs for any service.

a) Executive Management Services

Description – Represents charges for Xcel executive management and services, including, but not limited to, officers of Xcel.

Methods of Allocation – Executive Management indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Asset Ratio with 15 percent of Assets assigned to Xcel Energy Inc.

b) Investor Relations

Description – Provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.

Methods of Allocation – Investor Relations indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Asset Ratio with 15 percent of Assets assigned to Xcel Energy Inc.

c) Internal Audit

Description – Reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks.

Method of Allocation – Internal Audit indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio with 15 percent of Assets assigned to Xcel Energy Inc.

d) Legal

Description - Provides legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate and other legal matters.

Method of Allocation – Legal indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio with 15 percent of Assets assigned to Xcel Energy Inc.

e) Claims Services

Description - Provides claims services related to casualty, public and company claims.

Method of Allocation - Claims Services costs will be direct charged, and administrative support functions that cannot be direct charged will be allocated using the Labor Dollars Ratio.

f) Corporate Communications

Description – Provides corporate communications, speech writing and coordinates media services. Provides advertising and branding development for the companies within the Xcel system. Manages and tracks all contributions made on behalf of the Xcel system.

Method of Allocation – Corporate Communications indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio with 15 percent of Assets assigned to Xcel Energy Inc.

g) Employee Communications

Description – Develops and distributes communications to employees.

Method of Allocation – Employee Communications indirect costs will be allocated based on the Employee Ratio.

h) Corporate Strategy & Business Development

Description – Facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance and evaluates business opportunities. Develops and facilitates process improvements.

Method of Allocation – Corporate Strategy & Business Development indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio with 15 percent of Assets assigned to Xcel Energy Inc.

i) Government Affairs

Description - Monitors, reviews and researches government legislation.

Method of Allocation – Government Affairs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio with 15 percent of Assets assigned to Xcel Energy Inc.

j) Facilities & Real Estate

Description – Operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment.

Method of Allocation – Facilities & Real Estate indirect costs will be allocated to the Operating Companies based on the Square Footage Ratio.

k) Facilities Administrative Services

Description – Includes but is not limited to the functions of Mail Delivery, Duplicating and Records Management.

Method of Allocation - Facilities Administrative Services indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio with 15 percent of Assets assigned to Xcel Energy Inc.

l) Supply Chain

Description – Includes contract negotiations, development and management of supplier relationships and acquisition of goods and services. Also includes inventory planning and forecasting, ordering, accounting and database management. Warehousing services includes receiving, storing, issuing, shipping, returns, and distribution of material and parts.

Method of Allocation – Supply Chain will be direct charged, and administrative support functions that cannot be direct charged will be allocated using the Labor Dollars Ratio.

m) Supply Chain Special Programs

Description – Develops and implements special programs utilized across the company such as procurement cards, travel services, and compliance with corporate MWBE (minority women business expenditures) program goals.

Methods of Allocation – Supply Chain Special Programs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

n) Human Resources

Description – Establishes and administers policies related to employment, compensation and benefits. Maintains HR computer system, the tuition reimbursement plan, and diversity program. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general HR support services.

Methods of Allocation – Human Resources indirect costs will be allocated based on the Employee Ratio.

o) Finance & Treasury

Description – Coordinates activities related to securities issuance, including maintaining relationships with financial institutions, cash management, investing activities and monitoring the capital markets. Performs financial and economic analysis.

Method of Allocation – Finance & Treasury indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio with 15 percent of Assets assigned to Xcel Energy Inc.

p) Accounting, Financial Reporting & Taxes

Description - Maintains the books and records. Prepares financial and statistical reports, tax filings and ensures compliance with the applicable laws and regulations. Maintains the accounting systems. Coordinates the budgeting process.

Method of Allocation – Accounting, Financial Reporting & Taxes indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio with 15 percent of Assets assigned to Xcel Energy Inc.

q) Business Unit Accounting and Budgeting

Description - Provides financial analysis, budgeting and administrative support for the business units.

Method of Allocation – Business Unit Accounting and Budgeting indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

r) Payment & Reporting

Description – Processes payments to vendors and prepares statistical reports.

Method of Allocation – Payment & Reporting indirect costs will be allocated to the Operating Companies based on the Invoice Transaction Ratio.

s) Receipts Processing

Description – Processes payments received from customers of the Operating Companies and affiliates.

Method of Allocation – Receipts Processing indirect costs will be allocated based on the Customer Bills Ratio.

t) Payroll

Description – Processes payroll including but not limited to time reporting, calculation of salaries and wages, payroll tax reporting and compliance reports.

Method of Allocation – Payroll indirect costs will be allocated based on the Employee Ratio.

u) Rates & Regulation

Description – Determines the Operating Companies' regulatory strategy, revenue requirements and rates for electric and gas customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.

Method of Allocation – Rates & Regulation indirect costs will be allocated to the Operating Companies based on the Revenue Ratio or the Labor Dollars Ratio.

v) Energy Supply Engineering and Environmental

Description – Provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Oversees environmental clean up projects.

Method of Allocation – Energy Supply Engineering and Environmental services will be direct charged, and administrative support functions that cannot be direct charged will be allocated using the Labor Dollars Ratio.

w) Energy Supply Business Resources

Description - Provides performance, specialists and analytical services to the Operating Companies' generation facilities.

Method of Allocation – Energy Supply Business Resources indirect costs will be allocated using the MWh Generation Ratio.

x) Energy Markets Regulated Trading & Marketing

Description - Provides electric trading services to the Operating Companies' electric generation systems including load management, system optimization and resource acquisition.

Method of Allocation – Energy Markets Regulated Trading & Marketing indirect costs will be allocated to the Operating Companies based on the Total MWh Sales Ratio.

y) Energy Markets – Fuel Procurement

Description – Purchases fuel for Operating Companies electric generation systems (excluding nuclear).

Method of Allocation – Energy Markets Fuel Procurement indirect costs will be allocated based on the MWh Generation Ratio.

z) Energy Delivery Marketing

Description - Develops new business opportunities and markets the products and services for the Delivery Business Unit.

Method of Allocation – Energy Delivery Marketing will be direct charged.

aa) Energy Delivery Construction, Operations & Maintenance (COM)

Description – Constructs, maintains and operates electric and gas delivery systems.

Method of Allocation – Energy Delivery COM indirect costs will be allocated based on the Delivery Services Gross Plant Ratio.

bb) Energy Delivery Engineering/Design

Description – Provides engineering and design services in support of capacity planning, construction, operations and material standards.

Method of Allocation – Energy Delivery Engineering/Design services will be direct charged, and administrative support functions that cannot be direct charged will be allocated based on the Labor Dollars Ratio.

cc) Marketing & Sales

Description - Provides marketing and sales services for the Operating Companies and affiliates for their electric and natural gas customers including strategic planning, segment identification, business analysis, sales planning and customer service.

Method of Allocation – Marketing & Sales indirect costs will be allocated based on the Revenue Ratio.

dd) Customer Service

Description – Provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center and credit and collections.

Method of Allocation – Customer Service indirect costs will be allocated based on the Customers Ratio.

ee) Information Technology

Description – Provides various communications and electronic data processing services including but not limited to, development and support of mainframe computer software applications, procurement and support of personal computers, operation of a data center and installation and operation of a communications system. Also administers the IBM contract that may provide for the services listed above.

Method of Allocation – Information Technology will be direct charged.

ff) Aviation Services

Description – Provides aviation and travel services to employees.

Method of Allocation – Aviation Services will be direct charged.

gg) Fleet

Description – Oversees the Operating Companies' Fleet Services Group.

Method of Allocation – Fleet will be direct charged.

Allocation Ratios

The following ratios will be utilized as outlined above.

Revenue Ratio - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Employee Ratio - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Assets Ratio, with 15 Percent of Assets assigned to Xcel Energy Inc. - Based on the total assets as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned fifteen percent of the total assets. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Assets Ratio - Based on the total assets as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Square Footage Ratio - Based on the total square footage as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Invoice Transaction Ratio - Based on the sum of the monthly number of invoice transactions processed for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Customer Bills Ratio – Based on the average of the monthly total number of customer bills issued during the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

MWh Generation Ratio - Based on the sum of the monthly electric MWh generated during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total MWh Sales Ratio - Based on the sum of the monthly electric MWh hours sold during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This includes sales to ultimate customers, wholesale customers, and non-requirement sales for resale. This ratio will be determined annually, or at such time as may be required due to significant changes.

Customers Ratio - Based on the average of the monthly total electric customers (and/or gas customers, or residential, business and large commercial and industrial customers where applicable) for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Labor Dollars Ratio - Based on the XES department (performing center) labor dollars charged to Operating companies and other affiliates for the month. The numerator of which is the labor dollars charged to an Operating Company or affiliate company and the denominator of which is for all Operating Companies and affiliate companies charged by the department for the month.

Delivery Services Gross Plant Ratio - Based on transmission and distribution gross plant for the Delivery Business unit, both electric and gas for the prior year ending December 31, the numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Northern States Power Company (WI)
d/b/a Xcel Energy
For Year Ended 12/31/02

Transactions with Affiliates Annual Reporting

Regulated Operating Companies

	Amounts Billed to Affiliates (1)	Amounts Billed from Affiliates (2)	Other (3)	Net Intecompany (Payable) Receivable (4)
NSP Minnesota	$567,115	$7,558,400	$1,252,089	($5,739,196)
Interchange Agreement	80,199,548	220,673,952	0	(140,474,404)
Gas Coordinating Agreement		168,698	0	(168,698)
Receipts on Customer Accounts	(10,159,000)	(81,946,820)	0	71,787,820
Customer Refund Checks	(233,844)	0	0	(233,844)
Deposits in Transit		(3,340,761)	0	3,340,761
ESOP 401K Match		586,508	0	(586,508)
Allocation of Software		2,257,822	0	(2,257,822)
	$70,373,820	$145,957,799	$1,252,089	($74,331,891)
Black Mountain Gas	None	None	None	None
Public Service of Colorado	58,020	126,036	7,489	(60,527)
Southwestern Public Service	113,251	59,932	65,531	118,849
Cheyenne Light Fuel and Power	(132)	790	52	(870)
	$70,544,958	**$146,144,557**	**$1,325,160**	**($74,274,439)**

This report is prepared in accordance with Docket 4220-AU-127. Additional information is available upon request.

(1) This column generally represents Operating and Maintenance or Capital expenses provided by NSPW for the benefit of an affiliate
(2) This column generally represents Operating and Maintenance or Capital expenses provided by the affiliate for the benefit of NSPW
(3) This column generally represents the net convenience payments made between NSPW and affiliates. A debit balance indicates a receivable, meaning that NSPW made more convenience payments for the affiliates than the affiliates made for NSPW.
(4) This column represents the net amount due to NSPW by the affiliate (a debit balance) or the net amount owed to the affiliate by NS (a credit balance) for all transactions.

E-PRIME TRANSACTIONS
Year End 2002

		E-PRIME TRANSACTION INFORMATION							
Description	Date	Delivery	Daily Volume (MMBtu)	Delivery Period Start	Stop	No. of Days	Monthly Volume (MMBtu)	Rate (MMBtu)	Transaction Amount DR.<CR.>
Sales	1/24/02-1/31/02	DMC	1,200	24	31	8	-9,600	$ 1.9700	($18,912.00)
Total Sales							**-9,600**		**($18,912.00)**
Purchases	1/19/02-1/31/02	DMC	1,200	19	31	13	15,600	$ 2.2000	$34,320.00
Total Purchases							**15,600**		**$34,320.00**
Capacity Release	4/1/02-10/31/02	Field	10,000	152	365	214	-2,140,000	$ 0.0050	($10,700.00)
Capacity Release	11/1/02-12/31/02	Field	11,346	1	61	61	-692,106	$ 0.0300	($20,763.18)
Total Cap Rel							**-2,832,106**		**($31,463.18)**
Totals							**-2,826,106**		**$ (16,055.18)**

This report has been prepared in accordance with Docket 4220-AG-122. Additional information is available upon request.

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RETURN ON COMMON EQUITY AND COMMON EQUITY PLUS ITC COMPUTATIONS

Note: Report on a corporate basis only; not consolidated. If you file monthly rate of return forms with the PSC, use the same method for completing this form. Use the average of the 12 monthly averages when computing average common equity.

Description (a)		Thousands of Dollars		
		Common Equity (b)	Common Equity plus ITC (c)	
Common Stock Outstanding		93,300	93,300	13
Premium on Capital Stock	based on monthly	33,338	33,338	14
Capital Stock Expense	averages if available			15
Retained Earnings		285,897	285,897	16
Deferred Investment Tax Credit				17
(Only common equity portion if				18
Form PSC-AF6 is filed on monthly				19
basis with the Commission)			8,561	20
Other (Specify):				21
				22
				23
				24
Total Average Common Stock Equity plus Deferred Investment				25
Credit (sum of lines 14 thru 25)		$412,535	$421,096	26
Net Income				27
Add:				28
Net Income		54,373	54,373	29
Other (Specify):				30
				31
Less:				32
Preferred Dividends				33
Other (Specify):				34
(If Form PSC-AF6 is filed with the Commission, net income must				35
be reduced by that portion of net income representing debt				36
cost of deferred investment tax credit as shown on the form.)			470	37
				38
				39
				40
				41
Adjusted Net Income		$54,373	$53,903	42
Percent return (line 43 divided by line 27 to the nearest hundredth				43
of a percent)		13.18%	12.80%	44

May not cross-check due to rounding.

Note: Report on a corporate basis only; not consolidated. If you file monthly rate of return forms with the PSC, use the same method for completing this form. Use the average of the 12 monthly averages when computing the rate base.

Thousands of Dollars

Average Rate Base (a)	Electric (b)	Gas (c)	Other (d)	Total (e)
Add Average:				
Utility Plant In Service	1,141,466	129,504		1,270,970
Allocation Of Common Plant	73,987	15,879		89,866
Completed Construction not Classified				0
Nuclear Fuel				0
Materials and Supplies	10,939	2,829		13,768
Other (Specify):				0
Invest in Chip.Flam.Impr.Co.	549			549
Regulatory Asset	2,346	477		2,823
Less Average:				
Reserve for Depreciation	498,659	72,412		571,071
Amortization Reserves	1,686			1,686
Customer Advances For Construction	13,172	2,296		15,468
Contribution in Aid of Construction				0
Other (Specify):				0
Accumulated Def.Inc.Taxes	120,701	4,978		125,679
Approp.Retained Earnings	5,468			5,468
Average Net Rate Base	$589,601	$69,003	$0	$658,604
RETURN				
Total Operating Income	69,775	7,743		77,518
Less: (Specify):				0
				0
				0
Adjusted Operating Income	$69,775	$7,743	$0	$77,518
Adjusted Operating Income As A Percent Of Average Net Rate Base (Rounded To Nearest Hundredth of a Percent)	11.83%	11.22%	0.00%	11.77%

REVENUES SUBJECT TO WISCONSIN REMAINDER ASSESSMENT

Report data necessary to calculate revenue subject to Wisconsin remainder assessment. For purposes of this schedule "out-of-state" and "in-state" refer to the geographic state of Wisconsin

Description (a)	This Year (b)
Operating revenues	481,413,725
Less: out-of-state operating revenues (retail only)	(15,297,266)
Less: in-state interdepartmental sales	(1,032,564)
Less: current year write-offs of uncollectible accounts Wisconsin utility customers only	(3,146,532)
Plus: current year collection of Wisconsin utility customer accounts previously written off	1,234,152
Other	
Revenues subject to Wisconsin remainder assessment	$463,171,515

May not cross-check due to rounding.

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Report hereunder the total overheads and the total direct cost of construction for the year. Projects under $1,000,000 for class A utilities and $500,000 for class B utilities, should be grouped by utility department and function.

ANNUAL CHARGES

Project Description (a)	Direct Charges: Company Labor (b)	Company Materials (c)	Contractor Payments (d)	Other (e)
Projects Over $1,000,000				
Electric Production				
French Island Stm Unit 1 & 2 Baghouse	63,014	985,594	6,759,646	(3,050,438)
Subtotal	63,014	985,594	6,759,646	(3,050,438)
Electric Transmission				
T-Corners Capacitor Project	943,489	1,314,525	70,702	254,846
Ironwood Install 2nd 88-35kv Transformer	16,706	(116,480)	196	576
Farmers Inn - Add 161-69Kv Transformer	117	876	310	0
Subtotal	960,312	1,198,920	71,208	255,422
Total	$1,023,327	$2,184,515	$6,830,854	($2,795,016)
% Of Total Direct Charges				

COMPLETED CONSTRUCTION CLEARED

Report hereunder the total cost of completed construction projects cleared from account 107 during the year. Projects under $1,000,000 for class A utilities and $500,000 for class B utilities, should be grouped by utility department and function.

Project Description (a)	Direct Charges: Company Labor (b)	Company Materials (c)	Contractor Payments (d)	Other (e)
Projects Over $1,000,000				
Electric Production				
French Island Stm Unit 1 & 2 Baghouse	65,112	1,206,470	8,794,250	(2,324,858)
Subtotal	65,112	1,206,470	8,794,250	(2,324,858)
Elec Transmission:				
T-Corners 115KV Upgrade	499,112	489,067	150,668	412,760
Eau Claire Rewind 112MVA Transformer	147,522	819,023	9,504	131,933
Farmers Inn - Add 161-69kv Transformer	112	4,603	310	0
Subtotal	646,746	1,312,693	160,482	544,693
Total	$711,859	$2,519,164	$8,954,732	($1,780,165)
% Of Total Direct Charges				

May not cross-check due to rounding.

CONSTRUCTION OVERHEADS (Continued)

Report hereunder the total overheads and the total direct cost of construction for the year. Projects under $1,000,000 for class A utilities and $500,000 for class B utilities, should be grouped by utility department and function.

	ANNUAL CHARGES				
	Overheads				
Total Direct Charges (f)	Engineering & Supervision (g)	Administration and General (h)	Allowance for Funds Used (i)	Taxes & Other (j)	Total Columns (f+g+h+i+j) (k)
4,757,817	318,326	100,250	87,637	12,445	5,276,475
4,757,817	318,326	100,250	87,637	12,445	5,276,475
2,583,562	91,109	52,790	123,739	186,339	3,037,539
(99,002)	(20,157)	(1,974)	8,950	3,300	(108,884)
1,303	0	0	(2)	23	1,323
2,485,863	70,952	50,816	132,687	189,661	2,929,979
7,243,679	$389,278	$151,066	$220,324	$202,106	$8,206,453

COMPLETED CONSTRUCTION CLEARED (Continued)

Report hereunder the total cost of completed construction projects cleared from account 107 during the year. Projects under $1,000,000 foe class A utilities and $500,000 for class B utilities, should be grouped by utility department and function.

	Overheads				
Total Direct Charges (f)	Engineering & Supervision (g)	Administration and General (h)	Allowance for Funds Used (i)	Taxes & Other (j)	Total Columns (f+g+h+i+j) (k)
7,740,976	70,722	124,199	109,220	14,572	8,059,689
7,740,976	70,722	124,199	109,220	14,572	8,059,689
1,551,607	27,910	35,562	114,789	111,701	1,841,570
1,107,982	86,669	22,820	0	33,015	1,250,486
5,025	0	0	0	25	5,050
2,664,614	114,579	58,382	114,789	144,742	3,097,106
10,405,590	$185,301	$182,581	$224,010	$159,314	11,156,795

May not cross-check due to rounding.

Report hereunder the total overheads and the total direct cost of construction for the year. Projects under $1,000,000 for class A utilities and $500,000 for class B utilities, should be grouped by utility department and function.

ANNUAL CHARGES

Project Description (a)	Direct Charges: Company Labor (b)	Company Materials (c)	Contractor Payments (d)	Other (e)
Gas Storage Distr. & General				
New Richmond/Viking Gas System Tie	18,030	313,256	580,215	1,797
Subtotal	18,030	313,256	580,215	1,797
Subtotal - Projects Over $1,000,000	1,041,357	2,497,771	7,411,069	(2,793,219)
Projects Under $1,000,000				
Electric	2,155,487	9,917,424	1,062,551	5,930,915
Gas	496,238	1,911,187	1,298,113	179,932
Common	24,984	2,418,752	713,744	37,779
Subtotal - Projects Under $1,000,000	2,676,709	14,247,363	3,074,409	6,148,626
Total	$3,718,066	$16,745,134	$10,485,478	$3,355,407
% Of Total Direct Charges				

COMPLETED CONSTRUCTION CLEARED

Report hereunder the total cost of completed construction projects cleared from account 107 during the year. Projects under $1,000,000 for class A utilities and $500,000 for class B utilities, should be grouped by utility department and function.

Project Description (a)	**Direct Charges:** Company Labor (b)	Company Materials (c)	Contractor Payments (d)	Other (e)
Subtotal - Projects Over $1,000,000	711,859	2,519,164	8,954,732	(1,780,165)
Projects Under $1,000,000				
Electric	2,586,202	11,584,347	2,310,082	4,394,639
Gas	451,181	1,994,424	1,684,099	330,754
Common	32,133	3,179,141	943,208	27,314
Subtotal - Projects Under $1,000,000	3,069,516	16,757,913	4,937,389	4,752,708
Total	$3,781,374	$19,277,077	$13,892,121	$2,972,543
% Of Total Direct Charges				

May not cross-check due to rounding.

CONSTRUCTION OVERHEADS (Continued)

Report hereunder the total overheads and the total direct cost of construction for the year. Projects under $1,000,000 for class A utilities and $500,000 for class B utilities, should be grouped by utility department and function.

	ANNUAL CHARGES					
	Overheads					
Total Direct Charges (f)	Engineering & Supervision (g)	Administration and General (h)	Allowance for Funds Used (i)	Taxes & Other (j)	Total Columns (f+g+h+i+j) (k)
913,298	123,223	18,337	42,229	3,561	1,100,649
913,298	123,223	18,337	42,229	3,561	1,100,649
8,156,977	512,501	169,403	262,553	205,667	9,307,102
19,066,377	2,123,325	227,041	349,117	425,709	22,191,568
3,885,470	613,625	87,933	63,371	98,007	4,748,406
3,195,259	8,360	12,758	32,587	4,934	3,253,898
26,147,107	2,745,309	327,732	445,075	528,650	30,193,873
$34,304,084	$3,257,810	$497,135	$707,628	$734,318	$39,500,974
	9.50%	1.45%	2.06%	2.14%	

COMPLETED CONSTRUCTION CLEARED (Continued)

Report hereunder the total cost of completed construction projects cleared from account 107 during the year. Projects under $1,000,000 foe class A utilities and $500,000 for class B utilities, should be grouped by utility department and function.

Overheads					
Total Direct Charges (f)	Engineering & Supervision (g)	Administration and General (h)	Allowance for Funds Used (i)	Taxes & Other (j)	Total Columns (f+g+h+i+j) (k)
10,405,590	185,301	182,581	224,010	159,314	11,156,795
20,875,270	2,472,919	659,329	1,023,865	578,792	25,610,175
4,460,458	162,643	132,824	63,371	100,974	4,920,271
4,181,797	7,220	61,305	19,322	7,191	4,276,835
29,517,525	2,642,782	853,458	1,106,558	686,958	34,807,281
$39,923,115	$2,828,083	$1,036,038	$1,330,568	$846,271	$45,964,076
	7.08%	2.60%	3.33%	2.12%	

May not cross-check due to rounding.

INVESTMENTS AND FUNDS (ACCTS. 123-128,incl.)

1. Report, with separate subheadings for each account the securities owned by the utility; include date of issue and date of maturity in description of any debt securities owned. Designate any securities pledged and explain purpose of pledge in footnote. Minor investments included in Acct. 124 may be grouped by classes.
2. Report separately each fund account showing nature of assets included therein and list any securities included in fund accounts.

Issuing Company And Type of Security (a)	Interest or Dividend Rate (b)	Par Value per Share (c)	No.of Shares or Principal amt. (d)	Book Cost End Of Year (e)
Investments in Associated Companies (123)				
Securities				
Chip.& Flam.Improvement Co.-Capital Stock	6%	$76	8,345	549,326
Clearwater Investments, Inc.-Capital Stock			100	150,000
NSP Lands, Inc.-Capital Stock			100	50,000
Equity in Undistributed Earnings				2,794,851
Total Account (123)				3,544,177
Other Investments (124)				
Tax Benefit Transfer Leases				3,081
Economic Development Loans				5,363,492
Wealth Op.Insurance Premium				895,671
Deferred Comp				10,340
Total Account 124				6,272,584
Special Funds (125-128)				
None				
Total				$9,816,761

ACCOUNTS RECEIVABLE (Accts. 142-143)

Particulars (a)	Amount end of year (b)
Customer accounts receivable (142):	
Electric department - estimated	35,346,452
Gas department - estimated	7,586,200
Water department	
Other -	
Total utility service	$42,932,652
Merchandising, jobbing and contract work	
Total (Acct.142)	$42,932,652
Other accounts receivable (143):	
Officers and employees	31,813
Subscriptions to capital stock	
All other (List separately only the large or unusual items):	
Damage claims, billing jobs and material sales	1,997,029
RDF tipping fees	231,535
Arpin and Wis Power & Light interconnection charges	589,968
Non-traditional gas sales	1,902,795
Sale of Eau Claire Barstow and Railroad buildings	1,090,722
Prudential premium rebate	768,686
	$6,612,548

May not cross-check due to rounding

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS - CR (Acct. 144)

Particulars (a)	Electric Utility Customers (b)	Gas Utility Customers (c)	Other Customers (d)	Total Utility Customers (e)
Balance first of year	1,084,758	(115,297)		969,460
Add: Provision for uncollectibles during year	1,506,576	426,293		1,932,869
Collection of accounts written off	864,203	208,448		1,072,651
other credits (explain):				0
Total credits	2,370,779	634,741	0	3,005,520
Less: Accounts written off	2,154,789	550,077		2,704,866
other debits (explain):				0
Total debits	2,154,789	550,077	0	2,704,866
Balance end of year	1,300,747	(30,633)	0	1,270,114

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS - CR (Acct. 144)(cont.)

Particulars (a)	Total Utility Customers (g)	Officers & Employees (h)	Other (i)	Total (j)
Balance first of year	969,460		0	969,460
Add: Provision for uncollectibles during year	1,932,869		103,000	2,035,869
Collection of accounts written off	1,072,651			1,072,651
other credits (explain):	0			0
Total credits	3,005,520	0	103,000	3,108,520
Less: Accounts written off	2,704,866			2,704,866
other debits (explain):	0			0
Total debits	2,704,866	0	0	2,704,866
Balance end of year	1,270,114	0	103,000	1,373,114
Loss on Wisconsin utility accounts:				
Accounts written off				3,146,532
Collection of such accounts previously written off				1,234,152
Net loss				1,912,380

Notes to explain "other" on lines 11, 14, 26 & 29 above:

May not cross-check due to rounding

RECEIVABLES FROM ASSOCIATED COMPANIES (Accts. 145-146)

Give particulars of any notes pledged or discounted. Show in column (a) date of issue, maturity date, and interest rate for any notes receivable

Name of Company (a)	Amount end of year: Notes Receivable (Acct 145) (b)	Amount end of year: Accts Receivable (Acct. 146) (c)
Public Service of Colorado		443,965
Southwestern Public Service Company		105,111
Xcel Energy, Inc.		848,083
Xcel Energy Venture		7,160
First Midwest Auto		54,620
NRG Energy, Inc.		718
Total	0	1,459,656

PREPAYMENTS (ACCT. 165)

Class of prepayments (a)		
Fuel		0
Prepaid Insurance		1,053,452
Prepaid Gas Reservations		234,000
Prepaid Taxes		13,747,061
Prepaid Vehicle License, Postage		17,956
Gas Imbalance		80,631
Michigan Utility Assessment		4,107
Wisconsin Remainder Assessment		278,592
Total	0	15,415,799

MISCELLANEOUS CURRENT AND ACCRUED ASSETS (ACCT. 174)

Minor items may be grouped by classes, showing number of such items.

Description of assets (a)		Balance end of year (b)
NONE		
Total		$0

UNAMORTIZED DEBT DISCOUNT AND EXPENSE

Report below the particulars called for with respect to the unamortized debt discount and expense or net premium applicable to each class and series of long-term debt. Show separately any unamortized debt discount and expense or call premiums applicable to refunded issues, including separate subtotal therefor. Show in column (a) the method of amortization for each amount of debt discount and expense or premium.

Explain any charges or credits in column (c) and (d) other than amortization in Acct. 428 or 429.

	Debt to which related (a)
Unamortized debt discount and expense (181):	
First Mortgage Bonds	
Series Due -	
Apr 01, 2023, 7-1/4%	
Oct 01, 2003, 5-3/4%	
Dec 01, 2026, 7-3/8%	
Oct 02, 2008, 7.64%	
Resource Recovery Financing, 6%	
Total Account 181	
Unamortized Loss on Reacquired Debt (189):	
Loss on Reacq. 16% Bonds	
Loss on Reacq. 8% Bonds	
Loss on Reacq. 9 1/4% Bonds, due 2016	
Loss on Reacq. 9 3/4% Bonds, due 2018	
Loss on Reacq. 7 1/4% Bonds, due 2003	
Resource Recovery Financeing, 7-3/4%	
Loss on Reacq. 9 1/8% Bonds, due 2021	
Total Account 189	
Subtotal	
Unamortized Premium on Long-Term Debt (226):	
Premium on First Mortgage Bonds	
Series Due:	
Apr 01, 2023, 7-1/4%	
Oct 01, 2003, 5-3/4%	
Dec 1, 2026, 7-3/8%	
Total	

May not cross-check due to rounding.

AND UNAMORTIZED PREMIUM ON DEBT (Accts. 181,225)

Report below the particulars called for with respect to the unamortized debt discount and expense or net premium applicable to each class and series of long-term debt. Show separately any unamortized debt discount and expense or call premiums applicable to refunded issues, including separate subtotal therefor. Show in column (a) the method of amortization for each amount of debt discount and expense or premium.

Explain any charges or credits in column (c) and (d) other than amortization in Acct. 428 or 429.

Discount and expense or (net premium) balance first of year (b)	Charges during year (c)	Credits during year (d)	Balance end of year (e)
812,800		38,400	774,400
57,750		33,000	24,750
409,024		16,464	392,560
506,959		75,025	431,934
108,474		5,470	103,004
$1,895,007	$0	$168,359	$1,726,648
2,512,346		247,116	2,265,230
12,580		7,548	5,032
2,160,693		102,080	2,058,613
1,877,907		88,720	1,789,187
102,900		58,800	44,100
303,274		15,291	287,983
2,998,135		120,328	2,877,807
$9,967,835	$0	$639,883	$9,327,952
$11,862,842	$0	$808,242	$11,054,600
1,215,390		57,420	1,157,970
36,750		21,000	15,750
222,944		8,952	213,992
1,475,084	0	87,372	1,387,712

May not cross-check due to rounding.

NOTES PAYABLE (Acct. 231)

Name of payee and purpose for which issued (a)	Date of note (b)	Date of maturity (c)	Interest rate (d)	Balance end of year (e)
None				
Total				0

May not cross-check due to rounding.

PAYABLES TO ASSOCIATED COMPANIES (Acct. 233 -234)

Include in column (a) description of any note payable indcluding date of issue, date of maturity, and inteest rate.

Name of company (a)	Amounts for the year: Notes Payable (233)	Amounts for the year: Accounts Payable (234)
NSP (MN)	6,880,000	
Northern States Power Company MN		1,881,039
Chyene fuel Power and Light		4,916
Viking Gas		167,858
Utility Eningeering		60,174
Xcel Energy Services		4,722,195
Chippewa Flambeau improvement Co.		101,516
Clearwater Investments		95,507
NSP Lands		86,283
Total	6,880,000	7,119,488

INTEREST ACCRUED (Acct. 237)

Class of Debt (a)	Balance end of Year
Interest on Bonds	3,818,813
Interest on Notes Payable	1,541,549
Other	187,050
Total	5,547,412

MISC. CURRENT AND ACCRUED LIABILITIES (Acct. 242)

Minor items may be group by classes.

Description (a)	Balance end of Year (b)
Environmental Clean-Up	2,027,000
Total	2,027,000

DISTRIBUTION OF TAXES TO ACCOUNTS

Explain basis for allocation if used.
If the total does not equal taxes accrued, include a reconciling schedule.

Function (a)	Wisconsin License Fee (b)	Wisconsin Income Tax (c)	Federal Income Tax (d)	FICA and Fed. and State Un-employment Tax (e)
Accts. 408.1 and 409.1:				
Electric	11,346,516	3,067,419	14,386,029	2,512,274
Gas	1,123,144	(320,996)	(596,186)	399,371
Water				
Heating				
Accts. 408.2 and 409.2		(177,970)	(647,216)	
Acct. 409.3				
Clearing accounts & Construction			(496,107)	198,097
Other: Adjustments made for Prior Years				
Total	$12,469,660	$2,568,453	$12,646,521	$3,109,742

Notes and explanations regarding tax distribution:

DISTRIBUTION OF TAXES TO ACCOUNTS (Cont.)

Local Property Tax (f)	State and Local Taxes Other Than Wisconsin (g)	Other Taxes (h)	(i)	Total (j)
(4,088)	762,804	9,825		32,080,780
(2,898)	158,819	1,452		762,706
140,993				(684,193)
	0	235,454		(62,556)
$134,007	$921,623	$246,732	$0	$32,096,737

Notes and explanations regarding tax distribution:

May not cross-check due to rounding

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INTEREST AND DIVIDEND INCOME (Acct. 419)

Security or account on which received (a)	Interest or dividend rate (b)	Amount (c)
(list items greater than $10,000 separately, others may be grouped):		
Clearwater	Various	15,317
Gateway Industrial Park	Various	52,250
LaCrosse Industrial Park	Various	45,875
Sparta Industrial Park	Various	80,000
St. Croix Business Park	Various	419,271
Temporary Cash Investments	Various	118,411
Interest Revenue on Income Tax Refund	Various	61,121
Various Other	Various	83,800
Total interest and dividends		$876,044
Expenses applicable to above (as listed hereunder):		
Total expenses		$0
Interest and dividend income, before taxes		$876,044

May not cross-check due to rounding

DETAIL OF CERTAIN GENERAL EXPENSE ACCOUNTS

Description of item (a)	Amount (b)
Acct. 923--OUTSIDE SERVICES EMPLOYED--State total cost, nature of service, and name of each person who was paid for services includible in this account, $10,000 or more in case of Class B utilities and $25,000 or more in case of Class A utilities.	
Contract labor service billings	380,229
Consulting service billings	2,071,084
Contract outside vendor service billings	157,639
EPRI	90,995
Michael Best & Friedrich (estimate)	315,747
Brooks and Jackson (estimate)	37,148
Loomis Ewert Parsley Davis and Gotting (estimate)	39,500
Kelly & Ryberg SC (estimate)	30,400
Other outside legal consulting	387,452
Total	$3,510,194
Acct. 924--PROPERTY INSURANCE--List hereunder major classes of expenses and also state extent to which utility is self-insured against insurable risks to its property:	
Premiums for insurance	1,211,259
Dividends received from insurance companies--cr.	
Amounts credited to Acct. 261, Property Insurance Reserve	
Other expenses (list major classes):	
Total	$1,211,259
Acct. 925--INJURIES AND DAMAGES--List hereunder major classes of expense. Also, state extent to which utility is self-insured against risks of injuries and damages to employes or to others:	
Premiums for insurance	485,526
Injury and Damages expenses for investigating and adjusting claims	924,993
Legal Accruals	1,100,000
Total	$2,510,519

May not cross-check due to rounding

DETAIL OF CERTAIN GENERAL EXPENSE ACCOUNTS (Cont.)

Description of item (a)	Amount (b)
Acct. 926--EMPLOYEE PENSIONS AND BENEFITS--Report total amount for utility here and show credit for amounts transferred to construction or other accounts, leaving the net balance in Acct. 926	
Pension accruals or payments to pension fund	(7,354,462)
Employees benefits (life, health, accident & hospital insur. etc.)	5,023,346
Total	($2,331,115)
Acct. 930.2--MISCELLANEOUS GENERAL EXPENSES	
Industry association dues	114,825
Shared costs	1,457,543
I T Expenses	166,030
Directors fees and expenses	129,003
Professional association dues	11,803
Other Expenses	481,945
Total	$2,361,149
Acct. 922--ADMINISTRATIVE EXPENSES TRANSFERRED--Cr.--Explain basis of computation of credit in this account.	
Shared asset costs from NSPW to service company	(1,696,867)
Company Use	(540,487)
Administrative and general transferred to capital	(242,382)
Computation of credit has been based upon "Analysis Allocation Method" which has been determined by periodic time studies	
Total	($2,479,734)

May not cross-check due to rounding

COMMON UTILITY PLANT AND ACCUMULATED DEPRECIATION

Utility Plant in Service					
Description (Use both title and account number) (a)	Additions during year (b)	Retirements during year (c)	Adjustments dr. or (cr.) (d)	Balance end of year Total (e)	Balance end of year Located in Wis (f)
Intangible plt-common (303)	2,257,822	0	0	18,907,605	18,907,605
Organization					
Total intangible	2,257,822	0	0	18,907,605	18,907,605
General plant					
Land & land rights (389)	0	0	0	2,018,780	1,967,651
Structures & improv (390)	1,650,944	0	(1,481,431)	27,772,076	26,867,773
Off furn & fixt (391)	157,430	0	0	18,919,850	18,726,785
Transportation equip (392)	0	0	0	462,891	456,865
Stores equip (393)	0	0	0	810,058	803,487
Tools, shop & gar (394)	122,482	0	0	1,211,215	1,168,096
Laboratory (395)	0	0	0	31,019	30,525
Power operated (396)	0	0	0	164,280	116,991
Communication (397)	67,353	0	0	20,959,330	20,204,187
Miscellaneous (398)	20,803	0	0	77,553	76,048
Other (399)					
Total general plant	2,019,012	0	(1,481,431)	72,427,052	70,418,408
Retirement Work in Progress					
TOTAL	4,276,834	0	(1,481,431)	91,334,657	89,326,013

ALLOCATION TO UTILITY DEPARTMENTS

Particulars (a)	Plant end of year (b)	Accumulated deprec. end of year (c)	Depreciation accruals (d)
Electric	75,195,823	39,720,849	3,643,507
Gas	16,138,834	8,525,051	450,121
Water			
Steam Heating			
Total	91,334,657	48,245,900	4,093,628

May not cross-check due to rounding.

COMMON UTILITY PLANT AND ACCUMULATED DEPRECIATION (cont.)

Accumulated provision for depreciation							
Straight line accruals Rate (g)	Amount (h)	Additional accruals (i)	Book cost of plant retired (j)	Cost of removal (k)	Salvage (l)	Other additions or (deductions) (m)	Balance end of year (n)
14.29	261,817		0				16,911,600
	261,817	0	0	0	0	0	16,911,600
2.37	663,663					(624,304)	5,464,309
5.00	988,032						14,669,290
Vari.	0	38,361			5,850		368,508
5.00	40,503						451,415
5.00	57,677						439,166
5.00	1,551						11,340
Vari	0	2,241					148,015
10.00	2,077,239						10,498,292
5.00	3,146						41,292
	3,831,811	40,602	0	0	5,850	(624,304)	32,091,627
				(6,048)	(649,050)		(757,327)
	4,093,628	40,602	0	(6,048)	(643,200)	(624,304)	48,245,900

Explanation of method of allocating common plant, accumulated depreciation, and depreciation expense by utility departments.

Common plant, depreciation reserve and depreciation expense has been allocated to utility departments on the basis of average percentages of utility plant in service, gross revenue and operating expenses (exclusive of joint utility administrative and general expenses, depreciation and taxes) of each department to the total.

Common property under capital leases is not included in these plant numbers.

May not cross-check due to rounding.

UTILITY FINANCIAL DATA - 01
ID NUMBER - 4220 UTILITY NAME - Northern States Power Company (WI) YEAR - 2002

Utility Plant in Service (1) (2)	Beg. of Year	End of Year
Electric	$1,226,448,474	$1,253,494,060
Gas	144,501,464	151,219,189
Water		
Heating (Steam)		
Total	**$1,370,949,938**	**$1,404,713,249**

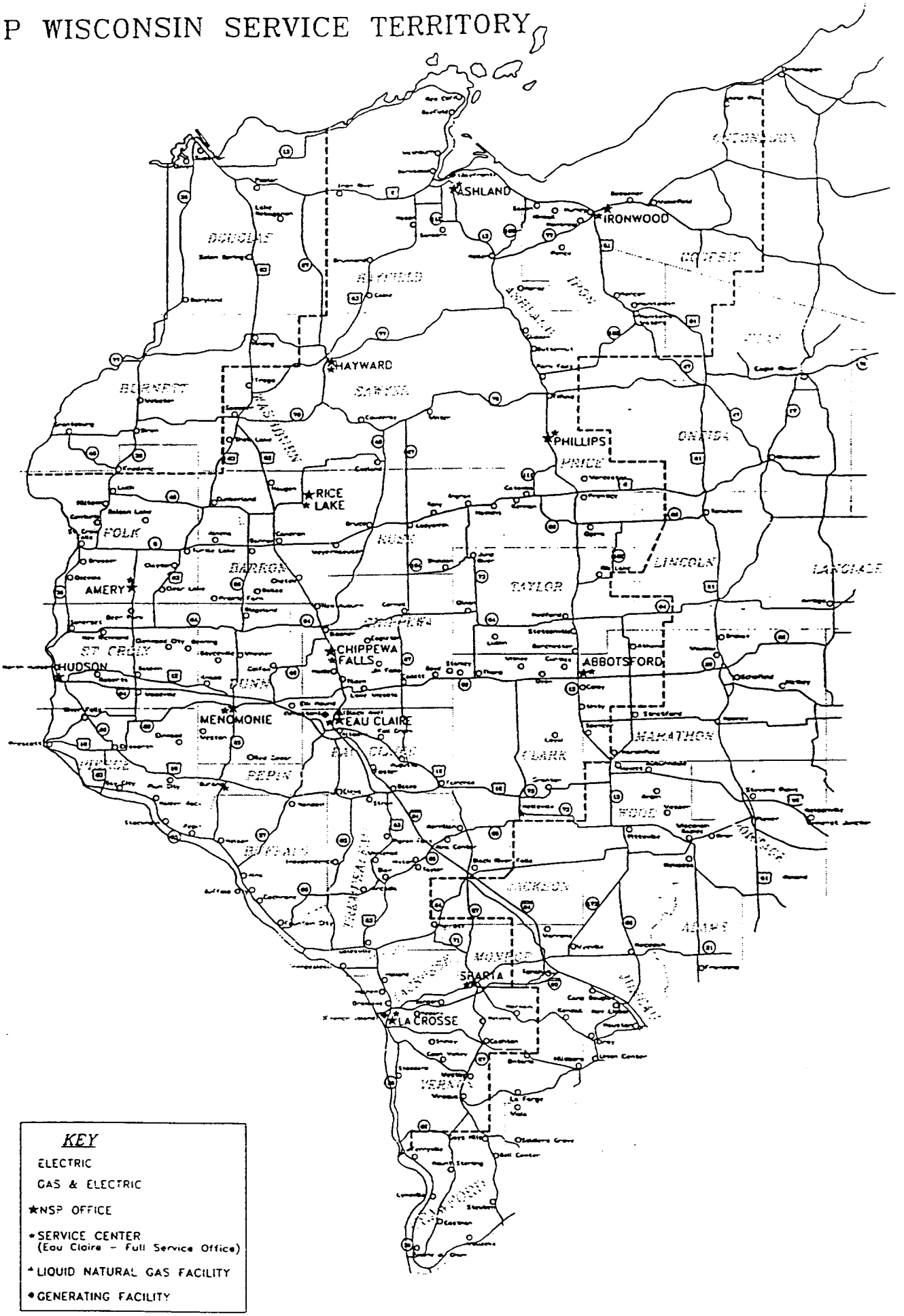
Accumulated Provision for Depreciation (1) (2)	Beg. of Year	End of Year
Electric	$483,345,330	$516,665,770
Gas	$69,176,411	$74,575,245
Water		
Heating (Steam)		
Total	**$552,521,741**	**$591,241,015**

Capitalization (1) (2)	Beg. of Year	End of Year
Long-Term Debt Outstanding	$313,087,786	$313,141,373
Advances From Affiliates		
Preferred Stock Outstanding		
Common Stock and Related Accounts	$152,991,288	$156,281,228
Retained Earnings	$256,474,233	$262,458,807
Other Comprehensive Income	$0	($1,726)
Customer Advances in Aid of Construction	$14,617,483	$16,363,009
Contributions in Aid of Construction		
Total	**$737,170,790**	**$748,242,691**

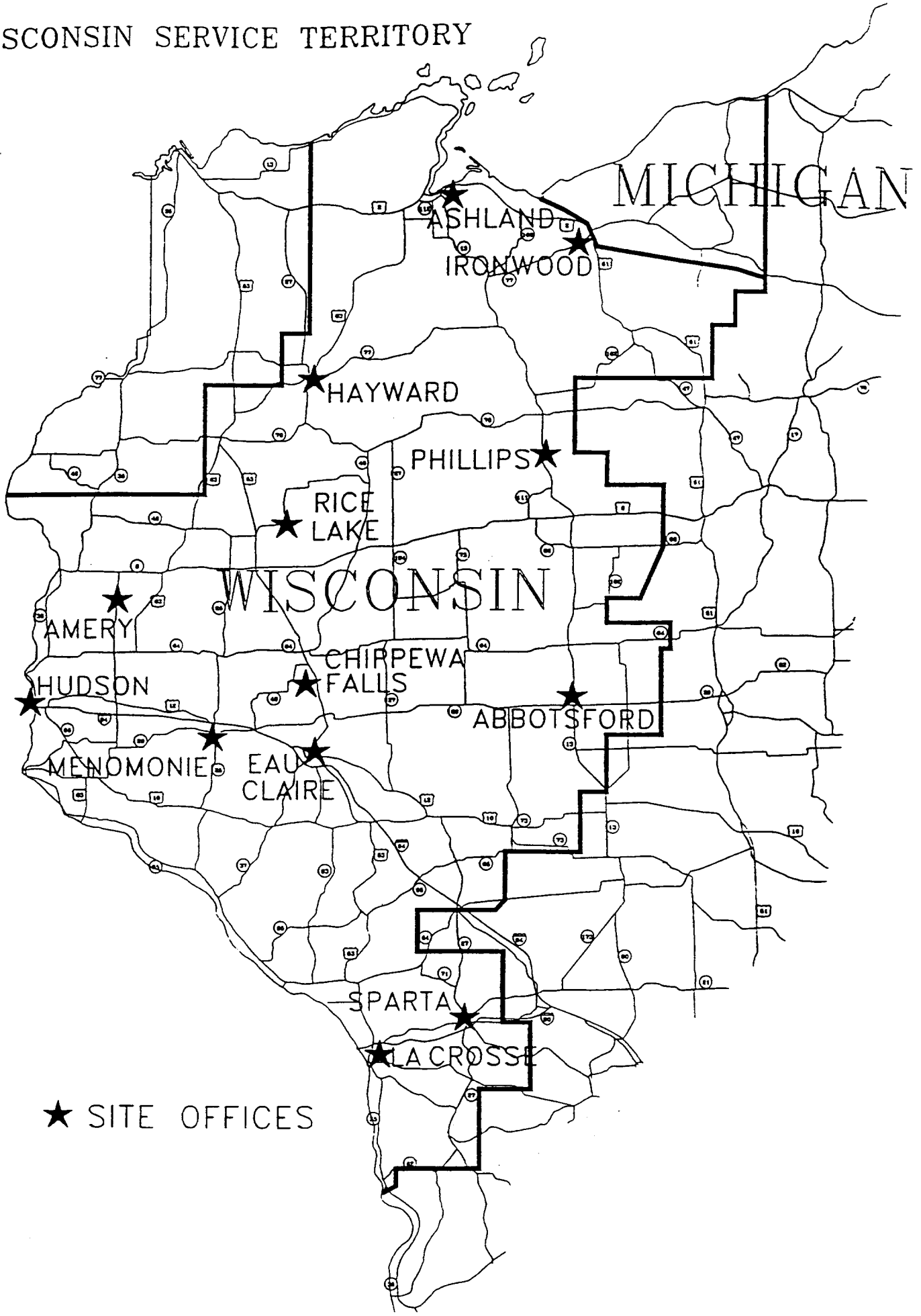
Disposition of Income	Last Year	This Year
Net Utility Operating Income:		
Electric (*)	$51,713,547	$69,946,363
Gas	$6,065,277	$7,741,429
Water		
Heating (Steam)		
Total Net Utility Operating Income	**$57,778,824**	**$77,687,792**
Total Other Income	$1,394,279	$816,066
Other Income Deductions	$1,816,529	$1,752,743
Taxes Applicable To Other Income	($1,104,996)	($739,035)
Net Other Income and Deductions	**$682,746**	**($197,642)**
Interest on Long-Term Debt	$22,366,504	$22,346,239
Net Amortization of Debt (428-429.1)	$895,620	$895,614
Interest on Debt to Associated Companies	$459,376	$162,751
Other Interest Expense	($582,832)	$62,439
Allowance for Construction Funds - Credit	$1,069,583	$350,139
Net Interest Charges	**$22,069,085**	**$23,116,904**
Net Extraordinary Items		
Net Income	**$36,392,485**	**$54,373,246**
Dividends - Preferred Stock		
Dividends - Common Stock	$43,468,426	$48,389,630
Other Income Adjustments		
Amount Transferred to Retained Earnings	**($7,075,941)**	**$5,983,616**

(*) Includes $201,752 and $164,130 of Chippewa Reservoir in 2001 & 2002 respectively.

NSP WISCONSIN SERVICE TERRITORY



NSP WISCONSIN SERVICE TERRITORY



ELECTRIC EXPENSES

Report all amounts under column d, "total operations" , on the basis and in conformity with the uniform system of accounts and accounting directives prescribed by this commission. Allocate "total operations" amounts jurisdictionally between Wisconsin (PSCW) jurisdiction and all other jurisdiction.

Particulars (a)	Wisconsin jurisdictional operations (b)	Other jurisdictional operations (c)	Total operations (d)
OPERATING EXPENSES			
Power production expenses (500-557)	178,658,203	4,325,887	182,984,090
Transmission expenses (560-573)	(16,952,800)	(414,019)	(17,366,819)
Distribution expenses (580-598)	19,248,835	716,897	19,965,732
Customer accounts expenses (901-905)	9,146,643	366,670	9,513,313
Customer service expenses (909-912)	5,119,640	(16,934)	5,102,706
Sales promotion expenses (915-918)	258,244	7,632	265,876
Administration and general expenses (920-932)	19,938,009	560,176	20,498,185
Total operation and maintenance expenses (401-402)	215,416,774	5,546,309	220,963,083
Depreciation expense (403)	37,485,556	1,062,342	38,547,898
Amortization of limited-term utility plant (404)			
Amortization of other utility plant (405)			
Amortization of utility plant acquistion adjustment (406)	468,120	10,095	478,215
Amortization of property losses (407)			
Taxes other than income taxes (408.1)	13,944,592	395,539	14,340,131
Income taxes (409.1)	34,307,892	869,980	35,177,872
Investment tax credits, deferred (412.1)			
Investment tax credits, restored (412.2)	(730,913)	(19,823)	(750,736)
Total operating expenses	300,892,021	7,864,442	308,756,463

May not cross-check due to rounding.

SALES TO ULTIMATE CUSTOMERS

1. Report data by rate schedule for all sales of retail electricity (including unbilled revenues and KWH) for each account. Show totals for each account and for combined sales to ultimate customers.
2. Report number of customers on the basis of number of meters plus the number of flat rate accounts. Where meter readings are added for billing purposes, count one customer for each group of meters so added. Compute the average on the basis of the 12 month ended figures.
3. If the customer count in any service classification includes customers counted more than once because of special services, such as water heating, etc., indicate in a footnote the number of such duplicate customers included in the classification.

	Wisconsin Geographical Operations		
Rate schedule ** (a)	Revenues (b)	KWH "000's" omitted (c)	Avg. no. Customers (d) *
Residential (440)	137,870,462	1,818,662	194,348
Commercial and Industrial (442)	203,172,027	3,766,601	36,466
Street Lighting (444)	3,294,735	22,922	636
Other Sales (445)	938,310	12,797	401
Interdepartmental (448)	160,900	2,068	9
Total Wisconsin	345,436,434	5,623,050	231,860

** Note: Rate Schedule Details are shown on Page 304 of FERC Report.

* Duplicate Customers: 9,353

May not cross-check due to rounding.

SALES TO ULTIMATE CUSTOMERS

1. Report data by rate schedule for all sales of retail electricity (including unbilled revenues and KWH) for each account. Show totals for each account and for combined sales to ultimate customers.
2. Report number of customers on the basis of number of meters plus the number of flat rate accounts. Where meter readings are added for billing purposes, count one customer for each group of meters so added. Compute the average on the basis of the 12 month ended figures.
3. If the customer count in any service classification includes customers counted more than once because of special services, such as water heating, etc., indicate in a footnote the number of such duplicate customers included in the classification.

	Wisconsin Geographical Operations		
Rate schedule (a)	Revenues (b)	KWH "000's" omitted (c)	Avg. no. Customers (d)

May not cross-check due to rounding.

SALES TO ULTIMATE CUSTOMERS

1. Report data by rate schedule for all sales of retail electricity (including unbilled revenues and KWH) for each account. Show totals for each account and for combined sales to ultimate customers.
2. Report number of customers on the basis of number of meters plus the number of flat rate accounts. Where meter readings are added for billing purposes, count one customer for each group of meters so added. Compute the average on the basis of the 12 month ended figures.
3. If the customer count in any service classification includes customers counted more than once because of special services, such as water heating, etc., indicate in a footnote the number of such duplicate customers included in the classification.

	Out-of-State (Michigan) Geographical Operations		
Rate schedule ** (a)	Revenues (b)	KWH "000's" omitted (c)	Avg. no. customers (d) *
Residential (440)	4,651,382	55,456	8,088
Commercial and Industrial (442)	5,292,523	79,284	1,387
Street Lighting (444)	168,340	868	18
Other Sales (445)	82,572	1,091	38
Interdepartmental (448)	4,949	54	1
Total Out-of-State	10,199,766	136,753	9,532
Total Utility	355,636,200	5,759,803	241,392

** Note: Rate Schedule Details are shown on Page 304 of FERC Report.

* Duplicate Customers: 371

May not cross-check due to rounding.

POWER COST ADJUSTMENT CLAUSE (if applicable)

Report below the revenue derived from the power cost adjustment clause for the year for each rate schedule that is reported on page E-2. Do not combine any of the rate schedules.

Rate schedules (a)	PCAC revenue (Wisconsin Only) (b)
Account 440	
Rg-1 Residential	($870,110)
Rg-2 Residential TOD	($74,615)
Rg-3 Residential Managed	($9)
Fg-1 Farm	($63,535)
Total Account 440	($1,008,269)
Account 442	
Cg-1 Sm General TOD	($2,374)
Cg-2 Sm General	($196,356)
Cg-5 General	($512,615)
Cg-6 Opt Off Peak	($1,822)
Cp-2 Peak Controlled Gen	($14,021)
Cp-9 Lg General TOD	($963,883)
Cp-1 Peak Controlled TOD	($311,982)
Rtp-1Power Supply Requirement	($49,476)
Rtp-1 Bundled Requirements	($82,121)
Total Account 442	($2,134,650)
Account 444	
S-1 Protective Lighting	($5,557)
Ms-2 Co. Owned St. Ltg	($8,717)
Ms-3 Cust. Owned St Ltg	($46)
Ms-4 Cust. Owned St Ltg	($5,430)
Ms-6 UG Area Ltg	($519)
Ms-7 Metered St Ltg	($389)
Total Account 444	($20,658)
Account 445	
Mp-1 Muni. Water Pumping	($6,997)
Total Account 445	($6,997)
Total Wisconsin	($3,170,574)

POWER COST ADJUSTMENT CLAUSE FACTOR (if applicable)

1. Report below in col. (b) the monthly PCAC Factors actually applied in determining monthly revenues for the year.
2. The monthly PCAC Factor may be stated as a percent or as dollars per Kwh according to your power cost adjustment clause.

Month (a)	Adjustment factor (Wisconsin Only) (b)
January	0.00000000
February	0.00000000
March	0.00000000
April	0.00000000
May	0.00000000
June	0.00000000
July	0.00000000
August	(0.00071613)
September	(0.00111000)
October	(0.00139516)
November	(0.00179000)
December	(0.00179000)

ACCUM. PROV. FOR DEPRECIATION OF PLANT IN SERVICE (Acct. 108)

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary plant accounts (a)	Balance first of year (b)	S.L. Dpr. rate % used (c)	Accruals during year: Straight line amount (d)	Accruals during year: Additional amount (e)
STEAM PRODUCTION				
Land and land rights (310)				
Structures & improvements (311)	8,871,888	3.22	417,644	
Boiler plant equipment (312)	34,202,841	3.30	1,975,848	
Engines & eng.-driven gen. (313)	0			
Turbogenerator units (314)	5,241,523	2.42	175,544	
Accessory elec. equipment (315)	3,097,750	3.41	176,008	
Misc. power equipment (316)	483,232	3.50	38,394	
Total steam production	51,897,234		2,783,438	0
NUCLEAR PRODUCTION				
Land and land rights (320)				
Structures & improvements (321)				
Reactor plant equip. (322)				
Turbogenerator units (323)				
Accessory elec. equipment (324)				
Misc. power plant equip. (325)				
Total nuclear prod. plant	0		0	0
HYDR. & PUMPED STORAGE				
Structures & improvements (331)	5,350,283	2.59	423,060	
Reser., dams & waterways (332)	45,070,475	2.66	3,284,171	
Water wheels, turb. & gen. (333)	12,151,986	2.41	855,136	
Accessory elec. equipment (334)	6,714,478	2.58	600,522	
Misc. power plant equip. (335)	1,209,970	2.11	74,393	
Roads, railroads & bridges (336)	0			
Total hydraulic production	70,497,192		5,237,282	0
OTHER PRODUCTION				
Structures & imprvmnts. (341)	2,234,337	0.19	4,136	
Fuel holders, prod. & access. (342)	2,308,281	0.00	0	
Prime movers (343)	27,472,872	1.02	321,652	
Generators (344)	15,168,296	1.10	198,126	
Accessory elec. equipment (345)	5,064,254	1.08	63,151	
Misc. power plant equipment (346)	575,820	2.14	12,889	
Total other production	52,823,860		599,954	0
TRANSMISSION PLANT				
Land and land rights (350)	0			
Structures & imprvmnts. (352)	755,291	2.63	66,136	
Station equipment (353)	41,682,481	3.29	4,116,603	
Towers and fixtures (354)	1,718,397	2.30	57,775	
Poles and fixtures (355)	23,302,689	2.88	2,471,745	
Overhead cond. & devices (356)	23,750,434	2.75	2,635,988	
Underground conduit (357)	8,809	2.63	1,723	
Undergound cond. & devices (358)	98,517	2.75	5,994	
Roads and trails (359)	74,992	2.50	2,308	
Total transmission	91,391,610		9,358,272	0

May not cross-check due to rounding.

ACCUMULATED PROVISION FOR DEPRECIATION OF PLANT IN SERVICE

Book cost of plant retired (f)	Cost of removal (g)	Salvage (h)	Other additions or deductions Debit (i)	Other additions or deductions Credit (j)	Balance end of year (k)
					0
					9,289,532
					36,178,689
					0
					5,417,067
					3,273,758
					521,626
0	0	0	0	0	54,680,672
					0
					0
					0
					0
					0
					0
0	0	0	0	0	0
					5,773,343
					48,354,646
					13,007,122
					7,315,000
					1,284,363
					0
0	0	0	0	0	75,734,474
					2,238,473
					2,308,281
					27,794,524
					15,366,422
					5,127,405
					588,709
0	0	0	0	0	53,423,814
					0
	1,330	1,330	124,423		697,004
37,734	9,982			118,158	45,869,526
					1,776,172
21,081					25,753,353
	1,729	1,729			26,386,422
					10,532
					104,511
				1,090	78,390
58,815	13,041	3,059	124,423	119,248	100,675,910

May not cross-check due to rounding.

ACCUMULATED PROVISION FOR DEPRECIATION OF PLANT IN SERVICE

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary plant accounts (a)	Balance first of year (b)	S.L. Dpr. rate % used (c)	Accruals during year: Straight line amount (d)	Accruals during year: Additional amount (e)
DISTRIBUTION PLANT				
Land and land rights (360)	0			
Structures & improvements (361)	464,614	2.63	51,635	
Station equipment (362)	27,808,888	3.50	2,763,180	
Storage battery equip. (363)	0			
Poles, towers & fixtures (364)	29,329,984	3.43	2,269,497	
Overhd cond. and devices (365)	25,605,366	3.43	2,715,873	
Underground conduit (366)	3,413,629	2.63	256,378	
Underground cond. & devices (367)	12,224,611	2.57	1,308,437	
Line transformers (368)	20,613,314	3.00	2,093,372	
Services (369)	29,003,493	5.20	2,844,653	
Meters (370)	7,262,210	4.55	865,410	
Install. on cust. prem. (371)	5,095,507	7.92	556,337	
Leased prop. on cust. prem. (372)	0			
St. lighting & signal sys. (373)	4,572,910	6.47	351,421	
Total distribution	165,394,526		16,076,193	0
GENERAL PLANT				
Structures and imprvmnts. (390)	1,598,899	2.86	135,967	
Office furniture & equip. (391)	2,072,554	5.00	74,800	
Transportation equipment (392)	1,642,376	VARIOUS	142,892	
Stores equipment (393)	89,042	5.00	6,833	
Tools, shop & garage equip. (394)	1,686,349	5.00	241,017	
Laboratory equipment (395)	1,113,673	5.00	139,456	
Power operated equipment (396)	755,981	VARIOUS	68,449	
Communication equipment (397)	3,535,719	10.00	490,595	
Miscellaneous equipment (398)	9,813	5.00	853	
Other tangible property (399)	0	20.00		
Total general	12,504,406		1,300,862	0
Total	444,508,828		35,356,001	0

DEPRECIATION SUMMARY

Total depreciation expense (columns (d) and (e))	35,356,001
Less amounts charged to clearing accounts	211,341
Plus allocation of depreciation on common plant	3,643,507
Total electric depreciation expense	38,788,167
Total reserve balance (column k)	476,025,931
Plus allocation of reserve on common plant (1)	38,250,179
Total depreciation reserve for electric utility	514,276,110

May not cross-check due to rounding.

ACCUMULATED PROVISION FOR DEPRECIATION OF PLANT IN SERVICE

Book cost of plant retired (f)	Cost of removal (g)	Salvage (h)	Other additions or deductions Debit (i)	Other additions or deductions Credit (j)	Balance end of year (k)
					0
7,468			85,213		423,568
119,150	64,639	205		90,388	30,478,872
					0
366,265	96,575	32,121			31,168,762
228,998	622,396	577,226			28,047,071
6,421	475	196			3,663,307
2,457,754	9,072	4,673			11,070,895
19,262	164	57			22,687,317
288,896	(15,968)	(32,207)			31,543,009
					8,127,620
32,690	3,289	2,984			5,618,849
					0
27,857	4,092	1,050			4,893,432
3,554,763	784,734	586,305	85,213	90,388	177,722,702
					1,734,866
					2,147,354
31,639	125,119	146,331			1,774,841
					95,875
					1,927,366
					1,253,129
6,482					817,948
					4,026,314
					10,666
					0
38,121	125,119	146,331	0	0	13,788,359
3,651,699	922,894	735,695	209,636	209,636	476,025,931

Explanation of items in columns (i) and (j):

TRANSFERS BETWEEN ACCOUNTS OR UTILITY DEPARTMENTS

(1) INCLUDES -1,470,670 OF ELECTRIC RETIREMENT WORK IN PROGRESS

May not cross-check due to rounding.

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MONTHLY PEAKS AND OUTPUT

1. Report hereunder the information called for pertaining to simultaneous peaks established monthly (in thousands of kilowatts) and monthly output (in thousands of kilowatt-hours).
2. Monthly peak col. (b) should be respondent's maximum kw. load as measured by the sum of its coincidental net generation and purchases plus or minus net interchange. minus temporary deliveries (not interchange) of emergency power to another system
3. State type of monthly peak reading (instantaneous (0), 15, 30, or 60 minutes integrated).
4. Monthly output should be the sum of respondent's net generation for load and purchases plus or minus net interchange and plus or minus net transmission or wheeling. Total for the year should agree with line 23 on page E-28.
5. If the utility has two or more power systems not physically connected, the information called for below should be furnished for each system.

	Monthly peak					
Month	KW (000's)	Day of week (Mon. etc.)	Date (Mo/Da/Yr)	Time Beginning (Hour:Min)	Type of reading (0,15,30,60)	Mo. output (MWH) (000's)
(a)	(b)	(c)	(d)	(e)	(f)	(g)
JAN	1,013	Wednesday	1/2/02	1900	Integrated	595,711
FEB	983	Monday	2/4/02	800	"	535,083
MAR	1,015	Monday	3/4/02	900	"	581,242
APR	1,051	Wednesday	4/17/02	1100	"	534,945
MAY	1,032	Friday	5/31/02	900	"	538,502
JUN	1,178	Monday	6/24/02	1500	"	585,350
JUL	1,240	Tuesday	7/30/02	1600	"	657,968
AUG	1,102	Thursday	8/1/02	1400	"	628,008
SEP	1,240	Monday	9/9/02	1500	"	575,786
OCT	946	Tuesday	10/1/02	1200	"	566,420
NOV	972	Tuesday	11/26/02	1800	"	553,491
DEC	1,057	Monday	12/16/02	1800	"	607,677
Total						6,960,183
System Name		Northern States Power Company (Wisconsin)				

GENERATION SUMMARY WORKSHEET

Utility: Northern States Power Company

		FERC Form 1 Page 402				
Plant Name	Unit ID	Generator Nameplate Capacity (MW)	Type of Prime Mover	Summer Capability (MW)	Winter Capability (MW)	Line 12 - Net Generation
COAL						
Bayfront	4	20.00	ST	23.00	23.00	38,203,894
Bayfront	5	20.00	ST	23.00	23.00	70,285,536
Bayfront	6	28.00	ST	29.00	29.00	152,238,600
TOTAL COAL		**68.00**		**75.00**	**75.00**	**260,728,030**
GAS						
Flambeau Station	1	19.30	GT	14.00	19.00	1,210,240
Wheaton	1	54.00	GT	56.00	71.00	8,243,443
Wheaton	2	54.00	GT	64.00	73.00	9,879,289
Wheaton	3	54.00	GT	55.00	71.00	9,383,885
Wheaton	4	54.00	GT	56.00	71.00	7,217,573
TOTAL GAS		**235.30**		**245.00**	**305.00**	**35,934,430**
OIL						
French Island	3	87.50	GT	76.00	96.00	1,966,760
French Island	4	87.50	GT	76.00	96.00	1,852,340
Wheaton	5	53.00	GT	57.90	76.90	11,434
Wheaton	6	53.00	GT	54.40	78.00	119,876
TOTAL OIL		**281.00**		**264.30**	**346.90**	**3,950,410**
HYDRO						
Apple River	1	0.80	HY	0.84	0.84	5,327,026
Apple River	2	0.80	HY	1.01	1.01	7,211,570
Apple River	3	0.80	HY	1.07	1.07	6,359,946
Apple River	4	-	HY	NOT IN	SERVICE	-
Big Falls	1	3.00	HY	2.60	2.69	15,763,788
Big Falls	2	3.00	HY	2.50	2.50	17,108,261
Big Falls	3	3.00	HY	2.60	2.60	9,744,254
Cedar Falls	1	2.00	HY	2.29	2.29	17,144,436
Cedar Falls	2	2.00	HY	2.16	2.16	15,735,416
Cedar Falls	3	2.00	HY	2.32	2.32	13,840,822
Chippewa Falls	1	3.60	HY	3.87	3.87	14,573,646
Chippewa Falls	2	3.60	HY	3.96	3.96	16,124,584
Chippewa Falls	3	3.60	HY	3.94	3.94	17,354,982
Chippewa Falls	4	3.60	HY	3.87	3.87	17,960,227
Chippewa Falls	5	3.60	HY	3.79	3.79	10,769,964
Chippewa Falls	6	3.60	HY	3.96	3.96	12,958,997
Cornell	1	10.00	HY	9.98	9.98	37,994,012
Cornell	2	10.00	HY	9.98	9.98	41,011,955
Cornell	3	10.00	HY	9.98	9.98	16,548,701
Cornell	4	0.80	HY	0.38	0.38	5,127,732
Dells	1	2.00	HY	2.40	2.40	12,622,959
Dells	2	1.60	HY	1.24	1.24	6,938,165
Dells	3	1.60	HY	1.24	1.24	7,707,640

Utility No 4220 Year Ended December 31, 2002

Form:

GENERATION SUMMARY WORKSHEET

Utility: Northern States Power Company

FERC Form 1 Page 402

Line 37 - Fuel Burned Primary Fuel **COAL TONS**	Line 37 - Fuel Burned Secondary Fuel **WOOD TONS**	Line 37 - Fuel Burned Tertiary **GAS MCF**	Line 38 - Fuel Htg Value Primary Fuel	Line 38 - Fuel Htg Value Secondary Fuel	Line 38 - Fuel Htg Value Tertiary
** N/A SEE NOTE BELOW		**	**	**	**
82,047	202,412	180,307	10,150	5,628	1004
**	**	**	**	**	**
GAS MCF	**OIL BBLS**				
25,791	-		1,003	-	
121,092	610		1,003	139,806	
140,680	604		1,003	139,806	
136,721	711		1,003	139,806	
99,238	1,789		1,003	139,806	
OIL BBLS					
6,924			140,000		
5,981			140,000		
2,475			139,806		
2,216			139,806		

**** BAY FRONT HAS A COMMON STEAM HEADER THAT FEEDS ALL THREE TURBINES. FUEL USEAGE BY TURBINE UNIT IS NOT AVAILABLE. NUMBERS SHOWN ARE FOR THE TOTAL PLANT.**

GENERATION SUMMARY WORKSHEET

Form:

Utility: Northern States Power Company

		FERC Form 1 Page 402				
Plant Name	Unit ID	Generator Nameplate Capacity (MW)	Type of Prime Mover	Summer Capability (MW)	Winter Capability (MW)	Line 12 - Net Generation
HYDRO (cont)						
Dells	4	1.60	HY	1.24	1.24	8,175,671
Dells	5	1.60	HY	1.24	1.24	8,559,417
Dells	6	0.50	HY	0.69	0.69	4,309,655
Dells	7	0.60	HY	0.74	0.74	4,600,092
Hayward	1	0.20	HY	0.20	0.20	1,548,980
Holcombe	1	11.30	HY	11.74	11.74	41,149,253
Holcombe	2	11.30	HY	11.76	11.76	43,373,924
Holcombe	3	11.30	HY	11.76	11.76	44,421,673
Jim Falls	HC1	24.80	HY	27.96	27.96	93,474,451
Jim Falls	HC2	24.80	HY	28.46	28.46	84,387,129
Jim Falls	MSF	0.60	HY	0.50	0.50	3,752,840
Ladysmith	1	1.00	HY	0.94	0.94	5,682,386
Ladysmith	2	0.90	HY	0.89	0.89	4,739,447
Ladysmith	3	2.00	HY	1.19	1.19	2,842,666
Menominee	1	2.70	HY	2.49	2.49	15,326,772
Menominee	2	2.70	HY	2.59	2.59	16,046,428
Riverdale	1	0.30	HY	0.31	0.31	2,010,052
Riverdale	2	0.30	HY	0.30	0.30	1,931,620
Saxon Falls	1	0.60	HY	0.75	0.75	5,417,020
Saxon Falls	2	0.60	HY	0.80	0.80	7,030,270
St Croix Fa	1	2.50	HY	3.29	3.29	14,650,043
St Croix Fa	2	2.50	HY	2.99	2.99	16,417,929
St Croix Fa	3	2.50	HY	2.99	2.99	14,098,264
St Croix Fa	4	2.45	HY	2.99	2.99	17,680,847
St Croix Fa	5	3.40	HY	2.99	2.99	17,411,413
St Croix Fa	6	3.40	HY	3.09	3.09	19,684,782
St Croix Fa	7	3.20	HY	3.19	3.19	18,626,043
St Croix Fa	8	3.20	HY	2.99	2.99	17,354,161
Superior Fa	1	1.00	HY	0.95	0.75	7,386,263
Superior Fa	2	1.00	HY	0.90	0.70	6,553,387
Thornapple	1	0.70	HY	0.75	0.75	5,265,512
Thornapple	2	0.70	HY	0.78	0.78	2,584,888
Trego	1	0.70	HY	0.77	0.77	4,784,009
Trego	2	0.50	HY	0.55	0.55	1,069,083
White River	1	0.50	HY	0.42	0.30	1,321,111
White River	2	0.50	HY	0.42	0.30	3,264,249
Wissota	1	6.00	HY	6.18	6.18	42,131,110
Wissota	2	6.00	HY	6.28	6.28	26,756,690
Wissota	3	6.00	HY	6.18	6.18	32,609,171
Wissota	4	6.00	HY	6.18	6.18	25,279,426
Wissota	5	6.00	HY	5.98	5.98	32,886,151
Wissota	6	6.00	HY	6.18	6.18	23,012,716
TOTAL HYDRO		**239.45**		**249.57**	**249.02**	**1,075,536,077**

GENERATION SUMMARY WORKSHEET

Form

Utility: Northern States Power Company

FERC Form 1 Page 402					
Line 37 - Fuel Burned Primary Fuel	Line 37 - Fuel Burned Secondary Fuel	Line 37 - Fuel Burned Tertiary	Line 38 - Fuel Htg Value Primary Fuel	Line 38 - Fuel Htg Value Secondary Fuel	Line 38 - Fuel Htg Value Tertiary

GENERATION SUMMARY WORKSHEET

0

Utility: Northern States Power Company

FERC Form 1 Page 402

Plant Name	Unit ID	Generator Nameplate Capacity (MW)	Type of Prime Mover	Summer Capability (MW)	Winter Capability (MW)	Line 12 - Net Generation
WIND						
OTHER RENEWABLES	**PHOTOVOLTAICS, FUEL CELLS**					
French Island	1	17.5	ST	15.00	15.00	18,168,976
French Island	2	17.5	ST	14.00	14.00	35,814,224
TOTAL OTHER RENEWABLES		**35.0**		**29.00**	**29.00**	**53,983,200**
		858.8	MW TOTAL located in Wisconsin and operated by utility	862.87	1004.92	1,430,132,147

Generating Units Operated by others or located outside of Wisconsin

				0.00		0
		0.0	MW TOTAL for all generating units outside of Wiscons and operated by others less joint plant amounts			0

Explanations

Utility No 4220 Year Ended December 31, 2002

Form:

GENERATION SUMMARY WORKSHEET

Utility: Northern States Power Company

FERC Form 1 Page 402

Line 37 - Fuel Burned Primary Fuel	Line 37 - Fuel Burned Secondary Fuel	Line 37 - Fuel Burned Tertiary	Line 38 - Fuel Htg Value Primary Fuel	Line 38 - Fuel Htg Value Secondary Fuel	Line 38 - Fuel Htg Value Tertiary
WOOD (TONS)	RDF (TONS)	GAS (MCF)			
20,342	19,956	801	6,439	5,602	1004.00
21,501	19,563	1,578	6,439	5,602	1004.00

COAL CONTRACT INFORMATION-SPECIFICATION AND COSTS

Particulars (a)	(b)	(c)
Vendor name	ARCH COAL	VENTURE FUELS
Term of agreement (mo/da/yr - mo/da/yr)	WESTERN-SEMINOE II	ANTELOPE
Plant name	Bay Front	Bay Front
Total cost of coal delivered	1,085,968.40	467,816.83
Total units delivered - 2,000 lb. tons	49,362.20	18,118.39
Avg. Btu's per lb. of coal delivered	11,016.00	8,814.00
Avg. percent moisture of coal delivered	11.62	26.88
Avg. percent sulfur of coal delivered	0.51	0.26
Avg. percent ash of coal delivered	6.67	5.21
	(h)	(i)
Vendor name	C.REISS	C. REISS
Term of agreement (mo/da/yr - mo/da/yr)	EAST KENTUCKY	WESTERN-SEMINOE II
Plant name	Bay Front	Bay Front
Total cost of coal delivered		155,352.50
Total units delivered - 2,000 lb. tons		50,935.12
Avg. Btu's per lb. of coal delivered		
Avg. percent moisture of coal delivered		TRANSPORTATION ONLY
Avg. percent sulfur of coal delivered		
Avg. percent ash of coal delivered		
	(n)	(o)
Vendor name	C.REISS	POWDER RIVER
Term of agreement (mo/da/yr - mo/da/yr)	NORTH ANTELOPE	NORTH ANTELOPE
Plant name	Bay Front	Bay Front
Total cost of coal delivered	18,108.49	
Total units delivered - 2,000 lb. tons	5,937.19	
Avg. Btu's per lb. of coal delivered		
Avg. percent moisture of coal delivered	TRANSPORTATION ONLY	
Avg. percent sulfur of coal delivered		
Avg. percent ash of coal delivered		
	(t)	(u)
Vendor name		
Term of agreement (mo/da/yr - mo/da/yr)		
Plant name		
Total cost of coal delivered		
Total units delivered - 2,000 lb. tons		
Avg. Btu's per lb. of coal delivered		
Avg. percent moisture of coal delivered		
Avg. percent sulfur of coal delivered		
Avg. percent ash of coal delivered		
	(z)	(aa)
Vendor name		
Term of agreement (mo/da/yr - mo/da/yr)		
Plant name		
Total cost of coal delivered		
Total units delivered - 2,000 lb. tons		
Avg. Btu's per lb. of coal delivered		
Avg. percent moisture of coal delivered		
Avg. percent sulfur of coal delivered		
Avg. percent ash of coal delivered		

ELECTRIC DISTRIBUTION LINES

1. If a utility has available the number of poles, but not miles of pole line, it will be considered satisfactory to determine miles of pole line by multiplying number of poles by average length of span, indicating in a footnote the average span used.
2. Urban distribution lines and rural distribution lines are to be reported separately for Wisconsin and for outside the state.
3. Urban distribution lines are defined as lines inside corporate limits of incorporated places, lines in urban areas adjacent to such corporate limits, and lines in unincorporated communities with urban characteristics. All pole lines used for urban distribution, including joint distribution and transmission, other joint distribution lines, and joint use of foreign lines are to be reported

Particulars (a)	Miles of: Pole line (b)	U.G. conduit (subway) (d)	Buried cable
Lines in Wisconsin:			
Urban distribution lines--primary voltage	2,163.65	39.48	550.64
Urban distribution lines--secondary voltage			
Rural distribution lines--primary voltage	5,945.00	0.95	508.53
Rural distribution lines--secondary voltage			
Total in Wisconsin	8,108.65	40.43	1,059.17
Lines outside the state:			
Urban distribution lines--primary voltage	94.85		4.05
Urban distribution lines--secondary voltage			
Rural distribution lines--primary voltage	344.93		36.45
Rural distribution lines--secondary voltage			
Total outside the state	439.78	0.00	40.50
Total lines of utility	8,548.43	40.43	1,099.67

NAMES OF CITIES, VILLAGES, AND TOWNS

NUMBER OF CUSTOMERS IN EACH SUPPLIED DIRECTLY WITH ELECTRICITY BY REPORTING UTILITY AT END OF YE
Report in alphabetical order first, cities, and second, incorporated villages. Next, report towns in alphabetical order under each county, also listed in alphabetical order. Show total for each group and for total company.

(CLASS A & B)

Location (a)	Customers end of year (b)	Location (a)	Customers end of year (b)
CITIES		CITIES (contd)	
Abbotsford-Clark	809	Sparta	4,249
Abbotsford-Marathon	354	Stanley	1,095
Alma	537	St. Croix Falls	1,128
Altoona	2,211	Thorp	937
Amery	1,513	Viroqua	2,181
Ashland	4,336	Washburn	1,144
Augusta	799	Whitehall	2
Barron	13	Total Cities	122,271
Bayfield	670		
Blair	707	VILLAGES	
Buffalo City	51		
Chetek	1,203	Alma Center	263
Chippewa Falls	6,678	Almena	369
Colby-Clark	554	Athens	573
Colby-Marathon	266	Baldwin	1,472
Cornell	1	Bay City	277
Durand	989	Birchwood	339
Eau Claire-Chippewa	603	Boyceville	549
Eau Claire-Eau Claire	27,928	Boyd	318
Fountain City	537	Bruce	488
Galesville	764	Butternut	273
Glenwood City	639	Cadott	3
Greenwood	600	Cameron	805
Hayward	1,596	Cashton	1
Hudson	5,325	Catawba	87
Hurley	1,147	Chaseburg	172
Independence	737	Clayton	249
La Crosse	24,437	Clear Lake	548
Ladysmith	1,861	Cochrane	306
Loyal	710	Colfax	606
Mellen	497	Conrath	55
Menomonie	6,415	Coon Valley	408
Mondovi	1,419	Curtiss	112
Montreal	531	Dallas	203
Neillsville	1,467	Deer Park	153
New Richmond	57	DeSoto-Crawford	52
Onalaska	5,811	DeSoto-Vernon	172
Osseo	925	Dorchester	449
Owen	561	Downing	112
Park Falls	1,555	Dresser	392
Phillips	1,053	Eleva	341
Prescott	1,798	Elk Mound	343
Rice Lake	8	Ellsworth	1,337
Shell Lake	863	Elmwood	459
		Ettrick	266

NAMES OF CITIES, VILLAGES, AND TOWNS

NUMBER OF CUSTOMERS IN EACH SUPPLIED DIRECTLY WITH ELECTRICITY BY REPORTING UTILITY AT END OF YEAR

Report in alphabetical order first, cities, and second, incorporated villages. Next, report towns in alphabetical order under each county, also listed in alphabetical order. Show total for each group and for total company.

(CLASS A & B)

Location (a)	Customers end of year (b)	Location (a)	Customers end of year (b)
VILLAGES (contd)		VILLAGES (contd)	
Fairchild	290	Trempealeau	2
Fall Creek	628	Turtle Lake-Polk	36
Genoa	147	Turtle Lake-Barron	562
Gilman	258	Unity-Clark	93
Glen Flora	73	Unity-Marathon	117
Granton	213	West Salem	2115
Hammond	660	Weyerhauser	185
Haugen	179	Wheeler	179
Hawkins	218	Wilson	93
Hixton	265	Withee	276
Holman	2,223	Woodville	559
Ingram	55	Total Villages	34,738
Kennan	92		
Knapp	240	TOWNS BY COUNTY	
Lublin	98		
Luck	603	Ashland County	
Maiden Rock	110		
Mason	56	Agenda	83
Melrose	305	Ashland	105
Melvina	55	Chippewa	111
Nelson	244	Gingles	225
New Auburn-Barron	5	Gordon	19
New Auburn-Chippewa	232	Jacobs	376
North Hudson	1,540	La Pointe	695
Norwalk	295	Marengo	54
Osceola	1,195	Morse	80
Pepin	570	Peeksville	27
Pigeon Falls	218	Sanborn	125
Plum City	314	Shanagolden	1
Prairie Farm	256	White River	211
Prentice	390		
Rib Lake	471	Total Ashland County	2,112
Ridgeland	206		
Roberts	630	Barron County	
Rockland	258		
Sheldon	175	Almena	233
Somerset	806	Arland	108
Spencer	924	Barron	62
Spring Valley	537	Bear Lake	20
Star Prairie	278	Cedar Lake	876
Stetsonville	278	Chetek	308
Stockholm	105	Clinton	198
Stoddard	426	Crystal Lake	98
Strum	493	Cumberland	43
Taylor	273	Dallas	117
Tony	82	Dovre	56

NAMES OF CITIES, VILLAGES, AND TOWNS

NUMBER OF CUSTOMERS IN EACH SUPPLIED DIRECTLY WITH ELECTRICITY BY REPORTING UTILITY AT END OF

Report in alphabetical order first, cities, and second, incorporated villages. Next, report towns in alphabetical order under each county, also listed in alphabetical order. Show total for each group and for total company.

(CLASS A & B)

Location (a)	Customers end of year (b)
Barron County (contd)	
Doyle	189
Lakeland	68
Maple Grove	165
Maple Plain	44
Oak Grove	190
Prairie Farm	138
Prairie Lake	65
Rice Lake	547
Sioux Creek	64
Stanfold	39
Stanley	235
Sumner	47
Turtle Lake	120
Vance Creek	130
Total Barron County	4,160
Bayfield County	
Barksdale	216
Bayfield	408
Bayview	141
Bell	122
Cable	520
Clover	114
Drummond	234
Eileen	117
Grand View	104
Iron River	2
Kelly	83
Keystone	10
Lincoln	76
Mason	34
Namekagon	205
Orienta	31
Oulu	68
Port Wing	263
Russell	362
Tripp	14
Washburn	48
Total Bayfield County	3,172
Buffalo County	
Alma	6

Location (a)	Customers end of year (b)
Buffalo County (contd)	
Belvidere	55
Buffalo	209
Canton	40
Glenco	2
Lincoln	43
Mondovi	3
Montana	17
Nelson	3
Naples	79
Waumandee	172
Total Buffalo County	629
Chippewa County	
Anson	740
Auburn	79
Bloomer	59
Cooks Valley	116
Delmar	116
Eagle Point	799
Edson	131
Goetz	3
Hallie	2,124
Howard	33
Lafayette	2,403
Ruby	12
Sigel	72
Tilden	738
Wheaton	234
Woodmohr	110
Total Chippewa County	7,769
Clark County	
Beaver	19
Colby	107
Eaton	126
Foster	22
Fremont	204
Grant	134
Green Grove	18
Hixon	51
Hoard	43
Longwood	26
Loyal	127
Lynn	76

NAMES OF CITIES, VILLAGES, AND TOWNS

NUMBER OF CUSTOMERS IN EACH SUPPLIED DIRECTLY WITH ELECTRICITY BY REPORTING UTILITY AT END OF YEAR

Report in alphabetical order first, cities, and second, incorporated villages. Next, report towns in alphabetical order under each county, also listed in alphabetical order. Show total for each group and for total company.

(CLASS A & B)

Location (a)	Customers end of year (b)
Clark County (contd)	
Mayville	83
Mentor	145
Pine Valley	167
Reseburg	73
Sherman	68
Thorp	71
Unity	166
Warner	8
Weston	121
Withee	181
Worden	29
York	125
Total Clark County	2,190
Crawford County	
Freeman	11
Dunn County	
Colfax	43
Dunn	175
Eau Galle	225
Elk Mound	89
Hay River	1
Lucas	51
Menomonie	791
New Haven	9
Otter Creek	1
Red Cedar	483
Sand Creek	161
Sheridan	30
Sherman	65
Spring Brook	272
Stanton	45
Tainter	309
Tiffany	91
Weston	61
Wilson	54
Total Dunn County	2,956
Eau Claire County	
Bridge Creek	53
Brunswick	98
Clear Creek	56
Drammen	4

Location (a)	Customers end of year (b)
Eau Claire County (contd)	
Fairchild	42
Lincoln	51
Otter Creek	69
Seymour	363
Union	943
Washington	1,447
Total Eau Claire County	3,126
Iron County	
Anderson	45
Carey	62
Gurney	51
Kimball	259
Knight	141
Mercer	1,477
Oma	121
Pence	115
Saxon	147
Sherman	13
Total Iron County	2,431
Jackson County	
Adams	76
Alma	96
Cleveland	21
Curran	29
Garden Valley	67
Hixton	56
Melrose	65
North Bend	92
Northfield	100
Springfield	81
Total Jackson County	683
La Crosse County	
Bangor	65
Barre	465
Burns	138
Campbell (French Island)	2,037
Farmington	393

NAMES OF CITIES, VILLAGES, AND TOWNS

NUMBER OF CUSTOMERS IN EACH SUPPLIED DIRECTLY WITH ELECTRICITY BY REPORTING UTILITY AT END OF

Report in alphabetical order first, cities, and second, incorporated villages. Next, report towns in alphabetical order under each county, also listed in alphabetical order. Show total for each group and for total company.

(CLASS A & B)

Location (a)	Customers end of year (b)
La Crosse County (contd)	
Greenfield	390
Hamilton	873
Holland	70
Medary	555
Onalaska	619
Shelby	1,395
Washington	43
Total La Crosse County	7,043
Lincoln County	
Somo	39
Marathon County	
Bern	26
Brighton	20
Frankfort	209
Halsey	34
Holton	13
Hull	155
Johnson	357
Rietbrock	73
Spencer	29
Wien	107
Total Marathon County	1,023
Monroe County	
Angelo	347
Greenfield	1
Jefferson	107
Lafayette	114
Leon	98
Little Falls	416
New Lyme	45
Portland	59
Ridgeville	38
Sheldon	1
Sparta	1,120
Wells	32
Total Monroe County	2,378

Location (a)	Customers end of year (b)
Oneida County	
Lynne	48
Pepin County	
Durand	183
Lima	86
Pepin	268
Stockholm	27
Waterville	330
Waubeek	95
Total Pepin County	989
Pierce County	
Clifton	271
Ellsworth	18
El Paso	5
Gilman	114
Hartland	22
Isabelle	108
Maiden Rock	49
Oak Grove	52
River Falls	18
Rock Elm	183
Salem	22
Spring Lake	146
Trenton	428
Trimbelle	12
Union	181
Total Pierce County	1,629
Polk County	
Alden	313
Apple River	35
Beaver	35
Black Brook	152
Bone Lake	108
Clayton	376
Clear Lake	256
Farmington	196
Garfield	274
Johnstown	3
Lincoln	576
Luck	163

NAMES OF CITIES, VILLAGES, AND TOWNS

NUMBER OF CUSTOMERS IN EACH SUPPLIED DIRECTLY WITH ELECTRICITY BY REPORTING UTILITY AT END OF Y

Report in alphabetical order first, cities, and second, incorporated villages. Next, report towns in alphabetical order under each county, also listed in alphabetical order. Show total for each group and for total company.

(CLASS A & B)

Location (a)	Customers end of year (b)
Polk County (contd)	
McKinley	88
Osceola	466
St. Croix Falls	81
Total Polk County	3,122
Price County	
Catawba	3
Eisenstein	113
Elk	311
Emery	31
Fifield	174
Flambeau	48
Georgetown	62
Hackett	8
Harmony	65
Hill	2
Kennan	18
Knox	132
Lake	477
Ogema	173
Prentice	111
Worchester	286
Total Price County	2,014
Rusk County	
Atlanta	113
Big Bend	28
Big Falls	23
Dewey	185
Flambeau	258
Grant	330
Grow	104
Hawkins	9
Lawrence	12
Marshall	118
Richland	6
Strickland	8
Stubbs	291
Thornapple	76
True	64
Wilson	3
Total Rusk County	1,628

Location (a)	Customers end of year (b)
Sawyer County	
Bass Lake	1,043
Couderay	73
Edgewater	64
Hayward	1,160
Lenroot	864
Round Lake	41
Sand Lake	1,068
Total Sawyer County	4,313
St. Croix County	
Baldwin	180
Cady	79
Cylon	65
Eau Galle	59
Emerald	81
Forest	122
Glenwood	139
Hammond	392
Hudson	1,578
Kinnickinnic	134
Richmond	212
Rush River	43
Somerset	527
Springfield	151
Stanton	137
Star Prairie	1,183
St. Joseph	574
Troy	385
Warren	141
Total St. Croix County	6,182
Taylor County	
Chelsea	72
Ford	26
Greenwood	39
Little Black	112
Rib Lake	100
Roosevelt	61
Taft	26
Westboro	227
Total Taylor County	663

NAMES OF CITIES, VILLAGES, AND TOWNS

NUMBER OF CUSTOMERS IN EACH SUPPLIED DIRECTLY WITH ELECTRICITY BY REPORTING UTILITY AT END OF YEAR

Report in alphabetical order first, cities, and second, incorporated villages. Next, report towns in alphabetical order under each county, also listed in alphabetical order. Show total for each group and for total company.

(CLASS A & B)

Location (a)	Customers end of year (b)
Trempealeau County	
Albion	121
Burnside	38
Caledonia	20
Dodge	159
Ettrick	38
Gale	155
Hale	3
Lincoln	157
Pigeon	139
Preston	95
Sumner	21
Trempealeau	165
Unity	30
Total Trempealeau County	1,141
Vernon County	
Bergen	242
Christiana	42
Coon	228
Genoa	44
Hamburg	113
Harmony	92
Jefferson	128
Sterling	4
Viroqua	245
Wheatland	10
Total Vernon County	1,148
Vilas County	
Boulder Junction	130
Manitowish Waters	1,130
Presque Isle	810
Winchester	539
Total Vilas County	2,609
Washburn County	
Barronett	11
Bashaw	24
Beaver Brook	73
Birchwood	285

Location (a)	Customers end of year (b)
Washburn County (contd)	
Evergreen	1
Long Lake	194
Sarona	51
Spring Brook	144
Stinnett	10
Stone Lake	149
Trego	198
Total Washburn County	1,140
Total Towns	66,348
Total Company	223,357

*1 customer for each group of meters billed

ELECTRIC UTILITY OPERATIONS - 01

ID NUMBER - 4220 UTILITY NAME - Northern States Power Company (WI) YEAR - 2002

Sales/Revenue Data: (Wisconsin Only)			
Account	Avg. No. Cust.	Megawatt Hours	Revenues
Residential (Incl. Farm) (440 & 441)	194,349	1,818,662	$137,870,461
Small Com. & Ind. (442-1)	34,900	1,025,215	67,671,546
Large Com. & Ind. (442-2)	1,566	2,741,386	135,500,482
Pub. St. & Highwy. (444)	636	22,922	3,294,735
Other Sales to Pub. Auth. (445)	401	12,797	938,310
Sales to Railroads (446)			
Interdepartmental (448)	9	2,068	160,900
Total Retail Sales	231,861	5,623,050	$345,436,434
Investor Owned Utilities			
Municipally Owned Utilities	9	550,395	19,903,873
Cooperatives			
Sales at State Lines			
Total Wholesale Sales	9	550,395	$19,903,873
Total Wisconsin Sales	231,870	6,173,445	$365,340,307
Forfeited Discounts (450)			$507,574
Misc. Service Rev. (451)			716,755
Sales of Water & Wat. Pr. (453)			
Rent from Electric Prop. (454)			606,168
Interdepartmental Rents (455)			
Other Electric Revenues (456)			1,535,621
Total Other Op. Revenues			$3,366,118
Total Electric Op. Revenues			$368,706,425
Expenses:			
Account			Expenses
Fossil Steam Power (500-514)			$10,497,099
Nuclear Steam Power (517-532)			
Hydraulic Power (535-545)			7,359,485
Other - Turbine (546-554)			3,464,585
Other - Recip (546-554)			
Other - Purchases (555)			
Other Power Supply Expenses (556-557)			161,662,921
Power Production Expenses (Total Company)			$182,984,090
Power Production Expenses (WI Only)			$178,658,203
Transmission Expenses (WI Only)			(16,952,800)
Distribution Expenses (WI Only)			19,248,835
Customer Accounts Expense (WI Only)			9,146,643
Customer Service Expense (WI Only)			5,119,640
Sales Expenses (WI Only)			258,244
Administration & General (WI Only)			19,938,009
Total O & M Expenses (WI Only)			$215,416,774
Depreciation Expense (WI Only)			$37,485,556
Amortization Expense (404-407) (WI Only)			468,120
Taxes - Other (408.1) (WI Only)			13,944,592
Taxes - Inc. (409.1-411.4) (WI Only)			34,307,892
Disposition of Plant - NET (411.6-411.7) (WI Only)			
Investment Tax Credits - NET (412.1-412.2)(WI Only)			(730,913)
Total Utility Operating Expense (WI Only)			$300,892,021
Net Utility Operating Income (WI Only)			$67,814,404

ELECTRIC UTILITY OPERATIONS - 02
ID NUMBER - 4220 UTILITY NAME - Northern States Power Company (WI) YEAR - 2002

Energy Account:	Megawatt Hours		
Net Generation	**Out-of-State**	**Wisconsin**	**Total****
Steam - Fossil Fuel			314,711
Steam - Nuclear			
Hydraulic			1,075,536
Internal Combustion - Turbine			39,884
Internal Combustion - Recip.			
All Other			
Total Generation			1,430,131
Purchases			
Investor Owned Utilities			
Municipally Owned Utilities			
Cooperatives			
Other Sources			5,530,052
Total Purchases			5,530,052
Interchanges - Net Incoming			
Investor Owned Utilities			0
Municipally Owned Utilities			
Cooperatives			0
Other Sources			0
Total Net Interchanges			0
Total Energy			**6,960,183**
SALES, USE & LOSSES:			
Sales			6,323,631
Energy Used by Utility			6,897
Losses and Unaccounted For			629,655
Total Energy			**6,960,183**
FUEL STATISTICS			
	Record Units Indicated		
Plant Type/Fuel Used	**Out-of-State**	**Wisconsin**	**Total****
Steam - Fossil Fuel			
Tons of Coal			82,047
Therms of Gas			183,799
Gallons of Fuel Oil			
Tons-Other			283,774
Steam - Nuclear			
MWD Thermal			
Internal Combustion - Turbine			
Therms of Gas			525,093
Gallons of Fuel Oil			895,020
Internal Combustion - Reciprocating			
Therms of Gas			
Gallons of Fuel Oil			
Btu's of Fuel Used in Fossil Steam Plants/kwh gen.			16,234
Btu's of Fuel Used in Nuclear Steam Plants/kwh gen.			
Btu's of Fuel Used in Turbine Plants/kwh gen.			16,300
Btu's of Fuel Used in Reciprocating Plants/kwh gen.			

**Amounts available on system wide basis, unavailable for direct jurisdictional split

ELECTRIC UTILITY OPERATIONS - 03

ID NUMBER - 4220 UTILITY NAME - Northern States Power Company (WI) YEAR - 2002

GENERATING CAPACITY:

	Megawatts of Capacity		
Plant Type	**Out-of-State**	**Wisconsin**	**Total**
Steam - Fossil Fuel			103.0
Steam - Nuclear			
Internal Combustion - Turbine			516.3
Internal Combustion - Recip.			
Other - Hydraulic			239.5
Total			**858.8**

Maximum System Demand (MW)			**1,240**

TRANSMISSION LINES:

	Miles of Line		
Plant Type	**Out-of-State**	**Wisconsin**	**Total**
Less than 100 kilovolt	108.97	1371.96	1,480.93
100-344 kilovolt	1	791.46	792.46
345 kilovolts and greater		165.85	165.85
Total	**109.97**	**2,329.27**	**2,439.24**

DISTRIBUTION LINES:

	Miles of Line		
Plant Type			
Pole Line	439.78	8,108.65	8,548.43
Underground Conduit	0.00	40.43	40.43
Buried Cable	40.50	1,059.17	1,099.67
Total Miles	**480.28**	**9,208.25**	**9,688.53**

PLANT INVESTMENT AND RELATED DATA:

Account	$
Utility Plant Assigned to Electric (Total Company)	$1,253,494,060
Depr. Reserve Assigned To Electric (Total Company)	516,665,770
Depr. Accruals (Incl. Clearing Acct. Charges)	39,032,936
Maintenance - Electric Plant (Total Company)	17,561,729

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NAMES OF CITIES, VILLAGES, AND TOWNS

NUMBER OF CUSTOMERS IN EACH SUPPLIED DIRECTLY WITH GAS BY REPORTING UTILITY AT END OF YEAR

Report in alphabetical order first, cities, and second, incorporated villages. Next, Report towns in alphabetical order under each county, also listed in alphabetical order. Show total for each group and for total company.

(CLASS A & B)

Location (a)	Customers end of year (b)
Cities	
Altoona	2,022
Ashland	3,301
Bayfield	451
Chippewa Falls	3,804
Eau Claire-Chippewa	426
Eau Claire-Eau Claire	18,184
Hudson	4,056
Hurley	757
La Crosse	16,860
Mellen	319
Menomonie	3,629
Montreal	420
New Richmond	2,368
Onalaska	5,563
Park Falls	1,124
Phillips	767
Washburn	889
Total Cities	64,940
Villages	
Butternut	179
Elk Mound	215
Fall Creek	286
Holmen	2,342
North Hudson	1,149
Prentice	276
Rib Lake	347
Total Villages	4,794
Towns by County	
Ashland County	
Ashland	3
Gingles	32
Jacobs	277
Morse	26
Sanborn	277
Total Ashland County	615
Bayfield County	
Barksdale	117
Bayfield	145
Bayview	5
Eileen	11
Hughes	4
Iron River	290
Russell	284
Washburn	5
Total Bayfield County	861
Chippewa County	
Hallie	1,303
Lafayette	1,163
Wheaton	62
Eagle point	268
Total Chippewa County	2,796
Dunn County	
Colfax	3
Elk Mound	16
Menomonie	389
Red Cedar	222
Tainter	464
Total Dunn County	1,094
Eau Claire County	
Brunswick	119
Lincoln	1
Pleasant Valley	337
Seymour	466
Union	331
Washington	1,418
Total Eau Claire County	2,672
Iron County	
Carey	1
Kimball	47
Pence	59
Saxon	51
Total Iron County	158
La Crosse County	
Campbell	1,473
Greenfield	3
Holland	315
Medary	235
Onalaska	1,465
Shelby	1,450
Total La Crosse County	4,941
Monroe County	
Barre	3
Fort McCoy	1
Total Monroe County	4

NAMES OF CITIES, VILLAGES, AND TOWNS

NUMBER OF CUSTOMERS IN EACH SUPPLIED DIRECTLY WITH GAS BY REPORTING UTILITY AT END OF YEAR

Report in alphabetical order first, cities, and second, incorporated villages. Next, Report towns in alphabetical order under each county, also listed in alphabetical order. Show total for each group and for total company.

(CLASS A & B)

Location (a)	Customers end of year (b)	Location (a)	Customers end of year (b)
Price County			
Eisenstein	28		
Elk	238		
Fifield	116		
Hill	2		
Lake	237		
Ogema	127		
Prentice	28		
Worcester	317		
Total Price County	1,093		
St. Croix County			
Hudson	1,573		
Richmond	243		
Stanton	90		
Star Prairie	33		
Troy	237		
Total St. Croix County	2,176		
Taylor County			
Rib Lake	14		
Westboro	80		
Total Taylor County	94		
TOTAL WISCONSIN	86,238		

GAS OPERATING EXPENSES

Particulars (a)	Wisconsin Jurisdictional Operations (b)	Other Jurisdictional Operations (c)	Total Operations (d)
OPERATING EXPENSES			
Manufactured gas production expenses (700-742)	298,119	20,953	319,072
Purchased gas expenses (804-813)	68,254,680	4,607,131	72,861,811
Total production expenses	68,552,799	4,628,084	73,180,883
Storage expenses (840-848.3)	179,220	12,596	191,816
Transmission expenses (850-867)	0	0	0
Distribution expenses (870-894)	3,475,896	217,906	3,693,802
Customer accounts expenses (901-905)	2,939,976	188,793	3,128,769
Customer service expenses (909-912)	1,212,415	(7,087)	1,205,328
Sales promotion expenses (915-918)	353	0	353
Administrative and general expenses (920-932)	3,263,329	192,860	3,456,189
Total operation and maintenance	79,623,988	5,233,152	84,857,140
Depreciation expense (403)	5,329,389	274,865	5,604,254
Amortization limited-term utility investment (404)			0
Amortization of other utility plant (405)			0
Amortization utility plant acquistion adjustment (406)	(204,534)	(10,157)	(214,691)
Amortization of property losses (407.1)			0
Amortization of conversion expenses (407.2)			0
Taxes other than income taxes (408.1)	1,552,166	79,277	1,631,443
Income taxes (409.1)	3,232,639	158,248	3,390,887
Investment tax credits, deferred (412.1)			0
Investment tax credits, restored (412.2)	(53,195)	(2,838)	(56,033)
Total operating expenses	89,480,453	5,732,547	95,213,000

Note: Depreciation reflects the inclusion of small amounts of recorded electric costs excluded from electric jurisdictional data.

OPERATING REVENUES FROM NATURAL GAS UTILITY

1. Report data by rate schedule (including unbilled revenues and therms), classified between space heating and non-space heating customers. Customer counts are based on the average number of meters in service - using 12 month end figures. Where meters are combined for billing purposes, each combined group of meters counts as one customer.
2. For industrial interruptible sales, report data by priority of interruption.
3. Report all data for transportation customers although customers are already included in Accounts 480-484.
4. For other operating revenues, report details of major items and then group the remaining items in each account. Report the name of lessee and description of property for major items of rent revenue.

Rate Schedule (a)		Wisconsin Geographical Operations Revenues (b)	Therms (c)	Average Customers (d)
Sales of Gas Revenues				
Residential (480)				
Non-space heating	201-231	$ 751,709	898,010	2,393
Space heating	201-231	45,285,435	61,067,500	73,108
Other				
Total Account 480		$ 46,037,144	61,965,510	75,501
Commercial and Industrial (481)				
Commercial - Non-space heating	202-222-232	$ 4,215,876	6,911,530	1,241
Commercial - Space heating	202-222-232	24,578,514	38,969,681	8,904
Industrial - Non-space heating	203-204	620,897	1,376,940	3
Industrial - Space heating	203-204	-	-	-
Other	206-207	19,464,274	47,719,763	300
Total Account 481		$ 48,879,561	94,977,914	10,448
Sales for Resale (483)				
Interdepartmental (484)				
Firm		$ 81,789	144,632	2
Interruptible		789,875	2,069,035	6
Other				
Total Account 484		$ 871,664	2,213,667	8
Total Sales of Gas		95,788,369	159,157,091	85,957
Other Operating Revenues				
Transportation (489)				
C&I Firm		$ 504,301	14,409,179	4
C&I Interruptible		710,754	17,178,867	6
Other		(69,157)	4,992,453	-
Total Account 489		$ 1,145,898	36,580,499	10
Total Throughput		$ 96,934,267	195,737,590	85,967
Forfeited Discounts (487)		$ 119,995		
Miscellaneous Service Revenues (488)				
CONNECTION CHARGE		$ 140,720		
RETURN CHECK CHARGE		4,725		
MISCELLANEOUS		1,110		
Total Account 488		$ 146,555		
Rent from Property (493)		$ -		
Total Account 493		$ -		
Other Gas Revenues (495)				
INTEREST ON CUSTOMER LOANS		3,613		
SALES & USE TAX HANDLING COMMISSION		$ 10,785		
GMS GAINS		(298,592)		
MISCELLANEOUS		(2,804)		
Total Account 495		$ (286,999)		
Penalty Revenues (497)				
Utility Incentive Revenues (498)				
Total Other Operating Revenues		$ 1,125,449		
Total Wisconsin Operating Revenues		96,913,818	195,737,590	85,967

OPERATING REVENUES FROM NATURAL GAS UTILITY

1. Report data by rate schedule (including unbilled revenues and therms), classified between space heating and non-space heating customers. Customer counts are based on the average number of meters in service - using 12 month end figures. Where meters are combined for billing purposes, each combined group of meters counts as one customer.
2. For industrial interruptible sales, report data by priority of interruption.
3. Report all data for transportation customers although customers are already included in Accounts 480-484.
4. For other operating revenues, report details of major items and then group the remaining items in each account. Report the name of lessee and description of property for major items of rent revenue.

Rate Schedule (a)		Wisconsin Out-of-State Geographical Operations Revenues (b)	Therms (c)	Average Customers (d)
Sales of Gas Revenues				
Residential (480)				
Non-space heating	301	$ 24,774	35,050	61
Space heating	301	3,364,017	5,194,740	4,505
Other				
Total Account 480		$ 3,388,791	5,229,790	4,566
Commercial and Industrial (481)				
Commercial - Non-space heating	302	$ 110,733	184,130	52
Commercial - Space heating	302	1,663,185	2,791,560	577
Commercial - Interruptible	303	184,852	397,590	6
Commercial - Contract Service	304	618,551	1,871,200	2
Industrial - Interruptible	303	55,303	166,530	1
Industrial - Contract Service	304	-	-	1
Total Account 481		$ 2,632,624	5,411,010	639
Sales for Resale (483)				
Interdepartmental (484)				
Firm		$ 5,999	10,530	1
Interruptible		-	0	0
Other				
Total Account 484		$ 5,999	10,530	1
Total Sales of Gas		$ 6,027,414	10,651,330	5,206
Other Operating Revenues				
Transportation (489)				
C&I Firm		$ -		
C&I Interruptible				
Other				
Total Account 489		$ -	-	-
Total Throughput		$ 6,027,414	10,651,330	5,206
Forfeited Discounts (487)		$ 6,448		
Miscellaneous Service Revenues (488)				
CONNECTION CHARGE		$ 3,737		
RETURN CHECK CHARGE		125		
MISCELLANEOUS				
Total Account 488		$ 3,862		
Rent from Property (493)		$ -		
Total Account 493		$ -		
Other Gas Revenues (495)				
INTEREST ON CUSTOMER LOANS		-		
SALES & USE TAX HANDLING COMMISSION		$ 292		
GMS GAINS		-		
MISCELLANEOUS		-		
Total Account 495		$ 292		
Penalty Revenues (497)				
Utility Incentive Revenues (498)				
Total Other Operating Revenues		$ 10,602		
Total Out-of-State Operating Revenues		6,038,016	10,651,330	5,206

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GAS OPERATION AND MAINTENANCE EXPENSES

Particulars (a)	Total Amount (b)	Labor Expense (c)	Other Expense (d)
MANUFACTURED GAS PRODUCTION EXPENSES			
(List applicable prescribed accounts)			
Liquefied Petroleum Gas Expenses (717)	0	0	0
Liquefied Petroleum Gas (728)	13,780	0	13,780
Miscellaneous Production Expense (735)	305,292	427	304,865
Maintenance of Production Equipment (742)	0	0	0
		0	0
Total manufactured gas production expenses	319,072	427	318,645

GAS OPERATION AND MAINTENANCE EXPENSES (Cont.)

Particulars (a)	Total Amount (b)	Labor Expense (c)	Other Expense (d)
PURCHASED GAS EXPENSES			
Natural gas city gate purchases (804)	73,882,436	91,695	73,790,741
Other gas purchases (805)	(1,190,719)		(1,190,719)
Purchased gas expenses (807)	0	0	0
Gas withdrawn from stor.--Debit (808.1)	0		0
Gas delivered to stor.--Credit (808.2)	0		0
Gas used for other ut. op.--Cr. (812)	0		0
Other gas supply expenses (813)	170,094	507	169,587
Total purchased gas expenses	$72,861,811	$92,202	$72,769,609
STORAGE EXPENSES			
Operation supervision and eng. (840)	66,857	20,577	46,280
Operation labor and expenses (841)	123,146	37,901	85,245
Rents (842)	1,813	0	1,813
Fuel (842.1)	0		0
Power (842.2)	0		0
Gas losses (842.3)	0		0
Maint. supervision and eng. (843.1)	0		0
Maint. of struct. & improv. (843.2)	0		0
Maintenance of gas holders (843.3)	0		0
Maint. of purification equip. (843.4)	0		0
Maint. of liquefication equip. (843.5)	0		0
Maint. of vapor equip. & other (843.6-843.9)	0		0
Total storage expenses	$191,816	$58,478	$133,338
TRANSMISSION EXPENSES			
Operation supervision and eng. (850)	0		
Sys. control & load dispatching (851)	0	0	0
Communications system expenses (852)	0		
Compressor stat. labor & expen. (853)	0		
Gas for compressor station fuel (854)	0		
Other fuel & power for com. sta. (855)	0		
Mains expenses (856)	0	0	0
Measuring & reg. stat. expenses (857)	0		0
Trans. & comp. of gas by others (858)	0		
Other expenses (859)	0		
Rents (860)	0		
Maint. supervision & engineer. (861)	0		
Maint. of struct. & improv. (862)	0		
Maintenance of mains (863)	0		
Maint. of compr. stat. equip. (864)	0		
Maint. of meas. & reg. st. eq. (865)	0		
Maint. of communication equip. (866)	0		
Maintenance of other equipment (867)	0		
Total transmission expenses	$0	$0	$0
DISTRIBUTION EXPENSES			
Operation supervision & engin. (870)	173,048	113,515	59,533
Distribution load dispatching (871)	75,973	75,878	94
Compressor stat. labor & expen. (872)	0		0
Compressor station fuel & power (873)	0		0
Mains and services expenses (874)	508,498	454,958	53,540
Meas. & reg. stat. expen.--Gen. (875)	150,535	90,690	59,844
Meas. & reg. stat. expen.--Ind. (876)	0	0	0
Subtotal--dist. exp.--carried forward	$908,054	$735,042	$173,011

May not cross-check due to rounding

DETAIL OF NATURAL GAS CITY GATE PURCHASES, ACCOUNT 804

Particulars (a)	Total Amount (b)	Labor Expense (c)	Other Expense (d)	
PURCHASED GAS EXPENSES			0	7
Wages and Salaries (804.11)	91,695	91,695	0	8
Supplies and Expenses (804.12)	7,011		7,011	9
Miscellaneous Purchased Gas Expenses (804.13)	-		0	10
Gas Contract Reservation Fees (804.21)	6,423,516		6,423,516	11
Gas Contract Commodity Costs (804.22)	30,958,916		30,958,916	12
Spot Gas Commodity Costs (804.23)	22,338,055		22,338,055	13
Other Gas Purchases (804.24)	901,233		901,233	14
Gas Surcharges (804.25)			0	15
Financial Instruments Expenses (804.26)	80,600		80,600	16
Gas Purchase Miscellaneous Expenses (804.27)	-		0	17
Gas Costs for Opportunity Sales (804.28)	2,719,686		2,719,686	18
Purchased Gas Sold - Credit (804.32)	(2,719,686)		(2,719,686)	19
Gas Commodity Costs Transferred to Storage - Credit (804.33)	(4,499,999)		(4,499,999)	20
Gas Used in Utility Operations - Credit (804.34)			0	21
Gas Used for Transmission Pumping and Compression - Credit (804.3	(927,036)		(927,036)	22
Total Purchased Gas Expenses	55,373,990	91,695	55,282,295	23
TRANSMISSION EXPENSES				24
Transmission Contract Reservation Fees (804.41)	14,908,292		14,908,292	25
Commodity Transmission Fees (804.42)	469,954		469,954	26
Gas Transmission Surcharges (804.43)			0	27
Gas Transmission Fuel Expenses (804.44)	927,036		927,036	28
No-Notice Service Expenses (804.45)	182,147		182,147	29
Other Transmission Fees and Expenses (804.46)	(161)		(161)	30
Miscellaneous Transmission Expenses (804.48)	34,735		34,735	31
Penalties, Unauthorized Use and Overrun, Utility (804.49)			0	32
Penalties, Unauthorized Use and Overrun, End-User (804.51)			0	33
Transmission Services Sold - Credit (804.52)	(2,448,946)		(2,448,946)	34
Gas Transmission Expenses Transferred to Storage - Credit (804.53)	(169,540)		(169,540)	35
Gas Transmission Expenses Used in Utility Operations - Credit (804.54)			0	36
Gas Transmission Costs for Opportunity Sales (804.55)	2,083		2,083	37
Total Transmission Expenses	13,903,516	-	13,903,516	38
STORAGE EXPENSES				39
Storage Reservation Fees (804.61)	838,729		838,729	40
Stored Gas Costs for System Use (804.62)	3,766,200		3,766,200	41
Stored Penalties (804.63)			0	42
Stored Gas Costs for Opportunity Sales (804.64)			0	43
Storage Capacity Released or Sold - Credit (804.72)			0	44
Stored Gas Sold - Credit (804.73)			0	46
Total Storage Expenses	4,604,929	-	4,604,929	47
Total Expenses - Account 804	73,882,436	91,695	73,790,741	48

PSCW Form Revised 11-01

May not cross-check due to rounding.

GAS OPERATION AND MAINTENANCE EXPENSES (Cont.)

Particulars (a)	Total Amount (b)	Labor Expense (c)	Other Expense (d)
dist. exp. (Amount brought forward)	$908,054	$735,042	$173,011
Meas. & reg. sta. ex.-City gate (877)	72,861	43,896	28,965
Meter & house regulator expenses (878)	100,579	362,482	(261,903)
Customer installations expenses (879)	335,139	264,120	71,019
Other expenses (880)	1,354,803	888,709	466,094
Rents (881)	1,581	0	1,581
Maint. supervision & eng. (885)	52,293	14,870	37,423
Maint. of struct. & improv. (886)	0	0	0
Maintenance of mains (887)	113,465	67,337	46,127
Maint. of compres. stat. equip. (888)	0		0
Maint. of meas. & reg. st. eq.-Gen. (889)	0		0
Maint. of meas. & reg. st. eq.-In. (890)	0		0
Maint. of meas. & reg. st. eq.-City (891)	30,227	20,581	9,646
Maintenance of services (892)	214,105	142,841	71,264
Maint. of meters and house reg. (893)	510,695	301,091	209,604
Maintenance of other equipment (894)	0		0
Total distribution expenses	$3,693,802	$2,840,971	$852,831
CUSTOMER ACCOUNTS EXPENSES			
Supervision (901)	6,514	5,681	833
Meter reading expenses (902)	673,537	569,130	104,406
Customer records & collect. exp. (903)	1,940,385	812,038	1,128,347
Uncollectible accounts (904)	433,330		433,330
Miscell. customer accts. expen. (905)	75,003	40,253	34,750
Total customer accts. expenses	$3,128,768	$1,427,103	$1,701,666
CUSTOMER SERVICE EXPENSES			
Supervision (907)	0	0	0
Customer assistance expenses (908)	1,003,970	240,918	763,052
Informational advertising expenses (909)	34,814	0	34,814
Miscell. customer accts. expen. (910)	166,544	0	166,544
Total customer service expenses	$1,205,328	$240,918	$964,410
SALES PROMOTION EXPENSES			
Supervision (911)	0		0
Demonstrating & selling expenses (912)	353	49	304
Advertising expenses (913)	0		0
Miscell. sales expenses (916)	0		0
Total sales promotion expenses	$353	$49	$304
ADMINISTRATIVE AND GENERAL EXPENSES			
Administrative and general salaries (920)	1,408,599	1,408,599	0
Office supplies and expenses (921)	1,378,643	606	1,378,037
Admin. expenses transferred--cr. (922)	(428,631)		(428,631)
Outside services employed (923)	521,629	12	521,618
Property insurance (924)	72,085		72,085
Injuries and damages (925)	182,852	0	182,852
Employee pensions and benefits (926)	(305,938)	(305,938)	0
Regulatory commission expenses (928)	172,378	210	172,169
Duplicate charges--cr. (929)	0		0
Instit. or goodwill advert. (930.1)	47,093	0	47,093
Miscellaneous general expense (930.2)	313,996	3,205	310,791
Rents (931)	91,818	0	91,818
Maintenance of general plant (932)	1,664	0	1,664
Total administ. & gen. expenses	$3,456,188	$1,106,692	$2,349,496
Total gas operat. & maint. expenses	$84,857,138	$5,766,839	$78,771,654

May not cross-check due to rounding

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Name of Respondent	This Report Is:	Date of Report
Northern States Power Company	(1) [X] An Original	(Mo, Da, Yr)
(Wisconsin)	(2) [ ] A Resubmission	Dec. 31, 2002

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

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold; Account 103, Experimental Gas Plant Unclassified; and Account 106, Completed Construction Not Classified-Gas.
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 which have not been classified to primary accounts 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 accummulated depreciation provision. Include also in column (d) reversals of tentative distributions or prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the reversals.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	1. Intangible Plant		
2	301 Organization		
3	302 Franchises and Consents		
4	303 Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant	0	0
6	2. Manufactured Gas Production Plant		
7	304 Land and Land Rights		
8	305 Structures and Improvements		
9	306 Boiler Plant Equipment		
10	307 Other Power Equipment		
11	308 Coke Ovens		
12	309 Producer Gas Equipment		
13	310 Water Gas Generating Equipment		
14	311 Liquefied Petroleum Gas Equipment		
15	312 Oil Gas Generating Equipment		
16	313 Generating Equipment - Other Processes		
17	314 Coal, Coke and Ash Handling Equipment		
18	315 Catalytic Cracking Equipment		
19	316 Other Reforming Equipment		
20	317 Purification Equipment		
21	318 Residual Refining Equipment		
22	319 Gas Mixing Equipment		
23	320 Other Equipment		
24	TOTAL Manufactured Gas Production Plant	0	0
25	Other Storage Plant		
26	360 Land and Land Rights	155,136	
27	361 Structures and Improvements	370,903	
28	362 Gas Holders	1,625,796	
29	363 Purification Equipment	182,925	
30	363.1 Liquefaction Equipment	137,507	
31	363.2 Vaporizing Equipment	1,032,389	
32	363.3 Compressor Equipment	277,050	
33	363.4 Meas. and Reg. Equipment	1,504	
34	363.5 Other Equipment	2,213,938	
35	TOTAL Other Storage Plant	5,997,148	0

May not cross-check due to rounding.

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

of the prior years tentative account distribution of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the 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
			0	301	2
			0	302	3
			0	303	4
0	0	0	0		5
					6
			0	304	7
			0	305	8
			0	306	9
			0	307	10
			0	308	11
			0	309	12
			0	310	13
			0	311	14
			0	312	15
			0	313	16
			0	314	17
			0	315	18
			0	316	19
			0	317	20
			0	318	21
			0	319	22
			0	320	23
0	0	0	0		24
					25
			155,136	360	26
			370,903	361	27
			1,625,796	362	28
			182,925	363	29
			137,507	363	30
			1,032,389	363	31
			277,050	363	32
			1,504	363	33
			2,213,938	364	34
0	0	0	5,997,148		35

May not cross-check due to rounding.

Name of Respondent	This Report Is:	Date of Report
Northern States Power Company	(1) [X] An Original	(Mo, Da, Yr)
(Wisconsin)	(2) [ ] A Resubmission	Dec. 31, 2002

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
36	4. Transmission Plant		
37	365.1 Land and Land Rights		
38	365.2 Rights-of-Way		
39	366 Structures and Improvements		
40	367 Mains		
41	368 Compressor Station Equipment		
42	369 Measuring and Reg. Sta. Equipment		
43	370 Communication Equipment		
44	371 Other Equipment		
45	TOTAL Transmission Plant	0	0
46	5. Distribution Plant		
47	374 Land and Land Rights	5,688	
48	375 Structures and Improvements	0	
49	376 Mains	57,755,923	2,210,779
50	377 Compressor Station Equipment	0	
51	378 Meas. and Reg. Sta. Equip.-General	1,399,947	(24)
52	379 Meas. and Reg. Sta. Equip.-City Gate	2,863,158	(14)
53	380 Services	36,511,053	2,327,922
54	381 Meters	10,154,503	156,329
55	382 Meter Installations	7,059,277	166,457
56	383 House Regulators	3,195,379	22,593
57	384 House Reg. Installations		
58	385 Industrial Meas. and Reg. Sta. Equipment		
59	386 Other Prop. on Customers' Premises		
60	387 Other Equipment		
61	TOTAL Distribution Plant	118,944,928	4,884,042
62	6. General Plant		
63	389 Land and Land Rights	23,856	
64	390 Structures and Improvements	183,227	
65	391 Office Furniture and Equipment	332,850	
66	392 Transportation Equipment	272,845	
67	393 Stores Equipment	2,677	
68	394 Tools, Shop, and Garage Equipment	1,049,328	36,229
69	395 Laboratory Equipment	469,695	
70	396 Power Operated Equipment	358,658	
71	397 Communication Equipment	0	
72	398 Miscellaneous Equipment	0	
73	Subtotal	2,693,136	36,229
74	399 Other Tangible Property	0	
75	TOTAL General Plant	2,693,136	36,229
76	TOTAL (Accounts 101 and 106)	127,635,212	4,920,271
77	Gas Plant Purchased (See Instr. 8)		
78	(Less) Gas Plant Sold (See Instr. 8)		
79	Experimental Gas Plant Unclassified	0	
80	TOTAL Gas Plant in Service	127,635,212	4,920,271

May not cross-check due to rounding.

Name of Respondent Northern States Power Company (Wisconsin)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr) Dec. 31, 2002

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					36
			0	365	37
			0	365	38
			0	366	39
			0	367	40
			0	368	41
			0	369	42
			0	370	43
			0	371	44
0	0	0	0		45
					46
			5,688	374	47
			0	375	48
8,711			59,957,991	376	49
			0	377	50
			1,399,923	378	51
			2,863,144	379	52
558,621			38,280,354	380	53
		10,433,248	20,744,080	381	54
10,423		(7,215,311)	0	382	55
35		(3,217,937)	0	383	56
			0	384	57
			0	385	58
			0	386	59
			0	387	60
577,790	0	0	123,251,180		61
					62
			23,856	389	63
			183,227	390	64
			332,850	391	65
			272,845	392	66
			2,677	393	67
			1,085,557	394	68
			469,695	395	69
26,743			331,915	396	70
			0	397	71
			0	398	72
26,743	0	0	2,702,622		73
			0	399	74
26,743	0	0	2,702,622		75
604,533	0	0	131,950,950		76
			0		77
			0		78
			0		79
604,533	0	0	131,950,950		80

May not cross-check due to rounding.

Name of Respondent	This Report Is:	Date of Report
Northern States Power Company	(1) [X] An Original	(Mo,Da,Yr)
(Wisconsin)	(2) [ ] A Resubmission	DEC. 31, 2002

ACCUM. PROVISION FOR DEPREC OF GAS PLANT IN SERVICE (108)

Line No.	Account (a)	Balance first of Year (b)	S.L. Depr Rate % used (c)	Accruals during year: Straight line amount (d)	CIAC amortization (e)	Book cost of plant retired (f)
1						
2						
3						
4						
5	TOTAL Intangible Plant	N/A	N/A	0	0	0
6	2. Manufactured Gas Production Plant					
7						
8	305 Structures and Improvements					
9	306 Boiler Plant Equipment					
10	307 Other Power Equipment					
11	308 Coke Ovens					
12	309 Producer Gas Equipment					
13	310 Water Gas Generating Equipment					
14	311 Liquefied Petroleum Gas Equipment					
15	312 Oil Gas Generating Equipment					
16	313 Generating Equipment - Other Processes					
17	314 Coal, Coke and Ash Handling Equipment					
18	315 Catalytic Cracking Equipment					
19	316 Other Reforming Equipment					
20	317 Purification Equipment					
21	318 Residual Refining Equipment					
22	319 Gas Mixing Equipment					
23	320 Other Equipment					
24	TOTAL Manufactured Gas Production Plant	0		0	0	0
25	Other Storage Plant					
26						
27	361 Structures and Improvements	296,288	1.83	6,779		
28	362 Gas Holders	1,788,375	0.00			
29	363 Purification Equipment	165,723	0.85	1,563		
30	363.1 Liquefaction Equipment	137,507	0.00	0		
31	363.2 Vaporizing Equipment	676,380	3.13	32,358		
32	363.3 Compressor Equipment	277,050	0.00	0		
33	363.4 Meas. and Reg. Equipment	1,504	0.00	0		
34	363.5 Other Equipment	1,383,640	4.21	93,107		
35	TOTAL Other Storage Plant	4,726,467		133,807	0	0
36	4. Transmission Plant					
37						
38						
39	366 Structures and Improvements					
40	367 Mains					
41	368 Compressor Station Equipment					
42	369 Measuring and Reg. Sta. Equipment					
43	370 Communication Equipment					
44	371 Other Equipment					
45	TOTAL Transmission Plant	0		0	0	0

May not cross-check due to rounding.

Name of Respondent	This Report Is:	Date of Report
Northern States Power Company	(1) [X] An Original	(Mo,Da,Yr)
(Wisconsin)	(2) [ ] A Resubmission	Dec. 31, 2002

ACCUM. PROVISION FOR DEPREC OF GAS PLANT IN SERVICE (108)

Cost of Removal (g)	Salvage (h)	Other additions (deductions) (i)	Balance end of Year (j)		(k)	(l)	Line No.
					Total deprec. exp. (cols. (d)		1
					and (e))	4,933,198	2
					Less amounts charged to		3
					clearing accounts	27,308	4
					Plus allocation of deprec. on		5
0	0	0	0		on common plant	450,121	6
					Total gas depr. expense	5,356,011	7
			0	305	Total balance (col (j))	66,081,166	8
			0	306			9
			0	307	Plus allocation of reserve on		10
			0	308	common plant (1)	8,494,079	11
			0	309			12
			0	310	Total depr. res. for gas util.	74,575,245	13
			0	311			14
							15
			0	312	Explanation of items in col. (i)		16
			0	313			17
			0	314			18
			0	315			19
			0	316	Explanation of items in col. (L)		20
			0	317			21
			0	318	Plus allocation of reserve on common plant (1)		22
			0	319	includes -30,972 of GAS RETIREMENT W-IN-P		23
			0	320			24
0	0	0	0				25
							26
							27
			303,067	361			28
			1,788,375	362			29
			167,286	363			30
			137,507	363			31
			708,738	363			32
			277,050	363			33
			1,504	363			34
			1,476,747	364			35
0	0	0	4,860,274				36
							37
							38
							39
			0	366			40
			0	367			41
			0	368			42
			0	369			43
			0	370			44
			0	371			45
0	0	0	0				46
							47
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							55

May not cross-check due to rounding.

Name of Respondent	This Report Is:	Date of Report
Northern States Power Company	(1) [X] An Original	(Mo,Da,Yr)
(Wisconsin)	(2) [ ] A Resubmission	Dec. 31, 2002

ACCUM. PROVISION FOR DEPREC OF GAS PLANT IN SERVICE (cont.)

Line No.	Account (a)	Balance first of Year (b)	S.L. Depr Rate % used (c)	Accruals during year: Straight line amount (d)	Accruals during year: CIAC amortization (e)	Book cost of plant retired (f)
46	5. Distribution Plant					
47						
48	375 Structures and Improvements	0				
49	376 Mains	23,083,567	2.88	1,689,893		8,711
50	377 Compressor Station Equipment	0				
51	378 Meas. and Reg. Sta. Equip.-General	644,358	4.40	61,597		
52	379 Meas. and Reg. Sta. Equip.-City Gate	959,569	3.67	105,077		
53	380 Services	23,234,876	5.31	1,972,615		558,621
54	381 Meters	4,450,992	4.20	706,210		
55	382 Meter Installations	2,156,122	4.20	103,044		10,423
56	383 House Regulators	1,106,231	4.20	44,924		35
57	384 House Reg. Installations	0				
58	385 Industrial Meas. and Reg. Sta. Equipment	0				
59	386 Other Prop. on Customers' Premises	0				
60	387 Other Equipment	0				
61	TOTAL Distribution Plant	55,635,715		4,683,360	0	577,790
62	6. General Plant					
63						
64	390 Structures and Improvements	122,986	3.14	5,753		
65	391 Office Furniture and Equipment	302,955	VARIOUS	5,722		
66	392 Transportation Equipment	247,664	VARIOUS	3,631		
67	393 Stores Equipment	1,631	5.00	134		
68	394 Tools, Shop, and Garage Equipment	355,255	5.00	53,628		
69	395 Laboratory Equipment	169,741	5.00	23,485		
70	396 Power Operated Equipment	245,219	VARIOUS	23,678		26,743
71	397 Communication Equipment	0	10.00			
72	398 Miscellaneous Equipment	0				
73	Subtotal	1,445,451		116,031	0	26,743
74	399 Other Tangible Property	0		0	0	0
75	TOTAL General Plant	1,445,451		116,031	0	26,743
76	TOTAL (Accounts 101 and 106)	61,807,633		4,933,198	0	604,533
77	Gas Plant Purchased (See Instr. 8)					
78	(Less) Gas Plant Sold (See Instr. 8)					
79	Experimental Gas Plant Unclassified	0		0	0	0
80	TOTAL Gas Plant in Service	61,807,633		4,933,198	0	604,533
81						
82						
83						
84						
85						
86						
87						
88						
89						
90						
91						
92						
93						
94						

May not cross-check due to rounding

Name of Respondent	This Report Is:	Date of Report
Northern States Power Company	(1) [X] An Original	(Mo,Da,Yr)
(Wisconsin)	(2) [ ] A Resubmission	Dec. 31, 2002

ACCUM. PROVISION FOR DEPREC OF GAS PLANT IN SERVICE (cont.)

Cost of Removal (g)	Salvage (h)	Other additions (deductions) (i)	Balance end of Year (j)		(k)	(l)	Line No.
					Explanation of items in col. (i) (cont.)		46
							47
			0	375			48
40,394	21,385		24,745,740	376			49
			0	377			50
			705,955	378			51
			1,064,646	379			52
6,544	15		24,642,341	380			53
442		3,370,711	8,527,471	381			54
28,814	508	(2,220,437)	0	382			55
848	2	(1,150,274)	0	383			56
			0	384			57
			0	385			58
			0	386			59
			0	387			60
77,042	21,910	0	59,686,153				61
							62
							63
			128,739	390			64
			308,677	391			65
			251,295	392			66
			1,765	393			67
			408,883	394			68
			193,226	395			69
			242,154	396			70
			0	397			71
			0	398			72
0	0	0	1,534,739				73
0	0	0	0	399			74
0	0	0	1,534,739				75
77,042	21,910	0	66,081,166				76
			0				77
			0				78
0	0	0	0				79
77,042	21,910	0	66,081,166				80
							81
							82
							83
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							90
							91
							92
							93
							94

May not cross-check due to rounding.

GAS PRODUCTION STATISTICS

Location of plant (a)	Type of plant (b)	Maximum daily capacity Therms (c)	Therms produced during year (d)	Total investment end of year (e)	Total production expense for year (f)
None					
TOTAL		0	0	$0	$0

GAS HOLDERS

	Telescopic & piston holders		Pressure holders			
Location (a)	Number (b)	Capacity Therms (c)	Number (d)	Capacity at atmospheric pressure (e)	Design pressure (f)	Operated pressure (g)
None						

LIQUID PETROLEUM GAS STORAGE

Report hereunder number of liquid petroleum gas storage tanks and total capacity in gallons by location.

None

May not cross-check due to rounding.

LIQUEFIED NATURAL GAS STORED, ACCOUNT 164.2

Particulars (a)	Amount $ (b)	Amount Therms (c)
Balance, beginning of year	$102,343	396,880
Gas delivered to storage (credit account 808.2)	166,513	383,720
Gas withdrawn from storage (debit account 808.1)	(71,280)	(276,420)
Other transactions or adjustments (explain):		
Balance, end of year	$197,576	504,180

LIQUEFIED NATURAL GAS STORED STATISTICS

Location of storage (a)	Total storage capacity Therms (b)	Maximum daily capacity Therms (c)	Total Investment end of year (d)	Maximum day's withdrawal (e)	Total production expense for year (f)
Eau Claire WI	2,700,000	180,000	4,164,492	-	-
La Crosse WI	1,300,000	Not operational	894,311	N/A	N/A
La Crosse WI (Propane)	153,000 gals	31,200	632,140	-	-
New Richmond WI (Propane)	25,500 gals	4,080	98,875	-	-
Tomah-Ft McCoy WI	30,600 gals	See Note A	207,330	-	-

(Propane) - Note A - not used for system supply; used for backup supply for Ft McCoy

PSCW Form Revised 11-01

May not cross-check due to rounding.

SUMMARY OF GAS ACCOUNT

Report below the specified information for each operating area constituting a separate gas system.

Particulars (a)	Total all systems therms (b)	In State therms (c)	Out of State therms (d)	
System Name	Total WI Company	Wisconsin Operations	Michigan Operations	9 10
Gas produced (gross):				11
Propane - air	0			12
Other gas	0			13
Total gas produced	0	0	0	14
Gas purchased:				15
Natural	169,644,850			16
Other gas	0			17
Total gas purchased	169,644,850	0	0	18
Add: Gas withdrawn from storage	13,459,080			19
Less: Gas delivered to storage	14,603,140			20
Total (lines 14 + 18 + 19 - 20)	168,500,790	0	0	21
Transport gas received	36,545,350			22
Total gas del. to mains (lines 21 + 22)	205,046,140	194,547,570	10,498,570	23
Gas sold (incl. interdepartmental)	169,808,421	159,157,091	10,651,330	24
Gas used by utility	272,747	252,944	19,803	25
Transport gas delivered	36,580,499	36,580,499	0	26
Total (lines 24 + 25 + 26)	206,661,667	195,990,534	10,671,133	27
Gas unaccounted for (lines 23 - 27)	(1,615,527)	(1,442,964)	(172,563)	28

SUMMARY OF SYSTEM LOAD STATISTICS

Report below the data specified for each operating area constituting a separate gas system.

Particulars (a)	Total all systems therms (b)	System therms (c)	System therms (d)	
System Name	Total WI Company			34 35
Maximum send-out in any one day	1,212,270			36
Date of such maximum	03/03/02			37
Maximum daily capacity:				38
Total manufactured-gas production capacity	35,280			39
Liquefied natural gas storage capacity	180,000			40
Maximum daily purchase capacity	1,098,190			41
Total maximum daily capacity: production liquefied natural gas storage, and purchases	1,313,470	0	0	42 43
Monthly send-out: January	26,249,080			44
February	22,884,370			45
March	26,092,980			46
April	15,980,550			47
May	12,024,780			48
June	8,983,570			49
July	9,701,880			50
August	7,569,250			51
September	9,544,940			52
October	17,330,590			53
November	22,692,800			54
December	25,991,350			55
Total send-out	205,046,140	0	0	56

May not cross-check due to rounding.

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PURCHASED GAS

Report below the specified information for each point of metering.

Particulars (a)	Total (b)	(c)	(d)
Name of vendor			
Point of metering		Bayfield WI	Butternut WI
Type of gas purchased		Natural	Natural
Therms of gas purchased per pipeline rate schedules:	0		
	205,046,140	1,146,260	279,970
(1) Includes Natural Gas from all Suppliers and Storage			
Total cost of gas purchased	$73,797,511		
Average cost per therm of gas purchased per pipeline rate schedules:	$0.3599		
Maximum therms purchased in any one day	Not available	Not available	Not available
Date of such maximum purchase (da/mo/yr)	Not available	Not available	Not available
Average B.t.u. content per cu. ft. of gas	1.000	1.000	1.000
Name of vendor			
Point of metering	Ashland WI	Bergland MI	Chip Falls WI
Type of gas purchased	Natural	Natural	Natural
Therms of gas purchased per pipeline rate schedules:	8,143,230	188,950	13,709,030
Total cost of gas purchased			
Average cost per therm of gas purchased per pipeline rate schedules:			
Maximum therms purchased in any one day	Not available	Not available	Not available
Date of such maximum purchase (da/mo/yr)	Not available	Not available	Not available
Average B.t.u. content per cu. ft. of gas	1.000	1.000	1.000
Name of vendor			
Point of metering	B H Acres WI	Bessemer MI	Colfax WI
Type of gas purchased	Natural	Natural	Natural
Therms of gas purchased per pipeline rate schedules:	365,590	3,128,620	17,053,420
Total cost of gas purchased			
Average cost per therm of gas purchased per pipeline rate schedules:			
Maximum therms purchased in any one day	Not available	Not available	Not available
Date of such maximum purchase (da/mo/yr)	Not available	Not available	Not available
Average B.t.u. content per cu. ft. of gas	1.000	1.000	1.000

PURCHASED GAS

Report below the specified information for each point of metering.

(e)	(f)	(g)	(h)	(i)	(j)
Control	Fall Creek WI	Hudson WI	Iron River WI	Mellen WI	Ogema WI
Natural	Natural	Natural	Natural	Natural	Natural
NO FLOW	1,242,460	10,260,720	455,920	723,910	163,160
	Not available	Not available	Not available	Not available	Not available
	Not available	Not available	Not available	Not available	Not available
	1.000	1.000	1.000	1.000	1.000
Eau Claire WI	Fifield WI	Hurley WI	Ironwood MI	Menomonie WI	Ond Pub School WI
Natural	Natural	Natural	Natural	Natural	Natural
22,692,840	172,020	2,003,930	5,196,370	8,134,450	116,860
Not available	Not available	Not available	Not available	Not available	Not available
Not available	Not available	Not available	Not available	Not available	Not available
1.000	1.000	1.000	1.000	1.000	1.000
Ewen MI	Glidden WI	Ind Mt Ski MI	LaCrosse WI	Montreal WI	Park Falls WI
Natural	Natural	Natural	Natural	Natural	Natural
240,960	490,840	134,900	50,439,420	445,400	15,471,890
Not available	Not available	Not available	Not available	Not available	Not available
Not available	Not available	Not available	Not available	Not available	Not available
1.000	1.000	1.000	1.000	1.000	1.000

PURCHASED GAS

Report below the specified information for each point of metering.

(e)	(f)	(g)	(h)	(i)	(j)
Phillips WI	Ramsay MI	Saxon WI	Wakefield MI	Westboro WI	Wheaton WI
Natural	Natural	Natural	Natural	Natural	Natural
3,132,490	493,050	50,300	789,910	135,560	25,556,310
Not available	Not available	Not available	Not available	Not available	Not available
Not available	Not available	Not available	Not available	Not available	Not available
1.000	1.000	1.000	1.000	1.000	1.000
Prentice WI	Rib Lake WI	Shelby WI	Washburn WI	Tomah - Fort McCoy WI	New Richmond WI
Natural	Natural	Natural	Natural	Natural	Natural
652,110	545,400	1,319,890	1,314,940	2,961,600	5,290,430
Not available	Not available	Not available	Not available	Not available	Not available
Not available	Not available	Not available	Not available	Not available	Not available
1.000	1.000	1.000	1.000	1.000	1.000
Marenisco MI	Kinnickinnic WI				
Natural	Natural				
325,810	77,220				
Not available	Not available				
Not available	Not available				
1.000	1.000				

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GAS MAINS CLASSIFIED BY TYPES AND SIZES

Classification	Wisconsin		Other		Total	
	No. of feet beg. of year	No. of feet end of year	No. of feet beg. of year	No. of feet end of year	No. of feet beg. of year	No. of feet end of year
(a)	(b)	(c)	(d)	(e)	(f)	(g)
Cast Iron:						
3 Inches					0	0
4 Inches					0	0
Inches					0	0
Inches					0	0
Inches					0	0
Inches					0	0
Inches					0	0
Inches					0	0
Total	0	0	0	0	0	0
Steel:						
3/4 Inches	1,196	1,196			1,196	1,196
1 Inches	48,483	48,483	92,049	92,049	140,532	140,532
1 1/4 Inches	120,460	120,460			120,460	120,460
1 1/2 Inches	30,680	30,680	50	50	30,730	30,730
2 Inches	832,626	833,051	168,212	168,212	1,000,838	1,001,263
2 1/2 Inches					0	0
3 Inches	219,183	219,183	33,989	33,989	253,172	253,172
4 Inches	429,418	429,635	37,294	37,294	466,712	466,929
6 Inches	282,971	282,971	46,589	46,589	329,560	329,560
8 Inches	175,318	198,818	2,520	2,520	177,838	201,338
10 Inches	9,095	10,165	4,532	4,532	13,627	14,697
12 Inches	77,334	77,334			77,334	77,334
16 Inches	18,276	18,276			18,276	18,276
Inches					0	0
Inches					0	0
Inches					0	0
Inches					0	0
Total	2,245,040	2,270,252	385,235	385,235	2,630,275	2,655,487
Plastic:						
5/8 Inches	6,252	6,252			6,252	6,252
1 Inches	43,424	43,424	1,491	1,491	44,915	44,915
1 1/4 Inches	77,691	77,691			77,691	77,691
1 1/2 Inches	136,455	136,455			136,455	136,455
2 Inches	5,117,629	5,284,918	193,085	193,485	5,310,714	5,478,403
3 Inches	155,621	155,621	2,253	2,253	157,874	157,874
4 Inches	1,446,105	1,486,899	48,091	48,091	1,494,196	1,534,990
6 Inches	49,674	49,674			49,674	49,674
Inches					0	0
Total	7,032,851	7,240,934	244,920	245,320	7,277,771	7,486,254
Other (specify):						
Inches					0	0
Inches					0	0
Inches					0	0
Inches					0	0
Inches					0	0
Inches					0	0
Inches					0	0
Inches					0	0
Total	0	0	0	0	0	0
Grand Total	9,277,891	9,511,186	630,155	630,555	9,908,046	10,141,741

GAS SERVICES (LOCATED IN WISCONSIN)

Number of services should include only those owned by utility.

	Number added during year		Number retired during year		Total services end of year	
Size (a)	Main to curb (b)	On customers premises (c)	Main to curb (d)	On customers premises (e)	Main to curb (f)	On customers premises (g)
1-1/2" & Under	2,012	2,012	33	33	77,027	76,233
2"					536	515
3"					57	57
4"					40	38
6"					2	2
8"					2	2
Total	2,012	2,012	33	33	77,664	76,847

GAS SERVICES (LOCATED OUTSIDE WISCONSIN)

Number of services should include only those owned by utility.

(a)	(b)	(c)	(d)	(e)	(f)	(g)
1-1/2" & Under	2	2	2	2	5,403	5,401
2"					17	17
3"					1	1
4"					3	3
Total	2	2	2	2	5,424	5,422
G. Total (Lines 34 & 53)	2,014	2,014	35	35	83,088	82,269

Have inactive services been retired in accordance with requirements of paragraph C of Account 380 of Uniform System of Accounts?

Have inactive services been disconnected from the gas supply in accordance with section 192.727(g) of the Wisconsin Administrative Code?

GAS METERS

Number of meters should include only those carried in Utility Plant Account 381.

Particulars (a)	Number end of year (b)
Diaphragmed meters (capacity at 1/2-inch water column pressure drop):	
2,400 cu. ft. per hour or less	96,902
Over 2,400 cu. ft. per hour	90
Rotary meters	527
Orifice meters	
Total end of year	97,519
In stock	3,762
Locked meters on customer's premises	679
Regular meters in customer's use	92,952
Prepayment meters in customer's use	
Meters in company use, included in Account 381	126
Total end of year (as above)	97,519
No. of diaphramgmed meters at end of year which compensate for temperature:	
Number of house regulators installed at end of year	*

* Regulators now combined with meters Acct. # 381

Attach to this sheet a map or maps of the territory served, showing loaction & company designation of points of purchase, production plants, large compressor stations and transmission lines. Show also the names of larger communities served and the boundaries of the utility's operating divisions.

Form of Calculating the HHI
(To Be Included as a Filing Requirement in the Annual Report)

Description

The Hirschman-Herfindahl Index (HHI) is to be provided by each natural gas utility for each of its rate classes. That is, a utility is required to provide a table similar to the following:

Class	Schedules	HHI	Is the utility the Provider With the Largest Market Share?
Residential Firm	Rg-1/Rt-1	10,000	Yes
Small Commercial Firm	Cg-1/Ct-1	10,000	Yes
Medium Commercial Firm	Cg-2/Ct-2	8,500	Yes
Large Commercial Firm	Cg-3/Ct-3	6,300	Yes
Industrial Firm	Lg-1/Lt-1	3,400	Yes
Small Industrial Interruptible	Ig-1/It-1	2,900	Yes
Large Industrial Interruptible	Ig-2/It-2	1,300	No
CNG Vehicles	Cng-1/Cnt-1	10,000	Yes
Crop Drying	Cd-1/Ct-1	10,000	Yes

The HHI is calculated by squaring the market shares of each provider in the class, and then summing those squared market shares. For example, if the utility had 100 percent of the market, the square of 100 is 10,000. Since the utility is the only provider in that example, that is the HHI. If the utility had 50 percent of the market, one marketer had 30 percent and another had 20 percent, the HHI would be: 502+302+202 = 2,500+900+400 = 3,800.

Instructions

If the utility so chooses, it may designate markets by pipeline areas. For example, a utility might define one market to be large industrial firm - Northern Natural area, and another market to be large industrial firm - ANR area. In all cases, the market share calculations should be based on annual calendar year throughput.

Hirschman-Herfindahl Index Form
Utility No. 4220 **Year ended December 31, 2002**
Northern States Power Company (Wisconsin) **Page 2**

	Class	Schedules	HHI	Is the utility the Provider With the Largest Market Share?
1	Residential	Rg-1	10,000	Yes
2	Firm Commercial	Gg-1	9,814	Yes
3	Large General Service	Lg-1	10,000	Yes
4	Contract Demand	Gt-2	10,000	No
5	Interruptible	Ig-1	5,261	Yes
6	Interdepartmental	Gg-1, Ig-1	10,000	Yes
7				
8				
9				
10				
11				
12				
13				
14				

GAS STORED (ACCOUNTS 117, 164.1, 164.2, and 164.3)

1. If during the year, adjustment was made to the stored gas inventory (such as to correct cumulative inaccuracies of gas measurements), furnish in a footnote an explanation of the reason for the adjustment, the MCF and dollar amount of adjustment, and account charged or credited.
2. Give in a footnote, a concise statement of the facts and the accounting performed with respect to any encroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.
3. If the company uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock" and the inventory basis and the accounting performed with respect to any encroachment of withdrawals upon "base stock," or restoration of previous encroachment, including brief particulars of any such accounting during the year.
4. If the company has provided accumulated provision for stored gas, which may not eventually be fully recovered from any storage project, furnish a statement showing: (a) date of FERC authorization of such accumulated provision, (b) explanation of circumstances requiring such provision, (c) basis of provision and factors of calculation, (d) estimated ultimate accumulated provision accumulation, and (e) a summary showing balance of accumulated provision and entries during the year.
5. Report pressure base of gas volumes as 14.73 psia at 60 Degrees F. (See Note 1)

Line No.	Description (a)	Noncurrent (Account 117) (b)	Current (Account 164.1) (c)	LNG (Account 164.2) (d)	LNG (Account 164.3) (e)	Total (f)
1	Balance at of Year of Year		3,119,449	102,343		3,221,792
2	Gas Delivered to Storage		4,506,926	166,513		4,673,440
3	Gas Withdrawn from Storage (contra Account)		(3,636,526)	(71,280)		(3,707,806)
4	Other Debits or Credits (Net)		0			0
5	Balance at End of Year		3,989,849	197,576		4,187,426
6	Therms		1,257,542	50,418		1,307,960
7	Amount Per Therm		3.17	3.92		3.20

This schedule is Page 220 (G) from FERC Form 2 (ED. 12-87.) Subaccounts to Account 164.1 are shown on Page 220 Supplemental in this annual report.

DETAIL OF STORED GAS, ACCOUNT 164.1

The instructions for page 220 also apply to this schedule. Subaccounts shown below conform with the changes to the Uniform System of Accounts adopted by the Public Service Commission in docket 05-US-112, order issued January 17, 2001. Column (i) is the sum of the dollar amounts in the subaccounts and should agree with the amounts reported for Account 164.1 on page 220.

Line No.	Description (a)	Commodity Storage Fees Account 164.11 (b)	Commodity Injection Fees Account 164.12 (c)	Other Storage Fees Account 164.14 (d)	Stored Gas Withdrawn or Forfeited - Credit Account 164.16 (e)
1	Balance at Beginning of Year		$14,825		
2	Gas Delivered to Storage		$20,961		
3	Gas Withdrawn from Storage		($17,060)		
4	Other Debits or Credits (Net)				
5	Balance at End of Year		$18,726		
6	Therms		1,257,542		
7	Amount Per Therm		$0.0149		

Line No.	Description (f)	Gas Commodity Costs Transferred to Storage - Debit Account 164.33 (g)	Gas Transmission Expenses Transferred to Storage - Debit Account 164.53 (h)		Total Account 164.1 (i)
8	Balance at Beginning of Year	$3,023,186	$81,438		$3,119,449
9	Gas Delivered to Storage	$4,341,011	$144,955		$4,506,926
10	Gas Withdrawn from Storage	($3,521,277)	($98,189)		($3,636,526)
11	Other Debits or Credits (Net)				
12	Balance at End of Year	$3,842,920	$128,203		$3,989,849
13	Therms	1,257,542	1,257,542		1,257,542
14	Amount Per Therm	$3.0559	$0.1019		$3.1727

May not cross-check due to rounding.

GAS UTILITY OPERATIONS - 01
ID NUMBER - 4220 UTILITY NAME - Northern States Power Company (WI) YEAR - 2002

Sales/Revenue Data: (Wisconsin Only)

	Avg. No. Cust.	Therms	Revenues
Residential (480)			
Non-Space Heating	2,393	898,010	$751,709
Space Heating	73,108	61,067,500	45,285,435
Total Retail Sales	75,501	61,965,510	$46,037,144
Commercial & Industrial (481)			
Firm Non-Space Heating	1,244	8,288,470	4,836,773
Firm Space Heating	8,904	38,969,681	24,578,514
Other	300	47,719,763	19,464,274
Total Commerical & Industrisl	10,448	94,977,914	$48,879,561
Other Sales to Public Authority (482)			
Interdepartmental Sales (484)	8	2,213,667	$871,663
Total Retail Gas Sales	85,957	159,157,091	95,788,368
Sales to Other Gas Utilities (483)			
Total Gas Sales			
Transportation Gas (489)	10	36,580,499	1,145,898
Total Gas Delivered			
Forfeited Discounts (487)			119,995
Misc. Service Revenue (488)			146,555
Rent from Gas Property (493)			0
Interdepartmental Rents (455)			0
Other (490 - 492, 495 - 496)			(286,999)
Total Other Op. Revenues			$1,125,449
Total Gas Op. Revenues	85,967	195,737,590	$96,913,817

Expenses:

Manufactured Gas			$319,072
Purchased Gas			72,861,811
Gas Storage			191,816
Manufactured, Purchased & Storage (Total Co)			$73,372,699
Manufactured, Purchased & Storage (Wis Only)			$68,732,018
Transmission Expense (Wis Only) (850-868)			0
Distribution Expense (Wis Only) (870-895)			3,475,896
Customer Accts Exp (Wis Only) (901-906)			2,939,976
Cusomer Service Exp (Wis Only) (907-910)			1,212,415
Sales Expense (Wis Only) (911-917)			353
Admin & General Exp (Wis Only) (920-935)			3,263,269
Total O & M Expenses (WI Only)			$79,623,927
Depreciation Expense (WI Only)			$5,329,374
Amortization Expense (WI Only)(404-407)			(204,534)
Taxes - Other (WI Only) (408.1)			1,552,166
Taxes - Income (WI Only) (409.1-411.4)			3,179,443
Disposition of Plant - NET (WI Only) (411.6-411.7)			
Total Utility Operating Expense (WI Only)			$89,480,376
Net Utility Operating Income (WI Only)			$7,433,441

GAS UTILITY OPERATIONS - 02
ID NUMBER - 4220 UTILITY NAME - Northern States Power Company (WI)

YEAR - 2002

ENERGY ACCOUNT

	OUT OF STATE	WISCONSIN	TOTAL
Manufactured Gas			0
Purchased Gas			169,644,850
Gas Withdrawn From Storage			13,459,080
Gas Delivered to Storage			14,603,140
Net Gas From Storage			(1,144,060)
Transport Gas Received			36,545,350
Total Gas Delivered To Mains			205,046,140
Gas Sold			169,808,421
Gas Used by Utility			272,747
Transport Gas Delivered			36,580,499
Losses and Unaccounted For			(1,615,527)
Total Other Op. Revenues			205,046,140

**Amounts available on system wide. Unavailable for direct jurisdictional split.

MAINS:

Plant Type	MILES OF LINE		
	OUT OF STATE	WISCONSIN	TOTAL
Transmission Main			0
Distribution Main	120	1801	1921
Total	120	1801	1921

PLANT INVESTMENT AND RELATED DATA:

Account			
Utility Plant Assigned to Gas (Total Company)			151,219,189
Depreciation Reserve Assigned to Gas (Total Company)			74,575,245
Depreciation Accruals (Including Clearing Acct Charges)			5,390,493
Maintenance - Gas Plant (Total Company)			922,448

Xcel Energy

1414 West Hamilton Avenue
P.O. Box 8
Eau Claire, WI 54702-0008
Telephone (800) 895-4999

May 9, 2003

RECEIVED
MAY 1 2 2003
DIV. OF WATER, COMPLIANCE
AND CONSUMER

Dear Ms. Engelke:

Enclosed you will find revised pages to Northern States Power Company Wisconsin's 2002 Annual Reports which was filed with the Public Service Commission of Wisconsin on April 1, 2003.

Revisions have been made to the following pages:
FERC Pages:

- Notes to Financial Statements
- Statements of Accumulated Comprehensive Income, Comprehensive Income, and Hedging Activities
- Purchased Power

PSCW Pages:

- Particulars Concerning Certain Income Deductions and Interest Charges Accounts

We apologize for the inconvenience. Should you have any questions, please contact me at 715-839-2417.

Sincerely,

Karen Everson

Karen Everson

Enclosure

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 Commmission 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 included herein.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Merger and Basis of Presentation — On Aug. 18, 2000, Northern States Power Co. (NSP) and New Century Energy, Inc. (NCE) merged and formed Xcel Energy, Inc. Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. Cash was paid in lieu of any fractional shares of Xcel Energy common stock. The merger was structured as a tax-free, stock-for-stock exchange for shareholders of both companies (except for fractional shares) and accounted for as a pooling-of-interests. At the time of the merger, Xcel Energy registered as a holding company under the PUHCA.

Pursuant to the merger agreement, NCE was merged with and into NSP. NSP, as the surviving legal corporation, changed its name to Xcel Energy. Also, as part of the merger, NSP transferred its existing utility operations that were being conducted directly by NSP at the parent company level to a newly formed wholly owned subsidiary of Xcel Energy, which was renamed NSP-Minnesota.

Consistent with pooling accounting requirements, results and disclosures for all periods prior to the merger have been restated for consistent reporting with post-merger organization and operations.

Business and System of Accounts — NSP-Wisconsin was incorporated in 1901 under the laws of Wisconsin. NSP-Wisconsin, a wholly owned subsidiary of Xcel Energy, is an operating utility engaged in the generation, transmission and distribution of electricity to approximately 230,000 retail customers in northwestern Wisconsin and in the western portion of the Upper Peninsula of Michigan. NSP-Wisconsin is also engaged in the distribution and sale of natural gas in the same service territory to approximately 90,000 customers in Wisconsin and Michigan.

NSP-Wisconsin owns the following direct subsidiaries: Chippewa and Flambeau Improvement Company, which operates hydro reserves; Clearwater Investments Inc., which owns interests in affordable housing; and NSP Lands, Inc., which holds real estate.

NSP-Wisconsin is subject to regulation by the Federal Energy Regulatory Commission (FERC), the Public Service Commission of Wisconsin (PSCW), and the Michigan Public Service Commission (MPSC). All of the utility companies' accounting records conform to the FERC uniform system of accounts or to systems required by state regulatory commissions, which are the same in all material aspects.

Basis of accounting – The accompanying financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). As required by the FERC, NSP-Wisconsin accounts for its investment in majority-owned subsidiaries using the equity method rather than by consolidating their assets, liabilities, revenues, and expenses as required by GAAP. Deferred taxes are shown as long term assets and liabilities at their gross amounts in the FERC presentation, as opposed to their GAAP presentation as net current assets and liabilities. If GAAP were followed, these 2002 financial statement lines would have greater/smaller values of:

Net utility plant	$ 2,147,000
Current assets	(285,000)
Current liabilities	46,918,000
Other long-term assets	(6,939,000)
Long-term debt and other long-term liabilities	(63,957,000)
Operating revenues	(213,000)
Operating expenses	(36,023,000)
Other income and deductions	1,854,000
Cash provided by operating activities	9,767,000
Cash provided by investing activities	(12,974,000)

Cash provided by financing activities..... 3,209,000

Principles of Consolidation — NSP-Wisconsin uses the equity method of accounting for its investments in subsidiaries and records its portion of earnings from such investments after subtracting income taxes. Chippewa and Flambeau Improvement Company is 75.86 percent owned; NSP Lands, Inc. is 100 percent owned; and Clearwater Investments, Inc. is 100 percent owned. The impact of consolidating these subsidiaries would be immaterial.

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based of the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated.

NSP-Wisconsin has various rate adjustment mechanisms in place that currently provide for the recovery of certain purchased natural gas and electric energy costs. These cost adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred.

NSP-Wisconsin's rates include a cost-of-energy adjustment clause for purchased natural gas, but not for purchased electricity or electric fuel. NSP-Wisconsin can request recovery of those electric costs prospectively through the rate review process, which normally occurs every two years, and an interim fuel-cost hearing process.

Property, Plant, Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and applicable interest expense. The cost of plant retired, plus net removal cost is charged to accumulated depreciation and amortization. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance are charged to expense as incurred. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses.

NSP-Wisconsin determines the depreciation of their plant by using the straight-line method, which spreads the original cost equally over the plant's useful life. Depreciation expense for NSP-Wisconsin, expressed as a percentage of average depreciable property, for the years ended December 31, is listed in the following table:

	2002	2001
NSP-Wisconsin	3.3%	3.1%

Allowance for Funds Used During Construction (AFDC) and Capitalized Interest — AFDC, a noncash item, represents the cost of capital used to finance utility construction activity. AFDC is computed by applying a composite pretax rate to qualified construction work in progress. The amount of AFDC capitalized as a utility construction cost is credited to other income and deductions (for equity capital) and interest charges (for debt capital). AFDC amounts capitalized are included in NSP-Wisconsin's rate base for establishing utility service rates. Interest capitalized as AFDC for NSP-Wisconsin is listed in the following table:

	2002	2001
	(Millions of dollars)	
NSP-Wisconsin	$ 0.4	$ 1.1

Environmental Costs — We record environmental costs when it is probable we are liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset based on our expectation that we will recover these costs from customers in future rates. Otherwise, we expense the costs. If an environmental expense is related to facilities we currently use, such as pollution-control equipment, we capitalize and depreciate the costs over the life of the plant, assuming the costs are recoverable in future rates or future cash flow.

We record estimated remediation costs, excluding inflationary increases and possible reductions for insurance coverage and rate recovery. The estimates are based on our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, we estimate and record only our share of the cost. We treat any future costs of restoring sites where operation may extend indefinitely as a capitalized cost of plant retirement. The depreciation expense levels we can recover in rates include a provision for these estimated removal costs.

Income Taxes — NSP-Wisconsin files consolidated federal (as part of Xcel Energy) and separate state income tax returns. Income taxes from the consolidated federal return are allocated to NSP-Wisconsin based on separate company computations of taxable income or loss. In accordance with the PUHCA requirements, the holding company also allocates its own net income tax benefits to its direct subsidiaries, with NSP-Wisconsin being one of the direct subsidiaries, based on the positive taxable income of each company in the consolidated federal or combined state returns. NSP-Wisconsin defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. We use the tax rates that are scheduled to be in effect when the temporary differences are expected to turn around, or reverse.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, we account for the reversal of some temporary differences as current income tax expense. We defer investment tax credits and spread their benefits over the estimated lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes. For more information on income taxes, see Note 5 to the Financial Statements.

Derivative Financial Instruments — On Jan. 1, 2001, NSP-Wisconsin adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activity," as amended by SFAS No. 137 and SFAS No. 138 (collectively referred to as SFAS No. 133). For more information on the impact of SFAS No. 133, see Notes 7 and 8 to the Financial Statements.

Use of Estimates — In recording transactions and balances resulting from business operations, NSP-Wisconsin uses estimates based on the best information available. We use estimates for such items as plant depreciable lives, tax provisions, uncollectible amounts, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we get better information or when we can determine actual amounts. Those revisions can affect operating results. Each year we also review the depreciable lives of certain plant assets and revise them, if appropriate.

Cash Items — NSP-Wisconsin considers investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. Excess funds are invested primarily in money market funds. NSP-Wisconsin had $0 of temporary cash investments at Dec. 31, 2002 and 2001.

Inventory — All inventories are recorded at average cost.

Regulatory Accounting — NSP-Wisconsin accounts for certain income and expense items using SFAS No. 71. Under SFAS No. 71:

- we defer certain costs, which would otherwise be charged to expense, as regulatory assets based on our expected ability to recover them in future rates; and
- we defer certain credits, which would otherwise be reflected as income, as regulatory liabilities based on our expectation they will be returned to customers in future rates.

We base our estimates of recovering deferred costs and returning deferred credits on specific ratemaking decisions or precedent for each item. We amortize regulatory assets and liabilities consistent with the period of expected regulatory treatment. Pages 232 and 278 describe in more detail the nature and amounts of these regulatory deferrals.

Intangible Assets and Deferred Financing Costs — Effective Jan. 1, 2002, NSP-Wisconsin implemented SFAS No. 142, "Goodwill and Other Intangible Assets," which requires different accounting for intangible assets as compared to goodwill. Intangible assets are amortized over their economic useful life and reviewed for impairment in accordance with SFAS No. 121, "Accounting for

the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of." Goodwill is no longer amortized after adoption of SFAS No. 142. Non-amortized intangible assets and goodwill are tested for impairment annually and on an interim basis if an event or circumstance occurs between annual tests that might reduce the fair value of that asset.

NSP-Wisconsin has an immaterial amount of unamortized intangible assets and no amounts of goodwill as of Dec. 31, 2002 and 2001.

Other assets include deferred financing costs, which we are amortizing over the remaining maturity periods of the related debt. NSP-Wisconsin's deferred financing costs, net of amortization at Dec. 31, is listed in the following table:

	2002	2001
	(Millions of dollars)	
NSP-Wisconsin	$ 1.7	$ 1.9

2. Special Charges

2002 and 2001 — Restaffing — During the fourth quarter of 2001, Xcel Energy expensed pretax special charges of $39 million for expected staff consolidation costs for an estimated 500 employees in several utility operating and corporate support areas of Xcel Energy. Approximately $36 million of these restaffing costs were allocated to Xcel Energy's utility subsidiaries consistent with service company cost allocation methodologies utilized under the requirements of the PUHCA. In the first quarter of 2002, the identification of affected employees was completed and additional pretax special charges of $9 million were expensed for the final costs of staff consolidations. Approximately $6 million of these restaffing costs were allocated to Xcel Energy's utility subsidiaries. All 564 of accrued staff terminations have occurred. See the summary of costs for NSP-Wisconsin below.

2000 — Merger Costs — Upon consummation of the merger in 2000, Xcel Energy expensed pretax special charges related to its regulated operations totaling $199 million. During 2000, an allocation of approximately $188 million of merger costs was made to Xcel Energy's utility subsidiaries consistent with prior regulatory filings, in proportion to expected merger savings by the Company and consistent with service company cost allocation methodologies utilized under the requirements of the PUHCA. These costs are reported on the accompanying consolidated financial statements as special charges.

Of the total pretax special charges recorded by Xcel Energy that related to its regulated operations, $159 million was recorded during the third quarter of 2000 and $40 million was recorded during the fourth quarter of 2000. See Note 13 to the Financial Statements for the quarterly impacts on NSP-Wisconsin.

The total pretax charges included $52 million related to one-time transaction related costs incurred in connection with the merger of NSP and NCE. These transaction costs included investment banker fees, legal and regulatory approval costs, and expenses for support of and assistance with planning and completing the merger transaction.

Also included in the total were $147 million of pretax charges pertaining to incremental costs of transition and integration activities associated with merging operations. These transition costs included approximately $77 million for severance and related expenses associated with staff reductions. All 721 of accrued staff terminations have occurred. The staff reductions were non-bargaining positions mainly in corporate and operations support areas. Other transition and integration costs included amounts incurred for facility consolidation, systems integration, regulatory transition, merger communications and operations integration assistance.

Accrued Special Charges — The following table summarizes activity related to accrued special charges in 2002 and 2001:

Dec. 31, 2000 Liability*	Expensed 2001	Payments 2001	Dec. 31, 2001 Liability*	Expensed 2002	Payments 2002	Dec. 31, 2002 Liability*

				(Millions of dollars)			
NSP-Wisconsin	3	2	(3)	2	1	(3)	—

* Reported on the balance sheets in other current liabilities.

3. Short-Term Borrowings

NSP-Wisconsin has an intercompany borrowing arrangement with NSP-Minnesota, with interest charged at NSP-Minnesota's short-term borrowing rate. At Dec. 31, 2002 and 2001, NSP-Wisconsin had $6.9 million and $34.3 million, respectively, in short-term borrowings. The weighted average interest rate for NSP-Wisconsin was 4.40 percent at Dec. 31, 2002 and 2.16 percent at Dec. 31, 2001.

4. Long-Term Debt

All property of NSP-Wisconsin is subject to the liens of its first mortgage indentures, which are contracts between the companies and their bondholders.

The annual sinking-fund requirements of first mortgage indentures are the amounts necessary to redeem 1 percent of the highest principal amount of each series of first mortgage bonds at any time outstanding, excluding resource recovery financing. NSP-Wisconsin expects to satisfy substantially all of its sinking fund obligations in accordance with the terms of their respective indentures through the application of property additions.

Maturities and sinking fund requirements for long-term debt for NSP-Wisconsin is listed in the following table:

	NSP-Wisconsin (Millions of dollars)
2003	$ 41
2004	1
2005	1
2006	1
2007	1

5. Income Taxes

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The reasons for the difference are:

	2002	2001
Federal statutory rate	35.0%	35.0%
Increases (decreases) in tax from:		
State income taxes, net of federal income tax benefit	5.7%	4.4%
Life insurance policies	(0.1)%	—
Tax credits recognized	(0.9)%	(1.4)%
Equity income from unconsolidated affiliates	(0.1)%	(0.4)%
Regulatory differences — utility plant items	0.6%	(1.1)%

Non-deductibility of merger costs	—	—
Other — net	0.2%	0.3%
Effective income tax rate	40.4%	36.8%

Income taxes comprise the following expense (benefit) items (Thousands of dollars):

	2002	2001
Current federal tax expense	$ 13,143	$ 15,691
Current state tax expense	2,907	3,237
Deferred federal tax expense	16,569	2,462
Deferred state tax expense	5,113	587
Deferred investment tax credits	(807)	(819)
Total income tax expense	$ 36,925	$ 21,158

The components of net deferred tax liability (current and noncurrent portions) at Dec. 31 were:

	2002	2001
	(Thousands of dollars)	
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 148,612	$ 121,023
Regulatory assets	17,436	11,117
Deferred investment tax credits	(6,018)	(6,284)
Other	6,051	3,722
Total deferred tax liabilities	$ 166,081	$ 129,578
Deferred tax assets:		
Differences between book and tax bases of property	$ 16,568	$ 7,984
Regulatory liabilities	732	411
Employee benefits and other accrued liabilities	(1,241)	(1,710)
Other	698	624
Total deferred tax assets	$ 16,757	$ 7,309
Net deferred tax liability	$ 149,324	$ 122,269

6. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its benefit employees, including those of NSP-Wisconsin. NSP-Wisconsin had 419 union employees , or approximately 70 percent of total benefit employees, covered under a collective bargaining agreement which expires at the end of 2004.

Pension Benefits — Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all utility employees, including those of NSP-Wisconsin. Benefits are based on a combination of years of service, the employee's average pay and Social Security benefits.

Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws. Plan assets principally consist of the common stock of public companies, corporate bonds and U.S. government securities.

A comparison of the actuarially computed pension benefit obligation and plan assets for Xcel Energy plans which benefit utility subsidiary employees, including those of NSP-Wisconsin, on a combined basis, is presented in the following table:

	2002	2001

	(Thousands of dollars)	
Change in Benefit Obligation		
Obligation at January 1	$ 2,409,186	$ 2,254,138
Service cost	65,649	57,521
Interest cost	172,377	172,159
Acquisitions	7,848	—
Plan amendments	3,903	2,284
Actuarial loss	65,763	108,754
Settlements	(994)	—
Special termination benefits	4,445	—
Benefit payments	(222,601)	(185,670)
Obligation at December 31	$ 2,505,576	$ 2,409,186
Change in Fair Value of Plan Assets		
Fair value of plan assets at January 1	$ 3,267,586	$ 3,689,157
Actual return on plan assets	(404,940)	(235,901)
Employer contributions — acquisitions	912	—
Settlements	(994)	—
Benefit payments	(222,601)	(185,670)
Fair value of plan assets at December 31	$ 2,639,963	$ 3,267,586
Funded Status of Plans at December 31		
Net asset	$ 134,387	$ 858,400
Unrecognized transition asset	(2,003)	(9,317)
Unrecognized prior service cost	224,651	242,313
Unrecognized (gain) loss	165,927	(712,571)
Xcel Energy net pension amounts recognized on balance sheet	$ 522,962	$ 378,825
NSP-Wisconsin prepaid pension asset recorded	38,557	28,563
Significant Assumptions		
Discount rate for year end valuation	6.75%	7.25%
Expected average long term increase in compensation level	4.00%	4.50%
Expected average long term rate of return on assets	9.50%	9.50%

The components of net periodic pension cost (credit) for Xcel Energy plans which benefit employees of its utility subsidiaries, including those of NSP-Wisconsin, are:

Xcel Energy	2002	2001
	(Thousands of dollars)	
Service cost	$ 65,649	$ 57,521
Interest cost	172,377	172,159
Expected return on plan assets	(339,932)	(325,635)
Curtailment	—	1,121
Amortization of transition asset	(7,314)	(7,314)
Amortization of prior service cost	22,663	20,835
Amortization of net gain	(69,264)	(72,413)
Net periodic pension credit under SFAS No. 87	$ (155,821)	$ (153,726)
NSP-Wisconsin		
Net SFAS No. 87 benefit credit recognized for reporting	$ (9,994)	$ (10,002)

Xcel Energy also maintains noncontributory defined benefit supplemental retirement income plans for certain qualifying executive

personnel. Benefits for these unfunded plans are paid out of Xcel Energy's operating cash flows.

Defined Contribution Plans — Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees, including those of NSP-Wisconsin. Total contributions to these plans, which benefit employees of the utility subsidiaries, were approximately $19 million in 2002 and $23 million in 2001. The total contribution for 2002 included $0.7 million for NSP-Wisconsin.

Until May 6, 2002 Xcel Energy had a leveraged employee stock ownership plan (ESOP) that covered substantially all employees of NSP-Minnesota and NSP-Wisconsin. Xcel Energy made contributions to this noncontributory, defined contribution plan to the extent it realized tax savings from dividends paid on certain ESOP shares. ESOP contributions had no material effect on Xcel Energy earnings because the tax savings provided by the dividends paid on ESOP shares essentially offset the contributions. Xcel Energy allocated leveraged ESOP shares to participants when it repaid ESOP loans with dividends on stock held by the ESOP.

In May 2002 the ESOP was merged into the Xcel Retirement Savings 401(k) Plan. Starting with the 2003 plan year, the ESOP component of the 401(k) will no longer be leveraged.

Xcel Energy's leveraged ESOP held no shares of Xcel Energy common stock at the end of 2002, 10.7 million shares of Xcel Energy common stock at May 6, 2002, 10.5 million shares of Xcel Energy common stock at the end of 2001, and 12.0 million shares of Xcel Energy common stock at the end of 2000. Xcel Energy excluded the following average number of uncommitted leveraged ESOP shares from earnings per share calculations: 0.7 million in 2002, 0.9 million in 2001, and 0.7 million in 2000. On Nov. 19, 2002, Xcel Energy paid off all of the ESOP loans. All uncommitted ESOP shares were released and will be used by Xcel Energy for its employer matching contribution to its 401(k) plan.

Postretirement Health Care Benefits — Xcel Energy has contributory health and welfare benefit plans that provide health care and death benefits to most Xcel Energy retirees, including those of NSP-Wisconsin. The former NSP discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees of NSP-Minnesota and NSP-Wisconsin who retired after 1999. However, employees of the former NCE who retired in 2002 continue to receive employer subsidized health care benefits. Employees of the former NSP who retired after 1998 are eligible to participate in the Xcel Energy health care program with no employer subsidy.

In conjunction with the 1993 adoption of SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pension," Xcel Energy elected to amortize the unrecognized accumulated postretirement benefit obligation (APBO) on a straight-line basis over 20 years.

Regulatory agencies for nearly all of Xcel Energy's retail and wholesale utility customers have allowed rate recovery of accrued benefit costs under SFAS No. 106. Additionally, certain state agencies, which regulate Xcel Energy's utility subsidiaries, have also issued guidelines related to the funding of SFAS No. 106 costs. Wisconsin retail regulators required external funding of accrued SFAS No. 106 costs to the extent such funding is tax advantaged. Plan assets held in external funding trusts principally consist of investments in equity mutual funds, fixed-income securities and cash equivalents.

A comparison of the actuarially computed benefit obligation and plan assets for Xcel Energy postretirement health care plans that benefit employees of its utility subsidiaries, including those of NSP-Wisconsin, is presented in the following table:

	2002	2001
	(Thousands of dollars)	
Change in Benefit Obligation		
Obligation at January 1	$ 662,853	$ 558,994
Service cost	5,967	5,258
Interest cost	48,304	45,177
Acquisitions	773	—
Plan amendments	—	—
Plan participants' contributions	5,755	3,517

Actuarial loss	57,175	98,655
Special termination benefits	(173)	—
Benefit payments	(44,263)	(48,748)
Obligation at December 31	$ 736,391	$ 662,853
Change in Fair Value of Plan Assets		
Fair value of plan assets at January 1	$ 242,803	$ 223,266
Actual return on plan assets	(13,632)	(3,701)
Plan participants' contributions	5,755	3,517
Employer contributions	60,320	68,469
Benefit payments	(44,263)	(48,748)
Fair value of plan assets at December 31	$ 250,983	$ 242,803
Funded Status of Plan at December 31		
Net obligation	$ 485,408	$ 420,050
Unrecognized transition asset (obligation)	(169,328)	(186,099)
Unrecognized prior service cost	10,675	12,559
Unrecognized gain (loss)	(200,634)	(132,354)
Total accrued benefit liability recorded	$ 126,121	$ 114,156
NSP-Wisconsin accrued benefit liability recorded	$ 4,899	$ 5,052
Significant Assumptions		
Discount rate for year end valuation	6.75%	7.25%
Expected average long term rate of return on assets	8.0 - 9.0%	9.0%

The assumed health care cost trend rate for 2002 is approximately 8 percent, decreasing gradually to 5.5 percent in 2007 and remaining level thereafter. A 1 percent change in the assumed health care cost trend rate would have the following effects:

	Xcel Energy	NSP-Wisconsin
	(Thousands of dollars)	
Effect of changes in the assumed health care cost trend rate		
1 percent increase in APBO components at Dec. 31, 2002	$ 79,028	$ 2,181
1 percent decrease in APBO components at Dec. 31, 2002	(65,755)	(1,889)
1 percent increase in service and interest components of the net periodic cost	6,285	142
1 percent decrease in service and interest components of the net periodic cost	(5,181)	(124)

The components of net periodic postretirement benefit cost of Xcel Energy's plans are:

	2002	2001
	(Thousands of dollars)	
Xcel Energy		
Service cost	$ 5,967	$ 6,160
Interest cost	48,304	46,579
Expected return on plan assets	(21,011)	(18,920)
Amortization of transition obligation	16,771	16,771
Amortization of prior service credit	(1,130)	(1,235)
Amortization of net loss	5,380	1,457
Net periodic postretirement benefit cost under SFAS		

No. 106	54,281	50,812
Additional cost recognized due to effects of regulation	4,043	3,738
Net cost recognized for financial reporting	$ 58,324	$ 54,550
NSP-Wisconsin		
Net periodic postretirement benefit cost recognized — SFAS No. 106	$ 1,531	$ 1,155

7. Financial Instruments

Fair Values

The estimated December 31 fair values of NSP-Wisconsin's recorded financial instruments are as follows:

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Thousands of dollars)			
Long-term investments	$ 10	$ 10	$ 9	$ 9
Long-term debt, including current portion	313,142	320,884	313,088	317,490

The carrying amount of cash, cash equivalents, short-term investments and other financial instruments approximates fair value because of the short maturity of those instruments. The fair value of NSP-Wisconsin's long-term debt is estimated based on the quoted market prices for the same or similar issues, or the current rates for debt of the same remaining maturities and credit quality.

The fair value estimates presented are based on information available to management as of Dec. 31, 2002 and 2001. These fair value estimates have not been comprehensively revalued for purposes of these financial statements since that date and current estimates of fair values may differ significantly from the amounts presented herein.

Guarantees

NSP-Wisconsin had the following guarantees outstanding on Dec. 31, 2002:

Guarantor	**NSP-Wisconsin**
Guarantee amount	$1.4 million
Exposure under guarantee	$0.1 million
Nature of guarantee	NSP-Wisconsin guarantees customer loans to encourage business growth and expansion.
Term of guarantee	Latest expiration in 2006.
Triggering events or circumstances requiring performance under the guarantee	Non-timely payment of the obligations or at the time the Debtor becomes the subject of bankruptcy or other insolvency proceedings.
Current carrying amount of the liability	n/a
Nature of any recourse	

provisions	None
Any assets held as collateral	None

8. Derivative Valuation and Financial Impacts

Use of Derivatives to Manage Risk

Business and Operational Risk — NSP-Wisconsin is exposed to commodity price risk in its generation and retail distribution operations. NSP-Wisconsin generally recovers natural gas costs in its jurisdictions on a dollar-for-dollar basis. NSP-Wisconsin has limited exposure to market price risk for the purchase of electric energy.

Interest Rate Risk — With the exception of short-term borrowings, NSP-Wisconsin does not have variable interest rates; therefore there is limited interest rate risk.

Derivatives as Hedges

2001 Accounting Change — On Jan. 1, 2001, Xcel Energy and its utility subsidiaries adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." This statement requires that all derivative instruments as defined by SFAS No. 133 be recorded on the balance sheet at fair value unless exempted. Changes in a derivative instrument's fair value must be recognized currently in earnings unless the derivative has been designated in a qualifying hedging relationship. The application of hedge accounting allows a derivative instrument's gains and losses to offset related results of the hedged item in the income statement, to the extent effective. SFAS No. 133 requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship to apply hedge accounting.

A fair value hedge requires that the effective portion of the change in the fair value of a derivative instrument be offset against the change in the fair value of the underlying asset, liability, or firm commitment being hedged. That is, fair value hedge accounting allows the gain or loss on the hedged item to offset the gain or loss on the derivative instrument in the same period. A cash flow hedge requires that the effective portion of the change in the fair value of a derivative instrument be recognized in Other Comprehensive Income, and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. The ineffective portion of a derivative instrument's change in fair value is recognized currently in earnings.

Xcel Energy's utility subsidiaries formally document hedge relationships, including, among other things, the identification of the hedging instrument and the hedged transaction, as well as the risk management objectives and strategies for undertaking the hedged transaction. Derivatives are recorded in the balance sheet at fair value. Xcel Energy's utility subsidiaries also formally assess, both at inception and at least quarterly thereafter, whether the derivative instruments being used are highly effective in offsetting changes in either the fair value or cash flows of the hedged items.

Financial Impacts of Derivatives

SFAS No. 133 had no impact on Other Comprehensive Income for 2002 and 2001, included in Stockholder's Equity, for NSP-Wisconsin.

9. Commitments and Contingent Liabilities

Leases — NSP-Wisconsin leases a variety of equipment and facilities used in the normal course of business. The leases are primarily for trucks, cars and power-operated equipment and are accounted for as operating leases. The amounts paid under operating leases during 2002 NSP-Wisconsin are listed in the following table:

Rental expense under operating leases was:

	2002	2001
	(Millions of dollars)	
NSP-Wisconsin	4.8	4.7

Future commitments under operating leases are:

	2003	2004	2005	2006	2007
	(Millions of dollars)				
NSP-Wisconsin	3.7	3.7	3.7	3.7	3.7

Nuclear Insurance — Although NSP-Wisconsin does not own a nuclear facility, any assessment made against NSP-Minnesota under the Price-Anderson liability provisions of the Atomic Energy Act of 1954 would be a cost included under the Interchange Agreement (see note 12) and NSP-Wisconsin would be charged its proportion of the assessment. NSP-Minnesota'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. NSP-Minnesota 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 case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $88 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.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $1.5 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $7.5 million for business interruption insurance and $21.6 million for property damage insurance if losses exceed accumulated reserve funds.

Fuel Contracts — The utility subsidiaries of Xcel Energy have contracts providing for the purchase and delivery of a significant portion of their current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2003 and 2025. In addition, the utility subsidiaries of Xcel Energy are required to pay additional amounts depending on actual quantities shipped under these agreements. The potential risk of loss for the utility subsidiaries of Xcel Energy, 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 most fuel costs.

The minimum purchase for NSP-Minnesota and NSP-Wisconsin are as follows:

	Coal	Nuclear Fuel	Natural Gas	Gas Storage & Transportation
	(Millions of dollars)			
NSP-Minnesota and NSP-Wisconsin (combined)	$ 219	$ 122	$ 284	$ 268

Purchased Power Agreements — NSP-Minnesota has entered into agreements with utilities and other energy suppliers for

purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. NSP-Minnesota has various pay-for-performance contracts with expiration dates through the year 2050. In general, these contracts provide for capacity payments, subject to meeting certain contract obligations and energy payments based on actual power taken under the contracts. Most of the capacity and energy costs are recovered through base rates and other cost recovery mechanisms.

NSP-Minnesota has a 500-megawatt participation power purchase commitment with the Manitoba Hydro Electric Board, which expires in April 2005. The current cost of this agreement is based on 80 percent of the costs of owning and operating NSP-Minnesota's Sherco 3 generating plant, adjusted to 1993 dollars. This agreement was extended during 2002 to include the period starting May 2005 through April 2015. The cost of the agreement for this extended period is based on a base price, which was established from May 2001 through April 2002 and will be escalated by the change in the United States Gross National Product to reflect the current year. In addition, NSP-Minnesota and Manitoba Hydro have seasonal diversity exchange agreements, and there are no capacity payments for the diversity exchanges. These commitments represent about 17 percent of Manitoba Hydro's system capacity and account for approximately 9 percent of NSP- Minnesota's 2002 electric system capability. The risk of loss from nonperformance by Manitoba Hydro is not considered significant, and the risk of loss from market price changes is mitigated through cost-of-energy rate adjustments.

At Dec. 31, 2002, the estimated future payments for capacity that NSP-Minnesota is obligated to purchase, subject to availability, are as follows (Thousands of dollars):

	NSP-Minnesota*
2003	$ 133,688
2004	129,578
2005	108,828
2006	108,129
2007 and thereafter	1,442,140
Total	$ 1,922,363

* Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Environmental Contingencies

We are subject to regulations covering air and water quality, the storage of natural gas and the storage and disposal of hazardous or toxic wastes. We continuously assess our compliance. Regulations, interpretations and enforcement policies can change, which may impact the cost of building and operating our facilities.

Site Remediation — We must pay all or a portion of the cost to remediate sites where past activities of our subsidiaries and some other parties have caused environmental contamination. At Dec. 31, 2002 there were two categories of sites for NSP-Wisconsin:

- third party sites, such as landfills, to which we are alleged to be a potentially responsible party (PRP) that sent hazardous materials and wastes, and
- sites of former manufactured gas plants (MGP's) operated by our subsidiaries or predecessors.

We record a liability when we have enough information to develop an estimate of the cost of remediating a site and revise the estimate as information is received. The estimated remediation cost may vary materially.

To estimate the cost to remediate these sites, we may have to make assumptions where facts are not fully known. For instance, we might make assumptions about the nature and extent of site contamination, the extent of required cleanup efforts, costs of alternative cleanup methods and pollution control technologies, the period over which remediation will be performed and paid for, changes in environmental remediation and pollution control requirements, the potential effect of technological improvements, the number and financial strength of other PRPs and the identification of new environmental cleanup sites.

We revise our estimates as facts become known, but at Dec. 31, 2002 our estimated liability for the cost of remediating sites was:

	Total Liability	Current Portion of Liability
	(Millions of dollars)	
NSP-Wisconsin	23.1	2.0

Some of the cost of remediation may be recovered from:

- insurance coverage;
- other parties that have contributed to the contamination; and
- customers.

Neither the total remediation cost nor the final method of cost allocation among all PRPs of the unremediated sites has been determined. We have recorded estimates of our share of future costs for these sites. We are not aware of any other parties' inability to pay, nor do we know if responsibility for any of the sites is in dispute.

Asbestos Removal — Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Since we intend to operate most of these facilities indefinitely, we cannot estimate the amount or timing of payments for its final removal. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Ashland MGP Site — NSP-Wisconsin was named as one of three PRPs for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland site includes property owned by NSP-Wisconsin and two other properties: an adjacent city lakeshore park area and a small area of Lake Superior's Chequemegon Bay adjoining the park.

The Wisconsin Department of Natural Resources (WDNR) and NSP-Wisconsin have each developed several estimates of the ultimate cost to remediate the Ashland site. The estimates vary significantly, between $4 million and $93 million, because different methods of remediation and different results are assumed in each. The Environmental Protection Agency (EPA) and WDNR have not yet selected the method of remediation to use at the site. Until the EPA and the WDNR select a remediation strategy for all operable units at the site and determine the level of responsibility of each PRP, we are not able to accurately determine our share of the ultimate cost of remediating the Ashland site.

In the interim, NSP-Wisconsin has recorded a liability for an estimate of its share of the cost of remediating the portion of the Ashland site that it owns, estimated using information available to date and using reasonably effective remedial methods. NSP-Wisconsin has deferred, as a regulatory asset, the remediation costs accrued for the Ashland site because we expect that the Public Service Commission of Wisconsin (PSCW) will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site, and has authorized recovery of similar remediation costs for other Wisconsin utilities.

We proposed, and the EPA and WDNR have approved, an interim action (a coal tar removal/ groundwater treatment system) for one operable unit at the site for which NSP-Wisconsin has accepted responsibility. The groundwater treatment system began operating in the fall of 2000. In 2002 NSP-Wisconsin installed additional monitoring wells in the deep aquifer to better characterize the extent and degree of contaminants in that aquifer while the coal tar removal system is operational. In 2002 a second interim response action was also implemented. As approved by the WDNR, this interim response action involved the removal and capping of a seep area in a city park. Surface soils in the area of the seep were contaminated with tar residues. The interim action also included the diversion and ongoing treatment of groundwater that contributed to the formation of the seep.

On Sept. 5, 2002, the Ashland site was placed on the National Priorities List (NPL). The NPL is intended primarily to guide the EPA in determining which sites require further investigation. Resolution of Ashland remediation issues is not expected until 2004 or 2005.

NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to the ultimate remediation cost of the entire site.

Plant Emissions — NSP-Wisconsin's French Island plant generates electricity by burning a mixture of wood waste and refuse derived fuel. The fuel is derived from municipal solid waste furnished under a contract with La Crosse County, Wisconsin. In late 2000, the EPA reversed a prior decision and found that the plant was subject to the federal large combustor regulations. Those regulations became effective on Dec. 19, 2000. NSP-Wisconsin did not have adequate time to install the emission controls necessary to come into compliance with the large combustor regulations by the compliance date. As a result, in early 2001, the EPA issued a finding of violation to NSP-Wisconsin. NSP-Wisconsin is engaged in ongoing settlement discussions with the EPA regarding the finding of violation. In April 2001, a conservation group sent NSP-Wisconsin a notice of intent to sue under the citizen suit provisions of the Clean Air Act. NSP-Wisconsin could be fined up to $27,500 per day for each violation.

In July 2001, the state of Wisconsin filed a lawsuit against NSP-Wisconsin in the Wisconsin Circuit Court for La Crosse County, contending that NSP-Wisconsin exceeded dioxin emission limits on numerous occasions between July 1995 and December 2000 at French Island. In September 2002, the Court approved a settlement in the case requiring NSP-Wisconsin to pay penalties of $167,579 and contribute $300,000 in installments through 2005 to help fund a household hazardous waste project in the La Crosse area.

In August 2001, NSP-Wisconsin received a Certificate of Authority to install control equipment necessary to bring the French Island plant into compliance with both the federal large combustor regulations and state dioxin standard. NSP-Wisconsin began construction of the new air quality equipment in late 2001 and completed construction in 2002. NSP-Wisconsin has reached an agreement with La Crosse County through which La Crosse County will pay for the extra emissions equipment required to comply with the regulations.

Legal Contingencies

In the normal course of business, Xcel Energy's utility subsidiaries are party to routine claims and litigation arising from prior and current operations. Xcel Energy's utility subsidiaries are actively defending these matters and have recorded an estimate of the probable cost of settlement or other disposition.

NSP-Wisconsin is the defendant in suits claiming electricity and/or stray voltage from NSP-Wisconsin's system has harmed plaintiffs' dairy herds and caused other damage and injuries. Total damages claimed in these proceedings are approximately $17.5 million. The ultimate outcome of these claims is not determinable at this time, and NSP-Wisconsin has recorded an estimate of costs necessary to settle or otherwise resolve these matters.

10. Related Party Transactions

NSP-Wisconsin receives various administrative, management, environmental and other support services from Xcel Energy Services Inc., which began operations in August 2000. Prior to this, all of these support services resided in former NSP for NSP-Minnesota and NSP-Wisconsin and were allocated to the former NSP subsidiaries, as appropriate.

Viking Gas Transmission Co. (Viking), a subsidiary of Xcel Energy through 2002, transports gas purchased by NSP-Wisconsin from various suppliers. NSP Wisconsin purchased $1.6 million of transportation service from Viking during 2002.

The electric production and transmission costs of the entire NSP system are shared by NSP-Minnesota and NSP-Wisconsin. A FERC approved agreement (Interchange Agreement) between the two companies provides for the sharing of all costs of generation and

transmission facilities of the system, including capital costs. Billings under the Interchange Agreement, which are included in the Consolidated Statements of Income, are as follows:

	2002	2001
	(Thousands of dollars)	
NSP-Wisconsin		
Operating revenues:		
Electric	$ 80,200	$ 85,895
Operating expenses:		
Purchased and interchange power	205,174	218,534
Gas purchased for resale	95	244
Other operations*	50,449	46,371

* Other operations expense includes $36,695 and $28,816 paid to Xcel Energy Services Inc. in 2002 and 2001.

NSP-Wisconsin obtains short-term borrowings from NSP-Minnesota at NSP-Minnesota's average daily interest rate, including the cost of NSP-Minnesota's compensating balance requirements. Corresponding interest charges on NSP-Wisconsin's statement of income include $0.2 million and $0.4 million for 2002 and 2001.

NSP-Wisconsin's receivable from affiliates primarily represents amounts receivable from NSP-Minnesota for the Interchange Agreement. NSP-Wisconsin's notes payable to affiliates represents amounts payable to NSP-Minnesota.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b) (c) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceeding Year				
2	Preceding yr. Reclassification from Account 219 Net Income				
3	Preceding Year Changes in Fair Value	(959)			
4	Total (lines 2 and 3)	(959)			
5	Balance of Account 219 at End of Preceding Yr/Beginning of Current Yr	(959)			
6	Current Year Reclassification From Account 219 to Net Income				
7	Current Year Changes in Fair Value	(767)			
8	Total (lines 6 and 7)	(767)			
9	Balance of Account 219 at End of Current Year	(1,726)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges [Specify] (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 72) (i)	Total Comprehensive Income (j)
1					
2					
3			(959)		
4			(959)	36,392,485	36,391,526
5			(959)		
6					
7			(767)		
8			(767)	54,373,246	54,372,479
9			(1,726)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	03/27/2003	Dec. 31, 2002

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 projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm 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 firm service which meets the definition of RQ service. For all transaction 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 expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term 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 expect 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 for each adjustment.

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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Northern States Power Co (MN) 1					
2	Northern States Power Co (MN) 1	AD				
3						
4						
5						
6	All transactions involving Purchased					
7	Power and Sales to Other Utilities					
8	are included in and shared through the					
9	Interchange Areement with utility					
10	affiliate (NSP Minnesota)					
11						
12						
13						
14						
	Total					

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 monnthly (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 (l) include 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 column (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.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,530,052					161,662,787	161,662,787	1
					-336,271	-336,271	2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
5,530,052					161,326,516	161,326,516	

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: a

Total dollars and MWH's will not match page 321, line 76, due to differences in accounting classification associated with the NSP Minnesota and Wisconsin Company Interchange Agreement. (see Note 10 of Notes to the Financial Statements).

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 account. 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 theis 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) advances on open account, (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.

Item (a)	Amount (b)
ANALYSIS OF DONATIONS - ACCOUNT 426.1	
CIVIC ORGANIZATIONS	
GOGEBIC COUNTY ECONOMIC DEVELOPMENT	2,000
CADOTT SPEC BUILDING	14,490
IRON COUNTY DEVELOPMENT	2,000
CHIPPEWA COUNTY ECONOMIC DEVELOPMENT	2,000
CLARK COUNTY ECONOMIC DEVELOPMENT	2,000
VILLAGE OF OSCEOLA	5,000
CITY OF LADYSMITH	5,000
WESTERN DAIRYLAND FRESH START	3,000
CHIPPEWA FALLS MAIN STREET	4,500
WEDA	2,500
DUNN COUNTY ECONOMIC DEVELOPMENT	3,000
ST CROIX ECONOMIC DEVELOPMENT	2,500
RIVER COUNTY RC&D CNCLCOMMUNITY GRANT	2,250
MISCELLANEOUS	20,994
SUBTOTAL 426.1 - CIVIC	71,234
CULTURAL ORGANIZATIONS	
MISCELLANEOUS	5,900
SUBTOTAL 426.1 - CULTURAL	5,900
EDUCATION, COLLEGES, HIGH SCHOOLS	
UNIVERSITY OF WISCONSIN-EXTENS	5,000
WISCONSIN PUBLIC UTILITY INST	6,500
BAYFIELD COUNTY EDC	2,000
STOUT UNIVERSITY FOUNDATION IN	2,000
UNIVERSITY OF WISCONSIN-EXTENS	5,000
UNIVERSITY OF WISCONSIN-STOUT	4,000
UNIVERSITY OF WISCONSIN-MULTI-YEAR SCHOLORSHIP	10,000
MUELLER COMMUNICATIONS-ENERGY	6,000
ENERGY SYMPOSIUM	3,000
MISCELLANEOUS	6,800
SUBTOTAL 426.1 - EDUCATION, COLLEGES, HIGH SCHOOLS	50,300

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 account. 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.

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(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) advances on open account, (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.

Item (a)	Amount (b)
HOSPITAL AND MEDICAL RESEARCH PROGRAMS	
MISCELLANEOUS	1,300
SUBTOTAL 426.1-HOSPITAL AND MEDICAL RESEARCH	1,300
YOUTH ORGANIZATIONS AND ACTIVITIES, FRATERNAL AND BUSINESS ORGANIZATIONS, CHAMBER OF COMMERCE, LOCAL CELEBRATIONS AND VETERANS ORGANIZATIONS	
CITY OF BAYFIELD	2,500
OSCEOLA COMMUNITY HEALTH FNDTN	7,000
EAU CLAIRE AREA CHAMBER OF COM	2,500
WISCONSIN CHAMBER OF COMMERCE	6,000
BOOK ACROSS THE BAY INC	2,500
LAKE SUPERIOR BIG TOP CHAUTAUQ	5,000
FRIENDS OF BEAVER CREEK	2,000
MISCELLANEOUS	15,527
SUBTOTAL 426.1 - ORGANIZATIONS	43,027
COMMUNITY WELFARE ORGANIZATIONS	
SALVATION ARMY	6,000
UWF-BADGER FUND	2,500
GOLDSTEIN'S	2,267
MISCELLANEOUS	9,500
SUBTOTAL 426.1 - COMMUNITY WELFARE	20,267
MISCELLANEOUS	
XCEL FOUNDATION DONATIONS	243,538
TOTAL 426.1	435,566
LIFE INSURANCE - ACCOUNT 426.2	
WEALTH OPTION AND OFFICER SURVIVOR BENEFITS	188,650
TOTAL 426.2	188,650
PENALTIES - ACCOUNT 426.3	
WDNR PENALTY FOR FRENCH ISLAND STEAM PLANT	250,800
TOTAL 426.3	250,800

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 account. 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) advances on open account, (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.

Item (a)	Amount (b)
INC DED - CIVIC, POLITICAL AND RELATED - ACCOUNT 426.4	
GEORGE CARR PROFESSIONAL SERVICES	1,212
EISENHOWER CENTER BUILDING FUND	10,000
ELECTRIC UTILITY ASSOCIATION	1,899
FRANKIN & ASSOCIATES	71,898
HAMILTON CONSULTING GROUP	20,263
HOUGH, FASSBENDER, OSBORNE AND ASSOCIATES	40,548
LEGISLATIVE DAY	5,607
NSP(W) INTERNAL CHARGES	6,682
XCEL CHARGES	69,071
WISCONSIN UTILITY ASSOCIATION	447
TOTAL 426.4	227,627
INCOME DEDUCTIONS-MISCELLANEOUS-ACCOUNT 426.5	
SERVICE CLUB DUES	30,788
DEFAULTED ECONOMIC DEVELOPMENT LOANS AND/OR GUARANTEES	600,383
XCEL CHARGES	19,526
NSP(W) INTERNAL CHARGES	(597)
TOTAL 426.5	650,100
INTEREST ON DEBT TO ASSOCIATED COMPANY - ACCOUNT 430	
SHORT-TERM LOAN FROM NSP-MN	129,853
SHORT-TERM LOAN FROM XCEL ENERGY SERVICES	32,898
TOTAL 430	162,751
OTHER INTEREST EXPENSE - ACCOUNT 431	
INTEREST ON CUSTOMER DEPOSITS	49,194
MISCELLANEOUS	13,245
TOTAL 431	62,439