

THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No.



FERC FINANCIAL REPORT FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)

Northern States Power Company (Minnesota)

Year/Period of Report

End of: 2023/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

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, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

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

- Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at <https://eCollection.ferc.gov>, and according to the specifications in the Form 1 and 3-Q taxonomies.
- The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.
- Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426
- For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

- Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
- Be 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 C.F.R. §§ 41.10-41.12 for specific qualifications.)

- 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 and 3.
- 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).
- 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.
- For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.
- Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.
- Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

<u>Schedules</u>	<u>Pages</u>
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

- e. The following format must be used for the CPA Certification Statement 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 [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF 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." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

- f. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at <https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online>.
- g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from <https://www.ferc.gov/general-information-0/electric-industry-forms>.

IV. When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

- FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
- FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 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. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); 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 any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

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

EXCERPTS FROM THE LAW

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

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

- 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
- 'Person' means an individual or a corporation;
- '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;
- '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 and the business of developing, transmitting, unitizing, or distributing power;
- "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 fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from 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

- "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.

- Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*. 10

GENERAL INSTRUCTIONS

- I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.
- 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 period, and use for statement of income accounts the current year's year to date amounts.
- III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

FERC FORM NO. 1 (ED. 03-07)

"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 FERC Form or FERC 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

The Commission may assess up to \$1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

**FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER**

IDENTIFICATION

01 Exact Legal Name of Respondent Northern States Power Company (Minnesota)		02 Year/ Period of Report End of: 2023/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 414 Nicollet Mall, Minneapolis, MN 55401		
05 Name of Contact Person Brian J. Van Abel		06 Title of Contact Person Executive Vice President, Chief Financial Officer
07 Address of Contact Person (Street, City, State, Zip Code) 414 Nicollet Mall, Minneapolis, MN 55401		
08 Telephone of Contact Person, Including Area Code 612-330-6747	09 This Report is An Original / A Resubmission (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 04/04/2024

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Brian J. Van Abel	03 Signature Brian J. Van Abel	04 Date Signed (Mo, Da, Yr) 04/04/2024
02 Title Executive Vice President, Chief Financial Officer		

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.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	N/A

18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	N/A
25	Unrecovered Plant and Regulatory Study Costs	230b	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	N/A
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	

45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
64	Hydroelectric Generating Plant Statistics	406	
65	Pumped Storage Generating Plant Statistics	408	N/A
66	Generating Plant Statistics Pages	410	
66.1	Energy Storage Operations (Large Plants)	414	N/A
66.2	Energy Storage Operations (Small Plants)	419	N/A
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	
69	Substations	426	

70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: <input checked="" type="checkbox"/> Two copies will be submitted <input type="checkbox"/> No annual report to stockholders is prepared		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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.

Brian J. Van Abel
Executive Vice President and Chief Financial Officer
414 Nicollet Mall Minneapolis, MN 55401

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

State of Incorporation: MN
Date of Incorporation: 2000-03-09
Incorporated Under Special Law: N/A

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.
(a) Name of Receiver or Trustee Holding Property of the Respondent:
(b) Date Receiver took Possession of Respondent Property:
(c) Authority by which the Receivership or Trusteeship was created:
(d) Date when possession by receiver or trustee ceased:

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

During the year 2023, the respondent furnished electric utility and natural gas utility service in the states of Minnesota and North Dakota and electric utility and intrastate natural gas transportation service in the state of South Dakota.

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

(1) Yes
(2) No

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CONTROL OVER RESPONDENT			
1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent 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 beneficiaries for whom trust was maintained, and purpose of the trust.			
Northern States Power Co. (a Minnesota corporation) is a first tier subsidiary of Xcel Energy Inc.			

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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	NSP Nuclear Corp	Nuclear generation support	100%	
2	Private Fuel Storage, LLC	Nuclear waste storage	32.8%	
3	United Power and Land Co.	Real estate holdings	100%	
4	Crowned Ridge Interconnection Co.	Transmission system interconnection	50%	

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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)	Date Started in Period (d)	Date Ended in Period (e)
1	Chairman, President, Chief Executive Officer	Robert C. Frenzel	508,403	2023-01-01	2023-12-31
2	Senior Vice President, Chief Nuclear Officer	Peter A. Gardner	507,917	2023-01-01	2023-12-15
3	President	Christopher B. Clark	380,000	2023-01-01	2023-12-31
4	Executive Vice President, Chief Operations Officer	Timothy J. O'Connor	303,087	2023-01-01	2023-12-31
5	Executive Vice President, Chief Financial Officer	Brian Van Abel	293,310	2023-01-01	2023-12-31
6	Senior Vice President, Chief Human Resources Officer	Patricia Correa	244,373	2023-01-01	2023-12-31
7	Executive Vice President, Group President, Utilities and Chief Customer Officer	Brett Carter	199,031	2023-01-01	2023-10-02
8	Executive Vice President, Chief Legal and Compliance Officer	Amanda J. Rome	180,363	2023-01-01	2023-09-30
9	Vice President, Treasurer	Paul A. Johnson	138,836	2023-01-01	2023-12-31
10	Vice President, Controller	Melissa Ostrom	134,927	2023-01-01	2023-12-31
11	Vice President, Corporate Secretary and Securities	Amy L. Schneider	125,145	2023-01-01	2023-12-31
12	Assistant Treasurer	Patricia L. Martin	89,209	2023-01-01	2023-12-31
13	Executive Vice President, Group President, Utilities and Chief Customer Officer	Amanda J. Rome	62,434	2023-10-01	2023-12-31
14	Salaries represent NSP-Minnesota's allocation of officers' salaries greater than \$50,000 for the period of time that was served as an officer for NSP-Minnesota.				

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DIRECTORS

- 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), name and abbreviated titles of the directors who are officers of the respondent.
- Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Christopher B. Clark, President	414 Nicollet Mall, Minneapolis, MN 55401	true	false
2	Robert C. Frenzel, Chairman and Chief Executive Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	true
3	Brian J. Van Abel, Executive Vice President and Chief Financial Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	false
4	^(a) Brett C. Carter, Executive Vice President and Chief Customer Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	false
5	^(b) Amanda J. Rome, Executive Vice President, and Chief Customer Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	false

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FOOTNOTE DATA			

(a) Concept: NameAndTitleOfDirector
Brett Carter resigned from Executive Vice President, Chief Customer Officer effective October 1, 2023.
(b) Concept: NameAndTitleOfDirector
Amanda Rome was elected director effective October 1, 2023 and was elected Executive Vice President, Chief Customer Officer effective October 31, 2023.

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INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	FERC Electric Tariff, Third Revised Volume No. 1 (Midwest Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER07-1415-000 - Order Granting Incentives, and Accepting Proposed Rate Formula Modifications, Subject to Conditions, Issued December 21, 2007, Accession No. 20071221-3012
2	FERC Electric Tariff, Fourth Revised Volume No. 1 (Midwest Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER10-541-000 - Approval of Tariff Revisions to Attachment O-NSP, Issued February 26, 2010, Accession No. 20100226-3041
3	FERC Electric Tariff updated effective 01-01-2012 (Midwest Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER12-297-000 - Approval of Tariff Revisions to Attachment O-NSP, Issued December 21, 2011, Accession No. 20111221-3033
4	FERC Electric Tariff updated effective 01-01-2013 (Midwest Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER13-674-000/001/002 Approval of Tariff Revisions to Attachment O-NSP, Issued March 20, 2013, Accession No. 20130320-3014
5	FERC Electric Tariff updated effective 11-19-2013 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP, Attachment GG-NSP; & Attachment MM)	ER14-421-000/001 Approval of Tariff Revisions to Attachment O-NSP, Issued March 11, 2014, Accession No. 20140311-3041
6	FERC Electric Tariff updated effective 01-06-2015 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER15-358-000 Approval of Tariff Revisions to Attachment O-NSP, Issued January 6, 2015, Accession No. 20150105-3035
7	FERC Electric Tariff updated effective 01-01-2016 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER16-197-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 30, 2015, Accession No. 20151230-3075
8	FERC Electric Tariff updated effective 01-01-2017 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER17-305-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 30, 2016, Accession No. 20161230-3022
9	FERC Electric Tariff updated effective 12-01-2017 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER18-12-000 Approval of Tariff Revisions to Attachment O-NSP, Issued November 29, 2017, Accession No. 20171129-3095

10	FERC Electric Tariff updated effective 01-01-2019 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER18-2322-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 20, 2018, Accession No. 20181220-3030
11	FERC Electric Tariff updated effective 01-01-2019 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER19-249-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 20, 2018, Accession No. 20181220-3011
12	FERC Electric Tariff updated effective 07-01-2019 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER19-2295-000 Approval of Tariff Revisions to Attachment O-NSP, Issued August 23, 2019 Accession No. 20190823-3078
13	FERC Electric Tariff updated effective 01-01-2021 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER21-200-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 11, 2020 Accession No. 20201211-3012
14	FERC Electric Tariff updated effective 01-01-2021 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER21-262-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 11, 2020 Accession No. 20201211-3016
15	FERC Electric Tariff updated effective 09-26-2022 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER22-1602-000 Approval of Tariff Revisions to Attachment O-NSP, Issued May 10, 2022 Accession No. 20220510-3053
16	FERC Electric Tariff updated effective 06-01-2023 (Midwest Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	ER23-1532-000 Approval of Tariff Revisions to Attachment O-NSP, Issued May 19, 2023 Accession No. 20230519-3029

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

Yes
 No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20170308-5088	03/08/2017	ER17-1120-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin	FERC Electric Tariff updated effective 01-01-2017 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)
2	20180313-5128	03/13/2018	ER18-1004-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin	FERC Electric Tariff updated effective 01-01-2018 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)
3	20190314-5169	03/14/2019	ER19-1310-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin	FERC Electric Tariff updated effective 01-01-2019 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)
4	20200319-5161	03/19/2020	ER20-1354-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin	FERC Electric Tariff updated effective 01-01-2020 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)
5	20210315-5372	03/15/2021	ER21-1439-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin	FERC Electric Tariff updated effective 01-01-2021 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)
6	20220315-5085	03/15/2022	ER22-1320-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin	FERC Electric Tariff updated effective 01-01-2022 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)

7	20230315-5198	03/15/2023	ER23-1395-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin	FERC Electric Tariff updated effective 01-01-2023 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)
8	20240315-5277	03/15/2024	ER24-1525-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin	FERC Electric Tariff updated effective 01-01-2024 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1	110-111	Comp Balance Sheet Assets and Other Defrd Debits	c	57
2	204-207	Electric Plant in Service (Acct 101 - 103, 106)	g	5, 46, 58, 75, 99
3	214	Electric Plant Held for Future Use (Acct 105)	a	2
4	216	Construction Work in Progress- Electric (Acct 107)	a	143
5	219	Accum Prov for Depr- Elec Utility Plant (Acct 108)	c	20-28
6	227	Materials and Supplies	a	17
7	227	Materials and Supplies	b, c	5
8	232	Other Regulatory Assets	f	24
9	234	Accumulated Deferred Income Taxes (Acct 190)	c	8
10	266-267	Accum. Deferred Investment Tax Credits (Acct 255)	h	8
11	269	Other Deferred Credits (Acct 253)	d, e	17
12	269	Other Deferred Credits (Acct 253)	a	25
13	272-273	Accumulated Deferred Income Taxes (Acct 281)	k	4
14	274-275	Accumulated Deferred Income Taxes (Acct 282)	k	2
15	276-277	Accumulated Deferred Income Taxes (Acct 283)	k	9
16	278	Other Regulatory Liabilities	f	25
17	300	Electric Operating Revenues (Acct 400)	b	19
18	310-311	Sales for Resale (Acct 447)	a	37

19	320-323	Electric Operation and Maintenance Expenses	b	112
20	328	Transmission of Electricity for Others	a	18
21	356	Common Utility Plant and Expenses	n/a	n/a

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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IMPORTANT CHANGES DURING THE QUARTER/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 Pages 104 or 105 of the Annual Report Form No. 1, 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.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. Franchise

City, State - Utility - Expiration

Chickamaw Beach, MN - Gas - January 16, 2043
Kilkenny, MN - Electric - February 08, 2043
Mound, MN - Electric - December 31, 2025
Owatonna, MN - Electric - January 16, 2043
West Union, MN - Electric - January 16, 2043
Cottage Grove, MN - Gas - October 31, 2043
Hadley, MN - Electric - May 07, 2043
Jasper, MN - Electric - May 15, 2043
Waldorf, MN - Electric - April 09, 2043
Winona, MN - Electric - April 02, 2043
Comstock, MN - Electric - August 15, 2043
Cottage Grove, MN - Electric - October 31, 2043
Grant, MN - Electric - September 04, 2043
Grant, MN - Gas - September 04, 2043
Ihlen, MN - Electric - July 10, 2043
Lake Wilson, MN - Electric - August 02, 2043
New Brighton, MN - Electric - August 21, 2043
New Brighton, MN - Gas - August 21, 2043
Bellechester, MN - Electric - December 19, 2043
Brooklyn Center, MN - Electric - October 08, 2043
Burlington, ND - Electric - November 05, 2043
Kingston, MN - Electric - November 29, 2043
Little Canada, MN - Electric - November 28, 2043
Little Canada, MN - Gas - November 28, 2043
Oakdale, MN - Electric - December 11, 2043
Oakdale, MN - Gas - December 11, 2043
Sauk Rapids, MN - Electric - September 24, 2043
Sauk Rapids, MN - Gas - September 24, 2043
Spring Hill, MN - Electric - November 26, 2043
St Joseph, MN - Electric - October 01, 2043
St Joseph, MN - Gas - October 01, 2043

2. Acquisitions

None.

3. Purchase or sale of an operating unit or system

NSP-Minnesota acquired the 100 MW Northern Wind Facility located in southwest Minnesota on January 18, 2023. This transaction was pursuant to the Commission's Order in Docket No. EC22-108-000 issued Oct. 26, 2022.

4. Important leaseholds acquired or given, assigned or surrendered

None.

5. Important extension or reduction of transmission or distribution system

None.

6. Obligations incurred as a result of securities or assumptions of liabilities

See Note 5 of the Financial Statements on Page 123 for disclosure regarding short-term borrowings, long-term debt and other financing activities.

7. Changes in articles of incorporation or amendments to charter.

None.

8. Wage scale changes

Union Employees — 6.1 percent increase effective Jan. 1, 2023.
Non-Union Employees — Merit based increase of 4.0 percent, effective March 16, 2023.
Nuclear Monticello T-Week Integrated Planner — 6.1 percent increase, effective June 15, 2023.
Nuclear Prairie Island Planner Buyers — 6.1 percent increase, effective August 1, 2023.
Nuclear Prairie Island Engineers — 4.0 percent increase, effective September 1, 2023.

9. Legal proceedings

See Note 9 of the Financial Statements on Page 123 for disclosures regarding material legal proceedings.

10. Other materially important transactions with associates

See Note 11 of the Financial Statements on Page 123 for disclosures regarding related party transactions.

13. Changes in officers, directors, major security holders and voting powers

Effective Oct. 1, 2023, Brett C. Carter resigned as Executive Vice President, Chief Customer Officer and Director.

Effective Oct. 1, 2023, Amanda J. Rome elected as Director.

Effective Oct. 31, 2023, Amanda J. Rome elected as Executive Vice President, Chief Customer Officer.

Effective Oct. 31, 2023, Amanda J. Rome resigned as Executive Vice President, General Counsel.

Effective Oct. 31, 2023, Ryan Long elected as Interim General Counsel.

Effective Dec. 15, 2023, Christopher Church elected as Senior Vice President, Chief Nuclear Officer.

Effective Jan. 1, 2024, Christopher B. Clark resigned as Director and President, NSP-Minnesota

Effective Jan. 1, 2024, Ryan Long resigned as Interim General Counsel.

Effective Jan. 1, 2024, Ryan Long elected as Director and President, NSP-Minnesota.

Effective Jan. 1, 2024, Amanda J. Rome elected as Interim General Counsel.

14. Cash management programs

Not applicable as proprietary capital ratio is greater than 30 percent.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200	27,485,045,414	26,203,840,362
3	Construction Work in Progress (107)	200	1,091,213,892	913,814,771
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		28,576,259,306	27,117,655,133
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	10,464,116,598	10,309,195,961
6	Net Utility Plant (Enter Total of line 4 less 5)		18,112,142,708	16,808,459,172
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	121,049,448	130,420,153
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		74,022,472	
9	Nuclear Fuel Assemblies in Reactor (120.3)		557,940,914	555,418,343
10	Spent Nuclear Fuel (120.4)		2,583,569,659	2,496,920,483
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	2,987,981,986	2,891,602,507
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		348,600,507	291,156,472
14	Net Utility Plant (Enter Total of lines 6 and 13)		18,460,743,215	17,099,615,644
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		25,896,733	28,919,931
19	(Less) Accum. Prov. for Depr. and Amort. (122)		12,174,890	12,221,441
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	3,501,594	3,596,598
23	Noncurrent Portion of Allowances	228		

24	Other Investments (124)		51,733,913	47,252,298
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		3,209,781,663	2,882,407,817
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		61,239,193	68,406,863
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,339,978,206	3,018,362,066
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		1,569,984	25,041,543
36	Special Deposits (132-134)		2,898,490	3,313,436
37	Working Fund (135)		119,200	119,200
38	Temporary Cash Investments (136)		29,418,710	36,439,175
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		481,790,307	481,417,687
41	Other Accounts Receivable (143)		104,006,781	116,734,294
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		49,402,649	46,806,293
43	Notes Receivable from Associated Companies (145)		57,000,000	
44	Accounts Receivable from Assoc. Companies (146)		15,660,663	46,325,133
45	Fuel Stock (151)	227	106,828,966	104,511,663
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	217,884,396	199,059,317
49	Merchandise (155)	227	1,088,329	1,311,697
50	Other Materials and Supplies (156)	227		

51	<u>Nuclear Materials Held for Sale (157)</u>	202/227		
52	<u>Allowances (158.1 and 158.2)</u>	228	200,000	150,000
53	<u>(Less) Noncurrent Portion of Allowances</u>	228		
54	<u>Stores Expense Undistributed (163)</u>	227		
55	<u>Gas Stored Underground - Current (164.1)</u>		27,166,326	77,077,473
56	<u>Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)</u>		2,381,847	1,970,403
57	<u>Prepayments (165)</u>		(a)24,748,689	30,657,724
58	<u>Advances for Gas (166-167)</u>			
59	<u>Interest and Dividends Receivable (171)</u>		1,414,765	1,001,317
60	<u>Rents Receivable (172)</u>		952,252	730,070
61	<u>Accrued Utility Revenues (173)</u>		291,363,874	373,504,067
62	<u>Miscellaneous Current and Accrued Assets (174)</u>		6	532,062
63	<u>Derivative Instrument Assets (175)</u>		111,174,145	157,586,211
64	<u>(Less) Long-Term Portion of Derivative Instrument Assets (175)</u>		61,239,193	68,406,863
65	<u>Derivative Instrument Assets - Hedges (176)</u>			
66	<u>(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)</u>			
67	<u>Total Current and Accrued Assets (Lines 34 through 66)</u>		1,367,025,888	1,542,269,316
68	<u>DEFERRED DEBITS</u>			
69	<u>Unamortized Debt Expenses (181)</u>		73,395,427	65,540,642
70	<u>Extraordinary Property Losses (182.1)</u>	230a		
71	<u>Unrecovered Plant and Regulatory Study Costs (182.2)</u>	230b	63,952,628	72,525,232
72	<u>Other Regulatory Assets (182.3)</u>	232	3,883,635,158	3,853,486,957
73	<u>Prelim. Survey and Investigation Charges (Electric) (183)</u>		1,439,654	800,567
74	<u>Preliminary Natural Gas Survey and Investigation Charges 183.1)</u>			
75	<u>Other Preliminary Survey and Investigation Charges (183.2)</u>			
76	<u>Clearing Accounts (184)</u>		746	
77	<u>Temporary Facilities (185)</u>			

78	Miscellaneous Deferred Debits (186)	233	43,354,022	58,483,787
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		10,036,019	11,014,692
82	Accumulated Deferred Income Taxes (190)	234	1,403,283,654	1,446,325,651
83	Unrecovered Purchased Gas Costs (191)		74,547,804	126,595,043
84	Total Deferred Debits (lines 69 through 83)		5,553,645,112	5,634,772,571
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		28,721,392,421	27,295,019,597

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FOOTNOTE DATA			

[\(a\)](#) Concept: Prepayments

The Form 1 reports prepayments at the total Company level, at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of the year prepayments balance in the formula. In addition, since prepayments are reported in the Form 1 at the total Company level, they are allocated to the electric utility based on the ratio of electric net plant to the sum of electric and gas net plant as reported in the Form 1, page 200. The formula allocates the electric prepayments to the transmission function using a gross plant allocator.

[\(b\)](#) Concept: AccumulatedDeferredIncomeTaxes

Refer to FERC page 232 for NSPM's regulatory asset related to nonplant excess ADIT.

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COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250	10,000	10,000
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		479,282,529	479,282,529
7	Other Paid-In Capital (208-211)	253	5,206,742,091	4,894,553,504
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	2,543,428,084	2,482,182,450
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(2,230,631)	(2,135,689)
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(19,876,201)	(18,428,482)
16	Total Proprietary Capital (lines 2 through 15)		8,207,355,872	7,835,464,312
17	LONG-TERM DEBT			
18	Bonds (221)	256	7,450,000,000	7,050,000,000
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	2,376,908	2,780,475
22	Unamortized Premium on Long-Term Debt (225)			

23	<u>(Less) Unamortized Discount on Long-Term Debt-Debit (226)</u>		49,067,939	45,306,088
24	<u>Total Long-Term Debt (lines 18 through 23)</u>		7,403,308,969	7,007,474,387
25	<u>OTHER NONCURRENT LIABILITIES</u>			
26	<u>Obligations Under Capital Leases - Noncurrent (227)</u>		^(a) 371,741,428	^(a) 255,925,918
27	<u>Accumulated Provision for Property Insurance (228.1)</u>			
28	<u>Accumulated Provision for Injuries and Damages (228.2)</u>			
29	<u>Accumulated Provision for Pensions and Benefits (228.3)</u>		144,038,000	129,038,000
30	<u>Accumulated Miscellaneous Operating Provisions (228.4)</u>			
31	<u>Accumulated Provision for Rate Refunds (229)</u>		187,228,510	66,804,236
32	<u>Long-Term Portion of Derivative Instrument Liabilities</u>		85,606,340	102,316,974
33	<u>Long-Term Portion of Derivative Instrument Liabilities - Hedges</u>			
34	<u>Asset Retirement Obligations (230)</u>		2,657,859,157	2,727,070,951
35	<u>Total Other Noncurrent Liabilities (lines 26 through 34)</u>		3,446,473,435	3,281,156,079
36	<u>CURRENT AND ACCRUED LIABILITIES</u>			
37	<u>Notes Payable (231)</u>		165,000,000	207,000,000
38	<u>Accounts Payable (232)</u>		601,268,902	640,064,264
39	<u>Notes Payable to Associated Companies (233)</u>			
40	<u>Accounts Payable to Associated Companies (234)</u>		91,119,845	90,598,559
41	<u>Customer Deposits (235)</u>		34,938,292	23,938,425
42	<u>Taxes Accrued (236)</u>	262	223,266,353	249,064,345
43	<u>Interest Accrued (237)</u>		79,305,747	75,426,024
44	<u>Dividends Declared (238)</u>		121,278,150	122,448,025
45	<u>Matured Long-Term Debt (239)</u>			
46	<u>Matured Interest (240)</u>			
47	<u>Tax Collections Payable (241)</u>		43,016,985	41,202,648
48	<u>Miscellaneous Current and Accrued Liabilities (242)</u>		15,271,819	47,491,796
49	<u>Obligations Under Capital Leases-Current (243)</u>		^(a) 91,284,357	^(a) 98,255,563

50	<u>Derivative Instrument Liabilities (244)</u>		122,538,659	143,953,988
51	<u>(Less) Long-Term Portion of Derivative Instrument Liabilities</u>		85,606,340	102,316,974
52	<u>Derivative Instrument Liabilities - Hedges (245)</u>		7,537,298	
53	<u>(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges</u>			
54	<u>Total Current and Accrued Liabilities (lines 37 through 53)</u>		1,510,220,067	1,637,126,663
55	DEFERRED CREDITS			
56	<u>Customer Advances for Construction (252)</u>		17,851,733	13,765,191
57	<u>Accumulated Deferred Investment Tax Credits (255)</u>	266	14,069,823	15,408,376
58	<u>Deferred Gains from Disposition of Utility Plant (256)</u>			
59	<u>Other Deferred Credits (253)</u>	269	320,809,377	321,326,825
60	<u>Other Regulatory Liabilities (254)</u>	278	4,423,262,055	4,081,245,120
61	<u>Unamortized Gain on Reacquired Debt (257)</u>			
62	<u>Accum. Deferred Income Taxes-Accel. Amort.(281)</u>	272	19,763,973	20,033,462
63	<u>Accum. Deferred Income Taxes-Other Property (282)</u>		2,854,781,587	2,708,114,707
64	<u>Accum. Deferred Income Taxes-Other (283)</u>		503,495,530	373,904,475
65	<u>Total Deferred Credits (lines 56 through 64)</u>		8,154,034,078	7,533,798,156
66	<u>TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)</u>		28,721,392,421	27,295,019,597

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: ObligationsUnderCapitalLeaseNoncurrent
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.
See Note 9 to the Financial Statements on page 123 for leasing disclosures.
(b) Concept: ObligationsUnderCapitalLeasesCurrent
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.
See Note 9 to the Financial Statements on page 123 for leasing disclosures.
(c) Concept: AccumulatedDeferredIncomeTaxesOther
Refer to FERC Page 278 for NSPM's regulatory liability related to nonplant excess ADIT
(d) Concept: ObligationsUnderCapitalLeaseNoncurrent
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.
See Note 9 to the Financial Statements on page 123 for leasing disclosures.
(e) Concept: ObligationsUnderCapitalLeasesCurrent
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.
See Note 9 to the Financial Statements on page 123 for leasing disclosures.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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STATEMENT OF INCOME

Quarterly

- Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
- Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
- Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
- Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
- If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

- Do not report fourth quarter data in columns (e) and (f)
- Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
- Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
- Use page 122 for important notes regarding the statement of income for any account thereof.
- 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 material refund to the utility with respect to power or gas purchases. State for each year effected 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 or gas purchases.
- Give concise explanations concerning significant amounts of any refunds made or received during the year 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.
- If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
- Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
- Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
- If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	5,924,063,546	6,499,229,959			5,162,301,320	5,479,199,211	761,762,226	1,020,030,748		
3	Operating Expenses											
4	Operation Expenses (401)	320	3,570,549,911	3,996,290,615			2,992,602,087	3,145,443,270	577,947,824	850,847,345		

5	Maintenance Expenses (402)	320	236,257,800	229,910,895			217,894,147	213,489,453	18,363,653	16,421,442		
6	Depreciation Expense (403)	336	831,238,367	877,806,251			770,935,123	825,951,308	60,303,244	51,854,943		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	(18,543,930)	(11,605,484)			(18,921,399)	(12,014,186)	377,469	408,702		
8	Amort. & Depl. of Utility Plant (404-405)	336	95,971,422	87,633,430			85,647,339	80,367,209	10,324,083	7,266,221		
9	Amort. of Utility Plant Acq. Adj. (406)	336	3,093,393	3,093,393			3,093,393	3,093,393				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		9,185,658	8,820,689			9,185,658	8,820,689				
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		(a)171,346,201	(d)225,977,190			165,581,053	225,971,008	5,765,148	6,182		
13	(Less) Regulatory Credits (407.4)		(b)189,531,027	(e)123,882,735			177,345,261	111,622,232	12,185,766	12,260,503		
14	Taxes Other Than Income Taxes (408.1)	262	239,339,559	277,860,873			215,415,677	252,630,725	23,923,882	25,230,148		
15	Income Taxes - Federal (409.1)	262	(176,734,294)	70,440,227			(194,438,348)	44,659,002	17,704,054	25,781,225		
16	Income Taxes - Other (409.1)	262	(1,957,168)	60,138,572			(9,297,456)	47,312,482	7,340,288	12,826,090		
17	Provision for Deferred Income Taxes (410.1)	234,272	671,806,784	326,568,319			642,643,760	306,637,914	29,163,024	19,930,405		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234,272	608,853,796	569,186,390			565,153,568	524,347,471	43,700,228	44,838,919		
19	Investment Tax Credit Adj. - Net (411.4)	266	(1,338,553)	(1,423,158)			(1,231,734)	(1,316,336)	(106,819)	(106,822)		

67	Interest on Debt to Assoc. Companies (430)		4,908,964	1,427,643								
68	Other Interest Expense (431)		27,171,063	3,199,797								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		20,712,776	12,464,036								
70	Net Interest Charges (Total of lines 62 thru 69)		322,057,192	277,954,779								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		707,233,792	674,768,340								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		707,233,792	674,768,340								

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FOOTNOTE DATA			

(a) Concept: RegulatoryDebits

	Electric	Gas
Minnesota Sales True-Up	\$ 62,838,993	\$ —
Minnesota Capital True-up	37,218,277	—
Minnesota Renewable Development Fund Rider	33,064,441	—
Minnesota Renewable Energy Standard Rider	16,044,945	—
Theoretical Depreciation Reserve Surplus	8,909,820	—
Minnesota Net Operating Loss	6,026,909	—
Minnesota Business Incentive and Sustainability Rider	871,212	—
Sherco Unit 3 Depreciation Deferral	503,130	—
Minnesota LED Streetlighting	103,326	—
Minnesota Gas Utility Infrastructure Rider	—	5,765,148
	\$ 165,581,053	\$ 5,765,148

(b) Concept: RegulatoryCredits

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	\$ 104,572,440	\$ 2,959,842
Minnesota Capacity Revenue Tracker	62,252,909	—
South Dakota Infrastructure Rider	3,279,145	—
Minnesota Transmission Cost Recovery Rider	3,072,567	—
Minnesota Incentive Compensation Refund	1,551,816	—
South Dakota Transmission Cost Recovery Rider	851,425	—
North Dakota Renewable Energy Rider	625,792	—
North Dakota AGIS Deferral	621,545	—
North Dakota Transmission Cost Recovery Rider	517,622	—
Minnesota Gas Decoupling	—	9,225,924
	\$ 177,345,261	\$ 12,185,766

(c) Concept: LifeInsurance

Income on Company Owned Life Insurance.

(d) Concept: RegulatoryDebits

	Electric	Gas
Minnesota Renewable Energy Standard Rider	\$ 126,550,522	\$ —
Minnesota Sales True-Up	57,319,434	—
Minnesota Renewable Development Fund Rider	28,442,085	—
Theoretical Depreciation Reserve Surplus	9,087,814	—
Minnesota Incentive Compensation Refund	1,580,697	—
Minnesota Business Incentive and Sustainability Rider	890,516	—
North Dakota Transmission Cost Recovery Rider	838,835	—
Minnesota Transmission Cost Recovery Rider	612,964	—
Sherco Unit 3 Depreciation Deferral	503,130	—
Minnesota LED Streetlighting	145,011	—
Minnesota Gas State Energy Policy Rider		6,182
	<u>\$ 225,971,008</u>	<u>\$ 6,182</u>

(e) Concept: RegulatoryCredits

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	\$ 109,385,216	\$ 2,616,467
South Dakota Transmission Cost Recovery Rider	709,083	—
South Dakota Infrastructure Rider	692,578	—
North Dakota AGIS Deferral	547,489	—
North Dakota Renewable Energy Rider	287,866	—
Minnesota Gas Utility Infrastructure Rider	—	9,644,036
	<u>\$ 111,622,232</u>	<u>\$ 12,260,503</u>

(f) Concept: LifeInsurance

Income on Company Owned Life Insurance.

(g) Concept: Penalties

Unnatural balance due to reversal of prior year accrual.

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STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. 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).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. 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.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. 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.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	<u>UNAPPROPRIATED RETAINED EARNINGS (Account 216)</u>			
1	<u>Balance-Beginning of Period</u>		2,482,104,827	2,393,857,679
2	<u>Changes</u>			
3	<u>Adjustments to Retained Earnings (Account 439)</u>			
4	<u>Adjustments to Retained Earnings Credit</u>			
9	<u>TOTAL Credits to Retained Earnings (Acct. 439)</u>			
10	<u>Adjustments to Retained Earnings Debit</u>			
10.1	<u>Rounding</u>			
15	<u>TOTAL Debits to Retained Earnings (Acct. 439)</u>			
16	<u>Balance Transferred from Income (Account 433 less Account 418.1)</u>		707,328,734	674,393,348
17	<u>Appropriations of Retained Earnings (Acct. 436)</u>			
22	<u>TOTAL Appropriations of Retained Earnings (Acct. 436)</u>			
23	<u>Dividends Declared-Preferred Stock (Account 437)</u>			
29	<u>TOTAL Dividends Declared-Preferred Stock (Acct. 437)</u>			
30	<u>Dividends Declared-Common Stock (Account 438)</u>			
30.1	<u>Dividends Declared-Common Stock (Account 438)</u>	238	(646,083,100)	(586,146,200)

36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(646,083,100)	(586,146,200)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,543,350,461	2,482,104,827
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
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)		77,623	77,623
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		77,623	77,623
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,543,428,084	2,482,182,450
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(2,135,689)	(2,510,681)
50	Equity in Earnings for Year (Credit) (Account 418.1)		(94,942)	374,992
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1	Rounding			
53	Balance-End of Year (Total lines 49 thru 52)		(2,230,631)	(2,135,689)

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STATEMENT OF CASH FLOWS

- Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
- Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
- 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 in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
- Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	707,233,792	674,768,340
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	877,128,073	916,877,302
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Nuclear Fuel	96,379,479	118,153,271
5.2	Amortization of Premium, Discount and Debt Expense	6,852,204	7,213,805
5.3	Amortization of Software and Other	102,017,308	95,664,065
8	Deferred Income Taxes (Net)	205,965,274	(214,166,896)
9	Investment Tax Credit Adjustment (Net)	(1,338,553)	(1,423,158)
10	Net (Increase) Decrease in Receivables	34,162,091	(92,888,269)
11	Net (Increase) Decrease in Inventory	(26,471,753)	(84,753,441)
12	Net (Increase) Decrease in Allowances Inventory	(50,000)	(69,582)
13	Net Increase (Decrease) in Payables and Accrued Expenses	(113,809,609)	59,059,188
14	Net (Increase) Decrease in Other Regulatory Assets	6,434,568	425,795,499
15	Net Increase (Decrease) in Other Regulatory Liabilities	299,610,321	(67,305,354)
16	(Less) Allowance for Other Funds Used During Construction	35,651,456	29,439,419

17	(Less) Undistributed Earnings from Subsidiary Companies	(95,004)	374,992
18	Other (provide details in footnote):		
18.1	Other: Decrease (Increase) in Accrued Utility Revenues	82,140,193	(53,111,959)
18.2	Other: Net Realized and Unrealized Hedging and Derivative Transactions	(3,861,842)	2,542,328
18.3	Other: Changes in Other Current Assets and Liabilities	(16,553,624)	6,502,978
18.4	Other: Changes in Noncurrent Liabilities and Deferred Amounts	98,610,487	112,801,572
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	2,318,891,957	1,875,845,278
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,894,631,631)	(1,662,060,183)
27	Gross Additions to Nuclear Fuel	(153,823,515)	(101,645,552)
28	Gross Additions to Common Utility Plant	(280,811,385)	(165,973,640)
29	Gross Additions to Nonutility Plant	(3,769,123)	(2,940,048)
30	(Less) Allowance for Other Funds Used During Construction	(35,651,456)	(29,439,419)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(2,297,384,198)	(1,903,180,004)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		(6,000,000)
40	Contributions and Advances from Assoc. and Subsidiary Companies		6,000,000
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		

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 (provide details in footnote):		
53.1	Investments in Utility Money Pool Arrangement	(300,000,000)	(1,522,000,000)
53.2	Repayments from Utility Money Pool Arrangement	243,000,000	1,613,000,000
53.3	Other: Miscellaneous Other Investing Activities	(4,481,614)	4,734,729
53.4	Other: Purchase of Investments in External Decommissioning Fund	(993,862,798)	(1,331,531,950)
53.5	Other: Proceeds from Sale of Investments in External Decommissioning Fund	958,739,195	1,297,175,998
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(2,393,989,415)	(1,841,801,227)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	782,509,833	488,844,125
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other: Capital Contributions (to) from Parent	351,337,196	124,130,593
64.2	Other: Borrowings under Utility Money Pool Arrangement	302,000,000	6,000,000
66	Net Increase in Short-Term Debt (c)		207,000,000
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,435,847,029	825,974,718
72	Payments for Retirement of:		
73	Long-term Debt (b)	(400,403,566)	(300,399,911)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		

76.1	Other: Repayments under Utility Money Pool Arrangement	(302,000,000)	(6,000,000)
76.2	Other: Miscellaneous Other Financing Activities		
78	Net Decrease in Short-Term Debt (c)	(42,000,000)	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(647,252,975)	(559,966,025)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	44,190,488	(40,391,218)
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(30,906,970)	(6,347,167)
88	Cash and Cash Equivalents at Beginning of Period	(b)64,913,354	71,260,521
90	Cash and Cash Equivalents at End of Period	(c)34,006,384	(c)64,913,354

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities		
Changes in Noncurrent Liabilities and Deferred Amounts		
Change in pension and employee benefit obligation	\$	(11,487,327)
Change in deferred debits		58,807,284
Change in deferred credits		(50,258,148)
Change in noncurrent liabilities		101,548,678
	\$	98,610,487

(b) Concept: CashAndCashEquivalents		
Cash (131)	\$	25,041,543
Special Deposits (132-134)		3,313,436
Working Fund (135)		119,200
Temporary Cash Investments (136)		36,439,175
Cash and Cash Equivalents at End of Period	\$	64,913,354

(c) Concept: CashAndCashEquivalents		
Cash (131)	\$	1,569,984
Special Deposits (132-134)		2,898,490
Working Fund (135)		119,200
Temporary Cash Investments (136)		29,418,710
Cash and Cash Equivalents at End of Period	\$	34,006,384

(d) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities		
Changes in Noncurrent Liabilities and Deferred Amounts		
Change in pension and employee benefit obligation	\$	44,869,000
Change in deferred debits		123,951,391
Change in deferred credits		(107,558,299)
Change in noncurrent liabilities		51,539,480
	\$	112,801,572

(e) Concept: CashAndCashEquivalents		
Cash (131)	\$	25,041,543
Special Deposits (132-134)		3,313,436
Working Fund (135)		119,200
Temporary Cash Investments (136)		36,439,175
Cash and Cash Equivalents at End of Period	\$	64,913,354

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

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SEE PAGE 123 FOR REQUIRED INFORMATION.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

1. Summary of Significant Accounting Policies

Business and System of Accounts - Northern States Power Co., a Minnesota corporation (NSP-Minnesota) is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. NSP-Minnesota is subject to regulation by the Federal Energy Regulatory Commission (FERC) and state utility commissions.

The electric production and transmission system of NSP-Minnesota and Northern States Power Co., a Wisconsin corporation (NSP-Wisconsin), (collectively, NSP System) is operated on an integrated basis and managed by NSP-Minnesota and NSP-Wisconsin. The electric production and transmission costs of the NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System. Such costs include current and potential obligations of NSP-Minnesota related to its nuclear generating facilities.

Basis of Accounting - The accompanying financial statements were prepared in accordance with the accounting requirements of the 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). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

- Current maturities of long-term debt are included as long-term debt, while GAAP requires such maturities to be classified as current liabilities.
- Accumulated deferred income taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net long-term assets and liabilities.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP presentation, while the FERC requires all regulatory assets and liabilities to be classified as noncurrent deferred debits and credits, respectively.
- Unrecognized tax benefits are recorded for temporary differences in accounts established for accumulated deferred income taxes in the FERC presentation, in contrast to the GAAP presentation as taxes accrued and noncurrent other liabilities.
- Costs for future removal obligations are classified as accumulated depreciation on the utility plant in the FERC presentation and as regulatory liabilities in the GAAP presentation.
- For certain capital projects where there is recovery of a return on construction work in progress (CWIP), certain amounts of allowance for funds used during construction (AFUDC) are not recognized in CWIP for GAAP, while for the FERC presentation, they are recorded in CWIP but the benefit is deferred as a liability and amortized over the life of the property as a reduction of costs.
- Certain commodity trading purchases and sales transactions are presented gross as expenses and revenues for the FERC presentation; however the net margin is reported as net sales for the GAAP presentation.
- Various expenses such as donations, lobbying and other non-regulatory expenses are presented as other income deductions for the FERC presentation and reported as operating expenses for the GAAP presentation.
- Income tax expense related to utility operations is shown as a component of operating expense in the FERC presentation, in contrast to the GAAP presentation as a below-the-line deduction from operating income.
- Wholly-owned subsidiaries are reported using the equity method of accounting in the FERC presentation and are required to be consolidated for GAAP.
- The setup of theoretical excess depreciation reserves is recorded as a regulatory asset and an increase to regulatory credits for FERC presentation, in contrast to a reduction to both accumulated depreciation and depreciation expense for GAAP presentation. The unwinding of the regulatory asset is recorded as an increase to regulatory debits for FERC presentation with an offsetting entry to depreciation expense and accumulated depreciation, resulting in no net impact to the balance sheet or income statement. Therefore, this brings FERC back into alignment with GAAP presentation over the average remaining life of the assets.
- Deferred financing costs are included as deferred debits in the FERC presentation, while GAAP presentation includes them with long-term liabilities.
- Non-service cost components of net periodic benefit costs that are reported on the income statement are recorded as operation expenses in the FERC presentation and as other income, net for GAAP presentation. Non-service costs that are eligible for capitalization are recorded as a component of net utility plant in the FERC presentation and as regulatory assets for GAAP.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

If GAAP were followed, these financial statement line items would have values greater/(lesser) than those shown by the FERC presentation of:

(Millions of Dollars)

Balance Sheet:

Net utility plant	\$	296
Current assets		262
Current liabilities		532
Other long-term assets		(4,279)
Long-term debt and other long-term liabilities		(4,251)

Statement of Income:

Operating revenue	\$	119
Operating expenses		221
Other income and deductions		(25)
Net Interest charges		(18)

Statement of Cash Flows:

Cash provided by operating activities	\$	(18)
Cash used in investing activities		17
Cash provided by financing activities		1

Use of Estimates — NSP-Minnesota uses estimates based on the best information available to record transactions and balances resulting from business operations.

Estimates are used for items such as plant depreciable lives or potential disallowances, asset retirement obligations (AROs), certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — NSP-Minnesota accounts for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income, are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or other comprehensive income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates and assumptions for recovery of deferred costs and refund of deferred credits are based on specific ratemaking decisions, precedent or other available information. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, NSP-Minnesota may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities. Such changes could have a material effect on NSP-Minnesota's results of operations, financial condition and cash flows.

See Note 4 for further information.

Income Taxes — NSP-Minnesota accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Income taxes are deferred for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities utilizing rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

Utility rate regulation has resulted in the recognition of regulatory assets and liabilities related to income taxes. The effects of NSP-Minnesota's tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most of its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, refundable to utility customers over the remaining life of the related assets. NSP-Minnesota anticipates that a tax rate increase would predominantly result in the establishment of a regulatory asset, subject to an evaluation of whether future recovery is expected.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

Reversal of certain temporary differences are accounted for as current income tax expense due to the effects of past regulatory practices when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes.

Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize over the book depreciable lives of related property. The requirement to defer and amortize these credits specifically applies to certain federal investment tax credits (ITCs), as determined by tax regulations and NSP-Minnesota tax elections. For tax credits otherwise eligible to be recognized when earned, NSP-Minnesota considers the impact of rate regulation to determine if these credits and related adjustments should be deferred as regulatory assets or liabilities.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. This evaluation includes consideration of whether tax credits are expected to be sold at a discount and impact the realization of amounts presented as deferred tax assets. Transferable tax credits are accounted for under ASC 740 *Income Taxes*, and valuation allowances and any adjustments for discounts incurred on sales transactions are recorded to deferred tax expense, typically recovered in regulatory mechanisms.

NSP-Minnesota measures and discloses uncertain tax positions that it has taken or expects to take in its income tax returns. A tax position is recognized in the financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

Interest and penalties are recorded separately to their respective line items in the income statement.

Xcel Energy Inc. and its subsidiaries, including NSP-Minnesota file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 6 for further information.

Utility Plant and Depreciation in Regulated Operations — Utility plant is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs and replacement of items determined to be less than a unit of property are charged to expense as incurred.

Utility plant is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made.

For investments in utility plant that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Depreciation expense is recorded using the straight-line method over the plant's commission approved useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Plant removal costs are typically recognized at the amounts recovered in rates as authorized by the applicable regulator. Accumulated removal costs are reflected in the balance sheet as a regulatory liability. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.7% for 2023, 4.0% for 2022 and 3.7% for 2021.

AROs — NSP-Minnesota records AROs as a liability in the period incurred (if fair value can be reasonably estimated), with the offsetting/associated costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion and the capitalized costs are typically depreciated over the useful life of the long-lived asset. Changes resulting from revisions to timing or amounts of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO.

See Note 9 for further information.

Nuclear Decommissioning — Nuclear decommissioning studies that estimate NSP-Minnesota's costs of decommissioning its nuclear power plants are normally performed at least every three years and submitted to the state commissions for approval. Due to other regulatory activity, the next decommissioning study has been deferred one year until 2024.

NSP-Minnesota recovers regulator-approved decommissioning costs of its nuclear power plants over each facility's expected service life, typically based on the triennial decommissioning studies. The studies consider estimated future costs of decommissioning and the market

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

value of investments in trust funds and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO.

Restricted funds for future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in nuclear decommissioning fund and other assets on the balance sheets.

See Notes 7 and 9 for further information.

Benefit Plans and Other Postretirement Benefits — NSP-Minnesota maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 8 for further information.

Environmental Costs — Environmental costs are recorded when it is probable NSP-Minnesota is liable for remediation costs and the amount can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. For certain environmental costs related to facilities currently in use, such as for emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation is performed. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for NSP-Minnesota's expected share of the cost.

Estimated future expenditures to restore sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 9 for further information.

Revenue from Contracts with Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. NSP-Minnesota recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs systematically 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 recognized.

A separate financing component of collections from customers is not recognized as contract terms are short-term in nature. Revenues are net of any excise or sales taxes or fees.

NSP-Minnesota recognizes physical sales to customers (native load and wholesale) on a gross basis in electric revenues and cost of sales. Revenues and charges for short-term physical wholesale sales of excess energy transacted through regional transmission organization (RTOs) are also recorded on a gross basis. Other revenues and charges settled/facilitated through an RTO are recorded on a net basis in cost of sales.

NSP-Minnesota has various rate-adjustment mechanisms that provide for the recovery of natural gas, electric fuel and purchased energy costs. Cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred.

When applicable, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

Cash and Cash Equivalents — NSP-Minnesota considers investments in instruments with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. NSP-Minnesota establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

Inventory — Inventory is recorded at the lower of average cost or net realizable value.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

Fair Value Measurements — NSP-Minnesota presents cash equivalents, interest rate derivatives, rabbi trust assets, commodity derivatives, pension and postretirement plan assets and nuclear decommissioning fund assets at estimated fair values in its financial statements.

For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to estimate fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, quoted prices for similar contracts or internally prepared valuation models may be used to determine fair value.

For rabbi trust assets, pension and postretirement plan assets and nuclear decommissioning fund assets, published trading data and pricing models, generally using the most observable inputs available, are utilized to determine fair value for each security.

See Notes 7 and 8 for further information.

Derivative Instruments — NSP-Minnesota uses derivative instruments in connection with its commodity trading activities, and to manage risk associated with changes in interest rates and utility commodity prices, including forward contracts, futures, swaps and options. Derivatives not qualifying for the normal purchases and normal sales exception are recorded on the balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship.

Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues.

Normal Purchases and Normal Sales — NSP-Minnesota enters into contracts for purchases and sales of commodities for use in its operations. At inception, contracts are evaluated to determine whether they contain a derivative, and if so, whether they may be exempted from derivative accounting if designated as normal purchases or normal sales.

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities are shown on a net basis in electric operating revenues in the statement of income.

Commodity trading activities are not associated with energy produced from NSP-Minnesota's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms.

See Note 7 for further information.

Other Utility Items

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity and is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in NSP-Minnesota's rate base.

Alternative Revenue — Certain rate rider mechanisms (including decoupling/sales true up and conservation improvement program (CIP)/demand-side management (DSM) programs) qualify as alternative revenue programs. These mechanisms arise from instances in which the regulator authorizes a future surcharge in response to past activities or completed events. When certain criteria are met, including expected collection within 24 months, revenue is recognized, which may include incentives and return on rate base items.

Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

Conservation Programs — Costs incurred for DSM and CIP programs are deferred if it is probable future revenue will recover the incurred cost. Revenues recognized for incentive programs for the recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the year they are earned. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Emissions Allowances — Emissions allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emissions allowances and any sales of these allowances are included in electric revenues.

Nuclear Refueling Outage Costs — NSP-Minnesota uses a deferral and amortization method for nuclear refueling costs. This method amortizes costs over the period between refueling outages consistent with rate recovery.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

Renewable Energy Credits (RECs) — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. An inventory accounting model is used to account for RECs.

Sales of RECs are recorded in electric revenues on a gross basis. The cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Cost of RECs that are utilized to support commodity trading activities are recorded in a similar manner as the associated commodities and are presented on a net basis in electric operating revenues in the statement of income.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2023 up to Feb. 21, 2024, the date NSP-Minnesota's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of this report. These financial statements contain all necessary adjustments and disclosures resulting from these evaluations.

2. Investments Accounted for by the Equity Method

In accordance with FERC regulations, NSP-Minnesota's investment in and income from all of its wholly owned subsidiaries are presented using the equity method of accounting. Subsidiaries accounted for under the equity method include:

Name	Geographic Area	Economic Interest
United Power & Land	United States	100%
NSP-Nuclear Corp.	United States	100
Crowned Ridge Interconnection Co.	United States	50
Private Fuel Storage, LLC*	United States	32.8

*The investment in Private Fuel Storage, LLC has been written down to zero.

Summarized Financial Information of Unconsolidated Investees

Summarized financial information for all equity-method subsidiaries and projects, including interests owned by NSP-Minnesota was as follows:

(Millions of Dollars)	2023		2022	
Current assets	\$	6	\$	7
Other assets		(2)		(3)
Total assets	\$	4	\$	4
Equity	\$	4	\$	4
Total liabilities and equity	\$	4	\$	4

(Millions of Dollars)	2023		2022	
Operating income	\$	—	\$	1
Net income	\$	—	\$	1

3. Joint Ownership of Generation, Transmission and Gas Facilities

Jointly owned assets as of Dec. 31, 2023:

(Millions of Dollars, Except Percent Owned)	Plant in Service		Accumulated Depreciation	Percent Owned	
Electric generation:					
Sherco Unit 3	\$	633	\$	480	59 %
Sherco common facilities		185		121	80
Sherco substation		5		4	59
Electric transmission:					
Grand Meadow		11		4	50
Huntley Wilmarth		49		2	50
CapX2020		820		141	51
Total ^(a)	\$	1,703	\$	752	

^(a) Projects additionally include \$2 million in CWIP.

NSP-Minnesota's share of operating expenses and construction expenditures is included in the applicable utility accounts. Respective owners are responsible for providing their own financing.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected or may require to be paid back to customers in future electric and natural gas rates. NSP-Minnesota would be required to recognize the write-off of regulatory assets and liabilities in net income or other comprehensive income if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

(Millions of Dollars)	Dec. 31, 2023	Dec. 31, 2022
Other Regulatory Assets		
Asset retirement recovery	\$ 2,772	\$ 2,665
Pension and retiree medical obligations ^(a)	339	344
Theoretical depreciation reserve surplus	220	229
Excess deferred taxes - TCJA	106	113
Recoverable deferred taxes on AFUDC recorded in plant	127	112
Nuclear refueling outage costs	62	42
Renewable resources and environmental initiatives	38	50
Contract valuation adjustments ^(b)	31	44
Purchased power contracts costs	21	27
PPA termination	24	46
Deferred Electric Commodity Costs	—	49
Other	144	132
Total other regulatory assets	\$ 3,884	\$ 3,853

(a) Prior period amounts have been reclassified to conform with current year presentation.

(b) 2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act (TCJA).

(c) Includes the fair value of certain long-term Purchase Power Agreements (PPAs) used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

Components of regulatory liabilities:

(Millions of Dollars)	Dec. 31, 2023	Dec. 31, 2022
Other Regulatory Liabilities		
Plant removal costs	\$ 2,028	\$ 1,949
Deferred income tax adjustments and TCJA refunds ^(a)	1,143	1,183
Investments	835	654
Excess deferred taxes - TCJA	19	23
Contract valuation adjustments ^(b)	16	56
Deferred electric energy costs	143	26
Investment tax credit deferrals	13	17
United States Department of Energy (DOE) Settlement	12	—
Other	215	173
Total other regulatory liabilities	\$ 4,424	\$ 4,081

(a) Includes the revaluation of recoverable/regulated plant accumulated deferred income taxes and revaluation impact of non-plant accumulated deferred income taxes due to the TCJA.

(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

NSP-Minnesota's regulatory assets not earning a return include the unfunded portion of pension and retiree medical obligations and net AROs (i.e. deferrals for which cash has not been disbursed). In addition, regulatory assets included \$479 million and \$369 million at Dec. 31, 2023 and 2022, respectively, of past expenditures not earning a return. Amounts are predominantly related to purchased natural gas and electric energy costs (including those related to Winter Storm Uri), sales true-up and revenue decoupling, various renewable resources/environmental initiatives and certain prepaid pension amounts.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

NSP-Minnesota meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility and the money pool.

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Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

Money Pool — Xcel Energy Inc. and its utility subsidiaries (e.g., NSP-Minnesota, NSP-Wisconsin, Public Service Company of Colorado, and Southwest Public Service Company) (Xcel Energy) have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool borrowings:

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31			
	2023		2022	
Borrowing limit	\$	250	\$	250
Amount outstanding at period end		—		—
Average amount outstanding		17		—
Maximum amount outstanding		135		4
Weighted average interest rate, computed on a daily basis		4.97 %		3.87 %
Weighted average interest rate at end of period		N/A		N/A

Commercial Paper — Commercial paper outstanding:

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31			
	2023		2022	
Borrowing limit	\$	700	\$	700
Amount outstanding at period end		165		207
Average amount outstanding		112		21
Maximum amount outstanding		265		290
Weighted average interest rate, computed on a daily basis		5.47 %		4.14 %
Weighted average interest rate at end of period		5.47		4.64

Letters of Credit — NSP-Minnesota uses letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2023 and 2022, there were \$15 million and \$15 million of letters of credit outstanding under the credit facility, respectively. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facility — In order to use commercial paper programs to fulfill short-term funding needs, NSP-Minnesota must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper exceeding available capacity under these credit facilities.

The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Features of NSP-Minnesota's credit facility:

Debt-to-Total Capitalization Ratio ^(a)		Amount Facility May Be Increased (Millions)	Additional Periods for Which a One-Year Extension May Be Requested ^(b)
2023	2022		
47.7 %	47.7 %	\$ 150	2

(a) The credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65%.

(b) All extension requests are subject to majority bank group approval.

The credit facility has a cross-default provision that NSP-Minnesota would be in default on its borrowings under the facility if it or any of its subsidiaries whose total assets exceed 15% of NSP-Minnesota's total assets, default on indebtedness in an aggregate principal amount exceeding \$75 million.

If NSP-Minnesota does not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2023, NSP-Minnesota was in compliance with all financial covenants on its debt agreements.

NSP-Minnesota had the following committed credit facility available as of Dec. 31, 2023 (in millions of dollars):

Credit Facility ^(a)	Drawn ^(b)	Available
\$ 700	\$ 180	\$ 520

(a) This credit facility matures in September 2027.

(b) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. NSP-Minnesota had NO direct advances on the facility outstanding at Dec. 31, 2023 and 2022.

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Bilateral Credit Agreement — In April 2022, NSP-Minnesota’s uncommitted bilateral credit agreement was renewed for an additional one-year term. The credit agreement is limited in use to support letters of credit.

As of Dec. 31, 2023, and 2022 NSP-Minnesota had \$65 million and \$54 million outstanding letters of credit under the \$75 million Bilateral Credit Agreement, respectively.

Long-Term Borrowings and Other Financing Instruments

Generally, the property of NSP-Minnesota is subject to the lien of its first mortgage indenture for the benefit of bondholders. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long term debt obligations for NSP-Minnesota as of Dec. 31 (in millions of dollars):

Financing Instrument	Interest Rate	Maturity Date	2023	2022
First mortgage bonds	2.60 %	May 15, 2023	\$ —	\$ 400
First mortgage bonds	7.125	July 1, 2025	250	250
First mortgage bonds	6.50	March 1, 2028	150	150
First mortgage bonds	2.25	April 1, 2031	425	425
First mortgage bonds	5.25	July 15, 2035	250	250
First mortgage bonds	6.25	June 1, 2036	400	400
First mortgage bonds	6.20	July 1, 2037	350	350
First mortgage bonds	5.35	Nov. 1, 2039	300	300
First mortgage bonds	4.85	Aug. 15, 2040	250	250
First mortgage bonds	3.40	Aug. 15, 2042	500	500
First mortgage bonds	4.125	May 15, 2044	300	300
First mortgage bonds	4.00	Aug. 15, 2045	300	300
First mortgage bonds	3.60	May 15, 2046	350	350
First mortgage bonds	3.60	Sept. 15, 2047	600	600
First mortgage bonds	2.90	March 1, 2050	600	600
First mortgage bonds	2.60	June 1, 2051	700	700
First mortgage bonds	3.20	April 1, 2052	425	425
First mortgage bonds ^(a)	4.50	June 1, 2052	500	500
First mortgage bonds ^(b)	5.10	May 15, 2053	800	—
Other long-term debt			2	3
Unamortized discount			(49)	(45)
Unamortized debt issuance cost			(73)	(66)
Current maturities			—	(400)
Total long-term debt			\$ 7,330	\$ 6,542

(a) 2022 financing.

(b) 2023 financing.

Maturities of long-term debt are as follows:

(Millions of Dollars)

2024	\$ —
2025	250
2026	—
2027	—
2028	150

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Deferred Financing Costs — Deferred financing costs of approximately \$73 million and \$66 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt at Dec. 31, 2023 and 2022, respectively.

Dividend Restrictions — NSP-Minnesota's dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividend payments are solely to be paid from retained earnings.

NSP-Minnesota's state regulatory commissions additionally impose dividend limitations, which are more restrictive than those imposed by the FERC.

Requirements and actuals as of Dec. 31, 2023:

Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual	
Low	High	2023	
47.2 %	57.6 %	52.3 %	

Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
\$ 1,508 million	\$ 15,702 million	\$ 16,140 million

6. Income Taxes

Unrecognized Tax Benefits

Federal Audit — NSP-Minnesota is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns expire as follows:

Tax Year(s)	Expiration
2014 - 2016	March 2025
2020	September 2024

Additionally, the statute of limitations related to the federal tax credit carryforwards will remain open until those credits are utilized in subsequent returns. Further, the statute of limitations related to the additional federal tax loss carryback claim filed in 2020 has been extended. As of Dec. 31, 2023 the Internal Revenue Service (IRS) issued its Revenue Agent's Report related to the federal tax loss carryback claim. The Company materially agrees with the report and re-recognized the related benefit in Dec. 2023.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2023, NSP-Minnesota's earliest open tax years subject to examination by state taxing authorities under applicable statutes of limitations are as follows:

State	Tax Year(s)	Expiration
Minnesota	2014-2016	September 2025
Minnesota	2019	May 2024

In 2020, Minnesota began an audit of tax years 2015-2018. In 2022, the state of Minnesota issued its audit report and in 2023, the Company agreed to the report without any material adjustments. No other state income tax audits are in progress as of Dec. 31, 2023.

Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the effective tax rate (ETR). In addition, the unrecognized tax benefit balance includes temporary tax positions for which deductibility is highly certain, but for which there is uncertainty about the timing. A change in the timing of deductibility would not affect the ETR but would accelerate the payment to the taxing authority.

Unrecognized tax benefits - permanent vs temporary:

(Millions of Dollars)	Dec. 31, 2023	Dec. 31, 2022
Unrecognized tax benefit — Permanent tax positions	\$ 18	\$ 31
Unrecognized tax benefit — Temporary tax positions	—	3
Total unrecognized tax benefit	\$ 18	\$ 34

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Changes in unrecognized tax benefits:

(Millions of Dollars)	2023	2022
Balance at Jan. 1	\$ 34	\$ 26
Additions based on tax positions related to the current year	2	2
Additions for tax positions of prior years	1	6
Reductions for tax positions of prior years	(18)	—
Reductions for tax positions related to settlements with taxing authorities	(1)	—
Balance at Dec. 31	\$ 18	\$ 34

Unrecognized tax benefits were reduced by tax benefits associated with net operating loss (NOL) and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2023	Dec. 31, 2022
NOL and tax credit carryforwards	\$ (18)	\$ (13)

As IRS and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately \$5 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2023	2022
Payable for interest related to unrecognized tax benefits at Jan. 1	\$ (3)	\$ (2)
Interest benefit (expense) related to unrecognized tax benefits	\$ 4	\$ (1)
Receivable (payable) for interest related to unrecognized tax benefits at Dec. 31	\$ 1	\$ (3)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2023 or 2022.

Other Income Tax Matters — NOL amounts represent the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2023	2022
Federal NOL carryforward	\$ —	\$ 3
Federal tax credit carryforwards	794	916
Valuation allowances for federal credit carryforwards	(5)	—
State NOL carryforwards	2	185
State tax credit carryforwards, net of federal detriment	56	70
Valuation allowances for state credit carryforwards, net of federal benefit	(52)	(58)

Federal carryforward periods expire between 2037 and 2043 and state carryforward periods expire starting 2025.

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.

Effective income tax rate for years ended Dec. 31:

	2023	2022
Federal statutory rate	21.0 %	21.0 %
State income tax on pretax income, net of federal tax effect	7.0	7.0
Increases (decreases) in tax from:		
Wind production tax credits ^(a)	(39.5)	(39.6)
Plant regulatory differences ^(b)	(5.7)	(6.7)
Other tax credits, net NOL & tax credit allowances	(1.3)	(1.3)
Other, net	0.2	(0.3)
Effective income tax rate	(18.3)%	(19.9)%

(a) Wind Production Tax Credits net of estimated transfer discount are credited to customers (reduction to revenue) and do not materially impact net income.

(b) Plant regulatory differences primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit are offset by corresponding revenue reductions.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2023	2022
Current federal tax (benefit) expense	\$ (154)	\$ 70

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Current state tax expense	3	26
Current change in unrecognized tax (benefit) expense	(13)	8
Deferred federal tax expense (benefit)	5	(237)
Deferred state tax expense	51	23
Deferred investment tax credits	(1)	(1)
Other	—	(1)
Total income tax benefit	\$ (109)	\$ (112)

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2023	2022
Deferred tax expense (benefit) excluding items below	\$ 319	\$ (284)
Adjustments to deferred income taxes for wind production tax credit cash transfers ^(a)	(150)	—
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(114)	70
Tax benefit allocated to other comprehensive income, and other	1	—
Deferred tax expense (benefit)	\$ 56	\$ (214)

(a) Proceeds from tax credit transfers are included in cash received (paid) for income taxes in the statement of cash flows.

Components of the net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2023	2022
Deferred tax liabilities:		
Differences between book and tax bases of property	\$ 3,343	\$ 3,080
Regulatory assets	(188)	(202)
Operating lease assets	129	98
Pension expense	64	68
Deferred fuel costs	20	49
Other	10	9
Total deferred tax liabilities	\$ 3,378	\$ 3,102
Deferred tax assets:		
Tax credit carryforward	\$ 850	\$ 986
Differences between book and tax bases of property	374	338
Operating lease liabilities	129	98
Rate refund	59	28
Regulatory liabilities	(55)	(66)
Tax credit valuation allowances	(57)	(58)
Other employee benefits	31	27
Deferred investment tax credits	4	5
NOL carryforward	0	15
Other	68	73
Total deferred tax assets	\$ 1,403	\$ 1,446
Net deferred tax liability	\$ 1,975	\$ 1,656

In December 2017, NSP-Minnesota remeasured our deferred tax assets and liabilities to the new federal corporate income tax rate of 21%. After filing the 2017 tax return, we completed a final remeasurement of our 2017 deferred tax assets and liabilities to the new corporate tax rate. NSP- Minnesota received guidance from its jurisdictions in 2018 and started the amortization of the deficient and excess accumulated deferred income tax (ADIT). The Protected ADITs, which are required by IRS normalization rules to be provided to customers, are amortized according to the rules of the Average Rate Assumption Method (ARAM) with amortization occurring over the remaining book life of the individual assets. The Unprotected ADITs, are amortized according to each jurisdiction. The Nonplant Unprotected have amortization periods ranging from 3-15 years. While, Plant Unprotected will use ARAM.

The amount of deficient and excess accumulated deferred income tax assets and liabilities that are considered protected and unprotected as of December 31, 2023 and 2022 is reflected below.

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(Millions of Dollars)	Dec. 31, 2023		Dec. 31, 2022	
	Account 182.3	Account 254	Account 182.3	Account 254
Protected				
Plant	\$ —	\$ 1,021	\$ —	\$ 1,061
Nonplant	92	—	98	—
Unprotected				
Plant	—	121	—	122
Nonplant	12	19	15	23
Total				
Plant	\$ —	\$ 1,142	\$ —	\$ 1,183
Nonplant	\$ 104	\$ 19	\$ 113	\$ 23

Excess and deficient ADITs in 2023 were amortized in the Statement of Income as follows:

(Millions of Dollars)	Dec. 31, 2023
Protected	
Plant	\$ (26)
Nonplant	4
Unprotected	
Plant	(7)
Nonplant	(1)
Total	
Plant	\$ (33)
Nonplant	\$ 3

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are actively traded instruments with observable actual trading prices.
- Level 2 — Pricing inputs are other than actual trading prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 include those valued with models requiring significant judgment or estimation.

Specific valuation methods include:

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs (net asset values). The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled funds require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate commingled funds may be redeemed with proper notice, however, withdrawals may be delayed or discounted as a result of fund illiquidity.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — Fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — Methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contracts relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges, the significance of the use of less observable inputs on a valuation is evaluated and may result in Level 3 classification.

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Electric commodity derivatives held by NSP-Minnesota include transmission congestion instruments, generally referred to as FTRs (financial transmission rights). FTRs purchased from an RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path.

The values of these instruments are derived from, and designed to offset, the costs of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of these instruments. FTRs are recognized at fair value and adjusted each period prior to settlement. Given the limited observability of certain variables underlying the reported auction values of FTRs, these fair value measurements have been assigned a Level 3 classification.

Net congestion costs, including the impact of FTR settlements are shared through fuel and purchased energy cost recovery mechanisms. As such, the fair value of the unsettled instruments (i.e., derivative asset or liability) is offset/deferred as a regulatory asset or liability.

Non-Derivative Fair Value Measurements

The Nuclear Regulatory Commission requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning these facilities. The fund contains cash equivalents, debt securities, equity securities and other investments. NSP-Minnesota uses the Minnesota Public Utilities Commission (MPUC) approved asset allocation for the escrow and investment targets by asset class for the qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning over the lives of the nuclear plants, assuming rate recovery of all costs. Realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund are deferred as a component of the regulatory asset.

Unrealized gains for the nuclear decommissioning fund were \$1.2 billion and \$1 billion as of Dec. 31, 2023 and 2022, respectively, and unrealized losses were \$29 million and \$90 million as of Dec. 31, 2023 and 2022, respectively.

Non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund:

(Millions of Dollars)	Dec. 31, 2023					
	Cost	Fair Value				Total
		Level 1	Level 2	Level 3	NAV	
Nuclear decommissioning fund						
Cash equivalents	\$ 41	\$ 41	\$ —	\$ —	\$ —	\$ 41
Commingled funds	721	—	—	—	1,049	1,049
Debt securities	784	—	771	9	—	784
Equity securities	508	1,339	2	—	—	1,341
Total	\$ 2,054	\$ 1,380	\$ 773	\$ 9	\$ 1,049	\$ 3,211

(Millions of Dollars)	Dec. 31, 2022					
	Cost	Fair Value				Total
		Level 1	Level 2	Level 3	NAV	
Nuclear decommissioning fund						
Cash equivalents	\$ 29	\$ 29	\$ —	\$ —	\$ —	\$ 29
Commingled funds	803	—	—	—	1,178	1,178
Debt securities	738	—	669	6	—	675
Equity securities	406	999	1	—	—	1,000
Total	\$ 1,976	\$ 1,028	\$ 670	\$ 6	\$ 1,178	\$ 2,882

For the years ended Dec. 31, 2023 and 2022, there were immaterial Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Dec. 31, 2023:

(Millions of Dollars)	Final Contractual Maturity				
	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Debt securities	\$ 4	\$ 261	\$ 269	\$ 246	\$ 780

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Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

Rabbi Trusts

NSP-Minnesota has established a rabbi trust to provide partial funding for future distributions of its deferred compensation plan. The fair value of assets held in the rabbi trusts were \$12 million and \$12 million at Dec. 31, 2023 and 2022, respectively, comprised of cash equivalents and mutual funds (level 1 valuation methods). Amounts are reported in nuclear decommissioning fund and other investments on the balance sheet.

Interest Rate Derivatives — NSP-Minnesota enters into contracts that effectively fix the interest rate on a specified principal amount of a hypothetical future debt issuance. These financial swaps net settle based on changes in a specified benchmark interest rate, acting as a hedge of changes in market interest rates that will impact specified anticipated debt issuances. These derivative instruments are designated as cash flow hedges for accounting purposes, with changes in fair value prior to occurrence of the hedged transactions recorded as other comprehensive income.

As of Dec. 31, 2023, accumulated other comprehensive loss related to interest rate derivatives included \$1 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings. As of Dec. 31, 2023, NSP-Minnesota had \$150 million of unsettled interest rate derivatives.

For the financial impact of qualifying interest rate cash flow hedges on NSP-Minnesota's accumulated other comprehensive loss included in the statements of common stockholder's equity and in the statements of comprehensive income, see Note 11.

Wholesale and Commodity Trading — NSP-Minnesota conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. NSP-Minnesota is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in the activities governed by this policy.

Derivative instruments entered into for trading purposes are presented in the statement of income as electric revenues, net of any sharing with customers. These activities are not intended to mitigate commodity price risk associated with regulated electric and natural gas operations. Sharing of these margins is determined through state regulatory proceedings as well as the operation of the FERC-approved joint operating agreement.

Commodity Derivatives — NSP-Minnesota enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale and FTRs.

The most significant derivative positions outstanding at December 31, 2023 and 2022 for this purpose relate to FTR instruments administered by Midcontinent Independent System Operator, Inc. (MISO). These instruments are intended to offset the impacts of transmission system congestion. Higher congestion costs in recent years have led to an increase in the fair value of FTRs. Settlements of FTRs are shared with electric customers through fuel and purchased energy cost-recovery mechanisms.

When NSP-Minnesota enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, the instruments are not typically designated as qualifying hedging transactions. The classification of unrealized losses or gains on these instruments as a regulatory asset or liability, if applicable, is based on approved regulatory recovery mechanisms. As of Dec. 31, 2023, NSP-Minnesota had no commodity contracts designated as cash flow hedges.

Gross notional amounts of commodity forwards, options and FTRs:

(Amounts in Millions) ^{(a)(b)}	Dec. 31, 2023	Dec. 31, 2022
Megawatt hours of electricity	38	44
Million British thermal units of natural gas	64	88

(a) Not reflective of net positions in the underlying commodities.

(b) Notional amounts for options included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — NSP-Minnesota continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented on the balance sheets. NSP-Minnesota's most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities.

As of Dec. 31, 2023, four of NSP-Minnesota's ten most significant counterparties for these activities, comprising \$24 million or 25% of this credit exposure, had investment grade credit ratings from Standard & Poor's Global Ratings, Moody's Investor Services or Fitch Ratings.

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Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

Three of the ten most significant counterparties, comprising \$26 million or 27% of this credit exposure, were not rated by these external ratings agencies, but based on NSP-Minnesota's internal analysis, had credit quality consistent with investment grade.

Three of these significant counterparties, comprising \$45 million or 47% of this credit exposure, had credit quality less than investment grade, based on internal analysis.

Five of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase and normal sale contracts and therefore not reflected on the balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies. As of Dec. 31, 2023 and 2022, there were \$12 million and \$4 million, respectively, of derivative liabilities with such underlying contract provisions, respectively.

Also, certain contracts may contain cross default provisions that may require the posting of collateral or settlement of the contracts if there was a failure under other financing arrangements related to payment terms or other covenants.

As of Dec. 31, 2023 and 2022, there were approximately \$80 million and \$76 million of derivative liabilities with such underlying contract provisions, respectively.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2023 and 2022.

Recurring Fair Value Measurements — NSP-Minnesota's derivative assets and liabilities measured at fair value on a recurring basis were as follows:

Impact of derivative activity:

(Millions of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:	
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2023		
Derivatives designated as cash flow hedges		
Interest rate	\$ (3)	\$ —
Total	<u>\$ (3)</u>	<u>\$ —</u>
Other derivative instruments		
Electric commodity	\$ —	\$ (48)
Natural gas commodity	—	(1)
Total	<u>\$ —</u>	<u>\$ (49)</u>
Year Ended Dec. 31, 2022		
Other derivative instruments		
Electric commodity	\$ —	\$ (7)
Natural gas commodity	—	—
Total	<u>\$ —</u>	<u>\$ (7)</u>

(Millions of Dollars)	Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
	Accumulated Other Comprehensive	Regulatory Assets and	
Year Ended Dec. 31, 2023			
Derivatives designated as cash flow hedges			
Interest rate	\$ 1 (a)	\$ —	\$ —
Total	<u>\$ 1</u>	<u>\$ —</u>	<u>\$ —</u>
Other derivative instruments			
Commodity trading	\$ —	\$ —	\$ (2) (b)
Electric commodity	—	45 (c)	—

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

Natural gas commodity		—	— (d)	(8) (d)(e)
Total	\$	—	\$ 45	\$ (10)
Year Ended Dec. 31, 2022				
Derivatives designated as cash flow hedges				
Interest rate	\$	1 (a)	\$ —	\$ —
Total	\$	1	\$ —	\$ —
Other derivative instruments				
Commodity trading	\$	—	\$ —	\$ 17 (b)
Electric commodity		—	1 (c)	—
Natural gas commodity		—	2 (d)	(8) (d)(e)
Total	\$	—	\$ 3	\$ 9

(a) Recorded to interest charges.

(b) Recorded to electric revenues. Presented amounts do not reflect non-derivative transactions or margin sharing with customers.

(c) Recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms and reclassified out of income as regulatory assets or liabilities, as appropriate. FTR settlements are shared with customers and do not have a material impact on net income. Presented amounts reflect changes in fair value between auction and settlement dates, but exclude the original auction fair value.

(d) Recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

(e) Relates primarily to option premium amortization.

NSP-Minnesota had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2023, and 2022.

Derivative assets and liabilities measured at fair value on a recurring basis were as follows:

(Millions of Dollars)	Dec. 31, 2023						Dec. 31, 2022					
	Fair Value			Fair Value Total	Netting (a)	Total	Fair Value			Fair Value Total	Netting (a)	Total
	Level 1	Level 2	Level 3				Level 1	Level 2	Level 3			
Current derivative assets												
Other derivative instruments:												
Commodity trading	\$ 7	\$ 32	\$ 32	\$ 71	\$ (42)	\$ 29	\$ 15	\$ 38	\$ 33	\$ 86	\$ (58)	\$ 28
Electric commodity	—	—	23	23	(7)	16	—	—	58	58	(2)	56
Natural gas commodity	—	5	—	5	—	5	—	5	—	5	—	5
Total current derivative assets	\$ 7	\$ 37	\$ 55	\$ 99	\$ (49)	\$ 50	\$ 15	\$ 43	\$ 91	\$ 149	\$ (60)	\$ 89
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	\$ 7	\$ 43	\$ 45	\$ 95	\$ (34)	\$ 61	\$ 21	\$ 40	\$ 66	\$ 127	\$ (59)	\$ 68
Total noncurrent derivative assets	\$ 7	\$ 43	\$ 45	\$ 95	\$ (34)	\$ 61	\$ 21	\$ 40	\$ 66	\$ 127	\$ (59)	\$ 68

(Millions of Dollars)	Dec. 31, 2023						Dec. 31, 2022					
	Fair Value			Fair Value Total	Netting (a)	Total	Fair Value			Fair Value Total	Netting (a)	Total
	Level 1	Level 2	Level 3				Level 1	Level 2	Level 3			
Current derivative liabilities												
Derivatives designated as cash flow hedges:												
Interest rate	\$ —	\$ 7	\$ —	\$ 7	\$ —	\$ 7	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
Other derivative instruments:												
Commodity trading	6	60	5	71	(43)	28	\$ 23	\$ 60	\$ 6	\$ 89	\$ (63)	\$ 26
Electric commodity	—	—	7	7	(7)	—	—	—	2	2	(2)	—
Natural gas commodity	—	3	—	3	—	3	—	2	—	2	—	2
Total current derivative liabilities	\$ 6	\$ 70	\$ 12	\$ 88	\$ (50)	38	\$ 23	\$ 62	\$ 8	\$ 93	\$ (65)	28
PPAs (b)						6						14
Current derivative instruments						\$ 44						\$ 42

Noncurrent derivative liabilities

Other derivative instruments:

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Commodity trading	\$ 14	\$ 49	\$ 37	\$ 100	\$ (36)	\$ 64	\$ 37	\$ 55	\$ 42	\$ 134	\$ (60)	\$ 74
Total noncurrent derivative	\$ 14	\$ 49	\$ 37	\$ 100	\$ (36)	64	\$ 37	\$ 55	\$ 42	\$ 134	\$ (60)	74
PPAs (b)						22						28
Noncurrent derivative instruments						\$ 86						\$ 102

- (a) NSP-Minnesota nets derivative instruments and related collateral on its balance sheets when supported by a legally enforceable master netting agreement. At Dec. 31, 2023 and 2022, derivative assets and liabilities include no obligations to return cash collateral. At Dec. 31, 2023 and 2022, derivative assets and liabilities include rights to reclaim cash collateral of \$3 million and \$6 million, respectively. Counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.
- (b) NSP-Minnesota currently applies the normal purchase exception to qualifying PPAs. Balance relates to specific contracts that were previously recognized at fair value prior to applying the normal purchase exception, and are being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives:

(Millions of Dollars)	Year Ended Dec. 31	
	2023	2022
Balance at Jan. 1	\$ 107	\$ 56
Purchases (a)	98	157
Settlements (a)	(65)	(195)
Net transactions recorded during the period:		
Gains (losses) recognized in earnings (b)	15	91
Net gains (losses) recognized as regulatory assets and liabilities (a)	(104)	(2)
Balance at Dec. 31	\$ 51	\$ 107

- (a) Relates primarily to FTR instruments administered by MISO.
- (b) Relates to commodity trading and is subject to substantial offsetting losses and gains on derivative instruments categorized as levels 1 and 2 in the income statement. See above tables for the income statement impact of derivative activity, including commodity trading gains and losses.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

(Millions of Dollars)	2023		2022	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	\$ 7,403	\$ 6,561	\$ 7,007	\$ 5,995

Fair value of NSP-Minnesota's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2023 and 2022, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

8. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

Xcel Energy, which includes NSP-Minnesota, has several noncontributory, qualified, defined benefit pension plans that cover almost all employees. All newly hired or rehired employees participate under the Cash Balance formula, which is based on pay credits using a percentage of annual eligible pay and annual interest credits.

The average annual interest crediting rates for these plans was 4.67, 4.86 and 1.96% in 2023, 2022, and 2021, respectively.

Some employees may participate under legacy formulas such as the traditional final average pay or pension equity. Xcel Energy's and NSP-Minnesota's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement program (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives who participated in the plan in 2008, when the SERP was closed to new participants.

The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's operating cash flows.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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Obligations of the SERP and nonqualified plan as of Dec. 31, 2023 and 2022 were \$12 million and \$11 million, respectively, of which \$2 million was attributable to NSP-Minnesota in 2023 and 2022, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of \$2 million in 2023 and \$17 million in 2022, respectively, of which immaterial amounts were attributable to NSP-Minnesota.

Xcel Energy's

postretirement health care benefit plan is a continuation of certain welfare benefit programs for current employees. A full time employee's date of hire or a retiree's date of retirement determine eligibility for each of the programs.

Xcel Energy's

investment-return assumption considers the expected long-term performance for each of the asset classes in its pension and postretirement health care portfolio. Xcel Energy considers the historical returns achieved by its asset portfolios over long time periods, as well as the long-term projected return levels from investment experts. Xcel Energy and NSP-Minnesota continually review their pension assumptions.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2023 were above the assumed level of 7.25%.
- Investment returns in 2022 were below the assumed level of 6.60%.
- Investment returns in 2021 were above the assumed level of 6.60%.
- In 2024, NSP-Minnesota's expected investment-return assumption is 7.25%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations consider many factors and generally result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

For each of the fair value hierarchy levels, NSP-Minnesota's pension plan assets measured at fair value:

(Millions of Dollars)	Dec. 31, 2023 ^(a)					Dec. 31, 2022 ^(a)				
	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	\$ 46	\$ —	\$ —	\$ —	\$ 46	\$ 26	\$ —	\$ —	\$ —	\$ 26
Commingled	110	—	—	265	375	201	—	—	201	402
Debt securities	—	127	1	—	128	—	129	1	—	130
Equity securities	8	—	—	—	8	11	—	—	—	11
Other	—	5	—	—	5	—	1	—	—	1
Total	\$ 164	\$ 132	\$ 1	\$ 265	\$ 562	\$ 238	\$ 130	\$ 1	\$ 201	\$ 570

^(a) See Note 7 for further information on fair value measurement inputs and methods.

For each of the fair value hierarchy levels, NSP-Minnesota's postretirement benefit plan assets that were measured at fair value:

(Millions of Dollars)	Dec. 31, 2023 ^(a)					Dec. 31, 2022 ^(a)				
	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Insurance contracts	—	—	—	—	—	—	1	—	—	1
Commingled funds	\$ —	\$ —	\$ —	\$ 1	\$ 1	\$ 1	\$ —	\$ —	\$ 1	\$ 2
Debt securities	—	2	—	—	2	—	2	—	—	2
Total	\$ —	\$ 2	\$ —	\$ 1	\$ 3	\$ 1	\$ 3	\$ —	\$ 1	\$ 5

^(a) See Note 7 for further information on fair value measurement inputs and methods.

Immaterial assets were transferred in or out of Level 3 for 2023. No assets were transferred in or out of Level 3 for 2022.

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Funded Status — Comparisons of the actuarially computed benefit obligation, changes in plan assets and funded status of the pension and postretirement health care plans for NSP-Minnesota are as follows:

(Millions of Dollars)	Pension Benefits		Postretirement Benefits	
	2023	2022	2023	2022
Change in Benefit Obligation:				
Obligation at Jan. 1	\$ 657	\$ 877	\$ 48	\$ 64
Service cost	21	27	—	—
Interest cost	36	25	3	2
Plan amendments	(1)	1	—	—
Actuarial (gain) loss	30	(139)	(2)	(13)
Plan participants' contributions	—	—	—	—
Benefit payments	(83)	(134)	(7)	(5)
Obligation at Dec. 31	\$ 660	\$ 657	\$ 42	\$ 48
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	\$ 570	\$ 853	\$ 5	\$ 3
Actual return on plan assets	52	(154)	—	—
Employer contributions	23	5	5	7
Plan participants' contributions	—	—	—	—
Benefit payments	(83)	(134)	(7)	(5)
Fair value of plan assets at Dec. 31	\$ 562	\$ 570	\$ 3	\$ 5
Funded status of plans at Dec. 31	\$ (98)	\$ (87)	\$ (39)	\$ (43)
Amounts recognized in the Balance Sheet at Dec. 31:				
Current liabilities	\$ —	\$ —	\$ (2)	\$ (1)
Noncurrent liabilities	(98)	(87)	(37)	(42)
Net amounts recognized	\$ (98)	\$ (87)	\$ (39)	\$ (43)

Significant Assumptions Used to Measure Benefit Obligations:	Pension Benefits		Postretirement Benefits	
	2023	2022	2023	2022
Discount rate for year-end valuation	5.49 %	5.80 %	5.54 %	5.80 %
Expected average long-term increase in compensation level	4.25 %	4.25 %	N/A	N/A
Mortality table	PRI-2012	PRI-2012	PRI-2012	PRI-2012
Health care costs trend rate — initial: Pre-65	N/A	N/A	6.50 %	6.50 %
Health care costs trend rate — initial: Post-65	N/A	N/A	5.50 %	5.50 %
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50 %	4.50 %
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50 %	4.50 %
Years until ultimate trend is reached	N/A	N/A	6	7

Accumulated benefit obligation for the pension plan was 599 million and 600 million as of Dec. 31, 2023 and 2022, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income (expense) in the statement of income.

Components of net periodic benefit cost (credit) and amounts recognized in other comprehensive income and regulatory assets and liabilities:

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

(Millions of Dollars)	Pension Benefits			Postretirement Benefits		
	2023	2022	2021	2023	2022	2021
Service cost	\$ 21	\$ 27	\$ 30	\$ —	\$ —	\$ —
Interest cost	36	25	25	3	2	2
Expected return on plan assets	(46)	(48)	(52)	—	—	—
Amortization of prior service cost	—	—	—	(1)	(3)	(3)
Amortization of net loss	11	24	34	—	1	2
Settlement charge ^(a)	—	38	35	—	—	—
Net periodic pension cost	22	66	72	2	—	1
Effects of regulation	16	(32)	(44)	—	—	—
Net benefit cost recognized for financial reporting	\$ 38	\$ 34	\$ 28	\$ 2	\$ —	\$ 1

Significant Assumptions Used to Measure Costs:

Discount rate	5.80 %	3.08 %	2.71 %	5.80 %	3.09 %	2.65 %
Expected average long-term increase in compensation level	4.25	3.75	3.75	—	—	—
Expected average long-term rate of return on assets	7.25	6.60	6.60	5.00	4.10	4.10

^(a) A settlement charge is required when the amount of lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2022 and 2021, as a result of lump-sum distributions during each plan year, NSP-Minnesota recorded a total pension settlement charge of \$38 million and \$35 million, respectively, which was not recognized in earnings due to the effects of regulation. There were no settlement charges recorded for the qualified pension plans in 2023.

(Millions of Dollars)	Pension Benefits		Postretirement Benefits	
	2023	2022	2023	2022
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	\$ 321	\$ 309	\$ 15	\$ 16
Prior service credit	—	—	—	(1)
Total	\$ 321	\$ 309	\$ 15	\$ 15
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Current regulatory assets	\$ 11	\$ 12	\$ —	\$ —
Noncurrent regulatory assets	310	297	14	14
Deferred income taxes	—	—	—	—
Net-of-tax accumulated other comprehensive income	—	—	1	1
Total	\$ 321	\$ 309	\$ 15	\$ 15

Measurement date	Dec 31, 2023	Dec 31, 2022	Dec 31, 2023	Dec 31, 2022
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Cash Flows —

Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2021 - 2024 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all 4 of Xcel Energy's pension plans were as follows:

- \$100 million in January 2024, of which \$41 million is attributable to NSP-Minnesota.
- \$50 million in 2023, of which \$23 million was attributable to NSP-Minnesota.
- \$50 million in 2022, of which \$5 million was attributable to NSP-Minnesota.
- \$131 million in 2021, of which \$34 million was attributable to NSP-Minnesota.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Xcel Energy's voluntary postretirement funding contributions were as follows:

- \$11 million expected in 2024, of which \$5 million is attributable to NSP-Minnesota.
- \$11 million during 2023, of which \$5 million, was attributable to NSP-Minnesota.
- \$13 million during 2022, of which \$7 million was attributable to NSP-Minnesota.
- \$15 million during 2021, of which \$8 million was attributable to NSP-Minnesota.

Targeted asset allocations:

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

	Pension Benefits		Postretirement Benefits	
	2023	2022	2023	2022
Long-duration fixed income and interest rate swap securities	38 %	38 %	— %	— %
Domestic and international equity securities	31	33	9	16
Alternative investments	20	18	13	12
Short-to-intermediate fixed income securities	9	9	77	71
Cash	2	2	1	1
Total	100 %	100 %	100 %	100 %

The asset allocations above reflect target allocations approved in the calendar year to take effect in the subsequent year

Plan Amendments — In 2023, Xcel Energy amended the Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) to reduce supplemental social security benefits for all active participants on and after Jan. 1, 2024.

There were no significant plan amendments made in 2022 which affected the postretirement benefit obligation.

In 2021, Xcel Energy amended the Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans.

Projected Benefit Payments

NSP-Minnesota's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Net Projected Postretirement Health Care Benefit Payments ^(a)
2024	\$ 100	\$ 5
2025	\$ 56	\$ 5
2026	\$ 56	\$ 4
2027	\$ 56	\$ 4
2028	\$ 55	\$ 4
2029-2033	\$ 273	\$ 15

^(a) Amount is reported net of expected Medicare Part D subsidies, which are immaterial.

Voluntary Retirement Program

Incremental to amounts presented above for postretirement benefits, Xcel Energy, which includes NSP-Minnesota, recognized new postemployment costs and obligations in the fourth quarter of 2023 for employees accepted to a voluntary retirement program.

Utilizing employee information and the following inputs, the estimated NSP-Minnesota obligations for the program of \$8 million for health plan subsidies and \$1 million for other medical benefits, each commencing in 2024, were recognized in the fourth quarter of 2023. These unfunded obligations are presented in other current liabilities and noncurrent pension and employee benefit obligations in the balance sheet as of Dec. 31, 2023.

Defined Contribution Plans

Xcel Energy, which includes NSP-Minnesota, maintains 401(k) and other defined contribution plans that cover most employees. The expense to these plans for NSP-Minnesota was approximately \$14 million, \$13 million, and \$12 million in 2023, 2022 and 2021, respectively.

Multiemployer Plans

NSP-Minnesota contributes to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees who may perform services for multiple employers and do not participate in the NSP-Minnesota sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota sponsored plans, in that if another participating employer ceases to contribute to a multiemployer pension plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

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9. Commitments and Contingencies

Legal

NSP-Minnesota is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation.

Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories.

In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on NSP-Minnesota's financial statements. Legal fees are generally expensed as incurred.

Rate Matters and Other

NSP-Minnesota is involved in various regulatory proceedings arising in the ordinary course of business. Until resolution, typically in the form of a rate order, uncertainties may exist regarding the ultimate rate treatment for certain activities and transactions. Amounts have been recognized for probable and reasonably estimable losses that may result. Unless otherwise disclosed, any reasonably possible range of loss in excess of any recognized amount is not expected to have a material effect on the financial statements.

Sherco — In 2018, NSP-Minnesota and Southern Minnesota Municipal Power Agency (Co-owner of Sherco Unit 3) reached a settlement with General Electric (GE) related to a 2011 incident, which damaged the turbine at Sherco Unit 3 and resulted in an extended outage. NSP-Minnesota notified the MPUC of its proposal to refund settlement proceeds to customers through the Fuel Clause Adjustment (FCA).

In March 2019, the MPUC approved NSP-Minnesota's settlement refund proposal. Additionally, the MPUC decided to withhold any decision as to NSP-Minnesota's prudence in connection with the incident at Sherco Unit 3 until after conclusion of an appeal pending between GE and NSP-Minnesota's insurers. In February 2020, the Minnesota Court of Appeals affirmed the district court's judgment in favor of GE.

In January 2021, the Minnesota Office of Attorney General and Minnesota Department of Commerce (DOC) recommended that NSP-Minnesota refund approximately \$17 million of replacement power costs previously recovered through the FCA. NSP-Minnesota responded that it acted prudently in connection with the Sherco Unit 3 outage, the MPUC has previously disallowed \$22 million of related costs and no additional refund or disallowance is appropriate.

In July 2022, the MPUC referred the matter to the Office of Administrative Hearings to conduct a contested case on the prudence of the replacement power costs incurred by NSP-Minnesota. In 2023, NSP-Minnesota and various parties filed recommendations, including the DOC which recommended a \$56 million customer refund. The Xcel Large Industrial customer group recommended a refund of \$72 million. A final decision by the MPUC is expected in mid-2024. A loss related to this matter is deemed remote.

MISO ROE Complaints —

In November 2013 and February 2015, customer groups filed two return on equity (ROE) complaints against MISO TOs, which includes NSP-Minnesota and NSP-Wisconsin. The first complaint requested a reduction in base ROE transmission formula rates from 12.38% to 9.15% for the time period of Nov. 12, 2013 to Feb. 11, 2015, and removal of ROE adders (including those for RTO membership). The second complaint requested, for a subsequent time period, a base ROE reduction from 12.38% to 8.67%.

The FERC subsequently issued various related orders related to ROE methodology/calculations and timing. NSP-Minnesota has processed refunds to customers for applicable complaint periods based on the ROE in the most recent applicable opinions.

The MISO TOs and various other parties have filed petitions for review of the FERC's most recent applicable opinions at the D.C. Circuit. In August 2022, the D.C. Circuit ruled that FERC had not adequately supported its conclusions, vacated FERC's related orders and remanded the issue back to FERC for further proceedings, which remain pending. Additional exposure, if any related to this matter is expected to be immaterial.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

Environmental

New and changing federal and state environmental mandates can create financial liabilities for NSP-Minnesota, which are normally recovered through the regulated rate process.

Site Remediation

Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. NSP-Minnesota may sometimes pay all or a portion of the cost to remediate sites where past activities of NSP-Minnesota's predecessors or other parties have caused environmental contamination.

Environmental contingencies could arise from various situations, including sites of former manufactured gas plants (MGPs); and third-party sites, such as landfills, for which NSP-Minnesota is alleged to have sent wastes to that site.

MGP, Landfill and Disposal Sites

NSP-Minnesota is investigating, remediating or performing post-closure actions at seven MGP, landfill or other disposal sites across its service territories.

NSP-Minnesota has recognized approximately \$1 million of costs/liabilities from final resolution of these issues, however, the outcome and timing are unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Water and Waste

Coal Ash Regulation — NSP-Minnesota's operations are subject to federal and state regulations that impose requirements for handling, storage, treatment and disposal of solid waste. Under the Coal Combustion Residuals Rule (CCR), utilities are required to complete groundwater sampling around their applicable landfills and surface impoundments.

NSP-Minnesota is conducting groundwater sampling and monitoring and implementing assessment of corrective measures at certain CCR landfills and surface impoundments. No results above the groundwater protection standards in the rule were identified.

Federal Clean Water Act Section 316(b) — The Federal Clean Water Act requires the United States Environmental Protection Agency (EPA) to regulate cooling water intake structures to assure they reflect the best technology available for minimizing impingement and entrainment of aquatic species. NSP-Minnesota estimates capital expenditures of approximately \$45 million may be required to comply with the requirements. NSP-Minnesota anticipates these costs will be recoverable through regulatory mechanisms.

Environmental Requirements — Air

Clean Air Act NOx Allowance Allocations — In June 2023, the EPA published final regulations under the "Good Neighbor" provisions of the Clean Air Act. The final rule applies to generation facilities in Minnesota, as well as other states outside of our service territory. The rule establishes an allowance trading program for Nitrogen Oxides (NOx) that will impact NSP-Minnesota's fossil fuel-fired electric generating facilities. Applicable facilities will have to secure additional allowances, install NOx controls and/or develop a strategy of operations that utilizes the existing allowance allocations. Guidelines are also established for allowance banking and emission limit backstops.

While the financial impacts of the final rule are uncertain and dependent on market forces and anticipated generation, NSP-Minnesota anticipates the annual costs could be significant, but would be recoverable through regulatory mechanisms.

NSP-Minnesota has joined other companies in litigation challenging the EPA's disapproval of Minnesota's state implementation plan. Currently, the regulation is under a judicial stay for Minnesota and not applicable to NSP-Minnesota pending the outcome of the litigation.

AROs — AROs have been recorded for NSP-Minnesota's assets. For nuclear assets, the ARO is associated with the decommissioning of NSP-Minnesota nuclear generating plants.

Aggregate fair value of NSP-Minnesota's legally restricted assets for funding future nuclear decommissioning was \$3.2 billion and \$2.9 billion at Dec. 31, 2023 and 2022, respectively.

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Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

(Millions of Dollars)	2023					
	Jan. 1, 2023	Amounts Incurred ^(a)	Amounts Settled	Accretion	Cash Flow Revisions ^(b)	Dec. 31, 2023
Electric						
Nuclear	\$ 2,160	\$ —	\$ —	\$ 105	\$ (158)	\$ 2,107
Wind	416	10	—	15	(17)	424
Steam and other production	75	—	—	2	—	77
Distribution	16	—	—	1	—	17
Natural gas						
Transmission and distribution	59	—	—	2	(29)	32
Other						
Miscellaneous	1	—	—	—	—	1
Total liability	\$ 2,727	\$ 10	\$ —	\$ 126	\$ (204)	\$ 2,658

(a) Amounts incurred relate to the Northern Wind farm placed in service in NSP-Minnesota.

(b) In 2023, AROs were revised for changes in timing and estimates of cash flows. Changes in wind and nuclear AROs were primarily incurred due to changes in useful lives. Changes in gas transmission and distribution AROs were changes to inflation and discount rate assumptions as well as updated mileage of gas lines and number of services.

(Millions of Dollars)	2022					
	Jan. 1, 2022	Amounts Incurred ^(a)	Amounts Settled ^(b)	Accretion	Cash Flow Revisions ^(b)	Dec. 31, 2022
Electric						
Nuclear	\$ 2,056	\$ —	\$ —	\$ 104	\$ —	\$ 2,160
Wind	384	25	—	15	(8)	416
Steam and other production	73	—	—	2	—	75
Distribution	16	—	—	—	—	16
Natural gas						
Transmission and distribution	55	—	—	2	2	59
Other						
Miscellaneous	1	—	—	—	—	1
Total liability	\$ 2,585	\$ 25	\$ —	\$ 123	\$ (6)	\$ 2,727

(a) Amounts incurred relate to the wind farms placed in service in 2022 (Dakota Range and Rock Aetna).

(b) In 2022, AROs were revised for changes in timing and estimates of cash flows. Changes in electric wind AROs were related to the repowering and extended retirement date of Nobles. Changes in gas transmission and distribution AROs were primarily related to changes in labor rates coupled with increased gas line mileage and number of services.

Indeterminate AROs — Outside of the recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of NSP-Minnesota's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2023. Therefore, an ARO has not been recorded for these facilities.

Nuclear Related

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to \$16.2 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has \$450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining \$15.8 billion of exposure is funded by the Secondary Financial Protection Program available from assessments by the federal government.

NSP-Minnesota is subject to assessments of up to \$166 million per reactor-incident for each of its three reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is \$25 million per reactor-incident during any one year. Maximum assessments are subject to inflation adjustments.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd (NEIL) and European Mutual Association for Nuclear Insurance (EMANI). The coverage limits are \$2.8 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage up to \$490 million and \$420 million at Monticello and Prairie Island, respectively, including the cost of replacement power during prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term.

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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 and EMANI 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. NSP-Minnesota could be subject to annual maximum assessments of \$15 million for business interruption insurance and \$32 million for property damage insurance if losses exceed accumulated reserve funds.

Nuclear Fuel Disposal — NSP-Minnesota is responsible for temporarily storing spent nuclear fuel from its nuclear plants. The United States Department of Energy is responsible for permanently storing spent fuel from U.S. nuclear plants, but no such facility is yet available.

NSP-Minnesota owns temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities. The Monticello dry-cask storage facility currently stores all 30 of the authorized canisters. Monticello's future spent fuel will continue to be placed in its spent fuel pool. The decommissioning plan addresses the disposition of spent fuel at the end of the licensed life. In October 2023, a certificate of need (CON) for additional storage at the Monticello site was approved by the MPUC to support possible life extension to 2040.

The PI dry-cask storage facility currently stores 50 of the 64 authorized casks. In February 2023, NSP-Minnesota filed a CON with the MPUC for additional storage at PI to support possible life extension to 2054.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's authorized retirement dates, which can be different than the currently approved NRC operating licenses. These decommissioning activities are planned to be completed at both facilities by 2101.

NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2. The MPUC reaffirmed a 60-year DECON scenario, where Monticello continues operations under a 10-year license extension (approved in August 2022). NRC approval of the extension is pending.

In February 2023, NSP-Minnesota also filed an application with the North Dakota Public Service Commission for an Advance Determination of Prudence for continued operation of the Monticello Plant until at least 2040. A decision is expected in 2024.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit. The MPUC ordered the next triennial decommissioning study be filed by Dec. 1, 2024.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. NSP-Minnesota had \$3.2 billion and \$2.9 billion of assets held in external decommissioning trusts at Dec. 31, 2023, and 2022, respectively.

See Note 9 to the financial statements for additional discussion.

Leases

NSP-Minnesota evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset. A contract determined to contain a lease is evaluated further to determine if the arrangement is a finance lease.

Right-of-use (ROU) assets represent NSP-Minnesota's rights to use leased assets. The present value of future operating lease payments is recognized in current and noncurrent operating lease liabilities. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets.

Most of NSP-Minnesota's leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using the estimated incremental borrowing rate (weighted average of 4.6%). For currently existing asset classes, NSP-Minnesota has elected to utilize the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from lease payments for the purposes of lease accounting and disclosure.

Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	Dec. 31, 2023	Dec. 31, 2022
PPAs	\$ 709	\$ 556
Other	125	78
Gross operating lease ROU assets	834	634
Accumulated amortization	(395)	(310)
Net operating lease ROU assets	\$ 439	\$ 324

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Components of lease expense:

(Millions of Dollars)	2023	2022	2021
Operating leases			
PPA capacity payments	\$ 100	\$ 98	\$ 96
Other operating leases ^(a)	13	9	8
Total operating lease expense ^(b)	\$ 113	\$ 107	\$ 104

^(a) Includes short-term lease expense of \$2 million, \$3 million and \$2 million for 2023, 2022 and 2021, respectively.

^(b) PPA capacity payments are included in electric fuel and purchased power on the statement of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

Commitments under operating leases as of Dec. 31, 2023 in Accounts 227 and 243:

(Millions of Dollars)	PPA ^{(a) (b)} Operating Leases	Other Operating Leases	Total Operating Leases
2024	\$ 99	\$ 11	\$ 110
2025	101	11	112
2026	89	11	100
2027	72	11	83
2028	40	10	50
Thereafter	—	125	125
Total minimum obligation	401	179	580
Interest component of obligation	(37)	(80)	(117)
Present value of minimum obligation	\$ 364	\$ 99	463
Less current portion			(91)
Noncurrent operating lease liabilities			\$ 372

Weighted-average remaining lease term in years 9.8

^(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

^(b) PPA operating leases contractually expire at various dates through 2039.

PPAs and Fuel Contracts

Non-Lease PPAs — NSP-Minnesota has entered into PPAs with other utilities and energy suppliers for purchased power to meet system load and energy requirements, operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered, and may also include capacity payments. Certain PPAs, accounted for as executory contracts with various expiration dates through 2033, contain minimum energy purchase commitments. Total energy payments on those contracts were \$185 million, \$182 million and \$149 million in 2023, 2022 and 2021, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of \$62 million, \$60 million and \$55 million in 2023, 2022 and 2021, respectively.

Capacity and energy payments are contingent on the independent power producing entities meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on financial results are mitigated through purchased energy cost recovery mechanisms.

At Dec. 31, 2023, the estimated future payments for capacity and energy that NSP-Minnesota is obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity	Energy ^(a)
2024	\$ 63	\$ 174
2025	27	53
2026	9	10
2027	8	10
2028	1	10
Thereafter	2	18
Total ^(b)	\$ 110	\$ 275

^(a) Excludes contingent energy payments for renewable energy PPAs.

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(b) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Fuel Contracts — NSP-Minnesota has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2024 and 2037. NSP-Minnesota is required to pay additional amounts depending on actual quantities delivered under these agreements.

Estimated minimum purchases for these contracts as of Dec. 31, 2023:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and
2024	\$ 115	\$ 142	\$ 88	\$ 148
2025	62	179	1	131
2026	21	63	—	128
2027	1	180	—	96
2028	—	50	—	28
Thereafter	—	177	—	47
Total (a)	\$ 199	\$ 791	\$ 89	\$ 578

(a) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

10. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the years ended Dec. 31:

(Millions of Dollars)	2023		
	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	\$ (16)	\$ (2)	\$ (18)
Other comprehensive loss before reclassifications, net of taxes of \$-	(3)	—	(3)
Losses reclassified from net accumulated other comprehensive loss:			
Amortization of interest rate hedges	1 (a)	—	1
Net current period other comprehensive income	(2)	—	(2)
Accumulated other comprehensive loss at Dec. 31	\$ (18)	\$ (2)	\$ (20)

(a) Included in interest charges.

(Millions of Dollars)	2022		
	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	\$ (17)	\$ (3)	\$ (20)
Other comprehensive loss before reclassifications, net of taxes of \$-		1	1
Losses reclassified from net accumulated other comprehensive loss:			
Amortization of interest rate hedges	1 (a)	—	1
Net current period other comprehensive income	1	1	2
Accumulated other comprehensive loss at Dec. 31	\$ (16)	\$ (2)	\$ (18)

(a) Included in interest charges.

11. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy Inc., including NSP-Minnesota. The services are provided and billed to each subsidiary in accordance with service agreements executed by each subsidiary. NSP-Minnesota uses the services provided by Xcel Energy Services Inc. whenever possible. Costs are charged directly to the subsidiary and are allocated if they cannot be directly assigned.

Xcel Energy, Inc., NSP-Minnesota, NSP-Wisconsin, Public Service Company of Colorado (PSCo) and Southwestern Public Service Company (SPS) have established a utility money pool arrangement.

See Note 5 for further information.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	4/4/2024	End of 2023/Q4

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. The Interchange Agreement provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs.

Significant affiliate transactions among the companies and related parties including billings under the Interchange Agreement for the years ended Dec. 31:

(Millions of Dollars)	2023	2022
Operating revenues:		
Electric	\$ 493	\$ 514
Gas	1	—
Operating expenses:		
Purchased power	63	70
Transmission expense	142	132
Other operating expenses — paid to Xcel Energy Services Inc.	719	673
Interest expense	5	—
Interest income	1	—

Accounts receivable and payable with affiliates at Dec. 31:

(Millions of Dollars)	2023		2022	
	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	\$ 9	\$ —	\$ 4	\$ —
PSCo	5	—	—	2
SPS	—	4	—	3
Other subsidiaries of Xcel Energy Inc.	1	87	42	86
	\$ 15	\$ 91	\$ 46	\$ 91

12. Supplementary Cash Flow Data

(Millions of Dollars)	Year Ended Dec. 31	
	2023	2022
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	\$ (311)	\$ (271)
Cash received (paid) for income taxes, net	256	(100)
Supplemental disclosure of non-cash investing transactions:		
Accrued utility plant additions	\$ 218	\$ 208
Inventory transfers to utility plant	55	10
Operating lease right-of-use assets	216	1
Allowances for funds used during construction	36	29

13. Workforce Reduction

In 2023, Xcel Energy implemented workforce actions to align resources and investments with evolving business and customer needs, and streamline the organization for long-term success.

In September 2023, Xcel Energy announced a voluntary retirement program to a group of eligible non-bargaining employees, with an enhanced retirement package including certain health care and cash benefits for accepted employees. Approximately 400 employees retired under this program in December 2023.

In November 2023, Xcel Energy, Inc. also reduced its non-bargaining workforce by approximately 150 employees through an involuntary severance program.

In the fourth quarter of 2023, Xcel Energy recorded total expense of \$72 million related to these workforce actions, of which \$32 million was attributable to NSP-Minnesota. Expenses relate to the estimated cost of future health plan subsidies and other medical benefits for the voluntary retirement program, as well as severance and other employee payouts and legal and other professional fees.

For further information on the estimated obligations for future health plan subsidies and other medical benefits, see Note 8 to the financial statements.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) 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.
4. Report data on a year-to-date basis.

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)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year	742,875			(3,211,336)	(17,920,863)		(20,389,324)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				8,425	570,322		578,747		
3	Preceding Quarter/Year to Date Changes in Fair Value				1,189,680	192,415		1,382,095		
4	Total (lines 2 and 3)				1,198,105	762,737		1,960,842	674,768,340	676,729,182
5	Balance of Account 219 at End of Preceding Quarter/Year	742,875			(2,013,231)	(17,158,126)		(18,428,482)		
6	Balance of Account 219 at Beginning of Current Year	742,875			(2,013,231)	(17,158,126)		(18,428,482)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				(84,639)	691,591		606,952		
8	Current Quarter/Year to Date Changes in Fair Value	(742,875)			669,178	(1,980,974)		(2,054,671)		
9	Total (lines 7 and 8)	(742,875)			584,539	(1,289,383)		(1,447,719)	707,233,792	705,786,073
10	Balance of Account 219 at End of Current Quarter/Year				(1,428,692)	(18,447,509)		(19,876,201)		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	23,122,767,218	20,219,431,155	1,969,837,956				933,498,107
4	Property Under Capital Leases	439,114,707	215,534,843					223,579,864
5	Plant Purchased or Sold							
6	Completed Construction not Classified	3,816,332,144	3,210,554,646	290,087,184				315,690,314
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	27,378,214,069	23,645,520,644	2,259,925,140				1,472,768,285
9	Leased to Others							
10	Held for Future Use	29,304,092						29,304,092
11	Construction Work in Progress	1,091,213,892	924,939,975	52,155,607				114,118,310
12	Acquisition Adjustments	77,527,253	77,527,253					
13	Total Utility Plant (8 thru 12)	28,576,259,306	24,647,987,872	2,312,080,747				1,616,190,687
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	10,464,116,598	9,184,752,318	781,259,356				498,104,924
15	Net Utility Plant (13 less 14)	18,112,142,708	15,463,235,554	1,530,821,391				1,118,085,763
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							

18	Depreciation	9,810,765,257	8,874,406,430	772,129,495				164,229,332
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	643,932,708	(9)300,927,255	9,129,861				333,875,592
22	Total in Service (18 thru 21)	10,454,697,965	9,175,333,685	781,259,356				498,104,924
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	9,418,633	(9)9,418,633					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	10,464,116,598	9,184,752,318	781,259,356				498,104,924

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases			
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.			
Account 101.1			
Finance Lease Asset	\$		—
Operating Right of Use Asset			439,114,707
Total	\$		439,114,707
(b) Concept: AmortizationOfOtherUtilityPlantUtilityPlantInService			
The amortization of other utility plant within account 111 includes the following:			
Intangible Plant	\$		148,139,743
Nuclear Production Plant			141,488,885
Other Production			8,292,611
Hydraulic Production Plant-Conventional			3,006,016
Total Amort of Other Utility Plant - Electric	\$		300,927,255
(c) Concept: AmortizationOfPlantAcquisitionAdjustment			
The amortization of plant acquisition adjustment within account 115 includes the following:			
Other Production	\$		9,343,140
Transmission			75,493
Total Amort of Plant Acquisition Adj - Electric	\$		9,418,633

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication	7,240,978	30,896,761		37,359,615	778,124
3	Nuclear Materials	113,532,706	115,272,234		116,776,046	112,028,894
4	Allowance for Funds Used during Construction	9,540,932	7,822,159		9,253,093	8,109,998
5	(Other Overhead Construction Costs, provide details in footnote)	105,537	132,826		105,931	132,432
6	SUBTOTAL (Total 2 thru 5)	130,420,153	154,123,980		163,494,685	121,049,448
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)		163,181,307		89,158,835	74,022,472
9	In Reactor (120.3)	555,418,343	104,009,271		101,486,700	557,940,914
10	SUBTOTAL (Total 8 & 9)	555,418,343	267,190,578		190,645,535	631,963,386
11	Spent Nuclear Fuel (120.4)	2,496,920,483	101,486,700		14,837,524	2,583,569,659
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,891,602,507		(96,379,479)		2,987,981,986
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	291,156,472				348,600,507
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					

17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

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FOOTNOTE DATA			

(a) Concept: NuclearFuelMaterialsAndAssembliesInStockAdditions
Consists of transfers from 120.1 , and direct trailing charges to asset after in-service
(b) Concept: FabricationCostsNuclearFuellnProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Classified to Account 120.2 and 120.3
(c) Concept: NuclearMaterialsNuclearFuellnProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Classified to Account 120.2 and 120.3
(d) Concept: AllowanceForFundsConstructionNuclearFuellnProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Classified to Account 120.2 and 120.3
(e) Concept: OtherOverheadConstructionCostsNuclearFuellnProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Classified to Account 120.2 and 120.3
(f) Concept: NuclearFuelMaterialsAndAssembliesInStockOtherReductions
Transferred to Account 120.3
(g) Concept: NuclearFuelAssembliesInReactorOtherReductions
Transferred to Account 120.4
(h) Concept: SpentNuclearFuelOtherReductions
Transferred to Account 120.3
(i) Concept: OtherOverheadConstructionCostsNuclearFuellnProcessOfRefinementConversionEnrichmentAndFabrication
Consists of Administrative and General Costs
(j) Concept: NuclearFuelAssembliesInReactor
Net Salvage Values (Line No: 15 to 16 Column: f) are not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982
(k) Concept: SpentNuclearFuel
Net Salvage Values (Line No: 15 to 16 Column: f) are not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

- Report below the original cost of electric plant in service according to the prescribed accounts.
- 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.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- 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 the 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) 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 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.
- 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.
- 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.
- 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.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	260,783,156	2,891,065				263,674,221
4	(303) Miscellaneous Intangible Plant	204,535,622	52,543,455	16,894,576			240,184,501
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	465,318,778	55,434,520	16,894,576			503,858,722
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	10,113,068		1,523			10,111,545
9	(311) Structures and Improvements	295,748,996	4,524,048	578,340			299,694,704
10	(312) Boiler Plant Equipment	1,522,506,363	23,393,338	165,795,484			1,380,104,217
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	329,618,927	5,554,688	55,644,841			279,528,774

13	(315) Accessory Electric Equipment	187,699,440	2,147,133	5,367,299		184,479,274
14	(316) Misc. Power Plant Equipment	54,655,604	343,936	1,679,003		53,320,537
15	(317) Asset Retirement Costs for Steam Production	20,240,869				20,240,869
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,420,583,267	35,963,143	229,066,490		2,227,479,920
17	B. Nuclear Production Plant					
18	(320) Land and Land Rights	1,757,711				1,757,711
19	(321) Structures and Improvements	608,862,639	29,615,560	2,406,063		636,072,136
20	(322) Reactor Plant Equipment	1,990,646,120	77,549,698	8,420,383		2,059,775,435
21	(323) Turbogenerator Units	643,188,438	44,782,150	7,097,943		680,872,645
22	(324) Accessory Electric Equipment	544,554,756	18,133,669	1,618,146		561,070,279
23	(325) Misc. Power Plant Equipment	210,509,641	2,174,195	331,084		212,352,752
24	(326) Asset Retirement Costs for Nuclear Production	(222,547,594)	(158,322,618)			(380,870,212)
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	3,776,971,711	13,932,654	19,873,619		3,771,030,746
26	C. Hydraulic Production Plant					
27	(330) Land and Land Rights	1,693,076				1,693,076
28	(331) Structures and Improvements	1,478,389	79,364			1,557,753
29	(332) Reservoirs, Dams, and Waterways	11,157,411	155,107			11,312,518
30	(333) Water Wheels, Turbines, and Generators	10,156,576				10,156,576
31	(334) Accessory Electric Equipment	3,295,922				3,295,922
32	(335) Misc. Power Plant Equipment	126,048	7,953			134,001
33	(336) Roads, Railroads, and Bridges	152,109				152,109
34	(337) Asset Retirement Costs for Hydraulic Production					
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	28,059,531	242,424			28,301,955
36	D. Other Production Plant					
37	(340) Land and Land Rights	33,624,745	2,763,397			36,388,142

38	(341) Structures and Improvements	521,092,532	1,885,198	163,270		522,814,460
39	(342) Fuel Holders, Products, and Accessories	28,428,019	2,183,678	297,236		30,314,461
40	(343) Prime Movers	143,823,722	3,862,174	66,526		147,619,370
41	(344) Generators	4,075,350,126	356,941,346	196,239,100		4,236,052,372
42	(345) Accessory Electric Equipment	344,399,042	30,129,073	7,380,247		367,147,868
43	(346) Misc. Power Plant Equipment	62,528,877	3,661,780	1,414,408		64,776,249
44	(347) Asset Retirement Costs for Other Production	361,521,242	(7,417,141)			354,104,101
44.1	(348) Energy Storage Equipment - Production	4,128,902				4,128,902
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	5,574,897,207	394,009,505	205,560,787		5,763,345,925
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	11,800,511,716	444,147,726	454,500,896		11,790,158,546
47	3. Transmission Plant					
48	(350) Land and Land Rights	169,631,547	3,389,064	157,458	(98)	172,863,055
48.1	(351) Energy Storage Equipment - Transmission					
49	(352) Structures and Improvements	157,833,309	11,951,996	522,098		169,263,207
50	(353) Station Equipment	1,493,863,966	94,980,143	1,664,669		1,587,179,440
51	(354) Towers and Fixtures	127,646,774	30,058	893		127,675,939
52	(355) Poles and Fixtures	1,588,386,480	97,039,544	149,796		1,685,276,228
53	(356) Overhead Conductors and Devices	701,277,652	63,510,444	424,851		764,363,245
54	(357) Underground Conduit	32,181,582				32,181,582
55	(358) Underground Conductors and Devices	35,433,528	296,582	113,800		35,616,310
56	(359) Roads and Trails	334,471	2,822,712			3,157,183
57	(359.1) Asset Retirement Costs for Transmission Plant	173,429				173,429
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	(a) 4,306,762,738	274,020,543	3,033,565	(98)	(a) 4,577,749,618
59	4. Distribution Plant					

60	(360) Land and Land Rights	19,792,554	507,671	168,682		98	20,131,641
61	(361) Structures and Improvements	63,787,497	3,143,680	132,609			66,798,568
62	(362) Station Equipment	765,479,470	45,640,064	2,092,313			809,027,221
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	650,535,941	94,890,995	748,397			744,678,539
65	(365) Overhead Conductors and Devices	655,121,856	68,639,692	2,661,542			721,100,006
66	(366) Underground Conduit	397,655,482	15,708,087	182,486			413,181,083
67	(367) Underground Conductors and Devices	1,430,081,925	56,700,084	1,327,204			1,485,454,805
68	(368) Line Transformers	529,089,102	46,247,419	6,320,365			569,016,156
69	(369) Services	421,786,234	35,114,762	469,711			456,431,285
70	(370) Meters	118,182,797	91,516,600	19,000,220			190,699,177
71	(371) Installations on Customer Premises	4,761,556	8,117,636				12,879,192
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	93,662,402	6,830,446	274,277			100,218,571
74	(374) Asset Retirement Costs for Distribution Plant	12,231,038					12,231,038
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,162,167,854	473,057,136	33,377,806		98	5,601,847,282
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						

83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	19,740,754	291,550				20,032,304
87	(390) Structures and Improvements	82,653,268	15,820,410	119,112			98,354,566
88	(391) Office Furniture and Equipment	103,246,712	39,332,402	10,164,346		88,632	132,503,400
89	(392) Transportation Equipment	227,393,626	20,885,962				248,279,588
90	(393) Stores Equipment	1,666,735	374,959	92,362			1,949,332
91	(394) Tools, Shop and Garage Equipment	135,485,006	20,003,124	4,584,044			150,904,086
92	(395) Laboratory Equipment	2,991,620	3,093	28,884			2,965,829
93	(396) Power Operated Equipment	58,772,486	12,006,780				70,779,266
94	(397) Communication Equipment	203,429,985	27,894,313	2,609,712			228,714,586
95	(398) Miscellaneous Equipment	1,902,514	31,526	45,364			1,888,676
96	SUBTOTAL (Enter Total of lines 86 thru 95)	837,282,706	136,644,119	17,643,824		88,632	956,371,633
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	837,282,706	136,644,119	17,643,824		88,632	956,371,633
100	TOTAL (Accounts 101 and 106)	22,572,043,792	1,383,304,044	525,450,667		88,632	23,429,985,801
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	22,572,043,792	1,383,304,044	525,450,667		88,632	23,429,985,801

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FOOTNOTE DATA			

(a) Concept: TransmissionPlant

Transmission Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 350 - Land & Land Rights	\$ 157,969	\$ —	\$ —	\$ —	\$ —	\$ 157,969
Account 352 - Structures & Improvements	22,477,830	—	(241,359)	—	—	22,236,471
Account 353 - Station Equipment	131,425,033	—	(42,787)	—	—	131,382,246
Account 354 - Towers & Fixtures	4,916,560	—	—	—	—	4,916,560
Account 355 - Poles & Fixtures	18,707,582	—	—	—	—	18,707,582
Account 356 - Overhead Conductors & Devices	13,815,771	394	—	—	—	13,816,165

(b) Concept: DistributionPlant

Distribution Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 361 - Structures & Improvements	\$ 838,281	\$ —	\$ —	\$ —	\$ —	\$ 838,281
Account 362 - Station Equipment	4,224,690	—	—	—	—	4,224,690

(c) Concept: IntangiblePlant

Electric Plant in Service (Accounts 101, 102, 103 and 106). The Form 1 reports total intangible plant (line 5), production plant (line 46), transmission plant (line 58), distribution plant (line 75) and general plant (line 99) at the beginning of the year and at the end of the year. The Company uses a 13-month average calculation for the plant in service balances included in the formula. Production plant and distribution plant balances are included in the development of the gross plant and net plant allocators that are used to allocate cost to the transmission function in the formula.

(d) Concept: ProductionPlant

Electric Plant in Service (Accounts 101, 102, 103 and 106). The Form 1 reports total intangible plant (line 5), production plant (line 46), transmission plant (line 58), distribution plant (line 75) and general plant (line 99) at the beginning of the year and at the end of the year. The Company uses a 13-month average calculation for the plant in service balances included in the formula. Production plant and distribution plant balances are included in the development of the gross plant and net plant allocators that are used to allocate cost to the transmission function in the formula.

(e) Concept: TransmissionPlant

Electric Plant in Service (Accounts 101, 102, 103 and 106). The Form 1 reports total intangible plant (line 5), production plant (line 46), transmission plant (line 58), distribution plant (line 75) and general plant (line 99) at the beginning of the year and at the end of the year. The Company uses a 13-month average calculation for the plant in service balances included in the formula. Production plant and distribution plant balances are included in the development of the gross plant and net plant allocators that are used to allocate cost to the transmission function in the formula.

(f) Concept: DistributionPlant

Electric Plant in Service (Accounts 101, 102, 103 and 106). The Form 1 reports total intangible plant (line 5), production plant (line 46), transmission plant (line 58), distribution plant (line 75) and general plant (line 99) at the beginning of the year and at the end of the year. The Company uses a 13-month average calculation for the plant in service balances included in the formula. Production plant and distribution plant balances are included in the development of the gross plant and net plant allocators that are used to allocate cost to the transmission function in the formula.

(g) Concept: GeneralPlant

Electric Plant in Service (Accounts 101, 102, 103 and 106). The Form 1 reports total intangible plant (line 5), production plant (line 46), transmission plant (line 58), distribution plant (line 75) and general plant (line 99) at the beginning of the year and at the end of the year. The Company uses a 13-month average calculation for the plant in service balances included in the formula. Production plant and distribution plant balances are included in the development of the gross plant and net plant allocators that are used to allocate cost to the transmission function in the formula.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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	^(a) See Footnote			
21	Other Property:			
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47	TOTAL			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: ElectricPlantHeldForFutureUseDescription

Electric Plant Held for Future Use (Account 105). The Form 1 reports the plant held for future use balances at the end of the year. NSP-Minnesota uses only the transmission-related land and land rights plant held for future use in the formula. NSP-Minnesota uses a 13-month average calculation for the plant in service balances included in the formula.

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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 \$1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	SHC Solar Generating Plant #1	171,447,722
2	SHC Solar Generating Plant #2	67,538,749
3	CSC Redevelopment ? Phase 1	35,750,326
4	PI TN-40 Casks (48-64)	29,033,910
5	0980 -Str 2 -27A (Phase 2)	25,399,259
6	SHC Solar Gen Plant III New-25233	17,290,259
7	MT 2nd License Renewal	16,958,363
8	BLL01 – Blue Lake Repowering	16,189,729
9	MN-Dist Fleet NewUnit Prchse EI Ops	14,749,152
10	ELR MN Sub Feeder Breakers	11,390,796
11	SHC SS West Collector Sub	10,711,526
12	0761 LAK ZUM Rebuild	10,669,596
13	PVW Pleasant Valley Repower	9,718,434
14	SHC to SSW Line 5651 T-Line	8,195,189
15	ITC-DI Services Platform SW 200117	8,043,882
16	AGIS Meter Data Mgmt (MDM) SW MN	7,738,127
17	0980 - Str 2-27A - 50 (Phase 1)	7,334,432
18	MN Transportation Units Over 50K	7,286,019
19	Rebuild Downtown St. Paul Manholes	7,135,784
20	BWF Border Wind Repower	6,554,238
21	0726 Moon Lake-GRE Currie tap rebui	6,443,693

22	LINE Convert Larimore LAR 4kV	6,288,518
23	DER Reinforce Merriam Park MPK Fdrs	6,222,780
24	NSM0734 West Gate Excelsor Line	5,990,491
25	AMI-Meter-Data-Lake-BS-SW-NSPM	5,966,484
26	Sioux Falls Renovation	5,947,736
27	Belgrade SC New	5,729,475
28	MT Groundwater Hardening	5,616,451
29	SUB Install Louise LOU TR2	5,551,865
30	SUB MN Feeder Load Monitoring	5,217,401
31	LINE Install Great Plains Area Sub	4,876,945
32	MT Install Vertical Engineered Barr	4,844,383
33	SHC SS East Collector Sub	4,841,557
34	Mallard TR1 TR2 and BKR 5T7	4,783,064
35	NSM0779 - Canisota Juntion - Salem,	4,740,231
36	ITC-VOIP Ref Prairie Island NP MN	4,571,111
37	PI Control Cable Replacement	4,520,791
38	MT - WRGM Replacement	4,301,378
39	Coon Creek 345KV Breakers	4,199,586
40	ITC ISO Intrfc & Stlmt Rpl SW MN-20	4,163,860
41	ITC-ADMS-OMS Merge Upgrade CE MN	4,047,501
42	SUB Reinf Dayton's Bluff DBL Sub	4,004,994
43	COMM MN Fiber Buildout	3,680,968
44	MN Energy Connection Pre-Con	3,678,553
45	Chanhassen New SC	3,661,590
46	Reinforce HYL feeder exits	3,593,645
47	ELR MPLS Network Protectors	3,568,908
48	MT Rplc Bleach House Tank/Pump	3,515,682
49	LINE Convert North Broadway NBY 4kV	3,500,698

50	HBC7 Hot Gas Path-24006	3,462,145
51	Lake Pulaski (LAP) TR06	3,364,340
52	AMI-DIST-NSPM-MN Full AMI	3,199,430
53	PRA BKR 4G9 & RLY 5G4, 5G9, NOR1, N	3,097,978
54	NSM0703 FRM KLK Rebuild	3,094,793
55	COMM MN Feeder Load Monitoring	2,978,711
56	ADMS Data - NSPM	2,839,975
57	ITC-My Energy Connection 3.0 SW MN	2,650,574
58	ITC-Monti VOIP Ref. Ph2 NP MN	2,630,195
59	HBC0-Diasys Controls Replacement-22	2,553,117
60	ELR MPLS Vault Tops	2,486,560
61	Reserve TR 115-13.8 kV 50 MVA (1 of 2)	2,451,513
62	Reserve TR 115-13.8 kV 50 MVA	2,447,924
63	MT #12 EDG Voltage Regulator	2,344,493
64	MT Equipment Sensors	2,342,177
65	Nighthawk Substation	2,340,049
66	BRT Gold Line Relocation NPT	2,321,421
67	Prairie Island Control Cables	2,210,507
68	C OH-UG BCR062 (Minnetonka)	2,131,709
69	Reinforce Shepard SHP062 and SHP071	2,043,600
70	PI 22 RCP Seal Repl	2,042,623
71	ASK1-Repl AQCS Baghouse Bags 2023-1	1,981,589
72	PI Equipment Sensors (A/I)	1,949,939
73	MISO LRTP4 pre-con MN	1,939,799
74	SUB ELR Install Gaiter Lake Sub	1,927,320
75	Relocate STP Tunnel Feeders	1,889,910
76	NSM0984 CNC SHC REPL STRS PH3	1,882,600
77	PI U1 Baffle Bolt Replacement	1,868,489

78	Rebuild Red River RED Feeders	1,847,415
79	Reserve TR 115/23.9 kV 50 MVA	1,791,889
80	MT 2026 ISFSI Expansion	1,784,082
81	Pot Parallel Prairie Island 345kV	1,783,763
82	ELR MN Sub Fences	1,778,604
83	MISO LRTP 2 pre-con MN	1,754,821
84	PI NI Drawer Replacement	1,729,520
85	PI SSIS Software Suite	1,729,024
86	HBC7C GT EXHAUST REPL-24689	1,725,085
87	Hugo Training Center Sub	1,680,515
88	NSM0953 NOB SPK REPL OPGW MN	1,641,166
89	MN-Dist Fleet ADD Unit Purchase E >	1,637,374
90	Extend Main Street MST074	1,630,182
91	NSM0992 CNC SHC REPL STRS PH3	1,620,127
92	MT ISI/IST Overhaul Program	1,608,642
93	Relocate STY061 (Oakdale Ave)	1,589,627
94	Reserve Transformer 118-14.3 kV 70	1,587,812
95	Louise- Install 115kV Bkr	1,570,006
96	T Underbuild Delano to Dassel	1,544,015
97	BRT Gold Line Relocation STP	1,535,323
98	SW Lic Rnwl-App Del-101630-MN-E	1,523,765
99	Replace FLS064 8th-10th S Phillips	1,521,810
100	FCR WSF063 mainline sub w41	1,516,933
101	C Install Elm Creek ECK342 Feeder	1,480,566
102	Install Feeder Tie SDX312-FSL311	1,478,009
103	MN-Fleet ADD Units EI Trans >50K	1,467,774
104	LINE Install Souris SOR083	1,463,937
105	Prairie Island Physical Security In	1,453,417

106	SW Lic Rnwl-Infra-102025-MN-E	1,422,600
107	Purch Synchrophasor Net HW MN	1,420,751
108	Install Network Monitoring Mpls	1,412,621
109	Minnesota Valley-Replace 69 kV & 11	1,366,848
110	0704 (HAS-W3410T) Private Comm Net	1,357,459
111	PI ERCS Computer Rm AC Repl	1,354,678
112	MT RX CW Piping Rplc - Ph 3	1,350,889
113	RRK - 115kV Ampacity Upgrade	1,343,667
114	MT T-2 T-3 TRB Bearing	1,321,262
115	FXW CESP Wind Resiliency Trnsfmr -2	1,294,967
116	NSM0790 Howard Lake- Waverly Rebuil	1,266,556
117	Reserve TR 69/13.8 kV 28 MVA	1,258,392
118	SUB Rebuild Belgrade Substation	1,234,988
119	ITC-SubTran Portal App SW 200123 MN	1,233,860
120	ELR MN Sub RTUs	1,219,556
121	MN Electric Vehicle Program FLEET	1,205,699
122	MT 2023 Maintenance Blanket	1,196,212
123	AMI-DIST-NSPM-ND Full AMI	1,194,325
124	FBW1 CESP Wind Resil Trnsfmr-26060	1,193,505
125	DKR1 CESP Wind Resil Trnsfmr-26059	1,189,884
126	MN EV Residential - Charging Equip	1,182,897
127	NSPM 0795 Avon - Brockway Tap	1,159,858
128	BS2 CESP Wind Resil Trnsfmr-26061	1,156,768
129	ITC-Electric Vehicles Ph2 SW 200095	1,142,353
130	Pot Parallel Removal Parkers Lake 1	1,116,873
131	Relocation MPLS SWLRT Road Project	1,071,305
132	MT Rplc Spare Rx Feedpump Motor	1,071,122
133	MN Failed Sub Equip Replacement	1,066,193

134	AMI-SW-License-BS-NSPM-NEW	1,049,439
135	SHC99 Emergent work	1,044,718
136	AMI-DIST-NSPM-SD Full AMI	1,039,365
137	MT #11 EDG Voltage Regulator	1,032,460
138	MN-Solar Garden Sub Work	1,019,075
139	MN SES Accruals	1,011,112
140	Wilmarth LZOP 115kV 5S8,5S9,5S10,5S	1,008,597
141	NSM0790 Waverly-Montrose Rebuild	1,003,499
142	Minor Projects	140,771,108
143	(a) (footnote to page 106)	
43	Total	924,939,975

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: ConstructionWorkInProgressProjectDescription

Construction Work in Progress (Account 107). The Form 1 reports the total Company construction work in progress (CWIP) balances at the end of the year. The Company uses a 13-month average calculation for the specific CWIP project balances included in the formula. The Company can only include CWIP in the formula related to Commission approved transmission projects.

FERC FORM No. 1 (ED. 12-87)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

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)
Section A. Balances and Changes During Year					
1	Balance Beginning of Year	8,749,310,738	8,749,310,738		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	699,409,442	699,409,442		
4	(403.1) Depreciation Expense for Asset Retirement Costs	(18,921,399)	(18,921,399)		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	17,959,664	17,959,664		
7	Other Clearing Accounts	157,572	157,572		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	698,605,279	698,605,279		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(508,556,090)	(508,556,090)		
13	Cost of Removal	(85,462,093)	(85,462,093)		
14	Salvage (Credit)	4,604,227	4,604,227		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(589,413,956)	(589,413,956)		

16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	15,904,369	(a)15,904,369		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	(b)8,874,406,430	8,874,406,430		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	1,699,200,240	(c)1,699,200,240		
21	Nuclear Production	2,457,002,817	(d)2,457,002,817		
22	Hydraulic Production-Conventional	19,406,172	(e)19,406,172		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,117,869,244	(f)1,117,869,244		
25	Transmission	1,176,035,881	(g)(h)1,176,035,881		
26	Distribution	1,983,268,682	(i)(j)1,983,268,682		
27	Regional Transmission and Market Operation				
28	General	421,623,394	(k)421,623,394		
29	TOTAL (Enter Total of lines 20 thru 28)	(l)8,874,406,430	8,874,406,430		

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToAccumulatedDepreciation

Net change in RWIP	\$	16,322,392
Net Transfers and Adjustments		180
(Gain)/Loss		(414,714)
Common Expense Allocation		(3,489)
Total	\$	15,904,369

(b) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

	<i>"Non-Legal" ARO Balances</i>	
Steam Production	\$	151,854,944
Nuclear Production		(68,487,898)
Hydraulic Production-Conventional		3,583,579
Other Production		115,775,362
Transmission		181,509,025
Distribution		243,811,998
General		807,603
Total	\$	628,854,613

(c) Concept: AccumulatedDepreciationSteamProduction

Accumulated Provision for Depreciation (Account 108). The Form 1 reports the accumulated provision for depreciation balances at the end of year. The Company uses a 13-month average calculation for the accumulated provision for depreciation balances included in the formula. Production and distribution accumulated provision for depreciation balances are included in developing the net plant allocator used to allocate costs to the transmission function in the formula.

(d) Concept: AccumulatedDepreciationNuclearProduction

Accumulated Provision for Depreciation (Account 108). The Form 1 reports the accumulated provision for depreciation balances at the end of year. The Company uses a 13-month average calculation for the accumulated provision for depreciation balances included in the formula. Production and distribution accumulated provision for depreciation balances are included in developing the net plant allocator used to allocate costs to the transmission function in the formula.

(e) Concept: AccumulatedDepreciationHydraulicProductionConventional

Accumulated Provision for Depreciation (Account 108). The Form 1 reports the accumulated provision for depreciation balances at the end of year. The Company uses a 13-month average calculation for the accumulated provision for depreciation balances included in the formula. Production and distribution accumulated provision for depreciation balances are included in developing the net plant allocator used to allocate costs to the transmission function in the formula.

(f) Concept: AccumulatedDepreciationOtherProduction

Accumulated Provision for Depreciation (Account 108). The Form 1 reports the accumulated provision for depreciation balances at the end of year. The Company uses a 13-month average calculation for the accumulated provision for depreciation balances included in the formula. Production and distribution accumulated provision for depreciation balances are included in developing the net plant allocator used to allocate costs to the transmission function in the formula.

(g) Concept: AccumulatedDepreciationTransmission

Accumulated Provision for Depreciation (Account 108). The Form 1 reports the accumulated provision for depreciation balances at the end of year. The Company uses a 13-month average calculation for the accumulated provision for depreciation balances included in the formula. Production and distribution accumulated provision for depreciation balances are included in developing the net plant allocator used to allocate costs to the transmission function in the formula.

(h) Concept: AccumulatedDepreciationTransmission

Transmission Serving Production	\$	49,703,720
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(i) Concept: AccumulatedDepreciationDistribution

Accumulated Provision for Depreciation (Account 108). The Form 1 reports the accumulated provision for depreciation balances at the end of year. The Company uses a 13-month average calculation for the accumulated provision for depreciation balances included in the formula. Production and distribution accumulated provision for depreciation balances are included in developing the net plant allocator used to allocate costs to the transmission function in the formula.

(j) Concept: AccumulatedDepreciationDistribution

Distribution Serving Production	\$	2,827,500
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(k) Concept: AccumulatedDepreciationGeneral

Accumulated Provision for Depreciation (Account 108). The Form 1 reports the accumulated provision for depreciation balances at the end of year. The Company uses a 13-month average calculation for the accumulated provision for depreciation balances included in the formula. Production and distribution accumulated provision for depreciation balances are included in developing the net plant allocator used to allocate costs to the transmission function in the formula.

(I) Concept: Accumulated Provision For Depreciation Of Electric Utility Plant

	<i>"Non-Legal" ARO Balances</i>	
Steam Production	\$	151,854,944
Nuclear Production		(68,487,898)
Hydraulic Production-Conventional		3,583,579
Other Production		115,775,362
Transmission		181,509,025
Distribution		243,811,998
General		807,603
Total	\$	628,854,613

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

- Report below investments in Account 123.1, Investments in Subsidiary Companies.
- Provide a subheading for each company and list thereunder 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.
- Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
- 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.
- 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.
- Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
- 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 different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
- Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	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)
1	UNITED POWER & LAND CO.			2,016,484	(94,539)	77	1,921,868	
2	UNITED POWER & LAND CO. - Capital Stock			4,020,000			4,020,000	
3	UNITED POWER & LAND CO. - Paid-In-Capital			749,588		77	749,511	
4	UNITED POWER & LAND CO. - Unappropriated Undistributed Subsidiary Earnings			(2,753,104)	(94,539)		(2,847,643)	
5	NSP NUCLEAR CO.			1,580,114	(403)	(15)	1,579,726	
6	NSP NUCLEAR CO. - Capital Contribution			962,698		(15)	962,713	
7	NSP NUCLEAR CO. - Unappropriated Undistributed Subsidiary Earnings			617,416	(403)		617,013	
42	Total Cost of Account 123.1 \$ 5,723,224.00		Total	3,596,598	(94,942)	62	3,501,594	

FOOTNOTE DATA

(a) Concept: InterestAndDividendRevenueFromInvestments

Annual allocation of unitary tax (benefit)/detriment.

(b) Concept: InterestAndDividendRevenueFromInvestments

Annual allocation of unitary tax (benefit)/detriment.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during 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)	104,511,663	106,828,966	Electric & Gas
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	^(a) 41,398,564	^(a) 60,783,380	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	157,660,437	157,395,060	Electric
8	Transmission Plant (Estimated)	759,981	921,173	Electric
9	Distribution Plant (Estimated)	4,582,660	4,125,403	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	^(a) (5,342,325)	^(a) (5,340,620)	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	199,059,317	217,884,396	
13	Merchandise (Account 155)	1,311,697	1,088,329	Electric
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17	^(a) (footnote to page 106)			0
20	TOTAL Materials and Supplies	304,882,677	325,801,691	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction

	Electric	Gas
Production	\$ 12,855,287	\$ —
Transmission	7,096,155	—
Distribution	19,726,924	1,720,198
Total	<u>\$ 39,678,366</u>	<u>\$ 1,720,198</u>

(b) Concept: PlantMaterialsAndOperatingSuppliesConstruction

	Electric	Gas
Production	\$ 21,789,999	\$ —
Transmission	14,165,217	—
Distribution	22,895,410	1,932,754
Total	<u>\$ 58,850,626</u>	<u>\$ 1,932,754</u>

(c) Concept: PlantMaterialsAndOperatingSuppliesOther

Includes a credit of \$2,814,617 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of \$2,527,708 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.

(d) Concept: PlantMaterialsAndOperatingSuppliesOther

Includes a credit of \$2,812,912 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of \$2,527,708 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.

(e) Concept: DescriptionOfMaterialsAndSuppliesOtherClasses

Materials & Supplies (Accounts 154 and 163). The Form 1 reports the materials and supplies balances at the beginning and end of the year. The Company uses the average of the beginning and end of the year materials and supplies balances in the formula rate (see page 106).

15	Total	(7,291)									(7,291)	
16												
17	Relinquished During Year:											
18	Charges to Account 509	(6,421)									(6,421)	
19	Other:											
20	Allowances Used											
20.1	Allowances Used											
21	Cost of Sales/Transfers:											
22	Beginning Balance Adj.	(2)									(2)	
23												
24												
25												
26												
27												
28	Total											
29	Balance-End of Year	1,207,450		93,016		69,262		69,262		1,870,074		3,309,064
30												
31	Sales:											
32	Net Sales Proceeds(Assoc. Co.)											
33	Net Sales Proceeds (Other)											
34	Gains											
35	Losses											
	Allowances Withheld (Acct 158.2)											
36	Balance-Beginning of Year	926		926		926		926		38,841		42,545
37	Add: Withheld by EPA											
38	Deduct: Returned by EPA											
39	Cost of Sales	926								926		1,852
40	Balance-End of Year			926		926		926		37,915		40,693

41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)	926	22						926	19	1,852	41	
45	Gains		22							19		41	
46	Losses												

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FOOTNOTE DATA			

[\(a\)](#) Concept: AllowancesReturnedByEnvironmentalProtectionAgencyNumber

Estimate. Amount to be finalized by EPA in first half of 2024.

41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

[\(a\)](#) Concept: AllowancesReturnedByEnvironmentalProtectionAgencyNumber

Estimate. Amount to be finalized by EPA in first half of 2024.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	^(a) Prairie Island Extended Power Uprate Project MN Docket E-002/CN-08-509	^(b) 78,884,915		^(d) Various	3,894,705	41,785,436
22	^(a) Benson Biomass PPA Termination MN Docket E-002/M-17-530 ND Docket PU-17-270 and SD Docket EL 18-027	48,044,295		407	4,677,899	22,167,192
49	TOTAL	126,929,210			8,572,604	63,952,628

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

In 2009, the Minnesota Public Utilities Commission (MPUC) granted NSP-Minnesota a Certificate of Need for an Extended Power Uprate (EPU) project at the Prairie Island (PI) nuclear generating plant. The total estimated cost of the EPU was \$294 million, of which approximately \$78.9 million had been incurred through 2012, including AFUDC of approximately \$12.8 million. Subsequently, NSP-Minnesota made a change of circumstances filing notifying the MPUC that there were changes in the size, timing and cost estimates for this project, revisions to economic and project design analysis and changes due to the estimated impact of revised scheduled outages. The information indicated reductions to the estimated benefit of the uprate project. As a result, NSP-Minnesota concluded that further investment in this project would not benefit customers. In February 2013, the MPUC issued an order terminating the CON for the PI EPU project.

In its 2014 Minnesota retail electric rate case under MPUC Docket 13-868, NSP-Minnesota received recovery of approximately \$59 million of deferred costs plus a debt-only return of 2.24 percent, to be recovered over 20.3 years.

On Nov. 19, 2015, the FERC approved a request under FERC Docket ER15-698 to allocate a portion of the amortization and debt-only return to NSP-Wisconsin under the Interchange Agreement. Approximately \$12 million will be amortized, beginning on Jan. 1, 2016 and continuing for 18.3 years.

In its 2021 North Dakota retail electric rate case settlement under PU-20-441, NSP-Minnesota received recovery of approximately \$4 million of deferred costs plus a return, to be recovered over 13.3 years.

In its 2023 South Dakota electric rate case under EL22-017, NSP-Minnesota received recovery of approximately \$4 million of deferred costs with a return to be recovered over a 11.3 year period beginning Jan. 1, 2023.

(b) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

On Aug. 28, 2017, NSP-Minnesota filed a Section 203 application with FERC (Docket No. EC17-166-000) under which Benson Power, LLC ("Benson Power") would sell and NSP-Minnesota would acquire a 62.3 MW (nameplate) biomass-fired electric generation plant, terminate a multi-year Power Purchase Agreement between NSP-Minnesota and Benson Power, and then shut down and dismantle the Benson Power Facility and remediate the plant site. The transaction was approved by the Commission on Feb. 23, 2018, and on June 29, 2018 the transaction with Benson Power closed. All plant acquisition, plant retirement costs, and contract termination costs will be recovered in the NSP-Minnesota and NSP-Wisconsin retail jurisdictions. The NSP-Minnesota retail orders are as follows:

- Minnesota – In the Matter of Petition of Northern States Power Company for Approval to Terminate the Power Purchase Agreement with Benson Power, LLC, Acquire the Benson Power Biomass Plant, and Subsequently Close the Facility, MPUC Docket No. E002/M-17-530, Order Approving Petitions, Approving Cost Recovery Proposals and Granting Variances (January 23, 2018) and Order Denying Reconsideration (March 28, 2018). Amortization period is July 1, 2018 through Sept. 10, 2028 (or 122.33 months).
- North Dakota – Northern States Power Company, Application for Advance Determination of Prudence and Application for Authority for Deferred Accounting, NDPSA Case Nos. PU-17-270 and PU-17-271 (June 30, 2017), Order Approving Petitions and Settlement Agreement (June 27, 2018). Amortization period is July 1, 2018 through June 30, 2029 (or 132 months).
- South Dakota – Request for Approval of Deferred Accounting for Certain Biomass Transaction Costs, Docket No. EL18-027 (May 31, 2018), Order Approving Deferred Accounting Treatment (June 28, 2018). Amortization period is Jan. 1, 2019 through Sept. 30, 2028 (or 117 months). Recovery ordered through the South Dakota Infrastructure Rider, Docket No. EL18-040 (Dec. 18, 2018).

On June 14, 2018, as supplemented on July 2, 2018, the NSP Companies filed modifications to certain exhibits in the Interchange Agreement to allow NSP-Minnesota to allocate to NSP-Wisconsin and recover a share of the costs incurred by NSP-Minnesota for the Benson Transaction. These modifications were accepted effective June 29, 2018, by letter order dated August 10, 2018 in Docket No. ER18-1786-000.

(c) Concept: UnrecoveredPlantAndRegulatoryStudyCostsNotYetRecognized

Transfers from Account No. 107 during 2012	\$ 77,690,096
Transfers from Account No. 107 during 2013	1,194,819
	\$ 78,884,915

(d) Concept: UnrecoveredPlantAndRegulatoryStudyCostsWrittenOffAccountCharged

Account No. 407 - amortization	\$ 4,217,516
Account No. 426.5 - accretion	(322,811)
	\$ 3,894,705

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2	NSP-674 GRE North Mankato-600101762358	5,933	561,640,192,926		
3	NSP-707 Chaska WCK Sub Fac Study-600101762859	8,585	561,640,192,926	40,000	561.6, 242
4	Sauk Centre Facilities Study Agmt-600101762359	16,471	561,640,192,926		
5	OTP Lake Preston Interconnection Req-600101768858	101,696	561,640,192,926	45,074	561.6
6	GRE Century Interc Req-600101768859	1,701	561,640,192,926	10,000	561.6, 242
7	GRE Eidswold Interc Req-600101770358	40,341	561,640,192,926	55,000	561.6, 242
8	MMPA East Shakopee (System Impact Study)-600101773358	4,176	561,640,192,926	10,000	561.6, 242
9	System Impact Study - Laketown-600101774859			10,000	561.6, 242
10	GRE Century Interc Req-600101775373	3,790	561,640,192,926	55,000	561.6, 242
20	Total	182,692		225,074	
21	Generation Studies				
22	J1498 Chanarambie Facilities Study-600101756873			55,831	561.7, 242
23	J1620 Pipestone Facilities Study-600101756881			41,281	561.7, 242
24	J1494 Chisago 115kV Facilities Study-600101756871			53,507	561.7, 242
25	J1581 Nobles County Facilities Study-600101756876			61,516	561.7, 242
26	J1572 Huntley BlueEarth Facilities Study-600101756875			42,891	561.7, 242

27	J1588 Bison 345kV Facilities Study-600101756878			44,039	561.7, 242
28	J1495 North Rochester Facilities Study-600101756872			32,923	561.7, 242
29	J1581 Nobles County Short Circuit-600101756891	252	561.7,408.1,925,926	5,821	561.7, 242
30	J1826 Cannon Falls Facilities Study-600101756885			18,510	561.7, 242
31	J1605 Sherburne 345kV Facilities Study-600101756879			59,081	561.7, 242
32	G621 Chanarambie Sub FaS Restudy-600101755858	34	561.7,408.1,925,926		
33	J1826 Cannon Falls Short Circuit-600101756900			8,259	561.7, 242
34	J1494 Chisago 115kV Short Circuit-600101756886			5,566	561.7, 242
35	J1495 North Rochester Short Circuit-600101756887			4,240	561.7, 242
36	J1588 Bison 345kV Short Circuit-600101756893			6,152	561.7, 242
37	J1498 Chanarambie Subs Short Circuit-600101756888			6,460	561.7, 242
38	J1605 Sherburne 345kV Short Circuit-600101756894			909	561.7, 242
39	J803 Tracy Sub FaS Restudy-600101752359	51,702	561.7,408.1,925,926	72,303	561.7, 242
40	J1620 Pipestone Split Rock Short Circuit-600101756896			6,520	561.7, 242
41	J1572 Huntley Blue Earth Short Circuit-600101756890			6,411	561.7, 242
42	S1013 Surplus Interconn Facilities Study	18,783	561.7,408.1,925,926		
39	Total	70,771		532,220	
40	Grand Total	253,463		757,295	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Asset Retirement Recovery	2,665,480,360	106,783,730			2,772,264,090
2	Benefit Cost Recovery Deficit	343,653,057	23,616,085	184	28,431,542	338,837,600
3	Benson Biomass PPA Termination - MN Docket E-002/GR-17-530 - ND Docket PU-17-271 - SD Docket EL 18-027 - Generally amortized through 2028	28,210,035		557	4,913,139	23,296,896
4	Costs to Relocate Facilities Underground - MN Docket E-002/M-99-799 - MN Docket E-002/M-04-1663 - Generally amortized over 36 months	1,163,172	238,346	142	811,446	590,072
5	Deferred Nuclear Outage Costs - Generally amortized over 23-24 months - MN Docket E-002/M-07-1489 - ND Docket PU-07-774 - SD Docket EL 07-035	42,488,354	^(a) 58,461,499	^(b) Various	38,766,642	62,183,211
6	Deferred Tax Collected in Rates in Excess of Current Tax Accrual Levels	875,151		282	162,018	713,133
7	Derivatives & Hedging – Retail Electric & Gas	2,284,024	650,692			2,934,716
8	Laurentian Biomass PPA Termination - MN Electric E-002/GR-17-551 - ND Docket PU-17-322 - SD Docket EL 22-017	18,083,333		557	17,051,588	1,031,745
9	Load Flexibility Tracker - MN Docket E-002/M-21-101		50,013			50,013
10	Mankato/Cannon Falls Lease Normalization	26,649,218	8,184,734	101.1	14,072,345	20,761,607
11	Minnesota Business Incentive and Sustainability Rider - MN Docket E-002/M-20-436 - MN Docket E-002/GR-21-630 - Amortized through 2024	1,742,404		407.3	871,212	871,192

12	Minnesota Capacity Revenue Tracker- MN Docket E-002/GR-21-630		62,252,909			62,252,909
13	Minnesota Deferred Electric Commodity Costs - 2021 - MN Docket E-002/AA-20-417 - MN Docket E-002/GR-21-630 - Generally amortized over 12 month period beginning September of following year	48,831,610	4,008,215	142	52,839,825	
14	Minnesota Electric Vehicle Tariff - MN Docket E-002/M-15-111 - MN Docket E-002/M-17-817 - MN Docket E-002/M-18-643 - MN Docket E-002/M-19-186 - MN Docket E-002/M-20-711 - MN Docket E-002/GR-21-630 - Amortized through 2024	2,019,108	1,631	912	1,138,671	882,068
15	Minnesota Gas Utility Infrastructure Cost Rider - MN Docket G-002/M-23-457	42,398,244	24,904,882	407.3	30,670,029	36,633,097
16	Minnesota LED Streetlighting - MN Docket E-002/GR-15-826 - MN Docket E-002/GR-21-630 - Amortized through 2024	223,347	25,042	407.3	128,369	120,020
17	Minnesota Deferred Gas Property Tax - 2022 - MN Docket E-002/GR-21-678		24,841			24,841
18	Minnesota Deferred Gas Property Tax - 2023 - MN Docket E-002/GR-21-678		2,601,337	408.1	529,560	2,071,777
19	Minnesota Gas Decoupling - MN Docket G-002/GR-21-678		9,225,924			9,225,924
20	Minnesota Renewable Development Fund Rider - MN Docket E-002/M-23-434	35,450,854	35,525,740	407.3	33,090,181	37,886,413
21	Minnesota Renewable Energy Standard- MN Docket E-002/M-23-454	14,662,044	118,659,295	407.3	133,321,339	
22	Minnesota Sales True-Up - 2021 - MN Docket E-002/GR-20-743 -Amortization began 04/2022 over 12-21 months based on customer class	53,453,435		407.3	53,453,435	
23	Net of Tax AFUDC in Plant Adjustments	112,466,576	14,607,023			127,073,599
24	Nonplant Excess ADIT	112,602,404		283	8,380,351	104,222,053
25	North Dakota AGIS Deferral - ND Docket PU-20-441	1,526,869	862,792			2,389,661
26	North Dakota Environmental Cleanup - ND Docket PU-17-894 - Amortized through 2026	4,212,041	175,453	735	1,247,380	3,140,114
27	Power Contract Valuation Adjustment - Generally amortized over term of related contract	42,091,888		244	13,832,006	28,259,882
28	Renewable*Connect Off-Peak - MN Docket E-002/M-19-33 - MN Docket E-002/M-21-222		467,377	142	256,545	210,832

29	Renewable*Connect Standard - MN Docket E-002/M-19-33 - MN Docket E-002/M-21-222		94,973	142	56,170	38,803
30	Sherco 3 Depreciation Deferral - MN Docket E-002/GR-15-826 - Amortized over 21 years (01/2014-12/2035)	6,037,555		407.3	503,130	5,534,425
31	South Dakota Infrastructure - SD Docket EL 23-025		8,858,490	407.4	8,229,734	628,756
32	South Dakota Ratemaking Differences - SD Docket F-3382 - SD Docket F-3422 - Amortized over plant lives	3,160,250	321,000	405	578,000	2,903,250
33	South Dakota Transmission Cost Recovery Rider - SD Docket EL 23-026		591,380	407.4	111,849	479,531
34	Theoretical Depreciation Reserve Surplus - MN Docket E-002/GR-17-147 - Amortized over plant lives	228,626,660		407.3	8,909,820	219,716,840
35	Transmission Formula Rates	15,094,964	9,431,870	565	8,120,746	16,406,088
44	TOTAL	3,853,486,957	490,625,273		460,477,072	3,883,635,158

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: IncreaseDecreaseInOtherRegulatoryAssets

Accounts charged:			
517		\$	1,892,652
519			832,705
520			9,294,933
523			398,906
524			2,359,594
528			1,013,584
530			7,920,927
531			4,076,195
532			30,672,003
Total		\$	58,461,499

(b) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:			
517		\$	1,697,710
519			649,157
520			5,601,030
523			249,393
524			1,205,066
528			486,817
530			10,083,727
531			2,714,971
532			16,078,771
Total		\$	38,766,642

(c) Concept: OtherRegulatoryAssets

	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Total
Electric	\$ 72,260,196 \$	28,145,812 \$	100,406,008
Gas	2,746,331	1,069,714	3,816,045
Total	\$ 75,006,527 \$	29,215,526 \$	104,222,053

*For purposes of calculating the NSP Companies transmission formula rate, the excess non-plant balances (excluding tax gross-up) are as follows. The Company uses the average of the beginning of the year and the end of the year balances in the formula. These balances are being flowed back to customers over various periods consistent with the nature of the item.

	Excess Balance 12/31/2022	Amortization 2023	Excess Balance 12/31/2023
Federal Net Operating Loss	\$ 75,504,246 \$	(4,194,680) \$	71,309,566
Post Employment Benefits - Long Term Disability	1,278,957	(127,896)	1,151,061
Post Employment Benefits - Retiree Medical	4,101,935	(410,193)	3,691,742
Total Electric	\$ 80,885,138 \$	(4,732,769) \$	76,152,369

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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 \$100,000, 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		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Conservation and Energy Management Program Costs Minnesota Electric (Docket E-002/M-23-145)	21,329,838	22,952,518	182.3	21,329,839	22,952,517
2	Conservation and Energy Management Program Costs Minnesota Gas Incentive (Docket G-002/M-23-146)	3,631,461	2,633,532	182.3	3,631,460	2,633,533
3	Federal and State Income Taxes Interest Receivable	3,502,196		171	3,411,500	90,696
4	Federal and State Income Tax Receivable	218	600			818
5	IPP Power Contract Billing Adjustments		532,056			532,056
6	JOA & Rate Payer Share MTM	17,925,214		557	7,422,845	10,502,369
7	Notes Receivable - 3rd Party	2,348,554	101,266	143	511,943	1,937,877
8	Prepays - Facility Fees	1,913,320	4,705	431	405,553	1,512,472
9	Minnesota Electric Retail Rate Case Expenses (Docket E-002/GR-21-630) - Amortized through Dec. 2024	355,305	2,038,481	928	1,562,100	831,686
10	Minnesota Gas Retail Rate Case Expenses (Docket G-002/GR-23-413) - Amortized through Dec. 2026		1,030,998	928	304,823	726,175
11	North Dakota Electric Retail Rate Case (Dockets PU-12-813 & PU-20-441) - Amortized through June 2024	382,303		928	359,404	22,899
12	North Dakota Gas Retail Rate Case Expenses (Dockets PU-21-381 & PU-23-367) - Amortized through Oct. 2026 & Feb. 2027	474,129	270,339	928	244,800	499,668

13	South Dakota Electric Retail Rate Case Expenses (Docket EL 22-017) - Amortized through Dec. 2025	621,249	316,612	928	460,887	476,974
14	Loan Receivable - 3rd Party	6,000,000	516,067	143	5,882,178	633,889
15	Debt Issuance Expense		393			393
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	58,483,787				43,354,022

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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 at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric - Plant	233,768,343	257,779,311
3	Electric - Non-Plant	1,170,275,469	1,092,733,812
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,404,043,812	1,350,513,123
9	Gas		
10		29,626,876	40,080,146
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	29,626,876	40,080,146
17.1	Other (Specify)	12,654,963	12,690,385
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,446,325,651	1,403,283,654

Notes

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Decommissioning	\$ —	\$ —
Electric Distribution Plant	143,295,665	162,444,561
Electric General Plant	766,298	1,418,573
Electric Intangible Plant	2,584,392	3,265,435
Electric Nuclear Fuel	29,624,347	29,931,181
Electric Nuclear Production Plant	44,552,368	40,101,848
Electric Production Plant	48,588,131	48,370,717
Electric Transmission Plant	47,398,890	57,875,333
Electric Transmission-Production Plant	2,358,090	2,309,061
Common (Allocation to Electric)	1,315,305	2,441,981
Regulatory Differences - Effect of Rate Changes	(92,722,451)	(95,898,029)
Regulatory Differences - Investment Tax Credit Gross-Up	6,007,308	5,515,650
Total Electric Plant Related Only	<u>\$ 233,768,343</u>	<u>\$ 257,776,311</u>

(b) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Electric:		
Avoided Tax Interest	\$129,459,225	\$136,774,207
Bad Debts	12,171,409	12,526,166
Customer Advances	2,114,072	6,130,593
Deferred Connection Fees	142,145,685	159,256,354
Deferred Rent	2,265,235	2,108,609
Deferred Revenue	712,408	430,451
Economic Development Securities - Write-Off	103,323	100,746

Employee Incentive Plans	3,965,595	3,987,185
Employee Retention	6,382	—
Employee Stock Ownership Program Dividends	6,487,006	7,533,930
End of Life Nuclear Fuel Amortization	29,592,532	29,899,366
Environmental Remediation	3,018,528	1,740,791
Excess Nonplant Accumulated Deferred Income Taxes	6,103,491	4,921,074
Federal Net Operating Loss	518,557	—
Fuel Tax Credit - Income Addback	6,351	6,911
Interest Income/Expense on Disputed Tax	215,070	(362,952)
Inventory Reserve	650,765	649,969
Investment Tax Credit	786,145	—
Mark to Market Adjustment	—	385,477
Medical Deductions - Self Insured	980,485	1,323,632
Minnesota Net Operating Loss	13,552,065	121,304
Monticello Extended Power Uprate Writedown	10,684,966	8,564,240
North Dakota Investment Tax Credit	63,614,482	55,496,566
North Dakota Investment Tax Credit - Valuation Allowance	(57,717,609)	(52,493,545)
North Dakota Investment Tax Credit - Federal Gross-Up	2,182,546	1,517,941
North Dakota Net Operating Loss	1,962	1,840
North Dakota Production Tax Credit - Levelization	3,613,269	5,776,021
Operating Lease Liabilities	90,360,911	118,245,506
Performance Recognition Awards	111,732	124,754
Post Employment Benefits - Retiree Medical	7,043,941	6,399,475
Post Employment Benefits - Long Term Disability	2,495,807	2,007,700
Post Employment Benefits - Voluntary Retirement Program	—	2,162,019
Public Utility Conservation Investment Programs	4,660,514	—
Rate Refund	27,068,355	59,479,067
Regulatory Asset/Liability - Decoupling	—	8,659,430
Regulatory Asset/Liability - Miscellaneous	9,492,250	11,435,958
Regulatory Asset/Liability - Net Operating Loss Tracker	—	458,131
Regulatory Asset/Liability - Renewable Energy Standard Rider	1,405,560	8,215,066
Regulatory Asset/Liability - Transmission Attach O	—	257,766
Regulatory Asset/Liability - Transmission Cost Recovery Rider	5,571,675	7,632,653
Regulatory Asset/Liability - Windsource	1,333,789	2,034,005
Regulatory Difference - Effect of Rate Changes	(92,722,451)	(95,898,029)
Regulatory Difference - Investment Tax Credit Gross-Up	6,007,308	5,518,650
Research and Experimentation Credit	51,595,874	35,765,466
Section 174 - Section 59(e) Adjustment	30,637,090	28,177,705
Severance Accrual	23,220	542,918
Solar Rewards Program	3,481,127	3,028,829
South Dakota Infrastructure Tracker	604,781	—
State Research Credit	5,751,754	—
State Tax Deduction Cash vs. Accrual	2,987,469	609,996
Texas Gross Margin Tax	—	307
Vacation Accrual	5,403,369	6,576,950
Wind Production Tax Credit	863,289,576	752,432,964

Workers Compensation		206,216	248,961
Total Electric	\$	1,404,043,812	\$ 1,350,513,123

Accumulated Deferred Income Taxes (Account 190). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances of non-property related items, and a prorated balance of property-related items in the formula. An adjustment is made to eliminate any accumulated deferred income tax balances related to regulatory differences related to income taxes.

Amortization of Excess ADIT (Electric only) included in 410.1 is \$3,546,522 for 2022 and \$2,831,721 for 2023.

		2022 ARAM	2023 ARAM
Unprotected ARAM:			
Decommissioning	\$	— \$	—
Electric Distribution Plant		1,379,735	977,529
Electric General Plant		33,695	34,439
Electric Intangible Plant		147,305	(135,178)
Electric Nuclear Fuel		—	(13,967)
Electric Production Plant		1,633,675	1,761,885
Electric Transmission Plant		337,641	194,558
Electric Transmission-Production Plant		4,843	5,354
Common (Allocation to Electric)		9,628	7,101
Total Electric	\$	3,546,522	\$ 2,831,721

Common allocation for financial reporting may be different than for rate making.

Common (Unallocated)	\$	10,613	\$ 7,858
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The Excess ADIT above in column c include the ungrossed amounts presented below. These amounts will be amortized over the book lives of the underlying assets.

		12/31/2023	12/31/2023	12/31/2023
		Excess	Gross up	Total Regulatory
Excess (Electric only)				
Flow Through	\$	508,583	\$ 198,097	\$ 706,680
Other Basis Differences (Unprotected)		(69,524,477)	(27,080,232)	(96,604,709)
	\$	(69,015,894)	\$ (26,882,135)	(95,898,029)

Includes Non-Utility and Common Allocated. The common allocation for the financial reporting is different from the allocation used in rate making.

Non-utility				
	Other Basis Differences (Unprotected)	\$ (8)	\$ (3)	(11)
		\$ (8)	\$ (3)	(11)
Common (allocated)				
	Other Basis Differences (Unprotected)	\$ (569,277)	\$ (221,737)	(791,014)
		\$ (569,277)	\$ (221,737)	(791,014)
Common (unallocated)				
	Other Basis Differences (Unprotected)	\$ (292,751)	\$ (114,028)	(406,779)
		\$ (292,751)	\$ (114,028)	(406,779)

(c) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Gas:		
Avoided Tax Interest	\$ 4,066,181	\$ 4,227,295
Bad Debts	921,153	1,322,384
Deferred Connection Fees	11,426,851	18,803,666
Deferred Rent	195,907	190,104
Economic Development Securities - Write-Off	7,820	10,636
Employee Incentive Plans	379,396	412,186
Employee Retention	611	—
Employee Stock Ownership Program Dividends	2,556,097	2,800,084
Environmental Remediation	64,894	65,051
Excess Nonplant Accumulated Deferred Income Taxes	382,276	320,999
Federal Net Operating Loss	27,292	—
Fuel Tax Credit - Income Addback	549	623
Interest Income/Expense on Disputed Tax	16,277	(38,317)
Inventory Reserve	56,281	58,599
Lower of Cost or Market on Gas Inventories	22,585	44,893
Medical Deduction - Self Insured	93,805	136,834
Minnesota Net Operating Loss	713,267	6,384
North Dakota Net Operating Loss	103	97
Operating Lease Liabilities	7,814,785	10,660,529
Performance Recognition Awards	10,690	12,897
Post Employment Benefits - Retiree Medical	673,907	661,563
Post Employment Benefits - Long Term Disability	238,779	207,551
Post Employment Benefits - Voluntary Retirement Program	—	223,504
Public Utility Conservation Investment Programs	3,852	827,847
Rate Refund	486,870	18,534
Regulatory Asset/Liability - Miscellaneous	294,805	—
Regulatory Difference - Effect of Rate Changes	(5,169,981)	(5,687,206)
Regulatory Difference - Investment Tax Credit Gross-Up	299,725	259,015
Research and Experimentation Credit	573,037	1,213,010
Section 174 - Section 59(e) Adjustment	2,649,622	2,540,386
Severance Accrual	2,222	56,126
State Research Credit	85,416	—
State Tax Deduction Cash vs. Accrual	195,123	19,225
Vacation Accrual	516,950	679,910
Workers Compensation	19,729	25,737
Total Gas	<u>\$ 29,626,876</u>	<u>\$ 40,080,146</u>

(d) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Other:		
Avoided Tax Interest	\$ 84	\$ 79
Deferred Compensation Plan Reserve	3,793,520	4,189,308
Low Income Housing Credit	85	—
Minnesota Alternative Minimum Tax Credit	155,177	—
Minnesota Net Operating Loss	43,495	86
North Dakota Net Operating Loss	2,651	850
Nonqualified Pension Plans	220,402	190,550
Other Comprehensive Income	7,172,778	7,752,111
Partnership Passthrough	363,193	364,436
Performance Share Plan	727,339	188,927
Regulatory Difference - Effect of Rate Changes	(15)	(16)
State Tax Deduction Cash vs. Accrual	176,254	4,054
Total Other	<u>\$ 12,654,963</u>	<u>\$ 12,690,385</u>

(e) Concept: AccumulatedDeferredIncomeTaxes

Refer to FERC page 232 for NSPM's regulatory asset related to nonplant excess ADIT.

FERC FORM NO. 1 (ED. 12-88)

4										
5	Total									

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2024-04-04	Year/Period of Report End of: 2023/ Q4
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Other Paid-in Capital

1. 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 a total of all accounts for reconciliation with the balance sheet, page 112. 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 briefly explain the origin and purpose of each donation.
- b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- c. Gain or 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 that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Donations Received from Stockholders (Account 208)	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	Reduction in Par or Stated Value of Capital Stock (Account 209)	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	Miscellaneous Paid-In Capital (Account 211)	
14	Beginning Balance Amount	4,894,553,504
15.1	Increases (Decreases) due to contribution of capital by parent	312,188,587
16	Ending Balance Amount	5,206,742,091
17	Historical Data - Other Paid in Capital	

18	<u>Beginning Balance Amount</u>	
19.1	<u>Increases (Decreases) in Other Paid-In Capital</u>	
20	<u>Ending Balance Amount</u>	
40	<u>Total</u>	5,206,742,091

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the 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. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. 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, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, 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) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	2.25% Apr 1, 2031 First Mortgage Bonds		425,000,000		5,122,108		1,776,500	03/30/2021	04/01/2031	03/30/2021	04/01/2031	425,000,000	9,562,500
3	3.20% Apr 1, 2052 First Mortgage Bonds		425,000,000		6,078,358		1,576,750	03/30/2021	04/01/2052	03/30/2021	04/01/2052	425,000,000	13,600,000
4	4.85% Aug 15, 2040 First Mortgage Bonds		250,000,000		3,019,146		707,500	08/11/2010	08/15/2040	08/11/2010	08/15/2040	250,000,000	12,125,000
5	3.40% Aug 15, 2042 First Mortgage Bonds		500,000,000		6,272,718		3,820,000	08/13/2012	08/15/2042	08/13/2012	08/15/2042	500,000,000	18,496,479 ^(a)
6	4.00% Aug 15, 2045 First Mortgage Bonds		300,000,000		3,897,956		4,899,000	08/11/2015	08/15/2045	08/11/2015	08/15/2045	300,000,000	12,000,000
7	^(a) 7.125% Jul 1, 2025 First Mortgage Bonds		250,000,000		1,898,333		2,330,000	07/07/1995	07/01/2025	07/07/1995	07/01/2025	250,000,000	17,812,500
8	5.25% Jul 15, 2035 First Mortgage Bonds		250,000,000		3,032,114		485,000	07/21/2005	07/15/2035	07/21/2005	07/15/2035	250,000,000	13,125,000
9	6.20% Jul 1, 2037 First Mortgage Bonds		350,000,000		4,336,843		1,988,000	06/26/2007	07/01/2037	06/26/2007	07/01/2037	350,000,000	21,700,000
10	6.25% Jun 1, 2036 First Mortgage Bonds		400,000,000		4,877,065		1,404,000	05/25/2006	06/01/2036	05/25/2006	06/01/2036	400,000,000	24,455,460 ^(a)
11	2.60% Jun 1, 2051 First Mortgage Bonds		700,000,000		9,787,023		13,174,000	06/15/2020	06/01/2051	06/15/2020	06/01/2051	700,000,000	18,200,000
12	4.50% Jun 1, 2052 First Mortgage Bonds		500,000,000		7,499,025		3,605,000	05/09/2022	06/01/2052	05/09/2022	06/01/2052	500,000,000	22,500,000
13	6.50% Mar 1, 2028 First Mortgage Bonds		150,000,000		1,474,885		1,761,001	03/17/1998	03/01/2028	03/17/1998	03/01/2028	150,000,000	9,750,000
14	2.90% Mar 1, 2050 First Mortgage Bonds		600,000,000		8,727,023		11,574,000	09/10/2019	03/01/2050	09/10/2019	03/01/2050	600,000,000	17,400,000
15	4.125% May 15, 2044 First Mortgage Bonds		300,000,000		3,821,358		873,000	05/13/2014	05/15/2044	05/13/2014	05/15/2044	300,000,000	12,375,000
16	3.60% May 15, 2046 First Mortgage Bonds		350,000,000		5,404,423		2,093,000	05/31/2016	05/15/2046	05/31/2016	05/15/2046	350,000,000	12,600,000
17	^(b) 5.10% May 15, 2053 First Mortgage Bonds		800,000,000		11,417,227		5,968,000	05/08/2023	05/15/2053	05/08/2023	05/15/2053	800,000,000	26,302,681 ^(a)
18	5.35% Nov 1, 2039 First Mortgage Bonds		300,000,000		4,153,918		570,000	11/17/2009	11/01/2039	11/17/2009	11/01/2039	300,000,000	16,156,992 ^(b)
19	3.60% Sep 15, 2047 First Mortgage Bonds		600,000,000		8,795,587		5,982,000	09/13/2017	09/15/2047	09/13/2017	09/15/2047	600,000,000	21,600,000
20	2.60% May 15, 2023 First Mortgage Bonds		400,000,000		4,524,626		732,000	05/20/2013	05/15/2023	05/20/2013	05/15/2023		3,871,111
21	Subtotal		7,850,000,000		104,139,736		65,318,751					7,450,000,000	303,632,723

22	Reacquired Bonds (Account 222)												
23													
24													
25													
26	Subtotal												
27	Advances from Associated Companies (Account 223)												
28													
29													
30													
31	Subtotal												
32	Other Long Term Debt (Account 224)												
33	Right of Way Debt											2,376,908	205,014
34	Interest on Debt to Associated Companies												4,908,964
35	Subtotal											2,376,908	5,113,978
33	TOTAL		7,850,000,000									7,452,376,908	308,746,701

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription
NSPMN 2.60% \$400MM FMB Retired May 15,2023

(b) Concept: ClassAndSeriesOfObligationCouponRateDescription
Minnesota Public Utilities Commission Docket No. E, G-002/S-22-559. Order dated December 13, 2022.

In May 2023, NSPMN issued \$800,000,000 of 5.10 percent First Mortgage Bonds, due May 15, 2053. NSPMN used the net proceeds to repay short-term borrowings, to help fund the redemption of the \$400M 2.6% FMB due 5/15/2023, and for other general corporate purposes.

(c) Concept: InterestExpenseBonds

Interest at stated rate	\$		17,000,000
Interest at swap loss			1,496,479
	\$		18,496,479

(d) Concept: InterestExpenseBonds

Interest at stated rate	\$		25,000,000
Interest at swap gain			(544,540)
	\$		24,455,460

(e) Concept: InterestExpenseBonds

Interest at stated rate	\$		26,406,667
Interest at swap gain			(103,986)
	\$		26,302,681

(f) Concept: InterestExpenseBonds

Interest at stated rate	\$		16,050,000
Interest at swap loss			106,992
	\$		16,156,992

(g) Concept: OtherLongTermDebt

	Balance Dec. 31, 2022	Additions	Reductions	Balance Dec. 31, 2023
Right of Way Debt	\$2,780,475	\$—	\$(403,566)	\$2,376,909

(h) Concept: InterestExpenseOtherLongTermDebt

Xcel Energy Service Inc	\$		4,048,361
Money Pool			860,603
	\$		4,908,964

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

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same 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 filed, 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)	707,233,792
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		60,771,100
9	Deductions Recorded on Books Not Deducted for Return	
10		1,657,549,687
14	Income Recorded on Books Not Included in Return	
15		(158,157,628)
19	Deductions on Return Not Charged Against Book Income	
20		(1,827,979,963)
21	Equity in Earnings of Subsidiary Companies	94,942
22	Total Income Tax Expense	(109,308,580)
27	Federal Tax Net Income	330,203,350
28	Show Computation of Tax:	
29	Federal Income Tax at 21 percent	69,342,704
30	Other	(235,790,435)
31	Total Federal Income Tax Payable	(166,447,731)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: TaxableIncomeNotReportedOnBooks

TAXABLE INCOME NOT REPORTED ON BOOKS:

Contributions in Aid of Construction	\$ 60,448,876
Gain/(Loss) on Dispositions (Tax)	322,224
	\$ 60,771,100

(b) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

DEDUCTIONS RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:

Avoided Cost Interest	\$ 32,013,528
Bad Debts	2,596,356
Book Amortization - Acquisition Adjustments	14,976
Book Amortization - Computer Software	89,778,847
Book Amortization - Other	14,433,915

Book Depreciation	809,156,228
Book Income - Wisconsin/South Dakota Allowance for Funds During Construction	209,000
Book Unamortized Cost of Reacquired Debt	978,673
Clearing Account Book Expense	31,609,259
Deferred Compensation Plan Reserve	1,382,790
Deferred Fuel Costs	103,420,030
Electric Vehicle Charging Tariff	1,137,041
Employee Incentive Plans	160,631
Employee Stock Ownership Plan Dividends	1,743,261
Executive Officer Nondeductible Compensation	12,052
Lobbying Expenses	1,793,000
Mark to Market Adjustment	11,490,268
Medical Deductions - Self Insured	1,877,500
Meals & Entertainment	2,005,000
Nuclear Decommissioning	35,891,249
Nuclear Fuel Expense	98,873,591
Operating Lease Liabilities	108,872,175
Penalties	138,351
Pension and Benefit Capitalized	1,476,484
Pension Expense	38,273,860
Performance Recognition Awards	53,388
Post Employment Benefits - Voluntary Retirement Program	8,510,000
Prairie Island Extended Power Uprate Writedown Amortization	3,561,965
Prepaid Insurance	5,491,283
Rate Refund	113,738,130
Regulatory Asset - Gas Safety Deferrals	5,696,397
Regulatory Asset - Miscellaneous	27,312,749
Regulatory Asset/Liability - Cancellation	4,355,088
Regulatory Asset/Liability - Decoupling	53,613,069
Regulatory Asset/Liability - Net Operating Loss Tracker	1,634,314
Regulatory Asset/Liability - Renewable Energy Standard Rider	24,281,112
Regulatory Asset/Liability - Transmission Attach O	1,534,374
Regulatory Asset/Liability - Transmission Cost Recovery Rider	7,309,458
Regulatory Asset/Liability - Windsource	2,487,673
Regulatory Reserve - Environmental	1,071,927
Severance Accrual	2,046,044
Suite and Entertainment Tickets	620,000
Vacation Accrual	4,722,466
Workers Compensation	172,185
	<u>\$ 1,657,549,687</u>

(c) Concept: IncomeRecordedOnBooksNotIncludedInReturn

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:	
Allowance for Funds During Construction - Equity (Non-Conservation Improvement Program)	(39,576,931)
Deferred Revenue	(1,011,311)
Deferred Revenue - Investment Tax Credit Grant	(68,945)
Insurance Fund Income (Cash Value)	(3,295,733)
Interest Income/Expense on Disputed Tax	(2,258,540)
Operating Lease Assets	(108,880,012)
Rate Surcharge	(3,066,156)
	<u>\$ (158,157,628)</u>

(d) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:	
Allowance for Funds During Construction - Debt (Non-Conservation Improvement Program)	(23,761,832)
Deferred Rent	(598,337)
Employee Retention	(723,859)
Environmental Remediation	(4,581,252)
External Qualified Nuclear Decommissioning Fund	(35,891,249)
Internally Developed Software	(323,000)
Low Income Discount Program	(308,000)
Net Operating Loss	(244,948)
Nonqualified Pension Plan	(108,186)
Performance Share Plan	(1,926,291)
Post Employment Benefits - Long Term Disability	(1,873,642)
Post Employment Benefits - Retiree Medical	(2,402,328)
Prepaid Advertising	(9,965)
Public Utility Conservation Investments Programs Adjustment	(15,749,910)
Rate Case/Restructuring Expense	(37,046,755)
Regulatory Asset - Nuclear Refueling Outage Costs	(19,694,857)
Regulatory Asset - Property Tax	(2,071,777)
Repair Expenditures	(64,100,000)
Section 174	(19,625,527)
Section 174 - Section 59(e) Adjustment	(22,946,881)
State Tax Deduction	(41,353,872)
Solar Rewards Program	(1,640,232)
South Dakota Infrastructure Tracker	(2,790,867)
Tax Amortization - Monticello Rerate	(6,228,057)
Tax Amortization - Computer Software	(101,347,971)
Tax Depreciation	(1,344,771,015)
Tax Expense - Spent Fuel Isolation Devices	(1,088,877)
Tax Removal Cost Over Book	(74,770,476)
	\$ (1,827,979,963)
(e) Concept: ComputationOfTax	

Northern States Power Company (a Minnesota corporation) is a member of an affiliated group which will file a consolidated federal income tax return for the year 2023. The other members of the affiliated group and the federal income tax provision of each are:

Xcel Energy Inc.	(42,787,136)
NSP Nuclear Corporation	(219)
United Power and Land Company	(38,755)
Northern States Power Company (Wisconsin) and Subsidiaries	37,615,651
Public Service Company of Colorado and Subsidiaries	182,714,737
Southwestern Public Service Company	76,527,344
Nicollet Holdings Company, LLC and Subsidiaries	(239,393)
Nicollet Project Holdings LLC and Subsidiaries	24,228
Xcel Energy Communications Group Inc. and Subsidiaries	(128,890)
Xcel Energy Markets Holdings Inc. and Subsidiaries	257,187
Xcel Energy International Inc.	(530)
Xcel Energy Nuclear Services, Inc.	297,549
Xcel Energy Retail Holdings Inc. and Subsidiaries	(21,604)
Xcel Energy Transmission Holding Company, LLC and Subsidiaries	(120,408)
Xcel Energy Ventures Inc. and Subsidiaries	(36,516)
Xcel Energy Venture Holdings, Inc. and Subsidiaries	(974,810)
Xcel Energy Wholesale Group Inc. and Subsidiaries	679,619
Xcel Energy WYCO Inc.	5,279,255
WestGas Interstate, Inc.	13,419
Xcel Energy Services Inc.	5,229,430

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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TAXES ACCRUED, PREPAID AND CHARGES 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 known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) 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.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) 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 (l) through (o) how the taxes were distributed. Report in column (o) 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 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) 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.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	Income	Federal Tax					(153,914,108)	(147,842,780)	6,071,328			(181,731,187)			27,817,079
2	Income Tax Adjustment	Federal Tax					(12,533,623)		12,533,623			(12,707,161)			173,538
3	FICA	Federal Tax		2022	3,009,364			3,009,364							
4	FICA	Federal Tax		2023			40,088,380	37,088,880		2,999,500		30,186,320			9,902,060
5	Unemployment	Federal Tax		2022	7,282			7,282							
6	Unemployment	Federal Tax		2023			189,584	185,098		4,486		150,918			38,666
7	Subtotal Federal Tax				3,016,646		(126,169,767)	(107,552,156)	18,604,951	3,003,986		(164,101,110)			37,931,343
8	Income	State Tax	Minnesota		12,085,775		2,323,621	40,582,669	26,173,273			(9,785,772)			12,109,393
9	Income Tax Adjustment	State Tax	Minnesota				(307,710)		307,710			441,759			(749,469)
10	Unemployment	State Tax	Minnesota	2023			3,617,746	3,573,556		44,190		2,114,503			1,503,243
11	Property Tax	State Tax	Minnesota	2022	218,160,000		(15,502,249)	202,657,751				(13,931,050)			(1,571,199)
12	Property Tax	State Tax	Minnesota	2023			202,068,000			202,068,000		181,230,000			20,838,000
13	Property Tax MN Settlement	State Tax	Minnesota	2023			(479,290)		479,290			1,617,327			(2,096,617)
14	Income	State Tax	North Dakota		184,718		240,052	774,494	349,724			(68,147)			308,199
15	Income Tax Adjustment	State Tax	North Dakota				(18,312)		18,312						(18,312)
16	Unemployment	State Tax	North Dakota	2022	807			807							
17	Unemployment	State Tax	North Dakota	2023			14,288	14,092		196		7,492			6,796
18	Property Tax	State Tax	North Dakota	2022	7,264,482		243,768	7,508,250				191,150			52,618
19	Property Tax	State Tax	North Dakota	2023			8,125,039	31,039		8,094,000		6,548,239			1,576,800
20	Unemployment	State Tax	South Dakota	2022	92			92							

21	Unemployment	State Tax	South Dakota	2023			17,359	17,359				9,102			(a) 8,257
22	Property Tax	State Tax	South Dakota	2022	6,378,000		(142,396)	6,235,604				(142,396)			
23	Property Tax	State Tax	South Dakota	2023			5,916,000			5,916,000		5,916,000			
24	(a) Personal Property FCA	State Tax	South Dakota	2023			1,116,710	1,116,710				1,116,710			
25	Personal Property	State Tax	Iowa	2023			204,000			204,000		204,000			
26	Personal Property	State Tax	Kansas	2023			1,516,648	1,516,648							(b) 1,516,648
27	Income	State Tax	Wisconsin				50,071	(88,234)	(c) (121,305)	17,000		50,069			(a) 2
28	Unemployment	State Tax	Wisconsin	2023			5,716	5,716				2,997			(a) 2,719
29	Income	State Tax	Texas		231,266		100,679	84,943	(b) (41,067)	205,935		64,635			(a) 36,044
30	Unemployment	State Tax	Georgia	2023	7		4			11		2			(a) 2
31	Unemployment	State Tax	Colorado	2023	20					20					
32	Subtotal State Tax				244,305,167		209,109,744	264,031,496	27,165,937	216,549,352		175,586,620			33,523,124
33	Denver Occ'l Privilege	Other Taxes		2023								132,650			(a) (132,650)
34	(b) Property Tax on Rail Car	Other Taxes		2022	4,800		(2,292)	2,508							(a) (2,292)
35	(c) Property Tax on Rail Car	Other Taxes		2023			2,400			2,400					(a) 2,400
36	Other	Other Taxes		2023			66,129	66,129				61,713			(a) 4,416
37	Use	Other Taxes		2023	1,737,732		27,445,324	25,472,441		3,710,615					(a) 27,445,324
38	Subtotal Other Tax				1,742,532		27,511,561	25,541,078		3,713,015		194,363			27,317,198
40	TOTAL				249,064,345		110,451,538	182,020,418	45,770,888	223,266,353		11,679,873			98,771,665

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: DescriptionOfTaxesAccruedPrepaidAndCharged	
South Dakota Personal Property Tax collected through the Fuel Clause Adjustment. See page 278.	
(b) Concept: DescriptionOfTaxesAccruedPrepaidAndCharged	
Property tax on railroad cars used to transport coal from mines to electric generating plants.	
(c) Concept: DescriptionOfTaxesAccruedPrepaidAndCharged	
Property tax on railroad cars used to transport coal from mines to electric generating plants.	
(d) Concept: TaxAdjustments	
Federal income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	\$ 477,909
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (211)	(122,982)
Federal income tax benefit (accrual and cash) in other accounts receivable (143)	7,100,083
Federal income tax receivable on carryback claim (143)	(1,383,683)
Rounding	1
Total	\$ 6,071,328
(e) Concept: TaxAdjustments	
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (186)	\$ (43,977)
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	14,210,511
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	(1,632,911)
Total	\$ 12,533,623
(f) Concept: TaxAdjustments	
Annual allocation of unitary benefit/detriment for Minnesota income taxes accrued as additional paid in capital (211)	\$ 1,150,035
State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)	103
State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	15,941
State income tax benefit (accrual and cash) in other accounts receivable (143)	25,007,194
Total	\$ 26,173,273
(g) Concept: TaxAdjustments	
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (186)	\$ (18,068)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	634,577
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	(308,799)
Total	\$ 307,710
(h) Concept: TaxAdjustments	
Annual allocation of unitary benefit/detriment for North Dakota income taxes accrued as additional paid in capital (211)	\$ (402,036)
State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)	497
State income tax benefit (accrual and cash) in other accounts receivable	751,263
Total	\$ 349,724

(i) Concept: TaxAdjustments		
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (186)	\$	(414)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)		18,726
Total	\$	18,312
(j) Concept: TaxAdjustments		
Annual allocation of unitary benefit/detriment for Wisconsin income tax accrued as additional paid in capital (211)	\$	(121,305)
(k) Concept: TaxAdjustments		
Annual allocation of unitary benefit/detriment for Texas income taxes accrued as additional paid in capital (211)	\$	(41,067)
(l) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	17,480,056
Other income and deductions (Account No. 409.2)		10,337,023
Total	\$	27,817,079
(m) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	223,998
Other Income and deductions (Account No. 409.2)		(50,460)
Total	\$	173,538
(n) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	3,391,469
Other income and deductions (Account No. 408.2)		319,584
Other		6,191,007
Total	\$	9,902,060
(o) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	16,938
Other income and deductions (Account No. 408.2)		1,654
Other		20,074
Total	\$	38,666
(p) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	7,078,978
Other income and deductions (Account No. 409.2)		5,030,415
Total	\$	12,109,393
(q) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	52,217
Other income and deductions (Account No. 409.2)		(801,686)
Total	\$	(749,469)
(r) Concept: TaxesIncurredOther		

Gas (Account No. 408.1)	\$	238,923
Other income and deductions (Account No. 408.2)		18,212
Other		1,246,108
Total	\$	1,503,243
<u>(s)</u> Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	(1,566,114)
Other income and deductions (Account No. 408.2)		(5,085)
Total	\$	(1,571,199)
<u>(t)</u> Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	20,772,000
Other income and deductions (Account No. 408.2)		66,000
Total	\$	20,838,000
<u>(u)</u> Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	(2,096,617)
<u>(v)</u> Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	200,271
Other income and deductions (Account No. 409.2)		107,928
Total	\$	308,199
<u>(w)</u> Concept: TaxesIncurredOther		
Other income and deductions (Account No. 409.2)	\$	(18,312)
<u>(x)</u> Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	849
Other income and deductions (Account No. 408.2)		57
Other		5,890
Total	\$	6,796
<u>(y)</u> Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	52,618
<u>(z)</u> Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	1,576,800
<u>(aa)</u> Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	1,031
Other income and deductions (Account No. 408.2)		69
Other		7,157
Total	\$	8,257
<u>(ab)</u> Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	1,516,648

(ac) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	2
(ad) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	340
Other income and deductions (Account No. 408.2)		23
Other		2,356
Total	\$	2,719
(ae) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	8,820
Other income and deductions (Account No. 409.2)		27,224
Total	\$	36,044
(af) Concept: TaxesIncurredOther		
Other	\$	2
(ag) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	14,608
Other income and deductions (Account No. 408.2)		2,313
Other		(149,571)
Total	\$	(132,650)
(ah) Concept: TaxesIncurredOther		
Other	\$	(2,292)
(ai) Concept: TaxesIncurredOther		
Other	\$	2,400
(aj) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	4,389
Other		27
Total	\$	4,416
(ak) Concept: TaxesIncurredOther		
Other	\$	27,445,324

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%	33,506			411.4	4,718		28,788	58 Years	
4	7%									
5	10%	13,450,850			411.4	1,122,891		12,327,959	57 Years	
6	30%	1,089,894			411.4	97,312		992,582	22 Years	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	14,574,250				1,224,921		13,349,329 ^(a)		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
11	Gas Utility									
12	4%	1,299			411.4	63		1,236	70 Years	
13	10%	764,577			411.4	106,293		658,284	50 Years	
14	TOTAL Gas Utility	765,876				106,356		659,520		
15	Common Utility									
16	4%	1,407			411.4	711		696	50 Years	
17	10%	66,843			411.4	6,565		60,278	50 Years	

18	TOTAL Common Utility	68,250				7,276		60,974		
47	OTHER TOTAL									
48	GRAND TOTAL	15,408,376				1,338,553		14,069,823		

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FOOTNOTE DATA			

(a) Concept: AccumulatedDeferredInvestmentTaxCredits

Accumulated Deferred Investment Tax Credits (Account 255). The formula excludes this account because the Company has chosen to utilize the amortization of tax credits against taxable income, that is, income tax expense is reduced by the amount of the amortized investment tax credit.

(b) Concept: AccumulatedDeferredInvestmentTaxCredits

(a) Common Allocation		
Electric - 93.17%	\$	56,809
Gas - 6.83%		4,165
	\$	60,974

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OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	CapX2020 Promissory Notes	28,072	232	26,879		1,193
2	Customer Prepayments	195,000	107	229,000	89,000	55,000
3	Deferred Compensation - Employees	9,913,010	131	1,114,973	2,781,572	11,579,609
4	Deferred Compensation - Employees (Wealth Op)	3,648,934	232	399,197	115,389	3,365,126
5	401 Nicollet Lease Credit	6,315,806	101	757,896		5,557,910
6	Deferred Revenue	2,546,880	(b) Various	4,076,292	3,064,981	1,535,569
7	Deferred Revenue-ITC Grant - Amortized over plant lives	832,426	405	68,939		763,487
8	Environmental & Regulatory Reserves	2,410,580	242	2,182,088	1,745,841	1,974,333
9	Executive PSP - Long Term	502,049			223,430	725,479
10	Long-Term Income Tax & Interest Payable	12,475,579	(c) Various	536,526	1,941,710	13,880,763
11	Unfunded Nonqualified Pension Benefit Costs	1,786,097			7,902	1,793,999
12	Nuclear Waste Strategy Coalition	38,851	232	1,356		37,495
13	Postemployment Benefit-Injury Compensation	9,776,223	(d) Various	2,233,293	359,651	7,902,581
14	Pre-Funded AFUDC: Metro Emissions Reduction Rider	45,637,945	405	2,164,871		43,473,074
15	Pre-Funded AFUDC: Mercury Emission Reduction Rider	245,793	405	26,942		218,851
16	Pre-Funded AFUDC: Minnesota Transmission Cost Recovery Rider	37,043,546	405	1,181,654	567,329	36,429,221

17	Pre-Funded AFUDC: FERC Transmission	36,378,514	405	672,259	0	35,706,255
18	Pre-Funded AFUDC: Renewable Energy Standards Rider	100,725,224	405	2,514,549	7,517,674	105,728,349
19	Pre-Funded AFUDC: South Dakota Transmission Cost Recovery Rider	2,063,367				2,063,367
20	Pre-Funded AFUDC: North Dakota Transmission Cost Recovery Rider	1,608,469				1,608,469
21	Coal Car Residual Value Deficit	3,582,059	151	279,598		3,302,461
22	Renewable Development Fund Obligations	42,591,359	232	35,864,258	35,500,000	42,227,101
23	Security Deposits	1,500	232	1,500		
24	Shared Network Upgrade	979,542	565	99,857		879,685
25	^(a) **Footnote from page 106b					
47	TOTAL	321,326,825		54,431,927	53,914,479	320,809,377

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: DescriptionOfOtherDeferredCredits
The Form 1 reports the other deferred credits balances at the beginning of year and at the end of the year. Included in this account is the credit for pre-funded AFUDC on CWIP related to the specific transmission projects that are included in the formula. These are jurisdictional amounts. The net pre-funded AFUDC amount used in the Attachment O formula is a total NSP system number (unjurisdictionalized). The formula requires the Company to use a 13 month average balance in the determination of the adjustment to rate base related to this account.

(b) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:			
447		\$	3,483,609
456			592,683
Total		\$	<u>4,076,292</u>

(c) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:			
236		\$	493,850
431			42,676
Total		\$	<u>536,526</u>

(d) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:			
131		\$	533,358
232			1,699,935
Total		\$	<u>2,233,293</u>

(e) Concept: DecreaseInOtherDeferredCredits
The amount reported for Pre-funded AFUDC-FERC Transmission is a jurisdictional amount. For purposes of calculating the Midcontinent ISO Formula Rate under Attachment O of the Northern States Power Companies FERC Tariff, a total company unjurisdictionalized amortization expense (405) amount is \$999,335.

(f) Concept: IncreaseInOtherDeferredCredits
The amount reported for Pre-funded AFUDC-FERC Transmission is a jurisdictional amount. For purposes of calculating the Midcontinent ISO Formula Rate under Attachment O of the Northern States Power Companies FERC Tariff, a total company unjurisdictionalized Pre-funded AFUDC (Total Accounts Other Expenses - 432, Other Revenue - 419.1) amount is \$0.

16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	20,033,462	(1,492,610)							1,223,121	19,763,973
18	Classification of TOTAL										
19	Federal Income Tax	15,614,251	(1,160,068)							939,052	15,393,235
20	State Income Tax	4,419,211	(332,542)							284,069	4,370,738
21	Local Income Tax										

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: AccumulatedDeferredIncomeTaxLiabilitiesAssetsAcceleratedAmortizationPropertyDescriptionOfDebitedAccountNumberForCreditAdjustments

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

(b) Concept: AccumulatedDeferredIncomeTaxLiabilitiesAssetsAcceleratedAmortizationPropertyAdjustmentsCreditedToAccount

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

(c) Concept: AccumulatedDeferredIncomeTaxesAcceleratedAmortizationProperty

Accumulated Deferred Income Taxes (Account No. 281). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances of non-property related items, and a prorated balance of property-related items in the formula. An adjustment is made to eliminate any accumulated deferred income tax balances related to regulatory differences related to income taxes.

(d) Concept: AccumulatedDeferredIncomeTaxesAcceleratedAmortizationProperty

All amounts in columns b - k are related to Electric Steam Production Plant

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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ACCUMULATED DEFERRED 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.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	2,546,121,674	126,600,825			Various ^(a)	605,151,670	Various ^(a)	626,051,251		2,693,622,080 ^(a)
3	Gas	161,720,600	8,752,530			Various ^(b)	78,381,045	Various ^(d)	75,963,065		168,055,150
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	2,707,842,274	135,353,355				683,532,715		702,014,316		2,861,677,230
6	Other (Non-Operating)	272,433			(7,174,954)			Various ^(f)	6,878		(6,895,643)
9	TOTAL Account 282 (Total of Lines 5 thru 8)	2,708,114,707	135,353,355		(7,174,954)		683,532,715 ^(a)		702,021,194 ^(b)		2,854,781,587
10	Classification of TOTAL										
11	Federal Income Tax	1,842,000,235	81,152,509		(4,897,223)		499,521,730		515,955,548		1,934,689,339
12	State Income Tax	866,114,471	54,200,847		(2,277,731)		184,010,985		186,065,646		920,092,248
13	Local Income Tax										

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherPropertyDescriptionOfDebitedAccountNumber

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

Based on a 2023 FERC Audit, the Company transferred the grossed-up recorded ADIT amounts related to AFUDC equity gross-up in Account 282, Accumulated Deferred Income Taxes – Other Property, instead of in Account 283, Accumulated Deferred income Taxes – Other. In 2023, the Company transferred the grossed-up balances from Account 282 to Account 283 and will prospectively report ADIT related to AFUDC equity gross-up in Account 283.

(b) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherPropertyDescriptionOfDebitedAccountNumber

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

Based on a 2023 FERC Audit, the Company transferred the grossed-up recorded ADIT amounts related to AFUDC equity gross-up in Account 282, Accumulated Deferred Income Taxes – Other Property, instead of in Account 283, Accumulated Deferred income Taxes – Other. In 2023, the Company transferred the grossed-up balances from Account 282 to Account 283 and will prospectively report ADIT related to AFUDC equity gross-up in Account 283.

(c) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherPropertyDescriptionOfCreditedAccountNumber

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

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(d) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherPropertyDescriptionOfCreditedAccountNumber

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

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(e) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

	Dec. 31, 2022	410.1 & Adjustments	Dec. 31, 2023
Decommissioning Nonqualified	\$ —	\$ —	\$ —
Electric Distribution Plant	805,993,411	17,344,436	823,337,847
Electric General Plant	80,980,938	12,159,137	93,140,075
Electric Intangible Plant	6,119,115	5,135,970	11,255,085
Electric Nuclear Fuel	17,537,688	5,124,449	22,662,137
Electric Nuclear Production Plant	503,100,276	(23,313,855)	479,786,421
Electric Production Plant	993,702,202	114,713,822	1,108,416,024
Electric Transmission Plant	911,215,291	12,889,710	924,105,001
Electric Transmission-Production Plant	24,923,014	866,685	25,789,699
Common (Allocation to Electric)	36,478,175	7,221,318	43,699,493
Regulatory Differences - Prior Flow Thru / Rate Change	(1,192,424,835)	31,885,475	(1,160,539,360)
Regulatory Differences - AFUDC Equity	106,106,109	(106,106,109)	—
Decommissioning Qualified	252,390,290	69,579,368	321,969,658
Total Electric Plant Related Only	\$ 2,546,121,674	\$ 147,500,406	\$ 2,693,622,080

Accumulated Deferred Income Taxes (Account No. 282). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances of non-property related items, and a prorated balance of property-related items in the formula. An adjustment is made to eliminate any accumulated deferred income tax balances related to regulatory differences related to income taxes.

Amortization of Excess ADIT (Electric only) included in 410.1 is \$41,156,507 for 2022 and \$33,014,789 for 2023.

2022 ARAM

2023 ARAM

Protected ARAM:			
Decommissioning	\$	—	\$ —
Electric Distribution Plant		4,664,039	4,771,727
Electric General Plant		2,794,314	2,091,087
Electric Intangible Plant		76,419	67,815
Electric Nuclear Fuel		339,415	(15,435)
Electric Production Plant		17,191,693	11,388,555
Electric Transmission Plant		1,394,250	2,462,803
Electric Transmission-Production Plant		84,889	70,139
Common (Allocation to Electric)		2,918,976	2,593,042
Total Protected ARAM		29,463,995	23,429,733
Unprotected ARAM:			
Decommissioning		—	—
Electric Distribution Plant		2,740,444	2,295,548
Electric General Plant		100,395	40,115
Electric Intangible Plant		327,641	(28,906)
Electric Nuclear Fuel		45,565	(3,273)
Electric Production Plant		6,903,403	6,423,364
Electric Transmission Plant		1,276,051	712,547
Electric Transmission-Production Plant		9,032	(25,020)
Common (Allocation to Electric)		289,458	171,269
Total Unprotected ARAM		11,691,989	9,585,644
Non Utility		523	(588)
Total Electric	\$	41,156,507	\$ 33,014,789
Common allocation for financial reporting may be different than for rate making.			
Common (Unallocated)	\$	3,536,551	\$ 3,059,163

The Flowback of permanent items included above in 410.1 is \$8,893,860 for 2022 for Electric only. In 2023, the permanent item, AFUDC Equity, was reclassified to FERC 283. Refer to footnotes to FERC 283 for 2023 Flowback.

The Excess ADIT above in column c include the ungrossed amounts presented below. These amounts will be amortized over the book lives of the underlying assets.

		Dec. 31, 2023	Dec. 31, 2023	Dec. 31, 2023
		Excess	Gross up	Total Regulatory
Excess (Electric only)				
Flow Through	\$	1,840,321	716,816	2,557,137
Method Life (Protected)		(686,214,278)	(267,284,885)	(953,499,163)
Other Basis Differences (Unprotected)		(150,843,009)	(58,754,325)	(209,597,334)
	\$	(835,216,966)	(325,322,394)	(1,160,539,360)

Includes Non-Utility and Common Allocated. The common allocation for the financial reporting is different from the allocation used in rate making.

Non-utility				
Flow Through	\$	99,050	38,581	137,631
Method Life (Protected)		1,147	447	1,594
Other Basis Differences (Unprotected)		—	—	—
	\$	100,197	39,028	139,225
Common (allocated)				
Flow Through	\$	17,514	6,822	24,336
Method Life (Protected)		(6,333,030)	(2,466,756)	(8,799,786)
Other Basis Differences (Unprotected)		(373,669)	(145,547)	(519,216)

Common (unallocated)	\$	(6,689,185)	\$	(2,605,481)	\$	(9,294,666)
Flow Through	\$	20,484	\$	7,979	\$	28,463
Method Life (Protected)		(7,407,157)		(2,885,135)		(10,292,292)
Other Basis Differences (Unprotected)		(437,046)		(170,233)		(607,279)
	\$	(7,823,719)	\$	(3,047,389)	\$	(10,871,108)

(f) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherPropertyDescriptionOfCreditedAccountNumber

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

Based on a 2023 FERC Audit, the Company transferred the grossed-up recorded ADIT amounts related to AFUDC equity gross-up in Account 282, Accumulated Deferred Income Taxes – Other Property, instead of in Account 283, Accumulated Deferred income Taxes – Other. In 2023, the Company transferred the grossed-up balances from Account 282 to Account 283 and will prospectively report ADIT related to AFUDC equity gross-up in Account 283.

(g) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherPropertyAdjustmentsDebitedToAccount

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

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(h) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherPropertyAdjustmentsCreditedToAccount

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

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Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify), include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Electric - Plant	46,242,438	4,050,704			(a) Various	30,345,462	(b) Various	152,027,957	171,975,637	(c)
4	Electric - Non-Plant	256,549,000	101,910,848	84,831,399		182.3	8,700,529	182.3	810,395	265,738,315	
5										0	
9	TOTAL Electric (Total of lines 3 thru 8)	302,791,438	105,961,552	84,831,399			39,045,991		152,838,352	437,713,952	(d)
10	Gas										
11	Gas	70,983,264	16,748,078	25,512,082		(a) Various	4,591,588	(b) Various	8,242,147	65,869,819	
17	TOTAL Gas (Total of lines 11 thru 16)	70,983,264	16,748,078	25,512,082			4,591,588		8,242,147	65,869,819	
18	TOTAL Other	129,773			(216,619)	(g) Various	1,395			(88,241)	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	373,904,475	122,709,630	110,343,481	(216,619)		43,638,974		161,080,499	503,495,530	(h)
20	Classification of TOTAL										
21	Federal Income Tax	258,108,505	85,870,556	75,315,175	(147,863)		34,102,218		112,245,579	346,659,384	
22	State Income Tax	115,795,970	36,839,074	35,028,306	(68,756)		9,536,756		48,834,920	156,836,146	

23	Local Income Tax										
NOTES											

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherDescriptionOfDebitedAccountNumber

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

Based on a 2023 FERC Audit, the Company transferred the grossed-up recorded ADIT amounts related to AFUDC equity gross-up in Account 282, Accumulated Deferred Income Taxes – Other Property, instead of in Account 283, Accumulated Deferred income Taxes – Other. In 2023, the Company transferred the grossed-up balances from Account 282 to Account 283 and will prospectively report ADIT related to AFUDC equity gross-up in Account 283.

(b) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherDescriptionOfCreditedAccountNumber

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

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(c) Concept: AccumulatedDeferredIncomeTaxesOther

	Balance at Beginning of Year	410.1 & Adjustments	Balance at End of Year
Electric Distribution Plant	\$ 140,836	\$ 13,809	\$ 154,645
Electric General Plant	560,743	(95,137)	465,606
Electric Intangible Plant	4,053,766	3,202,022	7,255,788
Electric Nuclear Production Plant	2,041,239	(354,541)	1,686,698
Electric Production Plant	—	—	—
Electric Transmission Plant	(273,572)	163,752	(109,820)
Common (Allocation to Electric)	38,492,158	2,524,204	41,016,362
Regulatory Differences - AFUDC Equity	1,227,268	120,279,090	121,506,358
Total Electric Plant Related Only	\$ 46,242,438	\$ 125,733,199	\$ 171,975,637

For 2023, the flowback of permanent items included in FERC 283, is \$7,618,214. The 2022 flowback amounts were included in FERC 282.

(d) Concept: AccumulatedDeferredIncomeTaxesOther

Accumulated Deferred Income Taxes (Account No. 283). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances of non-property related items, and a prorated balance of property-related items in the formula. An adjustment is made to eliminate any accumulated deferred income tax balances related to regulatory differences related to income taxes.

(e) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherDescriptionOfDebitedAccountNumber

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

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(f) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherDescriptionOfCreditedAccountNumber

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

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(g) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherDescriptionOfDebitedAccountNumber

To comply with the new IRS guidance identified in Private Letter Rulings 202141001 and 202124003, the Company reallocated timing differences to bifurcate cost of removal (COR) deferred income taxes from asset (life) deferred income taxes. This resulted in a recalculation of accumulated deferred income taxes and excess deferred income tax balances in FERC accounts 190, 281, 282, 283, 182.3 and 254.

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(h) Concept: AccumulatedDeferredIncomeTaxesOther

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Deferred Tax Collected in Rates in Excess of Current Tax Accrual Levels	1,182,970,621	282	40,320,942		1,142,649,679
2	Department of Energy Settlement Payment - MN Docket E-002/M-21-815	6,599	142	18,728,301	30,995,209	12,273,507
3	Derivatives and Hedging - Retail Electric & Gas	55,993,584	175	40,220,315		15,773,269
4	Electric Low Income Discount Program and PowerON Program - MN Docket E-002/GR-15-826 - MN Docket E-002/M-04-1956 - MN Docket E-002/M-17-629	11,603,746	(a) Various	20,903,172	18,831,255	9,531,829
5	Gas Low Income Discount Program - MN Docket G-002/GR-06-1429	4,019,665	(b) Various	4,263,976	2,829,829	2,585,518
6	ITC Gross-Up to Pre-Tax Rate Levels	6,307,033	190	529,368		5,777,665
7	Minnesota Deferred Electric Commodity Costs - MN Docket E-002/AA-20-417 - MN Docket E-002/GR-21-630 - MN Docket E-002/AA-21-295 - MN Docket E-002/AA-22-179		557	942,078,029	1,068,352,726	126,274,697
8	Minnesota Deferred Electric Property Tax - 2021- MN Docket E-002/GR-21-630	11,350,128	142	11,564,696	214,568	
9	Minnesota Deferred Electric Property Tax - 2022 - MN Docket E-002/GR-21-630	13,956,266	408.1	2,780,768	222,816	11,398,314
10	Minnesota Deferred Electric Property Tax - 2023 - MN Docket E-002/GR-21-630		408.1	10,741,170	25,826,913	15,085,743
11	Minnesota Electric Capital True-Up - 2022- MN Docket E-002/GR-21-630				13,579,811	13,579,811
12	Minnesota Electric Capital True-Up - 2023- MN Docket E-002/GR-21-630				23,700,000	23,700,000

13	Minnesota Electric Sales True-Up- MN Docket E-002/GR-21-630	21,505,674	407.3	21,505,674	30,891,232	30,891,232
14	Minnesota Electric Conservation and Energy Management Program Costs - MN Docket G-002/M-23-145 - Generally amortized over 12 month period following the expenditure	37,966,336	232	140,552,983	123,459,467	20,872,820
15	Minnesota Gas Conservation and Energy Management Program Costs - MN Docket G-002/M-23-146 - Generally amortized over 12 month period following the expenditure	3,645,231	232	23,392,104	25,333,629	5,586,756
16	Minnesota Gas Rate Case Deferral - MN Docket G-002/GR-09-1153 - MN Docket G-002/GR-21-678 - Amortized through 2024	2,243,854	928	1,461,691	271,774	1,053,937
17	Minnesota Gas State Energy Policy Rider - MN Docket G-002/M-21-151	68,752	142	68,752		
18	Minnesota Incentive Compensation Refund- MN Docket E-002/M-23-468	3,309,150	407.4	3,418,371	1,803,262	1,694,041
19	Minnesota Net Operating Loss - MN Docket E-002/GR-21-630				6,034,314	6,034,314
20	Minnesota Service Quality Program - MN Docket E,G-002/CI-02-2034 - MN Docket E,G-002/M-12-383	750,002	456	679,279	1,704,279	1,775,002
21	Minnesota Renewable Energy Standard- MN Docket E-002/M-23-454				1,382,901	1,382,901
22	Minnesota Transmission Cost Recovery Rider- MN Docket E-002/GR-23-467	4,147,905	407.4	99,380,299	96,307,732	1,075,338
23	Minnesota Winter Storm Uri Refund Accrual				394,425	394,425
24	NNG Refund		142	4,617,085	5,171,319	554,234
25	Nonplant Excess ADIT	23,186,807	190	4,486,489		18,700,318
26	North Dakota Deferred Electric Commodity Costs - ND Docket PU-23-011	4,110,448	557	63,347,326	62,271,056	3,034,178
27	North Dakota Earnings Sharing - ND Docket PU-20-441 - ND Docket PU-21-160 - ND Docket PU-22-183	13,707,480	456	304,451	1,138,396	14,541,425
28	North Dakota ITC	10,393,072	410.1	3,164,784		7,228,288
29	North Dakota Production Tax Credit Levelization - ND Docket PU-20-441 - ND Docket PU-23-312	18,513,156			8,861,959	27,375,115
30	North Dakota Purchased Gas Cost - ND Docket PU-23-008		805.1	69,575,872	72,117,055	2,541,183

31	North Dakota Renewable Energy Rider - ND Docket PU-23-312	1,173,806	407.4	5,814,400	5,188,609	548,015
32	North Dakota Retail Asset and Non-Asset Margin Sharing - ND Docket PU-10-657	7,571,341	557	7,202,576	4,174,821	4,543,586
33	North Dakota Transmission Cost Recovery Rider - ND Docket PU-23-315	563,879	407.4	2,358,075	1,840,454	46,258
34	Power Purchase Agreement	532,056				532,056
35	Pre-ARO Decommissioning	1,949,399,030			78,215,604	2,027,614,634
36	Renewable*Connect Classic - MN Docket E-002/GR-23-143	1,025,978	(a) Various	5,516,115	5,615,336	1,125,199
37	Renewable*Connect Government - MN Docket E-002/GR-23-143	99,281	555	339,565	324,266	83,982
38	Renewable*Connect Flex - MN Docket E-002/GR-23-143		(a) Various	3,090,080	3,541,926	451,846
39	Residential Payment Plan Credit Program - MN Docket E-002/M-20-760	1,756,489	(a) Various	1,756,489		
40	South Dakota Deferred Electric Commodity Costs - SD Docket EL 14-058 - SD Docket EL 22-017	8,126,367	557	62,780,287	59,618,439	4,964,519
41	South Dakota Electric Conservation and Energy Management Program Costs - SD Docket EL 23-013 - Generally amortized over 12 month period following the expenditure	24,974	232	841,563	872,217	55,628
42	South Dakota Infrastructure - SD Docket EL 23-025	2,162,111	407.4	2,162,111		
43	South Dakota Inver Hills Gain Sharing - SD Docket EL 22-017	235,000	142	235,000		
44	South Dakota Production Tax Credit Sharing - SD Docket EL 14-058 - SD Docket EL 22-017	3,400,918	557	10,430,989	7,030,071	
45	South Dakota Property Tax Collected in the Fuel Clause Adjustment - SD Docket EL 14-058 - SD Docket EL 22-017	261,949	408.1	772,509	1,889,219	1,378,659
46	South Dakota Retail Asset and Non-Asset Margin Sharing - SD Docket EL 14-058 - SD Docket EL 22-017	2,470,661	557	6,328,661	4,709,325	851,325
47	South Dakota Transmission Cost Recovery Rider - SD Docket EL 23-026	378,526	407.4	378,526		
48	Transmission Formula Rates	14,480,131	456	5,218,149	8,063,649	17,325,631
49	Unrealized Gains on Decommissioning Trust	654,184,034			180,346,522	834,530,556

50	Windsor - MN Docket E-002/M-01-1479 - MN Docket E-002/GR-13-868	3,643,080	Various	14,598,459	16,800,001	5,844,622
41	TOTAL	4,081,245,120		1,657,909,451	1,999,926,386	4,423,262,055

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment		
Accounts charged:		
142	\$	20,300,889
232		602,283
Total	<u>\$</u>	<u>20,903,172</u>

(b) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment		
142	\$	4,177,927
232		86,049
Total	<u>\$</u>	<u>4,263,976</u>

(c) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment		
Accounts charged:		
555	\$	5,475,901
912		40,214
Total	<u>\$</u>	<u>5,516,115</u>

(d) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment		
Accounts charged:		
555	\$	3,071,594
912		18,486
Total	<u>\$</u>	<u>3,090,080</u>

(e) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment		
Accounts charged:		
142	\$	713,783
254		1,042,706
Total	<u>\$</u>	<u>1,756,489</u>

(f) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment		
Accounts charged:		
555	\$	14,469,419
921		129,040
Total	<u>\$</u>	<u>14,598,459</u>

(g) Concept: OtherRegulatoryLiabilities		
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	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Total
Electric	\$ 12,634,126 \$	4,921,074 \$	17,555,200
Gas	824,119	320,999	1,145,118
Total	\$ 13,458,245 \$	5,242,073 \$	18,700,318

*For purposes of calculating the NSP Companies transmission formula rate, the excess non-plant balances (excluding tax gross-up) are as follows. The Company uses the average of the beginning of the year and the end of the year balances in the formula. These balances are being flowed back to customers over various periods consistent with the nature of the item.

	Excess Balance 12/31/2022	Amortization 2023	Excess Balance 12/31/2023
Pension Expense	\$ 15,110,107 \$	(1,511,011) \$	13,599,096
Total Electric	\$ 15,110,107 \$	(1,511,011) \$	13,599,096

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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Electric Operating Revenues

- The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- 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.
- If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.
- 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.)
- See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
- For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
- Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	1,679,937,185	1,629,315,036	10,669,105	10,721,559	1,385,188	1,368,821
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	1,846,623,840	1,864,063,304	14,404,301	14,505,025	162,224	161,184
5	Large (or Ind.) (See Instr. 4)	797,945,464	809,170,472	7,830,382	7,972,062	531	540
6	(444) Public Street and Highway Lighting	29,280,614	30,373,968	108,934	113,345	6,767	6,560
7	(445) Other Sales to Public Authorities	11,748,486	11,165,510	83,243	79,606	1,591	1,602
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales	717,395	574,363	5,646	4,685		
10	TOTAL Sales to Ultimate Consumers	4,366,252,984	4,344,662,653	33,101,611	33,396,282	1,556,301	1,538,707
11	(447) Sales for Resale	209,055,131	369,903,563	14,923,743	16,157,437		
12	TOTAL Sales of Electricity	4,575,308,115	4,714,566,216	48,025,354	49,553,719	1,556,301	1,538,707
13	(Less) (449.1) Provision for Rate Refunds	107,583,434	51,100,032				

14	TOTAL Revenues Before Prov. for Refunds	4,467,724,681	4,663,466,184	48,025,354	49,553,719	1,556,301	1,538,707
15	Other Operating Revenues						
16	(450) Forfeited Discounts	9,368,336	5,589,366				
17	(451) Miscellaneous Service Revenues	(b)2,498,086	(a)2,593,982				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	(c)5,268,969	5,594,594				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	(d)345,150,398	(b)466,480,169				
22	(456.1) Revenues from Transmission of Electricity of Others	(a)332,290,850	(b)335,474,916				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	694,576,639	815,733,027				
27	TOTAL Electric Operating Revenues	5,162,301,320	5,479,199,211				

Line12, column (b) includes \$ (19,499,901) of unbilled revenues.

Line12, column (d) includes (125,655) MWH relating to unbilled revenues

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FOOTNOTE DATA

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Commercial and industrial sales are classified as "Large" for purposes of this report if the customer has a twelve month average minimum registered demand of 1,000 kilowatts or more.

(b) Concept: MiscellaneousServiceRevenues

Connection charges	\$	2,382,549
NSF Check Fees		427,030
Other, less than \$250,000 each		(311,493)
	<u>\$</u>	<u>2,498,086</u>

(c) Concept: RentFromElectricProperty

Rent from Electric Property (Account No. 454). The rent revenue credit from electric property included in the formula is income directly related to transmission facilities, such as pole attachments, rentals and special use.

(d) Concept: OtherElectricRevenue

Includes reimbursement from NSP-Wisconsin for production costs shared under the FERC-approved Interchange Agreement between the companies. See Note 1 to the Financial Statements.

Fixed Production Expense	\$	226,921,330
Variable Production Expense		207,179,613
Total Interchange Agreement	<u>\$</u>	<u>434,100,943</u>

Also includes the following items:

Windsorce Program	\$	13,070,690
Renewable*Connect		8,993,901
Fees charged to burn Refuse Derived Fuel		8,316,621
Net distribution of commodity trading margins under Joint Operating Agreement		2,151,715
Purchased Power Reimbursement		844,405
Distribution Facility Fixed Charges		722,527
Manitoba Hydro Energy Service Agreement		592,683
Solar Gardens-Subscribed		461,000
Transmission Owner's Interconnection Facilities (TOIF) Billings		290,843
Work on Customers' Equipment		281,639
Conservation Improvement Program incentive, net of accruals and recoveries		(333,851)
North Dakota Earnings Test		(833,945)
Solar Energy Standard Exclusion		(1,242,352)
Service Quality Plans		(1,704,227)
Change in net over-recovered electric commodity costs		(121,650,669)
Other less than \$250,000 each		1,088,475
	<u>\$</u>	<u>345,150,398</u>

(e) Concept: RevenuesFromTransmissionOfElectricityOfOthers

Includes \$59,220,373 reimbursement from NSP-Wisconsin for transmission costs shared under the FERC-approved Interchange Agreement between the companies. See Note 1 to the Financial Statements.

(f) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Commercial and industrial sales are classified as "Large" for purposes of this report if the customer has a twelve month average minimum registered demand of 1,000 kilowatts or more.

(g) Concept: MiscellaneousServiceRevenues

Connection charges	\$	2,274,233
NSF Check Fees		309,750
Other, less than \$250,000 each		9,999
	\$	<u>2,593,982</u>

(h) Concept: OtherElectricRevenue

Includes reimbursement from NSP-Wisconsin for production costs shared under the FERC-approved Interchange Agreement between the companies. See Note 1 to the Financial Statements.

Fixed Production Expense	\$	236,163,196
Variable Production Expense		216,631,126
Total Interchange Agreement	\$	<u>452,794,322</u>

Also includes the following items:

Windsorce Program	\$	17,671,824
2020 Minnesota Deferred Property Tax*		12,251,763
Fees charged to burn Refuse Derived Fuel		7,867,350
Minnesota Incentive Compensation Refund*		2,101,585
Purchased Power Reimbursement		734,169
Distribution Facility Fixed Charges		719,246
Manitoba Hydro Energy Service Agreement		592,683
Solar Gardens-Subscribed		443,000
Transmission Owner's Interconnection Facilities (TOIF) Billings		274,242
Work on Customers' Equipment		263,383
Service Quality Plans		(293,542)
Solar Energy Standard Exclusion		(850,964)
Net distribution of commodity trading margins under Joint Operating Agreement		(3,629,540)
Renewable*Connect		(5,308,031)
Conservation Improvement Program incentive, net of accruals and recoveries		(5,560,692)
North Dakota Earnings Test		(5,992,914)
Change in net over-recovered electric commodity costs		(9,128,487)
Other less than \$250,000 each		1,530,772
	\$	<u>466,480,169</u>

*Represents reclass between FERC 440-448 and FERC 456

(i) Concept: RevenuesFromTransmissionOfElectricityOfOthers

Includes \$61,002,657 reimbursement from NSP-Wisconsin for transmission costs shared under the FERC-approved Interchange Agreement between the companies. See Note 1 to the Financial Statements.

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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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Minnesota					
2	A00 Water Heating	132	19,565	36	3,667	0.1482
3	A01 Residential	5,061,952	830,983,634	785,724	6,442	0.1642
4	A02 Residential Time of Day	5,998	867,569	616	9,737	0.1446
5	A03 Residential Underground	3,916,784	631,568,708	413,348	9,476	0.1612
6	A04 Residential TOD Underground	7,167	1,054,250	506	14,164	0.1471
7	A05 Energy Control	36,227	3,621,515	3,129	11,578	0.1000
8	A06 Limited Off Peak	2,519	282,402	361	6,978	0.1121
9	A07 Auto Protective Lighting	4,958	1,250,581			0.2522
10	A08 Residential Electric Vehicle	6,111	734,050			0.1201
11	A72 Resid TOU Pilot-Overhead	33,454	5,597,850	5,588	5,987	0.1673
12	A74 Resid TOU Pilot-Underground	31,393	5,168,252	3,481	9,018	0.1646
13	A80 Resid EV Pilot Bundled	5,934	897,211			0.1512
14	A81 Resid EV Pilot Pre-Pay	2,502	520,959			0.2082
15	A82 Resid EV Pilot Bundled Subs	511	60,094			0.1176
16	A83 Resid EV Pilot Pre-Pay Subs	89	7,622			0.0856
17	Unbilled-MN-Residential Sales	(59,310)	(5,769,262)			0.0973

18	North Dakota					
19	D01 Residential	606,358	73,534,706	69,127	8,772	0.1213
20	D02 Residential Time of Day	803	83,160	30	26,767	0.1036
21	D03 Residential Underground	168,375	19,322,031	12,949	13,003	0.1148
22	D04 Residential TOD Underground	162	16,862	10	16,200	0.1041
23	D05 Energy Control	3,054	262,625	287	10,641	0.0860
24	D10 Limited Off Peak	690	54,316	96	7,188	0.0787
25	D11 Auto Protective Lighting	293	59,877			0.2044
26	Unbilled-ND-Residential Sales	(11,404)	(1,362,946)			0.1195
27	South Dakota					
28	E01 Residential	361,855	48,246,918	47,610	7,600	0.1333
29	E02 Residential Time of Day	128		9	14,222	
30	E03 Residential Underground	484,293	63,357,980	42,065	11,513	0.1308
31	E04 Residential Time of Day	188	22,119	12	15,667	0.1177
32	E06 Residential Heat Pump	1,753	156,586	100	17,530	0.0893
33	E10 Energy Control	1,226	92,920	103	11,903	0.0758
34	E11 Limited Off Peak	6	346	1	6,000	0.0577
35	E12 Auto Protective Lighting	317	67,433			0.2127
36	Unbilled-SD-Residential Sales	(5,413)	(842,748)			0.1557
41	TOTAL Billed Residential Sales	10,745,232	1,687,912,141	1,385,188	7,757	0.1571
42	TOTAL Unbilled Rev. (See Instr. 6)	(76,127)	(7,974,956)			0.1048
43	TOTAL	10,669,105	1,679,937,185	1,385,188	7,702	0.1575

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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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Commercial Sales					
2	Minnesota					
3	A05 Energy Control	1,850	195,627	112	16,518	0.1057
4	A06 Limited Off Peak	1,284	199,281	79	16,253	0.1552
5	A07 Auto Protective Lighting	22,491	3,935,028			0.1750
6	A09 Small General Service	25	14,944	99	253	0.5978
7	A10 Small General Service	731,354	115,654,300	76,649	9,542	0.1581
8	A11 Water Heating	190	27,971	72	2,639	0.1472
9	A12 Small General TOD Service	39,000	5,695,246	3,023	12,901	0.1460
10	A13 Direct Current	5	8,451	1	5,000	1.6902
11	A14 General Service	7,555,430	1,032,234,907	42,996	175,724	0.1366
12	A15 General TOD Service	2,569,678	298,622,576	4,621	556,087	0.1162
13	A16 Small General kWh metered	16,194	2,619,760	3,128	5,177	0.1618
14	A18 Small General TOD Service	26,288	4,023,011	4,224	6,223	0.1530
15	A22 Small General TOD Low Wattage	901	136,088	2	450,500	0.1510
16	A23 Peak Control Tiered	976,792	128,216,348	1,284	760,741	0.1313
17	A24 Peak Control Time of Day	449,399	48,218,769	204	2,202,936	0.1073

18	A27 Tier 1 Energy Control	15,522	1,299,635	4	3,880,500	0.0837
19	A29 Hiawatha Light Rail	32,884	4,077,626	30	1,096,133	0.1240
20	A87 - EV Fleet Pilot Service	637	164,101			0.2576
21	A90 - EV Public Charging Pilot	655	180,243			0.2752
22	Unbilled-MN-Commercial Sales	(42,227)	(8,224,733)			0.1948
23	North Dakota					
24	D05 Energy Control	1,244	103,933	50	24,880	0.0835
25	D10 Limited Off Peak	463	55,028	35	13,229	0.1189
26	D11 Auto Protective Lighting	2,513	369,570			0.1471
27	D12 Small General Service	95,480	11,561,268	8,130	11,744	0.1211
28	D14 Small General TOD Service	2,530	285,031	191	13,246	0.1127
29	D16 General Service	638,682	71,046,227	3,946	161,856	0.1112
30	D17 General TOD Service	95,352	9,001,605	194	491,505	0.0944
31	D18 Small General TOD Service	544	69,214	99	5,495	0.1272
32	D19 Small General kWh metered	1,012	138,083	207	4,889	0.1364
33	D20 Peak Control	29,678	3,118,150	48	618,292	0.1051
34	D21 Peak Control Time of Day	14,862	1,327,243	11	1,351,091	0.0893
35	D22 Tier 1 Energy Control	109,171	9,308,472	55	1,984,927	0.0853
36	D34 Sm General TOD Low Wattage	44	4,275	4	11,000	0.0972
37	Unbilled-ND-Commercial Sales	(7,662)	(1,035,721)			0.1352
38	South Dakota					
39	E10 Energy Control	124	9,380	12	10,333	0.0756
40	E11 Limited Off Peak	355	30,303	8	44,375	0.0854
41	E12 Auto Protective Lighting	2,147	381,309			0.1776
42	E13 Small General Service	84,680	10,512,575	7,865	10,767	0.1241
43	E14 Small General TOD Service	2,624	327,253	381	6,887	0.1247
44	E15 General Service	672,645	70,995,550	4,127	162,986	0.1055
45	E16 General TOD Service	189,069	15,284,523	239	791,084	0.0808

46	E18 Small General TOD Service					
47	E20 Peak Control	42,751	4,725,906	73	585,630	0.1105
48	E21 Peak Control Time of Day	13,442	914,850	10	1,344,200	0.0681
49	E22 Energy Control	17,300	1,376,454	11	1,572,727	0.0796
50	Unbilled-SD-Commercial Sales	(3,101)	(585,820)			0.1889
41	TOTAL Billed Small or Commercial	14,457,291	1,856,470,114	162,224		
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(52,990)	(9,846,274)			
43	TOTAL Small or Commercial	14,404,301	1,846,623,840	162,224		

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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	Industrial Sales					
2	Minnesota					
3	A14 General Service	176,405	23,059,249	57	3,094,825	0.1307
4	A15 General TOD Service	4,931,382	517,717,488	301	16,383,329	0.1050
5	A23 Peak Control Tiered	18,453	2,010,779	5	3,690,600	0.1090
6	A24 Peak Control Time of Day	1,712,851	173,875,681	111	15,431,090	0.1015
7	A27 Tier 1 Energy Control	232,031	17,388,435	5	46,406,200	0.0749
8	A62 - Firm Real Time Pricing	20,987	2,435,826	3	6,995,667	0.1161
9	Unbilled-MN-Commercial Sales	(7,788)	(2,307,071)			0.2962
10	North Dakota					
11	D16 General Service	44,584	4,424,707	6	7,430,667	0.0992
12	D17 General TOD Service	96,755	8,721,621	5	19,351,000	0.0901
13	D21 Peak Control Time of Day	106,952	8,936,888	4	26,738,000	0.0836
14	D22 Tier 1 Energy Control	109,991	8,588,594	8	13,748,875	0.0781
15	Unbilled-ND-Commercial Sales	(2,295)	(276,023)			0.1203
16	South Dakota					
17	E15 General Service	22,741	2,305,639	6	3,790,167	0.1014

18	E16 General TOD Service	291,358	24,590,264	13	22,412,154	0.0844
19	E20 Peak Control	13,869	1,545,497	4	3,467,250	0.1114
20	E21 Peak Control Time of Day	48,023	3,804,328	3	16,007,667	0.0792
21	Unbilled-SD-Commercial Sales	14,083	1,123,562			0.0798
41	TOTAL Billed Large (or Ind.) Sales	7,826,382	799,404,996	531		
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	4,000	(1,459,532)			
43	TOTAL Large (or Ind.)	7,830,382	(a)797,945,464	531		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Commercial and industrial sales are classified as "Large" for purposes of this report if the customer has a twelve month average minimum registered demand of 1,000 kilowatts or more.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Minnesota					
2	A30 Street Lighting Company Owned	30,161	20,730,124	2,187	13,791	0.6873
3	A32 Street Lighting Customer Owned	21,709	2,024,554	420	51,688	0.0933
4	A34 Street Lighting Metered	34,650	3,244,309	3,322	10,430	0.0936
5	A37 Street Lighting St Paul	936	165,204	1	936,000	0.1765
6	Unbilled-MN-Street Lighting Sales	(224)	(158,326)			0.7068
7	North Dakota					
8	D30 Street Lighting Company Owned	741	529,400	68	10,897	0.7144
9	D31 Street Lighting Customer Owned	9,640	900,091	35	275,429	0.0934
10	D32 Street Lighting Ornamental	22	1,864	2	11,000	0.0847
11	D33 Street Lighting Metered	2,528	201,805	155	16,310	0.0798
12	Unbilled-ND-Street Lighting Sales	(53)	(11,232)			0.2119
13	South Dakota					
14	E30 Street Lighting Company Owned	834	905,813	137	6,088	1.0861
15	E31 Street Lighting Customer Owned	1,987	212,366	16	124,188	0.1069
16	E32 Street Lighting Metered	5,547	506,950	335	16,558	0.0914
17	E33 Street Lighting Ornamental	525	47,178	89	5,899	0.0899

18	Unbilled-SD-Street Lighting Sales	(69)	(19,486)			0.2824
41	TOTAL Billed Public Street and Highway Lighting	109,280	29,469,658	6,767	16,149	0.2697
42	TOTAL Unbilled Rev. (See Instr. 6)	(346)	(189,044)			0.5464
43	TOTAL	108,934	29,280,614	6,767	16,098	0.2688

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Minnesota					
2	A40 Small Municipal Pumping	5,631	928,616	872	6,458	0.1649
3	A41 Municipal Pumping	63,887	9,185,978	569	112,279	0.1438
4	A42 Fire Siren		38,974			
5	Unbilled-MN-Other Sales	(249)	(31,165)			0.1252
6	North Dakota					
7	D40 Small Municipal Pumping	649	79,906	61	10,639	0.1231
8	D41 Municipal Pumping	13,268	1,540,169	89	149,079	0.1161
9	D42 Fire Siren		1,153			
10	Unbilled-ND-Other Sales	57	1,070			0.0188
11	South Dakota					
12	E40 Fire Siren		3,785			
41	TOTAL Billed Other Sales to Public Authorities	83,435	11,778,581	1,591	52,442	0.1412
42	TOTAL Unbilled Rev. (See Instr. 6)	(192)	(30,095)			0.1567
43	TOTAL	83,243	11,748,486	1,591	52,321	0.1411

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

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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	Interdepartmental					
2	Interdepartmental Sales	5,646	717,395			0.1271
41	TOTAL Billed Interdepartmental Sales	5,646	717,395			0.1271
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	5,646	717,395			0.1271

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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 Page 310.
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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	(Footnote for Instruction 5)					
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		107,583,434			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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)
41	TOTAL Billed - All Accounts	33,227,266	4,385,752,885	1,556,301	21,350	0.1320
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(125,655)	(19,499,901)			0.1552
43	TOTAL - All Accounts	33,101,611	4,366,252,984	1,556,301	21,350	0.1319

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: RevenueFromSalesOfElectricityByRateSchedulesIncludingUnbilledRevenue

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

A00	\$	5,277
A01		199,183,143
A02		209,124
A03		155,504,658
A04		268,222
A05		1,474,092
A06		146,791
A07		847,376
A08		233,223
A09		1,009
A10		29,076,682
A11		7,784
A12		1,565,259
A13		194
A14		305,154,165
A15		281,066,106
A16		654,693
A17		—
A18		1,076,013
A21		—
A22		36,884
A23		39,097,672
A24		80,910,166
A27		9,174,405
A29		1,285,143
A30		932,258
A32		670,955
A34		1,048,517
A37		28,890
A40		224,425
A41		2,450,654
A62		802,879
A72		1,239,632
A74		1,228,304
A80		246,244
A81		102,772
A82		528
A83		52
A87		23,576
Minnesota jurisdiction		1,115,977,767

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

D01		\$	15,618,932
D02			21,105
D03			4,332,269
D04			4,206
D05			117,335
D10			32,003
D11			56,272
D12			2,474,514
D14			65,531
D16			17,276,488
D17			4,715,625
D18			13,860
D19			26,099
D20			753,551
D21			2,971,832
D22			5,411,066
D30			14,854
D31			193,284
D32			443
D33			51,233
D34			1,132
D40			16,888
D41			336,342
North Dakota jurisdiction		\$	54,504,864

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

E01			6,931,675
E02			2,453
E03			9,326,837
E04			3,576
E06			31,222
E10			23,705
E11			6,419
E12			36,155
E13			1,577,156
E14			48,887
E15			13,156,057
E16			8,754,212
E18			-
E20			1,076,462
E21			1,121,207
E22			323,011
E30			12,233
E31			29,256
E32			80,747
E33			7,430
South Dakota jurisdiction			\$42,548,700
Total Company			\$1,213,031,331

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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SALES FOR RESALE (Account 447)

- 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).
- Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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.
- Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
- 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.
- 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.
- Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
- 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.
- 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, line 24.
- Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	

			(c)								
1	NSP- Wisconsin	RQ									(b)0
2	Citigroup Energy, Inc.	OS	V6				120,000			3,063,140	(a)3,063,140
3	Citigroup Energy, Inc.	SF	V6				13,200		330,998		(d)330,998
4	City of Ada, MN	OS	V6					40,050			40,050
5	City of Ada, MN	LF	V6				5,546		486,842		486,842
6	City of Ada, MN	AD	V6							11,887	(a)11,887
7	City of Kasota, MN	OS	V6					22,275			22,275
8	City of Kasota, MN	LF	V6				4,124		246,104		246,104
9	City of Kasota, MN	AD	V6							(1,598)	(b)(1,598)
10	Consumers Energy Company	OS	V6					200,000			200,000
11	Dairyland Power Co	OS	V6					312,500			312,500
12	Dahlberg Light and Power Co	OS	V6				8,914	712,609	135,061		847,670
13	Dahlberg Light and Power Co	SF	V6				99,991		4,644,673		4,644,673
14	Dahlberg Light and Power Co	AD	V6							125,265	(a)125,265
15	Direct Energy Marketing	SF	V6				3,616		90,909		(b)90,909
16	Direct Energy Marketing	OS	V6				37,378			900,717	(b)900,717
17	Direct Energy Marketing	AD	V6				2,450			108,634	(b)108,634
18	East Texas Electric Cooperative, Inc.	SF	V6				131,400		2,587,266		(a)2,587,266
19	Great River Energy	OS	V6					(125,000)		2,100,000	(b)1,975,000
20	Great River Energy	SF	V6				100,800		3,102,440		(b)3,102,440
21	J. Aron & Company LLC	SF	V6				24,800		744,908		(b)744,908
22	J. Aron & Company LLC	OS	V6				267,200			8,125,449	(a)8,125,449
23	ICE NGX Canada Inc	OS	V6				397,600			8,139,746	(a)8,139,746
24	ICE NGX Canada Inc	SF	V6				102,400		6,907,876		(a)6,907,876

25	Mercuria Energy American Inc.	OS	V6					465,000			465,000
26	Midcontinent Independent System Operator	OS	V6				11,665,177	65,174,612	46,558,372	4,067,576	115,800,560 ^(u)
27	Midcontinent Independent System Operator	AD	V6				37,746			(887,524)	(887,524) ^(s)
28	Morgan Stanley Capital Group, Inc.	OS	V6				467,600			11,746,036	11,746,036 ^(s)
29	Morgan Stanley Capital Group, Inc.	SF	V6				43,400		1,052,607		1,052,607 ^(u)
30	NextEra Energy Power Marketing, LLC	OS	V6				247,735			6,044,496	6,044,496 ^(u)
31	NextEra Energy Power Marketing, LLC	SF	V6				533,520		15,625,345		15,625,345 ^(u)
32	NRG Power Marketing LLC	OS	V6				7,246			215,744	215,744 ^(s)
33	North Central Power Company, Inc.	OS	V6					148,058	11,485		159,543
34	Northwestern Wisconsin Electric Company	OS	V6					948,180			948,180
35	Shelleneno	OS	V6				17,600			489,418	489,418 ^(u)
36	Shelleneno	SF	V6				584,300		14,382,975		14,382,975 ^(u)
37	^(u) Footnote for 106b										
15	Subtotal - RQ						6,399,633				
16	Subtotal-Non-RQ						14,923,743	67,898,284	96,907,861	44,248,986	209,055,131
17	Total						14,923,743	67,898,284	96,907,861	44,248,986	209,055,131

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
Sales for Resales (Account No. 447). The revenue credit from sales for resale included in the formula are for bundled sales that are not included in the formula divisor.
(b) Concept: RevenueFromSalesOfElectricityForResale
Ownership interest or affiliation per instruction 2:
Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) are both wholly owned operating subsidiaries of Xcel Energy Inc. To address reconciling items between pages 300 (Electric Operating Revenues) and 310 (Sales for Resale), NSP-Minnesota has removed the volumes and dollars associated with the net production Interchange Agreement billings with NSP-Wisconsin. If included, NSP-Minnesota would have reflected 6,399,633 Mwh in column G, \$371,518,512 in column I, and \$371,518,512 in column K. See Note 1 to the Financial Statements.
(c) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(d) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(e) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(f) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(g) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(h) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(i) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(j) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(k) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(l) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(m) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(n) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(o) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading

(p) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(q) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(r) Concept: RevenueFromSalesOfElectricityForResale
Demand - Resource Adequacy Auction, Other - Ancillary Services
(s) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(t) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(u) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(v) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(w) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(x) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(y) Concept: RevenueFromSalesOfElectricityForResale
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(z) Concept: RevenueFromSalesOfElectricityForResale
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Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	3,041,499	3,408,576
5	(501) Fuel	218,422,593	284,472,170
6	(502) Steam Expenses	17,270,080	17,520,606
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	5,105,422	4,671,087
10	(506) Miscellaneous Steam Power Expenses	13,264,376	14,399,952
11	(507) Rents	1,456,294	1,415,102
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	258,560,264	325,887,493
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,459,264	1,285,539
16	(511) Maintenance of Structures	4,931,738	3,902,411
17	(512) Maintenance of Boiler Plant	19,449,464	17,112,746
18	(513) Maintenance of Electric Plant	6,754,263	3,473,602
19	(514) Maintenance of Miscellaneous Steam Plant	6,419,880	7,060,544
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	39,014,609	32,834,842

21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	297,574,873	358,722,335
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	34,613,674	38,834,193
25	(518) Fuel	96,379,479	118,153,272
26	(519) Coolants and Water	9,208,027	8,267,994
27	(520) Steam Expenses	54,394,215	50,586,702
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,607,515	2,924,434
31	(524) Miscellaneous Nuclear Power Expenses	123,893,804	121,481,633
32	(525) Rents	5,763,152	5,313,358
33	TOTAL Operation (Enter Total of lines 24 thru 32)	326,859,866	345,561,586
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	7,891,172	7,614,287
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment	26,005,094	29,836,448
38	(531) Maintenance of Electric Plant	13,295,965	11,972,440
39	(532) Maintenance of Miscellaneous Nuclear Plant	33,726,695	25,024,623
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	80,918,926	74,447,798
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	407,778,792	420,009,384
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	13,110	71,095
45	(536) Water for Power	24,494	35,532
46	(537) Hydraulic Expenses	243,134	1,198
47	(538) Electric Expenses	17,569	309,165

48	(539) Miscellaneous Hydraulic Power Generation Expenses	152,762	138,570
49	(540) Rents	35,806	23,067
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	486,875	578,627
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	78,063	240
54	(542) Maintenance of Structures	16,314	48,860
55	(543) Maintenance of Reservoirs, Dams, and Waterways	362,900	189,740
56	(544) Maintenance of Electric Plant	158,594	39,868
57	(545) Maintenance of Miscellaneous Hydraulic Plant	5,728	1,328
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	621,599	280,036
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	1,108,474	858,663
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	3,837,111	4,498,558
63	(547) Fuel	186,652,908	240,473,124
64	(548) Generation Expenses	8,044,508	8,061,409
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	20,689,590	23,515,092
66	(550) Rents	17,750,890	16,293,981
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	236,975,007	292,842,164
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,368,379	1,719,645
70	(552) Maintenance of Structures	7,661,502	6,860,460
71	(553) Maintenance of Generating and Electric Plant	9,730,564	10,748,762
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	11,100,501	13,371,788

73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	29,860,946	32,700,655
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	266,835,953	325,542,819
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,082,622,299	1,062,214,692
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	1,368,668	1,203,960
78	(557) Other Expenses	(a) 119,789,935	(a) 143,268,025
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	1,203,780,902	1,206,686,677
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	2,177,078,994	2,311,819,878
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	8,166,252	9,486,961
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	4,799,300	4,068,232
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	7,119,039	8,133,121
89	(561.5) Reliability, Planning and Standards Development	166,074	1,968
90	(561.6) Transmission Service Studies	76,321	25,542
91	(561.7) Generation Interconnection Studies	460,319	482,946
92	(561.8) Reliability, Planning and Standards Development Services	3,190,294	3,141,620
93	(562) Station Expenses	5,662,676	5,068,723
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	356,017	599,788
95	(564) Underground Lines Expenses	17,120	15,379
96	(565) Transmission of Electricity by Others	(a) 351,948,780	(a) 368,862,290
97	(566) Miscellaneous Transmission Expenses	8,215,403	8,638,072
98	(567) Rents	1,273,660	1,234,581

99	TOTAL Operation (Enter Total of Lines 83 thru 98)	391,451,255	409,759,223
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,395,430	2,356,030
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	5,543,700	9,103,900
109	(572) Maintenance of Underground Lines		1,992
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	7,939,130	11,461,922
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	399,390,385	421,221,145
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	177,776	187,179
116	(575.2) Day-Ahead and Real-Time Market Facilitation	275,727	223,648
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance	17,040	
121	(575.7) Market Facilitation, Monitoring and Compliance Services	10,589,583	10,276,196
122	(575.8) Rents	17,978	14,182
123	Total Operation (Lines 115 thru 122)	11,078,104	10,701,205
124	Maintenance		

125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	11,078,104	10,701,205
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	17,280,225	16,333,026
135	(581) Load Dispatching	757,288	1,145,333
136	(582) Station Expenses	3,032,286	3,025,752
137	(583) Overhead Line Expenses	6,170,008	4,933,639
138	(584) Underground Line Expenses	7,834,722	7,386,712
138.1	(584.1) Operation of Energy Storage Equipment	571	
139	(585) Street Lighting and Signal System Expenses	664,430	742,321
140	(586) Meter Expenses	150,285	(1,145,078)
141	(587) Customer Installations Expenses	2,271,257	1,347,236
142	(588) Miscellaneous Expenses	13,925,838	16,968,169
143	(589) Rents	3,110,938	2,901,539
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	55,197,848	53,638,649
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	101,855	83,913
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	1,690,316	1,716,010
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	47,801,680	51,441,608

150	(594) Maintenance of Underground Lines	6,737,175	5,239,674
151	(595) Maintenance of Line Transformers	3,116	
152	(596) Maintenance of Street Lighting and Signal Systems	1,635,241	1,507,407
153	(597) Maintenance of Meters	512,933	314,597
154	(598) Maintenance of Miscellaneous Distribution Plant	216,677	540,792
155	TOTAL Maintenance (Total of Lines 146 thru 154)	58,698,993	60,844,001
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	113,896,841	114,482,650
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	123,803	129,775
160	(902) Meter Reading Expenses	19,848,846	20,096,455
161	(903) Customer Records and Collection Expenses	25,493,999	24,102,289
162	(904) Uncollectible Accounts	24,400,214	17,081,485
163	(905) Miscellaneous Customer Accounts Expenses	251,300	278,844
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	70,118,162	61,688,848
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	99,581,455	140,847,934
169	(909) Informational and Instructional Expenses	1,207,479	1,033,307
170	(910) Miscellaneous Customer Service and Informational Expenses	417,386	245,827
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	101,206,320	142,127,068
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	8,303,773	7,633,299
176	(913) Advertising Expenses		

177	(916) Miscellaneous Sales Expenses	60,624	58,239
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	8,364,397	7,691,538
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	108,131,814	91,087,571
182	(921) Office Supplies and Expenses	71,918,981	69,989,064
183	(Less) (922) Administrative Expenses Transferred-Credit	66,472,499	64,263,099
184	(923) Outside Services Employed	20,801,187	21,133,076
185	(924) Property Insurance	7,393,588	10,062,689
186	(925) Injuries and Damages	14,655,916	17,752,560
187	(926) Employee Pensions and Benefits	108,296,100	83,039,174
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	11,989,354	9,501,872
190	(929) (Less) Duplicate Charges-Cr.	6,619,698	6,121,912
191	(930.1) General Advertising Expenses	3,602,887	3,884,214
192	(930.2) Miscellaneous General Expenses	4,820,648	4,536,316
193	(931) Rents	50,004,809	47,678,667
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	328,523,087	288,280,192
195	Maintenance		
196	(935) Maintenance of General Plant	839,944	920,199
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	329,363,031	289,200,391
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	3,210,496,234	3,358,932,723

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: OtherExpensesOtherPowerSupplyExpenses
Includes \$47,719,122 of fixed costs and \$14,863,309 of variable costs reimbursed to NSP-Wisconsin for production costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.
(b) Concept: TransmissionOfElectricityByOthers
Includes \$142,066,960 of fixed costs reimbursed to NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.
(c) Concept: TransmissionExpenses
Total Transmission Expense as reported in the Form 1, page 321, line 112 is reduced by amounts related to transactions with an affiliated Company based on the FERC-approved Interchange Agreement.
(d) Concept: OtherExpensesOtherPowerSupplyExpenses
Includes \$47,067,946 of fixed costs and \$22,831,577 of variable costs reimbursed to NSP-Wisconsin for production costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.
(e) Concept: TransmissionOfElectricityByOthers
Includes \$132,294,095 of fixed costs reimbursed to NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.
(f) Concept: MeterExpenses
Credit balance due to meter transfer install O&M credits.

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PURCHASED POWER (Account 555)

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.

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) 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 (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) 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 columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

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)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)
1	ACE Lincoln Heights Wind Holdings, LLC	AD					(42)					(1,375)		(1,375)
2	ACE Lincoln Heights Wind Holdings, LLC	LU					13,936					459,483		459,483
3	Adams Wind Generations	LU					52,427					3,486,394		3,486,394
4	AEP Energy Partners, Inc.	AD					32					1,496		1,496
5	Agassiz Beach, LLC	LU					3,223					95,897		95,897
6	Aurora Distributed Solar, LLC	LU					198,021					21,586,276		21,586,276
7	Best Power International LLC	AD										133		133
8	Best Power International LLC	LU					1,847					188,031		188,031
9	Big Blue Wind Farm, LLC	AD										2,636		2,636
10	Big Blue Wind Farm, LLC	LU					74,629					6,642,890		6,642,890
11	Bisson Windfarm, LLC	AD					(23)					(798)		(798)

12	Bisson Windfarm, LLC	LU					4,751					161,520		161,520
13	Boeve Windfarm, L.L.C.	AD					1					(46)		46
14	Boeve Windfarm, L.L.C.	LU					4,727					158,368		158,368
15	Calpine Energy Services, L.P.	OS											(376,425)	376,425
16	Cannon Falls Energy Center	AD					12					(10,277)		10,277
17	Cannon Falls Energy Center	LU		357			688,587				30,134,288	29,830,329		59,964,617
18	Carleton College	AD					(101)					(3,340)		(3,340)
19	Carleton College	LU					4,028					132,926		132,926
20	CG Windfarm, LLC	AD					(242)					(8,240)		(8,240)
21	CG Windfarm, LLC	LU					2,537					86,261		86,261
22	Cisco Wind Energy, L.L.C.	AD										7		7
23	Cisco Wind Energy, L.L.C.	LU					17,964					755,846		755,846
24	Citigroup Energy, Inc.	OS											2,530,714	2,530,714
25	Covanta Hennepin Energy Resource Co LP	AD										8,040		8,040
26	Covanta Hennepin Energy Resource Co LP	LU					196,576					5,362,155		5,362,155
27	Crowned Ridge Wind, LLC	LU					664,077					16,259,854		16,259,854
28	Dairyland Electric Cooperative Incorporated	LU					17,200					515,304		515,304
29	Dakota Range III, LLC	LU					524,898					9,950,325		9,950,325
30	Danielson Wind Farms, LLC	LU					49,365					3,282,747		3,282,747
31	Deuel Harvest Wind Energy LLC	AD					1,821					(38,073)		38,073
32	Deuel Harvest Wind Energy LLC	LU					334,331					6,242,179		6,242,179
33	Dragonfly Solar, LLC	AD					1					105		105
34	Dragonfly Solar, LLC	LU					1,065					90,515		90,515
35	East Ridge group	AD					(22)					(736)		(736)
36	East Ridge group	LU					19,975					659,188		659,188
37	EDF TRADING NORTH AMERICA LLC	OS											5,001,970	5,001,970
38	Electric Reliability Council of Texas	AD					(1,415)					(276,054)		(276,054)
39	Electric Reliability Council of Texas	SF					110,338					25,099,405		25,099,405
40	Elk Creek Solar, LLC	AD					(3,392)					(132,288)		(132,288)
41	Ewington Energy Systems, LLC	AD					6					1,791		1,791
42	Ewington Energy Systems, LLC	LU					88,269					2,894,843		2,894,843
43	Fenton Power Partners I, L.L.C.	AD										42,809		42,809
44	Fenton Power Partners I, L.L.C.	LU					311,387					34,785,493		34,785,493
45	Fey Windfarm, L.L.C.	AD					(31)					(1,072)		(1,072)
46	Fey Windfarm, L.L.C.	LU					5,050					176,754		176,754
47	Fillmore County Solar Project, LLC	LU					21,191					1,181,421		1,181,421
48	Garwin McNeilus	AD					643					15,276		15,276

49	Garwin McNeilus	LU				72,445					2,291,778		2,291,778
50	Grant County Windfarm, LLC	LU				51,276					3,486,782		3,486,782
51	Great American West Wind, LLC	LU				398,408					5,349,857		5,349,857
52	Great River Energy	AD									^(a) 44,233		44,233
53	Hastings Lock & Dam	LU		2		22,561				407,494	335,828		743,322
54	Heartland Divide Wind II, LLC	AD				(41)					^(a) (814)		(814)
55	Heartland Divide Wind II, LLC	LU				744,034					15,120,478		15,120,478
56	Hilltop Power, L.L.C.	LU				4,027					177,198		177,198
57	J. Aron & Company LLC	OS										^(b) 5,562,657	5,562,657
58	JJN Windfarm, LLC	AD				7					^(a) 227		227
59	JJN Windfarm, LLC	LU				2,475					82,897		82,897
60	JPMorgan Chase Bank New York	OS										^(b) 10,126,688	10,126,688
61	Kas Brothers Windfarm, L.L.C.	AD				(7)					^(a) (283)		(283)
62	Kas Brothers Windfarm, L.L.C.	LU				2,442					97,997		97,997
63	K-Brink Windfarm, L.L.C.	AD									^(a) (1)		(1)
64	K-Brink Windfarm, L.L.C.	LU				2,974					99,638		99,638
65	Keller Paving & Landscaping, Inc.	AD									^(a) 1,059		1,059
66	Keller Paving & Landscaping, Inc.	LU				212					6,546		6,546
67	KODA Energy, LLC	AD				(265)					^(a) (8,295)		(8,295)
68	KODA Energy, LLC	LU				3,598					97,986		97,986
69	Lake Benton Power Partners, L.L.C.	AD									^(a) 25,109		25,109
70	Lake Benton Power Partners, L.L.C.	LU				223,147					6,783,364		6,783,364
71	Louise Solar Project, LLC	LU				35,307					1,968,365		1,968,365
72	LSP Cottage Grove Incorporated	AD									^(a) (90,247)		(90,247)
73	LSP Cottage Grove Incorporated	LU		245		1,026,031				8,290,954	26,054,166		34,345,120
74	Manitoba Hydro	AD								^(a) (1,481,434)			(1,481,434)
75	Manitoba Hydro	LU		478		2,081,372				54,220,572	175,064,687		229,285,259
76	Mankato Energy Center I, L.L.C.	AD				236				93,750	^(a) (286,062)		(192,312)
77	Mankato Energy Center I, L.L.C.	LU		375		1,205,790				40,167,317	74,912,087		115,079,404
78	Mankato Energy Center II, L.L.C.	AD				(308)				130,238	^(a) (107,587)		22,651
79	Mankato Energy Center II, L.L.C.	LU		345		1,433,446				29,310,973	5,736,503		35,047,476
80	Marshall Solar	LU				104,277					7,773,531		7,773,531
81	Merrill Lynch Commodities, Inc.	OS										^(b) 503,735	503,735
82	Metro Wind LLC	AD				(3)					^(a) (71)		(71)
83	Metro Wind LLC	LU				670					19,771		19,771
84	MidAmerican Energy Company	LU		163						296,360			296,360
85	Midcontinental ISO	AD				(9,720)					^(a) (549,634)		(549,634)

86	Midcontinental ISO	SF				4,459,141					32,498,631		32,498,631
87	MinnDakota Wind LLC	AD				1,558					(55,374)		55,374
88	MinnDakota Wind LLC	LU				294,051					6,986,840		6,986,840
89	Miscellaneous	OS										(497,431)	497,431
90	Moraine Wind, L.L.C.	AD									(21,204)		21,204
91	Moraine Wind, L.L.C.	LU				78,159					2,824,107		2,824,107
92	Morgan Stanley Capital Group Inc.	LU				73,000					1,168,015		1,168,015
93	N A E Lakota Ridge, LLC	AD				(64)					(705)		(705)
94	N A E Lakota Ridge, LLC	LU				13,284					146,129		146,129
95	N A E Shaokatan Hills, LLC	AD	NAEMA			7,633					(98,953)		(98,953)
96	N A E Shaokatan Hills, LLC	LU				15,308					179,399		179,399
97	NAE Shaokatan, LLC	LU				22,081					651,771		651,771
98	Natural Gas Exchange Inc.	OS										22,419,162	22,419,162
99	New England ISO	OS										(3,846)	3,846
100	NextEra Energy Power Marketing, LLC	OS											13,937,049
101	North Star Solar	AD										(4,373)	(4,373)
102	North Star Solar	LU				189,109					13,543,161		13,543,161
103	NSP-M Solar Gardens	LU				1,531,792					208,471,711		208,471,711
104	Odell Wind Farm, LLC	LU				739,014					20,079,270		20,079,270
105	Olsen Wind Farm	AD				(4)					(141)		(141)
106	Olsen Wind Farm	LU				362					14,434		14,434
107	Otter Tail Power Company	AD										(3,089,102)	3,089,102
108	Pipestone	AD				(19)					(641)		(641)
109	Pipestone	LU				9,300					306,907		306,907
110	PJM Interconnection LLC	AD										(2,559)	(2,559)
111	PJM Interconnection LLC	OS										(6,163)	6,163
112	Poet, LLC	AD				97					(1,961)		1,961
113	Poet, LLC	LU				307					6,197		6,197
114	Prairie Rose Wind, LLC	AD										(146,030)	(146,030)
115	Prairie Rose Wind, LLC	LU				432,913					27,693,215		27,693,215
116	Ridgewind Power Partners, LLC	AD				3,001					(195,056)		195,056
117	Ridgewind Power Partners, LLC	LU				78,980					5,133,367		5,133,367
118	Rock Ridge Power Partners LLC	AD										(2)	(2)
119	Rock Ridge Power Partners LLC	LU				5,002					53,632		53,632
120	Ruthton Ridge	AD										(75)	75
121	Ruthton Ridge	LU				38,144					1,141,078		1,141,078
122	SAF Hydroelectric, L.L.C.	LU				28,103					1,572,101		1,572,101

123	Shane's Wind Machine LLC	LU					4,968					163,932		163,932
124	Shell Energy North America US LP	OS											1,774,346 ^(b)	1,774,346
125	Slayton Solar, LLC	LU					2,157					222,252		222,252
126	South Ridge Power Partners, LLC	AD					2					697 ^(a)		697
127	South Ridge Power Partners, LLC	LU					4,450					23,422		23,422
128	Southwest Power Pool, Inc.	AD					20					404 ^(a)		404
129	Southwest Power Pool, Inc.	OS					4,256					366,536		366,536
130	St Cloud	LU					37,175					1,369,901		1,369,901
131	St. Olaf College	AD					2					67 ^(a)		67
132	St. Olaf College	LU					11					348		348
133	St. Paul Cogeneration	AD										61,837 ^(a)		61,837
134	St. Paul Cogeneration	LU					153,120					15,005,716		15,005,716
135	Taygete Energy Project, LLC	SF					388,686					9,911,580		9,911,580
136	TG Windfarm, LLC	AD					(23)					(798) ^(a)		(798)
137	TG Windfarm, LLC	LU					4,751					161,520		161,520
138	Tholen Transmission-Trust	AD					47					1,546 ^(a)		1,546
139	Tholen Transmission-Trust	LU					39,761					1,312,123		1,312,123
140	Tofteland Windfarm, LLC	AD					(23)					(798) ^(a)		(798)
141	Tofteland Windfarm, LLC	LU					4,751					161,520		161,520
142	Uilk Wind Farm, LLC	LU					12,344					898,899		898,899
143	University of Minnesota	LU					2,282					52,804		52,804
144	Valley View Transmission	LU					19,443					1,506,773		1,506,773
145	Velva Windfarm, LLC	AD										1 ^(a)		1
146	Velva Windfarm, LLC	LU					24,804					818,524		818,524
147	Western Area Power Administration	AD	NAEMA, WSPP				957					22,968 ^(a)		22,968
148	Western Area Power Administration	LU					11,787					328,663		328,663
149	Westridge Windfarm, LLC	AD					(242)					(8,240) ^(a)		(8,240)
150	Westridge Windfarm, LLC	LU					2,537					86,261		86,261
151	Windcurrent Farms, L.L.C.	LU					5,005					175,173		175,173
152	Windvest Power Partners, LLC	AD					605					8,139 ^(a)		8,139
153	Windvest Power Partners, LLC	LU					4,030					56,576		56,576
154	Winona County Wind LLC	LU					4,320					288,888		288,888
155	Woodstock Hills, L.L.C.	AD										381 ^(a)		381
156	Woodstock Hills, L.L.C.	LU					36,662					732,916		732,916
157	Woodstock Municipal Wind, LLC	LU					1,371					91,734		91,734
158	Zephyr Wind LLC	LU					49,227					4,641,720		4,641,720
15	TOTAL						19,651,533	0	0	0	161,570,512	858,314,160	62,737,627	1,082,622,299

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: DemandChargesOfPurchasedPower Prior Period Adjustment
(b) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(c) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(d) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(e) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(f) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(g) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(h) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(i) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(j) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(k) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(l) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(m) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(n) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(o) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment
(p) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment

(g) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(t) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(s) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(i) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(u) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(v) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(w) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(x) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(y) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(z) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(aa) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ab) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ac) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ad) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ae) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(af) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ag) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ah) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ai) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment

(aj) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ak) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(al) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(am) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(an) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ao) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ap) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(aq) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ar) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(as) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(at) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(au) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(av) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(aw) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ax) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ay) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(az) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ba) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(bb) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment

(bc) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(bd) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(be) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(bf) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(bg) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(bh) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bi) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bj) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bk) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bl) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bm) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bn) Concept: OtherChargesOfPurchasedPower
Miscellaneous
(bo) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bp) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bq) Concept: OtherChargesOfPurchasedPower
Financial Trading
(br) Concept: OtherChargesOfPurchasedPower
Prior Period Adjustment
(bs) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bt) Concept: OtherChargesOfPurchasedPower
Financial Trading

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

- Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
- Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
- Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
- In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
- In column (e), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
- Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
- Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
- Report in column (i) and (j) the total megawatthours received and delivered.
- In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
- The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
- Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)
1	Buffalo Ridge Wind	Buffalo Ridge Wind	MISO	OS	3751	Buffalo Ridge	Buffalo Ridge						^(b) 214,848	214,848
2	Great River Energy	Various	Various	FNO	^(d) Various	Various	Various				54,683,405		^(b) 126,983	54,810,388
3	Marshall Solar	Marshall Solar	MISO	OS	3514	Lyon County	Lyon County						^(b) 141,111	141,111
4	MidAmerican Energy Company	Palo Alto	MISO	OS	3721	Palo Alto	Palo Alto						^(b) 287,168	287,168
5	Midcontinent ISO (MISO)	Various	Various	^(e) FNO	MISO OATT	Various	Various				120,300,671	78,683,337 ^(g)		198,984,008
6	Missouri River Energy Services (MRES)	Various	Various	FNO	304	Various	Various				6,580,505			6,580,505
7	North Star Solar PV LLC	North Star Solar	MISO	OS	2871	Chisago County	Chisago County						^(b) 339,285	339,285
8	^(a) Northern States Power-Minnesota	Blazing Star 2	MISO	OS	3418	Steep Bank Lake	Steep Bank Lake						820,733 ^(m)	820,733
9	Sioux Falls, City of	Western Area Power Administration (WAPA)	Sioux Falls, City of	OS	484	WAPA	Sioux Falls, City of						^(b) 213,547	213,547
10	South Dakota State Penitentiary (SDSP)	WAPA	SDSP	OS	385	WAPA	SDSP						^(b) 15,240	15,240
11	Southern MN Municipal Power Agency	Various	Various	FNO	304	Various	Various				8,170,351			8,170,351
12	Stoneray Power	Stoneray Power Partners	MISO	OS	3513	Chanarambie	Chanarambie						^(b) 290,585	290,585
13	Tenaska Nobles 2 Holdings LLC	Nobles 2 Wind Farm	MISO	OS	3347	Zephyr	Zephyr						1,495,991 ^(b)	1,495,991
14	University of North Dakota (UND)	WAPA	University of North Dakota	OS	440	WAPA	UND						^(b) 72,116	72,116
15	Walleye Wind, LLC	Walleye Wind	MISO	OS	1495	Rock County	Rock County						^(b) 594,281	594,281
16	Wisconsin Public Power, Inc. (WPPI)	Minnesota Power Authority	WPPI	OS	466								^(b) 40,320	40,320
17	^(b) Northern States Power-Wisconsin	^(d) Various	Various	OS	437	Various	Various				59,220,373			59,220,373

18	(c) Footnote from page 106b													
35	TOTAL							0	0	0	248,955,305	78,683,337	4,652,208	332,290,850

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: PaymentByCompanyOrPublicAuthority Affiliate - Generation Function of Northern States Power - MN
(b) Concept: PaymentByCompanyOrPublicAuthority Northern States Power Company (a Minnesota Corporation) and Northern States Power Company (a Wisconsin Corporation) are both operating company subsidiaries of Xcel Energy, Inc.
(c) Concept: PaymentByCompanyOrPublicAuthority Revenues from Transmission of Electricity from Others (Account 456.1). The revenue credit from transmission of electricity of others included in the formula are from loads that are not included in the formula divisor, and for transmission charges associated with Schedule 26, 26A, 37, and 38 of the MISO OATT.
(d) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName Reimbursement from NSP-Wisconsin for transmission costs shared through the FERC- approved Interchange Agreement. See Note 1 to the Financial Statements.
(e) Concept: StatisticalClassificationCode FNO, LFP, SFP, NF
(f) Concept: RateScheduleTariffNumber 28, 304 and OA97-25-000 et al.
(g) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers MISO Schedule 26-A revenue
(h) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Interconnection Network Upgrade revenue
(i) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Schedule 2 Revenue
(j) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Interconnection Network Upgrade revenue
(k) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Interconnection Network Upgrade revenue
(l) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Interconnection Network Upgrade revenue
(m) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Affiliate - Interconnection Network Upgrade revenue
(n) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Facilities Charge
(o) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Facilities Charge
(p) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Interconnection Network Upgrade revenue

(g) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Interconnection Network Upgrade revenue
(t) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Facilities Charge
(s) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Interconnection Network Upgrade revenue
(i) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Meter Charge

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

- Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
- In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
- In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
- Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
- Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
- Enter ""TOTAL"" in column (a) as the last line.
- Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Basin Electric Power	OS					2,400	2,400
2	Central MN Municipal Pw	FNS			1,407,512			1,407,512
3	Dairyland Power	OS					19,744	19,744
4	Great River Energy	FNS			45,071,395			45,071,395
5	ITC Midwest	OS					716,497	716,497
6	McLeod Coop Power	OLF			26,370			26,370
7	Midcontinent ISO (MISO)	LFP			63,773,269	72,202,033	1,000	135,976,302
8	MN Municipal Pwr Agy	FNS			1,518,974			1,518,974
9	Minnkota Power Coop	OLF				20,723	780,000	800,723
10	Missouri Riv Engy Serv	FNS			1,708,607			1,708,607
11	Montana-Dakota Util Co	OS					1,266,312	1,266,312
12	Northwestern Wis Elect	FNS			643,881			643,881

13	(a) Northern States Pwr-MN	OS					(b) 820,733	820,733
14	Otter Tail Pwr Co	OS					1,620,694 (a)	1,620,694
15	Rochester Public Util	FNS			1,670,030			1,670,030
16	PJM Interconnection	FNS			(4)			(4)
17	Southern MN Muncipl Pwr	FNS			16,295,509			16,295,509
18	Southwest Power Pool	FNS			186,708	529		187,237
19	Stearns Coop Electric	(b) OS				2,796	(b) 489	3,285
20	Verendrye Electric Coop	(a) OLF				125,619		125,619
21	(b) Northern States Pwr-WI	(b) OLF			142,066,960			142,066,960
	TOTAL		0	0	274,369,211	72,351,700	5,227,869	351,948,780

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Affiliate - Transmission Function of Northern States Power Company - MN

(b) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

Northern States Power Company (a Minnesota Corporation) and Northern States Power Company (a Wisconsin Corporation) are both operating company subsidiaries of Xcel Energy, Inc.

(c) Concept: StatisticalClassificationCode

Two year notification required for termination

(d) Concept: StatisticalClassificationCode

LFP, FNS, FNO, OS

(e) Concept: StatisticalClassificationCode

Four year notification required for termination

(f) Concept: StatisticalClassificationCode

OS, LFP

Two year notification required for termination

(g) Concept: StatisticalClassificationCode

Two year notification required for termination

(h) Concept: StatisticalClassificationCode

Reimbursement to NSP-Wisconsin for transmission shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

(i) Concept: EnergyChargesTransmissionOfElectricityByOthers

MISO Schedule 26-A expense & MISO Admin FERC fee

(j) Concept: OtherChargesTransmissionOfElectricityByOthers

Meter Agent Service Charges

(k) Concept: OtherChargesTransmissionOfElectricityByOthers

Facility Charges

(l) Concept: OtherChargesTransmissionOfElectricityByOthers

Interconnection upgrade charge

(m) Concept: OtherChargesTransmissionOfElectricityByOthers

2023 MISO Annual Membership

(n) Concept: OtherChargesTransmissionOfElectricityByOthers

Fixed Transmission Service Charge

(o) Concept: OtherChargesTransmissionOfElectricityByOthers

Interconnection upgrade charge

(p) Concept: OtherChargesTransmissionOfElectricityByOthers

Affiliate - Interconnection upgrade charge

(q) Concept: OtherChargesTransmissionOfElectricityByOthers

Interconnection upgrade charge

(r) Concept: OtherChargesTransmissionOfElectricityByOthers

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,697,753
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	
6	Shareholder Related Expenses	427,375
7	Director Fees and Expenses	1,698,597
8	SEC Filing Expense	(3,077)
46	<u>TOTAL</u>	4,820,648

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: OtherMiscellaneousGeneralExpenses

Credit balance due to refund of prior year expense.

FERC FORM NO. 1 (ED. 12-94)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

- Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
- Report in Section B 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.
- 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 of 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.
- 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)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			29,335,014	(31,478)	29,303,536
2	Steam Production Plant	96,259,119	986,992		(952,367)	96,293,744
3	Nuclear Production Plant	165,331,150	(32,286,540)			133,044,610
4	Hydraulic Production Plant-Conventional	1,510,277			(67,058)	1,443,219
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	171,512,415	12,135,346	415,759	(3,281,305)	180,782,215
7	Transmission Plant	92,338,813	5,255		(1,211,426)	91,132,642
8	Distribution Plant	169,980,520	234,059		(3,719)	170,210,860
9	Regional Transmission and Market Operation					
10	General Plant	38,368,398			(497,874)	37,870,524
11	Common Plant-Electric	35,634,431	3,489	61,942,410	(617)	97,579,713
12	TOTAL	770,935,123	(18,921,399)	91,693,183	(6,045,844)	837,661,063

B. Basis for Amortization Charges

ACCOUNT 404 Column (d) Computer software is amortized over its expected useful life of 3, 5, 7, 10, or 15 years.
as Other Deferred Credits (Account 253) is amortized over the life of the property, and thus appears as a credit to expense.

ACCOUNT 405 Column (e) Prefunded AFUDC recorded

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	Steam Production						
13	310	10,112					0 years
14	311	297,722		(11.8)%			6 years, 6 months
15	312	1,451,305		(11.5)%			7 years, 6 months
16	314	304,574		(11.7)%			6 years, 1 month, 6 days
17	315	186,089		(10.6)%			7 years, 1 month, 6 days
18	316	53,988		(10.5)%			6 years, 4 months, 24 days
19	317	20,241					0 years
20	Subtotal Steam Prod	2,324,031					
21	Nuclear Production						
22	320	1,758					0 years
23	321	622,467					12 years, 3 months, 18 days
24	322	2,025,211					11 years, 10 months, 24 days
25	323	662,031					12 years, 2 months, 12 days
26	324	552,813					13 years
27	325	211,431					12 years, 1 month, 6 days
28	326	(301,709)					0 years
29	Subtotal Nuclear Prod	3,774,002					
30	Hydro Production						
31	330	1,693					0 years
32	331	1,518		(26.4)%			10 years, 2 months, 12 days
33	332	11,235		(24.4)%			7 years, 4 months, 24 days

34	333	10,157		(26.7)%			10 years, 2 months, 12 days
35	334	3,296		(26.7)%			10 years, 2 months, 12 days
36	335	130		(26.7)%			10 years, 2 months, 12 days
37	336	152					0 years
38	337						
39	Subtotal Hydro Prod	28,181					
40	Other Production						
41	340	33,343					21 years, 7 months, 10 days
42	341	521,953		(9.8)%			27 years, 1 month, 6 days
43	342	29,371		(10.2)%			17 years, 1 month, 6 days
44	343	145,722		(8)%			20 years, 6 months
45	344	4,155,701		(10.3)%			24 years, 2 months, 12 days
46	345	355,773		(9.9)%			20 years, 3 months, 18 days
47	346	63,653		(10.3)%			26 years
48	347	357,813					0 years
49	348	4,129					0 years
50	Subtotal Other Prod	5,667,458					
51	Transmission						
52	350	171,247					
53	352	163,548	65 years	(15)%	1.8%	R4	54 years, 4 days
54	353	1,540,522	56 years	(20)%	2.2%	R2	43 years, 7 months, 13 days
55	354	127,661	75 years	(50)%	2.1%	R4	40 years, 8 months, 19 days
56	355	1,636,831	60 years	(55)%	2.6%	R2	51 years, 1 month, 10 days
57	356	732,820	67 years	(40)%	2.1%	R0.5	58 years, 7 months, 28 days
58	357	32,182	74 years	(5)%	1.4%	R4	60 years, 6 months, 7 days
59	358	35,525	50 years	(5)%	2.2%	R3	36 years, 10 months, 2 days
60	359.1	173					

61	Subtotal Transmission	4,440,509					
62	Distribution						
63	360	19,962					
64	361	65,293	63 years	(40)%	2.3%	R2.5	47 years, 6 months, 26 days
65	362	787,253	51 years	(30)%	2.6%	R2	36 years, 4 months, 28 days
66	364	697,607	44 years	(135)%	5.5%	R1.5	32 years, 2 months, 1 day
67	365	688,111	37 years	(30)%	3.6%	L0	29 years, 22 days
68	366	405,418	67 years	(30)%	2%	R2.5	52 years, 6 months, 11 days
69	367	1,457,768	51 years	(20)%	2.5%	R2.5	35 years, 8 months, 19 days
70	^(e) 368	517,867	32 years	(5)%	3.3%		19 years, 3 months, 26 days
71	^(f) 368	31,185	25 years	(10)%	4.4%		16 years, 2 months, 9 days
72	^(g) 369	103,777	42 years	(100)%	5.1%	R1.5	24 years, 3 months, 7 days
73	^(h) 369	335,332	44 years	(10)%	2.7%	R4	26 years, 9 months, 11 days
74	370	154,441	15 years	(5)%	5.8%		8 years, 15 days
75	371		10 years		10%	SQ	10 years
76	373	96,940	29 years	(50)%	5.3%	L0	23 years, 3 months, 7 days
77	374	12,231					
78	Subtotal Distribution	5,373,185					
79	General						
80	389	19,887					
81	⁽ⁱ⁾ 390	89,419	55 years	(20)%	2.2%	R1.5	44 years
82	^(j) 390	1,085				SQ	
83	^(k) 391	32,125	20 years		4.9%		8 years, 6 months, 15 days
84	^(l) 391	85,750	6 years		16.5%		3 years, 4 months, 2 days
85	^(m) 392	7,255	10 years	6%	9.3%		6 years, 1 month, 17 days

86	(b) 392	55,125	10 years	12%	8.7%		5 years, 5 months, 5 days
87	(b) 392	28,688	12 years	15%	7%		5 years, 4 months, 24 days
88	(b) 392	146,768	12 years	10%	7.4%		5 years, 6 months, 15 days
89	393	1,808	20 years		4.9%		7 years, 2 months, 19 days
90	394	143,195	15 years		6.6%		8 years, 3 months
91	395	2,979	10 years		9.9%		4 years, 2 months, 5 days
92	396	64,776	12 years	25%	6.1%		4 years, 3 months
93	(b) 397	31,501	10 years		10%		8 years, 8 months, 16 days
94	(b) 397	62,745	10 years		9.9%		5 years, 9 months, 7 days
95	(b) 397	7,663	15 years		6.5%		3 years, 6 months, 15 days
96	(b) 397	68,909	15 years		6.6%		8 years, 3 months, 4 days
97	(b) 397	45,253	20 years		5%		9 years, 29 days
98	398	1,896	15 years		6.6%		10 years, 2 months, 16 days
99	Subtotal General	896,827					
100	TOTAL	22,504,193					

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FOOTNOTE DATA			

(a) Concept: AmortizationOfLimitedTermPlantOrProperty			
The Amortization of Limited Term Electric Plant within Account 404 includes the following:			
Intangible Plant	\$	18,504,130	
Nuclear Production Plant		10,724,056	
Hydraulic Production Plant - Conventional		106,828	
Total	\$	29,335,014	
(b) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments			
Transmission Serving Production	\$	3,848,872	
(c) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments			
Distribution Serving Production	\$	131,171	
(d) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments			
NSP-Minnesota received approval from the Minnesota Public Utilities Commission and FERC to amortize the regulatory asset related to the theoretical excess depreciation reserve (MPUC Docket No. E,G002/D-17-147 and FERC Docket No. ER18-913-001, respectively). The unwinding of the regulatory asset is recorded as an increase to regulatory debits for FERC presentation with an offsetting entry to depreciation expense and accumulated depreciation, resulting in no net impact to the balance sheet or income statement. The amounts below were included in FERC Account 403 Depreciation Expense in the current year by functional class:			
Distribution Plant	\$	(4,633,263)	
Transmission Plant		(4,171,205)	
General Plant		(105,352)	
Total	\$	(8,909,820)	
(e) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
368 Line Transformers			
(f) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
368 Line Capacitors			
(g) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
369 Overhead Services			
(h) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
369 Underground Services			
(i) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
390 Structures and Improvements			
(j) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
390 Structures and Improvements - Leasehold Improvements			
(k) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			

391 Office Furniture and Equipment			
(l) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
391 Network Equipment			
(m) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
392 Transportation Equipment - Automobiles			
(n) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
392 Transportation Equipment - Light Trucks			
(o) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
392 Transportation Equipment - Trailers			
(p) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
392 Transportation Equipment - Heavy Trucks			
392/396 Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1).			
392 Transportation Equipment	\$	14,481,672	\$ 237,836,000
396 Power Operated Equipment		3,477,993	64,776,000
Total	\$	<u>17,959,665</u>	<u>\$ 302,612,000</u>
(q) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
397 Communication Equipment			
(r) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
397 Communication Equipment - Two Way			
(s) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
397 Communication Equipment - AMR			
(t) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
397 Communication Equipment - EMS			
(u) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
397 Communication Equipment - Smart Grid			
(v) Concept: DepreciablePlantBase			
(1) Column (b) Computation: Depreciable Plant Balances are an average of the beginning and ending plant balance for the year.			
(2) Column (c) through (g): Subaccounts 311-348. A remaining life technique is applied to each generating facility The Monticello Nuclear facility depreciation end of life was extended 10 years in docket E002-GR-21-630_2022 MN Elec Rate Case. South Dakota also approved this via settlement, docket EL22-17_2022 Elec Rate Case. Wind farms were extended ten years; Blazing Star I & II, Courtenay, Crowned Ridge, Dakota Range, Foxtail, Freeborn, Lake Benton II, Grand Meadows, Nobles, Rock Aetna and Northern Wind. The wind life extensions were approved in docket E subaccounts 350-398, the parameters were approved in docket EG002-D-22-299, in the TD&G study, for the Minnesota Jurisdiction. South Dakota approved updated TD&G rates, based off docket EG002-D-21-584.			
(3) P337 Line 23 - 29 (d) - Effective Aug 1, 1981, Nuclear Plant Decommissioning costs are recovered using an external sinking fund calculation.			

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REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to 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.
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 columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than \$25,000) may be grouped.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
						Department (f)	Account No. (g)	Amount (h)				
1	MINNESOTA PUBLIC UTILITIES COMMISSION											
2	Electric Assessments	8,829,361		8,829,361		Elec	928	7,822,150				
3	Gas Assessments					Gas	928	1,007,211				
4	GR-09-1153 2010 Natural Gas Rate Increase - Amortized through 2024	(1,064,667)		(1,064,667)		Gas	928			186	(1,064,667)	
5	GR-21-678 2022 Natural Gas Rate Increase - Amortized through 2024	179,573		179,573		Gas	928			186	179,573	
6	GR-21-630 2022 Electric Rate Increase - Amortized through 2024	1,562,100		1,562,100		Elec	928			186	1,562,100	
7	CI-21-135 & CI-21-610 February 2021 Natural Gas Price Investigation		6,039	6,039		Gas	928	6,039				

8	AA-18-373 Sherco Unit 3		976,710	976,710		Elec	928	976,710				
9	WS-17-410 Freeborn Wind Site Permit		1,157	1,157		Elec	928	1,157				
10	E002/GR-13-868 Sherco 3 Fuel Recovery 2012 Turbine Failure	414,180		414,180		Elec	928	414,180				
11	Electric Miscellaneous - Minnesota	11,893	2,189	14,082		Elec	928	13,882				
12	Gas Miscellaneous - Minnesota					Gas	928	200				
13	NORTH DAKOTA PUBLIC SERVICE COMMISSION											
14	Gross Receipts Tax Assessment Electric	58,650		58,650		Elec	928	37,500				
15	Gross Receipts Tax Assessment Gas					Gas	928	21,150				
16	PU-22-402 Transmission Cost Recovery Rider	10,000		10,000		Elec	928	10,000				
17	PU-20-433 Heartland Divide PPAADP		3,826	3,826		Elec	928	3,826				
18	PU-20-441 2021 Electric Rate Increase - Amortized through 2024	321,714		321,714		Elec	928			186	321,714	
19	PU-21-381 2021 Gas Rate Increase - Amortized through 2024	244,800		244,800		Gas	928			186	244,800	
20	PU-12-813 ND Electric Future Rate Case	37,690		37,690		Elec	928	37,690				
21	PU-22-410 Advance Prudence MinnDakota Wind PPGA	(39,457)		(39,457)		Elec	928	(39,457)				
22	Electric Miscellaneous - North Dakota	20,700	489	21,189		Elec	928	20,828				
23	Gas Miscellaneous - North Dakota					Gas	928	361				

24	SOUTH DAKOTA PUBLIC UTILITIES COMMISSION											
25	Gross Receipts Tax Assessment	382,948		382,948		Elec	928	382,948				
26	EL23-026 Transmission Cost Recovery Rider	4,715		4,715		Elec	928	4,715				
27	EL23-025 Infrastructure Rider	7,274		7,274		Elec	928	7,274				
28	EL22-017 2022 SD Electric Rate Increase	389,676		389,676		Elec	928			186	389,676	
29	Other		2,133	2,133		Elec	928	2,133				
30	FEDERAL ENERGY REGULATORY COMMISSION											
31	ER22-80 Coyote Ridge Wind & ER22-93 Tatanka Ridge Wind		100	100		Elec	928	100				
32	EL22-78 MISO Complaint		5,904	5,904		Elec	928	5,904				
33	ER23-969 Northern Wind Post-Closing FERC Filings	3,598		3,598		Elec	928	3,598				
34	ER23-970 Rock Aetna Post-Closing FERC Filings	8,623		8,623		Elec	928	8,623				
35	Miscellaneous - Electric	1,751	486	2,237		Elec	928	2,103				
36	Miscellaneous - Gas					Gas	928	134				
46	TOTAL	11,385,122	999,033	12,384,155				10,750,959			1,633,196	

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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 and 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 and 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 and D Performed Internally:

1. Generation

a. hydroelectric

- i. Recreation fish and wildlife
- ii. Other hydroelectric

- b. Fossil-fuel steam
- c. Internal combustion or gas turbine
- d. Nuclear
- e. Unconventional generation
- f. Siting and heat rejection

2. Transmission

a. Overhead

b. Underground

- 3. Distribution
- 4. Regional Transmission and Market Operation
- 5. Environment (other than equipment)
- 6. Other (Classify and include items in excess of \$50,000.)
- 7. Total Cost Incurred

B. Electric, R, D and D Performed Externally:

- 1. Research Support to the electrical Research Council or the Electric Power Research Institute
- 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 and D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and 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 and 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.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	B(1)	Electric Power Research Institute		3,500,168	^(a) See Note	3,500,168	
2	B(2)	Edison Electric Institute		1,069,843	^(b) See Note	1,069,843	
3	B(4)	Renewable Development Fund		100,027	^(c) 253	100,027	

4	B(5)	Total		4,670,038		4,670,038	
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Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Accounts charged:	
183	\$ 164,675
524	2,226,504
580	157,444
923	62,393
930.2	889,152
	\$ 3,500,168

(b) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Accounts charged:	
426.4	\$ 134,666
930.2	935,177
	\$ 1,069,843

(c) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

The "Renewable Development Fund" is a program authorized by Minnesota Statute 116C3.779. Funding through this statute supports energy production and research and development of alternative sources of electricity. The projects listed below support the research and development of renewable sources of electricity. Also see page 269, Other Deferred Credits (Account 253).

Research Projects:

City of Red Wing	\$ 100,027
	\$ 100,027

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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	187,856,579		
4	Transmission	16,617,395		
5	Regional Market	453,510		
6	Distribution	32,791,242		
7	Customer Accounts	16,364,814		
8	Customer Service and Informational	1,921,114		
9	Sales	2,970,045		
10	Administrative and General	107,815,398		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	366,790,097		
12	Maintenance			
13	Production	73,393,942		
14	Transmission	2,000,650		
15	Regional Market			
16	Distribution	20,697,259		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	96,091,851		
19	Total Operation and Maintenance			

20	Production (Enter Total of lines 3 and 13)	261,250,521		
21	Transmission (Enter Total of lines 4 and 14)	18,618,045		
22	Regional Market (Enter Total of Lines 5 and 15)	453,510		
23	Distribution (Enter Total of lines 6 and 16)	53,488,501		
24	Customer Accounts (Transcribe from line 7)	16,364,814		
25	Customer Service and Informational (Transcribe from line 8)	1,921,114		
26	Sales (Transcribe from line 9)	2,970,045		
27	Administrative and General (Enter Total of lines 10 and 17)	107,815,398		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	462,881,948	7,654,454	470,536,402
29	Gas			
30	Operation			
31	Production - Manufactured Gas	2,567		
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	143,074		
34	Storage, LNG Termining and Processing	1,567,161		
35	Transmission	578,229		
36	Distribution	19,182,745		
37	Customer Accounts	4,055,984		
38	Customer Service and Informational	1,079,670		
39	Sales	131		
40	Administrative and General	9,285,142		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	35,894,703		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Termining and Processing	2,816,795		

47	Transmission	138,858		
48	Distribution	6,444,923		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	9,400,576		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	2,567		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	143,074		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru	4,383,956		
56	Transmission (Lines 35 and 47)	717,087		
57	Distribution (Lines 36 and 48)	25,627,668		
58	Customer Accounts (Line 37)	4,055,984		
59	Customer Service and Informational (Line 38)	1,079,670		
60	Sales (Line 39)	131		
61	Administrative and General (Lines 40 and 49)	9,285,142		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	45,295,279	1,457,383	46,752,662
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	508,177,227	9,111,837	517,289,064
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	202,700,435	61,453,853	264,154,288
69	Gas Plant	15,553,261	12,843,266	28,396,527
70	Other (provide details in footnote):	(a)1,108,567		1,108,567
71	TOTAL Construction (Total of lines 68 thru 70)	219,362,263	74,297,119	293,659,382
72	Plant Removal (By Utility Departments)			
73	Electric Plant	12,977,904	3,803,097	16,781,001

74	Gas Plant	597,420	794,811	1,392,231
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	13,575,324	4,597,908	18,173,232
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Merchandise (Acct No. 155)		2,266	2,266
80	Regulatory Assets (Acct No. 182.3)	11,008,986	214,488	11,223,474
81	Preliminary Survey and Investigation (Acct No. 183)	126,456	284	126,740
82	Miscellaneous Deferred Debits (Acct No. 186)		14,987	14,987
83	Miscellaneous Deferred Credits (Acct No. 253)	177,244	8,794	186,038
84	Regulatory Liabilities (Acct No. 254)	207,578	8,572	216,150
85	Non-utility (Accts No. 416-417.1)	5,130,484	44,655	5,175,139
86	Gain on Disposition of Property (421.1)	92,458		92,458
87	Miscellaneous Income and Deductions (Accts No. 426.1-426.5)	594,144	39,025	633,169
88	Non-utility CWP and RWP	1,109,476	59,911	1,169,387
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	18,446,826	392,982	18,839,808
96	TOTAL SALARIES AND WAGES	759,561,640	88,399,846	847,961,486

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: SalariesAndWagesUtilityPlantConstructionOther

E120.1 Nuclear fuel in process of refinement, conversion, enrichment and fabrication

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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 Electric 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 the order of the Commission or other authorization.

Instruction 1:		Allocated to Utility Departments		Cost at
Account		Electric	Gas	Dec. 31, 2023
COMMON UTILITY PLANT IN SERVICE AND COMPLETED NOT CLASSIFIED (ACCOUNTS 101 AND 106)				
301	Organization	90,204	10,404	100,608
303	Computer Software	592,323,234	68,320,532	660,643,766
Total intangible plant		<u>592,413,438</u>	<u>68,330,936</u>	<u>660,744,374</u>
389	Land and land rights	14,860,708	1,089,032	15,949,740
390	Structures and improvements	269,549,503	19,753,307	289,302,810
391	Office furniture and equipment	232,006,464	17,002,052	249,008,516
392	Transportation equipment	13,021,592	2,634,380	15,655,972
393	Stores equipment	229,354	16,808	246,162
394	Tools/shop/garage equipment	13,968,631	1,031,442	15,000,073
395	Laboratory equipment	—	—	—
396	Power operated equipment	1,534,793	211,976	1,746,769
397	Communications equipment	1,068,761	78,322	1,147,083
398	Miscellaneous equipment	41,823	3,065	44,888
399.1	Asset retirement costs for general plant	318,680	23,354	342,034
Total		<u>1,139,013,747</u>	<u>110,174,674</u>	<u>1,249,188,421</u>

COMMON UTILITY PLANT HELD FOR FUTURE USE (ACCOUNT 105)				
389	Land and Land Rights	26,322,692	2,981,400	29,304,092
COMMON UTILITY PLANT CONSTRUCTION WORK IN PROGRESS (ACCOUNT 107)				
	General Plant	104,030,494	10,087,816	114,118,310

Instruction 2:				
COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (ACCOUNT 108 AND 111)				
	General Plant	451,395,200	46,709,724	498,104,924

Common utility plant and accumulated provision for depreciation has been allocated to the various utilities on the basis of customers, employee labor, or direct assignment based on actual use.

		"Non-Legal" ARO Balance	
	Common General	\$	995,269
	Common Intangible		—
	Total Common		<u>995,269</u>

Instruction 3:				
Common Utility Plant Expenses				
		Electric	Gas	Total
403	Depreciation Expense	35,634,431	2,421,917	38,056,348
403.1	Depreciation Expense - ARC	3,489	251	3,740
404	Amortization of limited term plant	61,942,410	7,049,268	68,991,678
405	Amortization of other plant	(617)	(42)	(659)
407.4	Amortization of regulatory credits	(23,992)	(1,725)	(25,717)

411.1	Accretion expense	20,503	1,474	21,977
Total		97,576,224	9,471,143	107,047,367

Basis of Allocation of Common Utility Expenses:

From	Through	Allocation Methods
403	403	Depreciation allocator (excluding integrated software)
404	404	Software amortization allocator
405	405	Depreciation allocator (excluding integrated software)
407.4	407.4	3-factor (operating revenue, plant in service, supervised O&M)
411.1	411.1	3-factor (operating revenue, plant in service, supervised O&M)

Common Utility Plant and Accumulated Provision for Depreciation and Amortization. The Form 1 reports common utility plant and accumulated provision for depreciation and amortization allocated to the electric department at the end of the year. The Company uses a 13-month average calculation for the electric department common utility plant and accumulated provision for depreciation and amortization in the formula.

Common plant operation and maintenance charges and rents are not separately accounted for and, therefore, are not available.

Instruction 4: The use of common utility plant classification was recommended by Federal Power Commission letter dated Aug. 14, 1969.

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AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Midcontinent Ind Sys Operator (MISO)				
8	MISO - Net Purchases (Account 555)	15,590,581	23,677,242	49,197,656	65,005,188
9	MISO - Net Sales (Account 447)	(41,562,864)	(53,185,207)	(109,888,893)	(114,913,037)
10	MISO - Transmission Rights	(10,855,145)	(23,129,701)	(31,142,282)	(34,197,871)
11	MISO - Ancillary Services	(296,904)	142,912	1,467,330	1,841,532
12	MISO - Uplift Charges	(931,529)	(408,571)	(1,247,735)	(699,852)
13	Electric Reliability Council of TX (ERCOT)				
14	ERCOT - Net Purchases (Account 555)	302,588	(41,384)	24,257,151	24,758,209
15	ERCOT - Net Sales (Account 447)				
16	ERCOT - Transmission Rights				
17	ERCOT - Ancillary Services				
18	ERCOT - Uplift Charges	58,559	64,258	63,893	65,142
19	New England Ind Sys Operator (NEISO)				

20	NEISO - Net Purchases (Account 555)				
21	NEISO - Net Sales (Account 447)				
22	NEISO - Transmission Rights				
23	NEISO - Ancillary Services	1,493	3,845	3,845	3,846
24	NEISO - Uplift Charges				
25	PJM Interconnection				
26	PJM - Net Purchases (Account 555)	386	386	386	386
27	PJM - Net Sales (Account 447)				
28	PJM - Transmission Rights				
29	PJM - Ancillary Services	871	875	875	875
30	PJM - Uplift Charges	(288)	(288)	(520)	2,343
31	Southwest Power Pool (SPP)				
32	SPP - Net Purchases (Account 555)	42,442	91,447	209,298	355,357
33	SPP - Net Sales (Account 447)				
34	SPP - Transmission Rights				
35	SPP - Ancillary Services	509	972	1,469	2,190
36	SPP - Uplift Charges	1,351	2,522	7,569	9,393
46	TOTAL	(37,647,950)	(52,780,692)	(67,069,958)	(57,766,299)

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PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff. In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	0	0	7,322,401	0	0	862,526
2	Reactive Supply and Voltage	0	0	(1,008,599)	0	0	(578,272)
3	Regulation and Frequency Response	0	0	1,552,319	0	0	3,595,006
4	Energy Imbalance	0	0		0	0	
5	Operating Reserve - Spinning	0	0	1,357,424	0	0	2,078,827
6	Operating Reserve - Supplement	0	0	227,568	0	0	123,463
7	Other	0	0	1,773,512	0	0	973,197
8	Total (Lines 1 thru 7)			11,224,625			7,054,747

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: AncillaryServicesPurchasedNumberOfUnits
Number of units is not available
(b) Concept: AncillaryServicesPurchasedNumberOfUnitsPower
Unit of measure is not available
(c) Concept: AncillaryServicesSoldNumberOfUnits
Volume of units is not available
(d) Concept: AncillaryServicesSoldUnitsOfMeasure
Unit of measure is not available
(e) Concept: AncillaryServicesPurchasedNumberOfUnits
Number of units is not available
(f) Concept: AncillaryServicesPurchasedNumberOfUnitsPower
Unit of measure is not available
(g) Concept: AncillaryServicesPurchasedAmount
Unnatural balance due to prior period resettlements as a result of ER23-523 MISO Schedule 2 rate changed to \$0
(h) Concept: AncillaryServicesSoldNumberOfUnits
Volume of units is not available
(i) Concept: AncillaryServicesSoldUnitsOfMeasure
Unit of measure is not available
(j) Concept: AncillaryServicesSoldAmount
Unnatural balance due to prior period resettlements as a result of ER23-523 MISO Schedule 2 rate changed to \$0
(k) Concept: AncillaryServicesPurchasedNumberOfUnits
Number of units is not available
(l) Concept: AncillaryServicesPurchasedNumberOfUnitsPower
Unit of measure is not available
(m) Concept: AncillaryServicesSoldNumberOfUnits
Volume of units is not available
(n) Concept: AncillaryServicesSoldUnitsOfMeasure
Unit of measure is not available
(o) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of units is not available		
(p) Concept: AncillaryServicesPurchasedNumberOfUnitsPower		
Unit of measure is not available		
(q) Concept: AncillaryServicesSoldNumberOfUnits		
Volume of units is not available		
(r) Concept: AncillaryServicesSoldUnitsOfMeasure		
Unit of measure is not available		
(s) Concept: AncillaryServicesPurchasedNumberOfUnits		
Number of units is not available		
(t) Concept: AncillaryServicesPurchasedNumberOfUnitsPower		
Unit of measure is not available		
(u) Concept: AncillaryServicesSoldNumberOfUnits		
Volume of units is not available		
(v) Concept: AncillaryServicesSoldUnitsOfMeasure		
Unit of measure is not available		
(w) Concept: AncillaryServicesPurchasedNumberOfUnits		
Number of units is not available		
(x) Concept: AncillaryServicesPurchasedNumberOfUnitsPower		
Unit of measure is not available		
(y) Concept: AncillaryServicesPurchasedAmount		
NSPP Real-Time Short-Term Reserve Cost Distribution Amount	\$	1,773,512
(z) Concept: AncillaryServicesSoldNumberOfUnits		
Volume of units is not available		
(aa) Concept: AncillaryServicesSoldUnitsOfMeasure		
Unit of measure is not available		
(ab) Concept: AncillaryServicesSoldAmount		
NSPP Real-Time Ramp Capability Amount	\$	24,708
NSPP Day-Ahead Ramp Capability Amount	\$	88,615
NSPP Day-Ahead Short-Term Reserve Amount	\$	680,362
NSPP Real-Time Short-Term Reserve Amount	\$	179,512
	<u>\$</u>	<u>973,197</u>

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MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. 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 on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: Northern States Power Co. Integrated System									
1	January	7,295	30	19	5,982	1,634				
2	February	7,226	2	19	5,939	1,590				
3	March	6,662	14	8	5,528	1,418				
4	Total for Quarter 1				17,449	4,642	0			0
5	April	7,135	13	20	5,918	1,452				
6	May	9,006	31	18	7,404	1,895				
7	June	9,654	21	19	7,943	2,060				
8	Total for Quarter 2				21,265	5,407	0			0
9	July	10,622	27	17	8,855	2,087				
10	August	10,932	23	18	9,040	2,139				
11	September	9,939	5	18	8,164	2,099				
12	Total for Quarter 3				26,059	6,325	0			0
13	October	8,837	2	18	7,205	1,863				
14	November	7,143	27	18	5,863	1,544				
15	December	6,947	11	18	5,666	1,548				

16	Total for Quarter 4				18,734	4,955	0			0
17	Total				83,507	21,329	0	0	0	0

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FOOTNOTE DATA			

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto

The Northern States Power Co. Integrated System refers to the interconnected production and transmission facilities of both Northern States Power Co. (a Minnesota corporation) which has customers in Minnesota, North Dakota and South Dakota, and Northern States Power Co. (a Wisconsin corporation) which has customers in Michigan and Wisconsin, (collectively, the "NSP Companies"). The construction, operation and maintenance of the two companies' systems is coordinated.

(b) Concept: FirmNetworkServiceForSelf

"Firm Network Service - For Self" includes load in the Otter Tail Power Balancing Authority (OTP BA). The NSP Companies' load in the OTP BA at the OTP coincident peak is:

	(a)	(e)
January		336
February		319
March		298
April		251
May		310
June		368
July		343
August		270
September		342
October		247
November		279
December		280
Total		3,643

"Firm Network Service - For Self" does not include the NSP Companies' load on transmission assets in the Great River Energy Balancing Authority (GRE BA). The NSP Companies' load in the GRE BA at the Great River Energy coincident peak is:

	(a)	(e)
January		64
February		60
March		54
April		51
May		53
June		50
July		65
August		55
September		72
October		48
November		51
December		50
Total		673

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2024-04-04	Year/Period of Report End of: 2023/ Q4
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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)	33,101,611
3	Steam	6,690,871	23	Requirements Sales for Resale (See instruction 4, page 311.)	6,399,633
4	Nuclear	11,954,426	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	14,923,743
5	Hydro-Conventional	42,350	25	Energy Furnished Without Charge	255
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	49,940
7	Other	16,339,848	27	Total Energy Losses	203,846
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	35,027,495	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	54,679,028
10	Purchases (other than for Energy Storage)	19,651,533			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	0			

19	Transmission By Others Losses	
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	54,679,028

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MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non-integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: Northern States Power Co. Integrated System					
29	January	4,706,720	1,256,917	5,079	30	19
30	February	4,303,792	1,136,035	5,056	2	19
31	March	4,777,832	1,535,741	4,672	14	9
32	April	4,479,327	1,359,793	5,114	13	17
33	May	4,277,802	912,826	6,389	31	18
34	June	4,548,356	1,185,077	6,796	20	17
35	July	5,300,981	1,581,233	7,673	27	16
36	August	5,286,860	1,458,988	7,806	23	16
37	September	4,541,165	1,175,190	6,878	5	16
38	October	4,043,337	1,008,320	6,308	2	17
39	November	4,038,057	1,087,313	4,934	27	18
40	December	4,374,799	1,226,310	4,781	11	18
41	Total	54,679,028	14,923,743			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: EnergyActivity

The Northern States Power Co. Integrated System refers to the interconnected production and transmission facilities of both Northern States Power Co. (a Minnesota corporation) which has customers in Minnesota, North Dakota and South Dakota, and Northern States Power Co. (a Wisconsin corporation) which has customers in Michigan and Wisconsin. The construction, operation and maintenance of the two companies' systems is coordinated. This table shows the integrated system peak and the demand of each jurisdiction at the time of the integrated system peak. The monthly peaks reported in column d of page 401b are the sums of the monthly peaks for the states of Minnesota, North Dakota and South Dakota shown below.

Day	Hour	Integrated System	Northern States Power Co. (a Minnesota corporation)			Northern States Power Co. (a Wisconsin corporation)		Michigan
			Minnesota	North Dakota	South Dakota	Wisconsin		
30-Jan	1900	6,171	4,367	373	339	1,068	24	
2-Feb	1900	6,133	4,351	375	330	1,052	25	
14-Mar	900	5,672	4,057	312	303	979	21	
13-Apr	1700	6,056	4,521	254	339	922	20	
31-May	1800	7,541	5,600	342	447	1,130	22	
20-Jun	1700	8,001	5,895	421	480	1,184	21	
27-Jul	1600	9,005	6,750	373	550	1,309	23	
23-Aug	1600	9,231	6,906	347	553	1,402	23	
5-Sep	1600	8,227	6,157	271	450	1,325	24	
2-Oct	1700	7,420	5,513	346	449	1,091	21	
27-Nov	1800	5,999	4,302	324	308	1,044	21	
11-Dec	1800	5,808	4,171	313	297	1,005	22	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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Steam Electric Generating Plant Statistics

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 Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA 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 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by 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.

Line No.	Item (a)	Plant Name: A S King	Plant Name: Angus Anson	Plant Name: Black Dog 2, 5, & 6	Plant Name: Blue Lake	Plant Name: High Bridge 7,8,9	Plant Name: Inver Hills	Plant Name: Monticello	Plant Name: Prairie Island	Plant Name: Riverside	Plant Name: Sherburne County	Plant Name: Wilmarth
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Gas Turbine	CC / Gas Turb ^(a)	Gas Turbine	Combined Cycle	Gas Turbine	Nuclear ^(b)	Nuclear ^(c)	Combined Cycle	Steam ^(d)	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional		Conventional	Ind Enclosures	Conventional	Ind Enclosures	Conventional	Conventional	Conventional	Conventional	Conventional
3	Year Originally Constructed	1968	1994	1987	1974	1924	1972	1971	1973	1911	1976	1948
4	Year Last Unit was Installed	1968	2005	2018	2005	2008	1972	1971	1974	2009	1987	1951
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	598.40	405.70	554.30	559.30	644.10	280.50	685.00	1,186.20	585.90	2,084.50	25.00
6	Net Peak Demand on Plant - MW (60 minutes)	512	354	544	383	621	307	665	1,122	510	1,618	20
7	Plant Hours Connected to Load	2,270	1,796	6,155	413	6,087	902	7,669	7,145	6,395	8,203	7,922
8	Net Continuous Plant Capability (Megawatts)	511	401	523	545	580	357	646	1,092	502	1,879	18
9	When Not Limited by Condenser Water	511	401	523	545	580	357	646	1,092	500	1,879	18
10	When Limited by Condenser Water	511	343	491	454	530	272	617	1,040	454	1,879	18
11	Average Number of Employees	78	8	22	5	25	6	338	440	22	218	26
12	Net Generation, Exclusive of Plant Use - kWh	915,212,000	227,425,179	1,795,657,000	62,764,000	2,462,547,000	78,430,000	4,817,539,000	7,136,887,000	2,474,547,000	5,536,137,860	98,753,000
13	Cost of Plant: Land and Land Rights	1,335,100	1,155,578	952,692	141,878	523,581	351,801	778,651	969,282	450,133	10,264,609	499,773
14	Structures and Improvements	39,821,319	8,445,268	57,936,972	2,446,794	71,185,478	1,858,081	283,343,998	352,728,139	57,827,975	231,379,617	13,306,687
15	Equipment Costs	672,424,287	148,211,675	311,799,297	116,504,441	358,454,519	63,131,287	1,362,624,084	2,151,447,031	279,196,318	1,088,135,764	66,568,848
16	Asset Retirement Costs	4,604,709	712,520	64,419	170,055	20,138	26,851	(89,517,597)	(291,352,616)	421,964	11,627,501	1,935,846
17	Total cost (total 13 thru 20)	718,185,415	158,525,041	370,753,380	119,263,168	430,183,716	65,368,020	1,557,229,136	2,213,791,836	337,896,390	1,341,407,491	82,311,154
18	Cost per KW of Installed Capacity (line 17/5) Including	1,200.1762	390.7445	668.8677	213.2365	667.8834	233.0411	2,273.3272	1,866.2889	576.7134	643.5152	3,292.4462
19	Production Expenses: Oper, Supv, & Engr	683,452	115,095	182,806	51,076	175,312	86,705	15,505,628	19,108,046	206,358	1,806,056	335,717
20	Fuel	38,170,656	10,949,811	47,859,694	9,746,711	95,522,963	2,605,006	37,967,413	58,412,066	88,382,899	225,509,903	3,355,009
21	Coolants and Water (Nuclear Plants Only)							4,456,428	4,751,599			
22	Steam Expenses	4,226,944						24,119,825	30,274,390		9,471,426	1,912,696

23	Steam From Other Sources																					
24	Steam Transferred (Cr)																					
25	Electric Expenses	811,607	148,512	2,242,534	298,107	1,828,569	328,186	138,134	2,469,382	2,234,866	4,235,376	45,697										
26	Misc Steam (or Nuclear) Power Expenses	2,927,165	628,230	1,180,183	102,068	1,209,330	134,916	54,027,652	69,866,152	1,064,907	8,221,555	1,322,985										
27	Rents	279,521	41,004	95,234	22,808	91,329	21,697	2,452,507	3,310,645	95,253	934,273	134,285										
28	Allowances																					
29	Maintenance Supervision and Engineering	587,693	73,300	106,155	57,941	101,635	45,807	4,531,713	3,359,459	106,001	702,158	8,232										
30	Maintenance of Structures	1,027,713	1,125,936	1,385,302	215,683	1,056,189	184,854			1,416,769	2,989,333	261,846										
31	Maintenance of Boiler (or reactor) Plant	2,858,922								10,162,905	15,842,189									14,109,984	1,129,134	
32	Maintenance of Electric Plant	547,251	935,249	1,888,890	910,736	2,230,008	650,727	5,832,075	7,463,890	1,897,258	4,567,085	1,435,168										
33	Maintenance of Misc Steam (or Nuclear) Plant	1,242,219	22,173	94,357	60,051	188,921	181,895	13,730,316	19,996,379	155,512	3,742,234	712,892										
34	Total Production Expenses	53,363,143	14,039,310	55,035,155	11,465,181	102,404,256	4,239,793	172,924,596	234,854,197	95,559,823	276,289,383	10,653,661										
35	Expenses per Net kWh	0.0583	0.0617	0.0306	0.1827	0.0416	0.0541	0.0359	0.0329	0.0386	0.0499	0.1079										

35	Plant Name	A S King	A S King	A S King	Angus Anson	Angus Anson	Black Dog 2, 5, & 6	Blue Lake	Blue Lake	High Bridge 7,8,9	Inver Hills	Inver Hills	Monticello	Prairie Island	Riverside	Riverside	Sherburne County	Sherburne County	Wilmarth	Wilmarth	Wilmarth
36	Fuel Kind	Coal	Gas	Oil	Gas	Oil	Gas	Gas	Oil	Gas	Gas	Oil	Nuclear	Nuclear	Gas	Oil	Coal	Oil	Gas	RDF	Wood
37	Fuel Unit	T	Mcf	bbl	Mcf	bbl	Mcf	Mcf	bbl	Mcf	Mcf	bbl	g	g	Mcf	bbl	T	bbl	Mcf	T	T
38	Quantity (Units) of Fuel Burned	537,489	107,801	60	2,809,229	159	13,601,824	806,009	1,902	15,157,516	1,149,021	6,227	451,673	658,895	17,917,792	7	3,297,515	21,238	32,782	170,300	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8,873	1,198	83,528	1,011	196,420	995	959	134,293	1,010	1,038	59,059	112,459	114,329	1,002	138,694	9,220	153,913	888	6,051	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	45.859	7.601	101.066	3.208	92.849	3.698	5.085	108.265	3.909	3.609	162.022			4.205	52.723	44.452	127.064	7.139	2.236	
41	Average Cost of Fuel per Unit Burned	59.322	7.601	101.066	3.208	92.849	3.698	5.085	108.265	3.909	3.609	162.022			4.205	52.723	48.152	127.064	7.139	21.293	
42	Average Cost of Fuel Burned per Million BTU	3.343	6.347	28.809	3.173	11.255	3.716	5.300	19.195	3.871	3.478	65.319	0.726	0.797	4.198	9.051	2.611	19.656	8.035	1.759	
43	Average Cost of Fuel Burned per kWh Net Gen		0.027			0.034	0.027		0.080	0.025	0.064		0.010	0.010		0.032		0.029	0.041		
44	Average BTU per kWh Net Generation		8,065.00			10,583.00	7,390.00		14,523.00	6,551.00	15,091.00		10,597.00	10,675.00		7,601.00		11,008.00	22,435.00		

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FOOTNOTE DATA			

<p>(a) Concept: PlantKind</p>
<p>Black Dog Unit 2 & 5 are combined cycle plants. Black Dog Unit 6 is a gas turbine.</p>
<p>(b) Concept: PlantKind</p>
<p>Instruction 12 - Monticello Nuclear Generating Plant (p. 403.1)</p>
<p>(a) Operating and maintenance costs of the Monticello Plant are expensed as incurred. NSP-Minnesota uses a deferral and amortization method for nuclear refueling operation and maintenance costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric cases.</p>
<p>(b) NSP-Minnesota buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.</p>
<p>(c) The Monticello Plant is a General Electric BWR-3 Nuclear Power Plant. Fuel material is UO2 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 85 metric tons of uranium metal with a nominal U-235 enrichment of 4.0 weight percent in the fresh fuel. The reactor is licensed to operate at 2,004 MWt.</p>
<p>(c) Concept: PlantKind</p>
<p>Instruction 12 - Prairie Island Nuclear Generating Plant (p. 403)</p>
<p>(a) Operating and maintenance costs of the Prairie Island Plant are expensed as incurred. NSP-Minnesota uses a deferral and amortization method for nuclear refueling operation and maintenance costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric cases.</p>
<p>(b) NSP-Minnesota buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.</p>
<p>(c) The Prairie Island Plant has two identical Westinghouse 2 loop PWR Nuclear Power Plants. Fuel material is UO2 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 47 metric tons of uranium metal with a nominal U-235 enrichment of 4.95 weight percent in the fresh fuel. The reactor is licensed to operate at 1677 MWt.</p>
<p>(d) Concept: PlantKind</p>
<p>Sherburne County Generating Plant Unit 3 is jointly owned by NSP-Minnesota (59 percent) and Southern Minnesota Municipal Power Agency (41 percent). See Note 3 of the Financial Statements on Page 123 for disclosures regarding Sherco Unit 3. Sherburne County Generating Plant Unit 2 retired Dec. 31, 2023.</p>
<p>(e) Concept: FuelBurnedAverageHeatContent</p>
<p>The Coal BTU numbers for the AS King and Sherburne plant are estimates</p>
<p>(f) Concept: FuelBurnedAverageHeatContent</p>
<p>The "Average Heat Content of Fuel Burned" is calculated as:</p>
<p>Coal: Btu/pound Oil: BTU/gallons Gas: Btu/cubic ft</p>
<p>(g) Concept: FuelBurnedAverageHeatContent</p>
<p>The Coal BTU numbers for the AS King and Sherburne plant are estimates</p>
<p>(h) Concept: AverageCostOffuelBurnedPerMillionBritishThermalUnit</p>
<p>The Coal BTU numbers for the AS King and Sherburne plant are estimates</p>
<p>(i) Concept: AverageCostOffuelBurnedPerMillionBritishThermalUnit</p>
<p>The Coal BTU numbers for the AS King and Sherburne plant are estimates</p>

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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Hydroelectric Generating Plant Statistics

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 plant, report on line 11 the approximate average number of employees assignable to each plant.
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.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0	FERC Licensed Project No. 0 Plant Name: Henn Is & Upper Dam
1	Kind of Plant (Run-of-River or Storage)		Run of river
2	Plant Construction type (Conventional or Outdoor)		Conventional
3	Year Originally Constructed		1908
4	Year Last Unit was Installed		1955
5	Total installed cap (Gen name plate Rating in MW)		13.90
6	Net Peak Demand on Plant-Megawatts (60 minutes)		12
7	Plant Hours Connect to Load		7,614
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions		7
10	(b) Under the Most Adverse Oper Conditions		6
11	Average Number of Employees		2
12	Net Generation, Exclusive of Plant Use - kWh		42,350,000
13	Cost of Plant		
14	Land and Land Rights		1,548,707
15	Structures and Improvements		1,519,829
16	Reservoirs, Dams, and Waterways		9,116,240

17	Equipment Costs		13,586,500
18	Roads, Railroads, and Bridges		152,109
19	Asset Retirement Costs		
20	Total cost (total 13 thru 20)		25,923,385
21	Cost per KW of Installed Capacity (line 20 / 5)		1,864.992
22	Production Expenses		
23	Operation Supervision and Engineering		13,110
24	Water for Power		24,494
25	Hydraulic Expenses		243,134
26	Electric Expenses		17,569
27	Misc Hydraulic Power Generation Expenses		152,762
28	Rents		35,806
29	Maintenance Supervision and Engineering		78,063
30	Maintenance of Structures		16,314
31	Maintenance of Reservoirs, Dams, and Waterways		362,900
32	Maintenance of Electric Plant		158,594
33	Maintenance of Misc Hydraulic Plant		5,728
34	Total Production Expenses (total 23 thru 33)		1,108,474
35	Expenses per net kWh		0.0262

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GENERATING PLANT STATISTICS (Small Plants)

- 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).
- 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.
- List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
- If net peak demand for 60 minutes is not available, give the which is available, specifying period.
- 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.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l))	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1	^(a) STEAM PLANTS												
2	Red Wing	1949	23.00	23	140,768,000	84,045,827	3,654,166	2,788,914	615,324	3,092,744	RDF, Gas	1.44	
3	WIND TURBINES												
4	Blazing Star Wind 1	2020	218.00	200	805,329,125	351,018,249	1,610,175	3,609,894		693,801			Wind
5	Lake Benton Wind	2019	100.20	103	431,440,838	182,607,011	1,822,425	1,200,203		806,006			Wind
6	Ben Fowke Wind Energy Center	2008	100.50	100	322,498,233	155,118,001	1,543,463	1,659,639		1,180,772			Wind
7	Nobles Wind	2010	212.80	199	745,620,471	309,947,681	1,456,521	3,182,206		1,268,582			Wind
8	Borders Wind	2015	150.00	147	582,321,545	284,660,151	1,897,734	1,857,531		1,185,264			Wind
9	Pleasant Valley Wind	2015	200.00	194	746,167,476	369,665,739	1,848,329	3,508,943		1,550,528			Wind
10	Courtenay Wind	2016	200.00	193	694,479,921	307,433,372	1,537,167	3,228,750		1,597,686			Wind
11	Foxtail Wind	2019	163.60	151	578,143,847	247,633,870	1,513,654	997,754		107,990			Wind

12	Blazing Star Wind 2	2020	218.00	200	830,130,228	385,059,695	1,766,329	3,734,483		1,742,661			Wind
13	Community Wind North	(b) 2020	26.40	26	109,257,193	36,425,347	1,379,748	544,194		294,897			Wind
14	Crowned Ridge	2020	200.60	198	776,213,280	346,066,466	1,725,157	2,101,887		1,613,338			Wind
15	Jeffers	2020	44.00	44	191,869,722	52,538,465	1,194,056	835,540		493,338			Wind
16	Mower County	2020	98.90	91	314,633,538	226,209,668	2,287,257	2,104,140		520,220			Wind
17	Freeborn	(c) 2021	218.00	199	757,606,021	359,188,639	1,647,654	4,397,991		1,307,298			Wind
18	Dakota Range 1 & 2	(d) 2022	304.00	291	946,496,459	419,492,819	1,379,911	2,940,179		(187,773)			Wind
19	Northern Wind CV	(e) 2023	100.20	91	327,099,344	199,146,276	1,987,488	1,833,678		594,987			Wind
20	Rock Aetna	2022	21.60	20	79,170,924	36,491,033	1,689,400						

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: PlantName
The Plant Cost is manually calculated (not calculated by the FERC software) - (col g = col f / col c)
(b) Concept: YearPlantOriginallyConstructed
Commercial Operations Date January 28, 2021
(c) Concept: YearPlantOriginallyConstructed
Commercial Operations Date March 23, 2021
(d) Concept: YearPlantOriginallyConstructed
Commercial Operations Date May 27, 2021
(e) Concept: YearPlantOriginallyConstructed
Not in commercial operation at year end 2021

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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TRANSMISSION LINE STATISTICS

- 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. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
- 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.
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- 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.
- 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.
- 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).
- 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.
- 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.
- Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

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	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	(5703;01) CHISAGO CO.	FORBES	500.0	500.0	TOWER	61.450	0.000	1	9-1192 ACSR	2,161,246	16,180,329	18,341,575				
2	(5702;01) FORBES	RIE	500.0	500.0	TOWER	203.628	0.000	1	9-1192.5 ACSR	1,723,645	87,965,399	89,689,044				
3	(5650;01) DAKOTA RANGE WIND	TWIN BROOKS SW. ST.	345.0	345.0	SINGLE POLE	0.091	0.000	1	6-795 ACSR							
4	(0998;01) SIOUX CITY (WAPA)	SPLIT ROCK	345.0	345.0	SINGLE POLE	0.000	4.427	1	6-954 ACSS		670,200	670,200				
5	(0998;01) SIOUX CITY (WAPA)	SPLIT ROCK	345.0	345.0	SINGLE POLE	0.000	0.629		6-954 ACSS/TW							
6	(0997;01) SPLIT ROCK	WHITE (WAPA)	345.0	345.0	SINGLE POLE	4.912	0.240	1	6-954 ACSS/TW	139,860	8,455,822	8,595,682				
7	(0996;01) DICKINSON SW STA (GRE)	PARKERS LAKE	345.0	345.0	TOWER	0.133	9.593	1	6-954 ACSR		576,104	576,104				
8	(0994;01) ALLEN S KING	CHISAGO CO.	345.0	345.0	SINGLE POLE	0.000	31.547	1	6-954 ACSR		1,648,291	1,648,291				
9	(0994;01) ALLEN S KING	CHISAGO CO.	345.0	345.0	TOWER	0.000	6.660		6-795 ACSR							
10	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	H-FRAME	5.160	0.000	1	6-954 ACSR	472,775	11,419,380	11,892,155				
11	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	9.551	0.000	1	6-954 ACSR							
12	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	2.328	15.288	1	6-954 ACSR							
13	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	0.058	11.056	1	6-954 ACSR							

14	(0991;01) MONTICELLO SUB	SHERBURNE CO.	345.0	345.0	TOWER	0.072	5.753	1	6-954 ACSR		196,978	196,978				
15	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	K-FRAME	0.787	0.000	1	6-795 ACSR	80,238	1,436,429	1,516,667				
16	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	SINGLE POLE	0.000	0.841		6-795 ACSR							
17	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	TOWER	3.541	17.150		6-795 ACSR							
18	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	H-FRAME	0.532	0.000	1	6-795 ACSR	272,767	1,672,480	1,945,247				
19	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	K-FRAME	1.997	0.000		6-795 ACSR							
20	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	TOWER	6.022	0.000		6-795 ACSR							
21	(0988;01) BLUE LAKE	PARKERS LAKE	345.0	345.0	SINGLE POLE	0.000	2.102	1	6-795 ACSR		478,209	478,209				
22	(0988;01) BLUE LAKE	PARKERS LAKE	345.0	345.0	TOWER	0.078	12.616		6-795 ACSR							
23	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	K-FRAME	20.911	1.175	1	6-795 ACSR		7,474,001	7,474,001				
24	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	SINGLE POLE	0.000	5.108		6-795 ACSR							
25	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.000	2.331		6-795 ACSR							
26	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.148	2.335		6-954 ACSR							
27	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	K-FRAME	22.073	0.000	1	6-795 ACSR	661,692	10,267,819	10,929,511				
28	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	SINGLE POLE	5.108	0.000		6-795 ACSR							
29	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	2.329	0.000		6-795 ACSR							
30	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.121	2.357		6-954 ACSR							
31	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	H-FRAME	16.425	0.489	1	6-954 ACSR	17,816	14,641,383	14,659,199				
32	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	3.362	0.000		6-954 ACSR							
33	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	0.198	1.043		6-954 ACSR							
34	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	5.810	5.795		6-954 ACSR							
35	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	9.533	0.000	1	6-954 ACSR	506,296	15,007,743	15,514,039				
36	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	19.929	0.000		6-954 ACSR							
37	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	8.891	0.000		6-954 ACSR							
38	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	H-FRAME	5.124	0.000		6-954 ACSR							

39	(0984;01) COON CREEK	TERMINAL	345.0	345.0	SINGLE POLE	0.000	4.613	1	6-795 ACSR	160,760	3,812,917	3,973,677				
40	(0984;01) COON CREEK	TERMINAL	345.0	345.0	TOWER	0.077	9.014		6-795 ACSR							
41	(0982;01) BLUE LAKE	SCOTT CO.	345.0	345.0	TOWER	8.156	0.000	1	6-795 ACSR	285,057	3,412,458	3,697,515				
42	(0982;01) CRANDALL	LAKEFIELD GENERATING	345.0	345.0	K-FRAME	2.205	0.000	1	6-795 ACSR	587,597	13,578,587	14,166,184				
43	(0982;01) CRANDALL	WILMARTH	345.0	345.0	H-FRAME	4.319	0.000	1	6-795 ACSR	24,675	406,619	431,294				
44	(0982;01) CRANDALL	WILMARTH	345.0	345.0	K-FRAME	25.203	0.000	1	6-795 ACSR							
45	(0982;01) CRANDALL	WILMARTH	345.0	345.0	SINGLE POLE	1.443	21.434	1	6-556.5 ACSR/T2							
46	(0982;01) HELENA	SCOTT CO.	345.0	345.0	3 POLE	1.421	0.000	1	6-397.5 ZTACSR		20,721,999	20,721,999				
47	(0982;01) HELENA	SCOTT CO.	345.0	345.0	H-FRAME	15.728	0.000		6-397.5 ZTACSR							
48	(0982;01) HELENA	SHEAS LAKE	345.0	345.0	K-FRAME	7.454	0.000	1	6-795 ACSR	95,480	1,602,336	1,697,816				
49	(0982;01) LAKEFIELD JCT (IPW)	LAKEFIELD GENERATING	345.0	345.0	K-FRAME	18.685	0.000	1	6-795 ACSR	214,005	7,464,429	7,678,434				
50	(0982;01) SHEAS LAKE	WILMARTH	345.0	345.0	K-FRAME	22.317	0.000	1	6-795 ACSR	271,747	4,686,721	4,958,468				
51	(0982;01) SHEAS LAKE	WILMARTH	345.0	345.0	TOWER	1.115	0.000		6-795 ACSR							
52	(0981-MN;01) ALLEN S KING	EAU CLAIRE	345.0	345.0	K-FRAME	2.682	0.000	1	6-795 ACSR	24,099	872,818	896,917				
53	(0981-MN;01) ALLEN S KING	EAU CLAIRE	345.0	345.0	TOWER	2.008	15.222		6-795 ACSR							
54	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.0	345.0	SINGLE POLE	31.453	0.545	1	6-954 ACSR	4,408,021	10,856,196	15,264,217				
55	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.0	345.0	TOWER	0.000	5.594		6-795 ACSR							
56	(0980;01) COON CREEK	KOHLMAN LAKE	345.0	345.0	SINGLE POLE	4.613	2.816	1	6-795 ACSR	1,384,573	2,657,526	4,042,099				
57	(0980;01) COON CREEK	KOHLMAN LAKE	345.0	345.0	TOWER	6.892	5.620		6-795 ACSR							
58	(0979;01) ADAMS	PLEASANT VALLEY (GRE)	345.0	345.0	K-FRAME	16.854	0.000	1	6-795 ACSR	41,979	5,206,476	5,248,455				
59	(0979;01) BYRON (SMMPA)	NORTH ROCHESTER	345.0	345.0	K-FRAME	13.517	0.000	1	6-795 ACSR	35,037	4,307,001	4,342,038				
60	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	345.0	345.0	H-FRAME	1.120	0.000	1	6-795 ACSR	43,098	5,274,529	5,317,627				
61	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	345.0	345.0	K-FRAME	15.177	0.000		6-795 ACSR							
62	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	K-FRAME	27.222	0.000	1	6-795 ACSR	67,126	10,786,995	10,854,121				
63	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	TOWER	2.422	0.000		6-954 ACSR							

64	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	H-FRAME	16.905	0.000	1	6-954 ACSR	868,700	16,182,943	17,051,643				
65	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	K-FRAME	3.371	0.000		6-954 ACSR							
66	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	TOWER	5.833	0.000		6-954 ACSR							
67	(0978;01) ELM CREEK	PARKERS LAKE	345.0	345.0	SINGLE POLE	0.586	0.000	1	6-954 ACSR	13,498	914,131	927,629				
68	(0978;01) ELM CREEK	PARKERS LAKE	345.0	345.0	TOWER	10.447	0.000		6-954 ACSR							
69	(0977;01) ALLEN S KING	KOHLMAN LAKE	345.0	345.0	TOWER	12.705	0.000	1	6-795 ACSR	1,136,939	2,280,784	3,417,723				
70	(0977;01) KOHLMAN LAKE	TERMINAL	345.0	345.0	SINGLE POLE	2.816	0.000	1	6-795 ACSR	1,136,938	2,189,075	3,326,013				
71	(0977;01) KOHLMAN LAKE	TERMINAL	345.0	345.0	TOWER	7.376	0.000		6-795 ACSR							
72	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.0	345.0	SINGLE POLE	3.816	0.000	1	6-795 ACSR	104,148	593,836	697,984				
73	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.0	345.0	TOWER	1.722	0.000		6-795 ACSR	873,092	4,579,023	5,452,115				
74	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	2 POLE	0.659	0.000	1	6-954 ACSR							
75	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	K-FRAME	8.890	0.000		6-954 ACSR							
76	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	SINGLE POLE	0.792	0.000		6-795 ACSR							
77	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	TOWER	17.122	0.000		6-795 ACSR							
78	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	TOWER	6.372	0.000		6-954 ACSR							
79	(0976;01) EDEN PRAIRIE	PARKERS LAKE	345.0	345.0	TOWER	9.486	0.000	1	6-795 ACSR	45,639	521,262	566,901				
80	(0976;01) HAMPTON	PRAIRIE ISLAND	345.0	345.0	K-FRAME	16.004	0.000	1	6-795 ACSR	1,296,677	6,949,323	8,246,000				
81	(0976;01) HAMPTON	PRAIRIE ISLAND	345.0	345.0	TOWER	3.564	0.000		6-795 ACSR							
82	(0975;01) ALLEN S KING	RED ROCK	345.0	345.0	K-FRAME	3.544	0.000	1	6-795 ACSR	401,128	2,690,176	3,091,304				
83	(0975;01) ALLEN S KING	RED ROCK	345.0	345.0	TOWER	21.857	0.000		6-795 ACSR							
84	(0974;01) MANKATO ENERGY CENTER	WILMARTH	345.0	345.0	H-FRAME	0.218	0.000	1	6-795 ACSR		888,655	888,655				
85	(0973;01) MONTICELLO SUB	QUARRY	345.0	345.0	SINGLE POLE	30.038	0.000	1	6-954 ACSS/TW	5,368,656	10,969,295	16,337,951				
86	(0972-MN;01) BROOKINGS CO.	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	8.862	0.000	1	6-954 ACSS/TW	7,954,672	57,171,639	65,126,311				
87	(0972-SD;01) BROOKINGS CO.	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	10.192	0.000	1	6-954 ACSS/TW	509,810	20,993,906	21,503,716				
88	(0972;01) HAWKS NEST LAKE	LYON CO.	345.0	345.0	SINGLE POLE	30.547	0.000	1	6-954 ACSS/TW		135,628	135,628				

89	(0972;01) HAWKS NEST LAKE	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	9.958	0.000	1	6-954 ACSS/TW	530,922	530,922				
90	(0971;01) BROOKINGS CO.	WHITE (WAPA)	345.0	345.0	SINGLE POLE	0.434	0.000	1	6-795 ACSS	13,748	933,240	946,988			
91	(0970;02) BROOKINGS CO.	WHITE (WAPA)	345.0	345.0	SINGLE POLE	0.378	0.000	1	6-795 ACSS		1,215,849	1,215,849			
92	(0969;02) BLAZING STAR 1	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	0.080	0.000	1	6-954		7,782	7,782			
93	(0968;01) BLAZING STAR 1	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	0.079	0.000	1	6-954						
94	(0967;01) HUNTLEY (ITC)	WILMARTH	345.0	345.0	SINGLE POLE	52.026	0.000	1	6-556.5 ACSR/T2	2,997,012	48,896,337	51,893,349			
95	(0966;01) BROOKINGS CO.	BIG STONE SOUTH	345.0	345.0	SINGLE POLE	71.980	0.000	1	6-556.5 ACSR/T2	3,526,999	57,810,786	61,337,785			
96	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.0	345.0	2 POLE	3.121	0.000	1	6-954 ACSS/TW	5,358,507	59,722,203	65,080,710			
97	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.0	345.0	SINGLE POLE	40.065	0.000		6-954 ACSS/TW						
98	(0964;01) HAMPTON	NORTH ROCHESTER	345.0	345.0	SINGLE POLE	37.851	0.000	1	6-397.5 TACSR/VR2	9,430,408	54,128,384	63,558,792			
99	(0962;01) HAZEL CREEK	LYON CO.	345.0	345.0	SINGLE POLE	24.543	0.000	1	6-954 ACSS/TW	340,384	26,971,692	27,312,076			
100	(0961;01) CHUB LAKE (GRE)	HAMPTON	345.0	345.0	SINGLE POLE	18.101	0.000	1	6-954 ACSS/TW	7,244,068	37,796,297	45,040,365			
101	(0960;01) CHUB LAKE (GRE)	HELENA	345.0	345.0	SINGLE POLE	20.870	0.000	1	6-954 ACSS/TW	8,314,945	36,282,633	44,597,578			
102	(0959;02) CEDAR MTN. (GRE)	HELENA	345.0	345.0	3 POLE	0.000	0.906	1	6-954 ACSS/TW						
103	(0959;02) CEDAR MTN. (GRE)	HELENA	345.0	345.0	SINGLE POLE	0.000	72.157		6-954 ACSS/TW						
104	(0958;01) CEDAR MTN. (GRE)	HELENA	345.0	345.0	3 POLE	0.906	0.000	1	6-954 ACSS/TW	15,584,347	112,135,762	127,720,109			
105	(0958;01) CEDAR MTN. (GRE)	HELENA	345.0	345.0	SINGLE POLE	72.196	0.000		6-954 ACSS/TW						
106	(0957;02) CEDAR MTN. (GRE)	LYON CO.	345.0	345.0	SINGLE POLE	0.000	49.488	1	6-954 ACSS/TW						
107	(0956;01) CEDAR MTN. (GRE)	LYON CO.	345.0	345.0	SINGLE POLE	49.488	0.000	1	6-954 ACSS/TW	5,315,434	65,839,990	71,155,424			
108	(0955-MN;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	2 POLE	3.355	0.000	1	6-954 ACSS/TW	6,637,015	84,241,012	90,878,027			
109	(0955-MN;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	SINGLE POLE	101.037	0.000		6-954 ACSS/TW						
110	(0955-ND;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	SINGLE POLE	34.384	0.000	1	6-954 ACSS/TW	1,513,232	22,705,097	24,218,329			
111	(0954;01) ALEXANDRIA SW. ST.	RIVERVIEW (GRE)	345.0	345.0	SINGLE POLE	45.160	0.000	1	6-954 ACSS/TW	2,327,849	37,137,830	39,465,679			
112	(0954;01) QUARRY	RIVERVIEW (GRE)	345.0	345.0	SINGLE POLE	36.090	0.000	1	6-954 ACSS/TW	1,860,437	29,680,864	31,541,301			
113	(0953;01) LAKEFIELD JCT (IPW)	NOBLES CO.	345.0	345.0	SINGLE POLE	22.671	0.000	1	6-397.5 ACSR/T2	3,515,668	56,724,281	60,239,949			
114	(0953;01) LAKEFIELD JCT (IPW)	NOBLES CO.	345.0	345.0	SINGLE POLE	13.270	0.000		6-954 ACSS/TW						
115	(0953-MN;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	10.689	0.000	1	6-397.5 ZTACSR	3,623,388	65,053,709	68,677,097			

116	(0953-MN;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	32.044	0.000		6-954 ACSS/TW							
117	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	4.427	0.000	1	6-954 ACSR	554,100	4,451,932	5,006,032				
118	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	5.073	0.000		6-954 ACSS/TW							
119	(0963;01) HAZEL CREEK	MINNESOTA VALLEY	230.0	345.0	2 POLE	0.633	0.000	1	6-954 ACSS/TW	355,907	9,176,023	9,531,930				
120	(0963;01) HAZEL CREEK	MINNESOTA VALLEY	230.0	345.0	SINGLE POLE	4.336	0.000		6-954 ACSS/TW							
121	(0929;01) BORDER WIND FARM (RES)	PEACE GARDEN	230.0	230.0	2 POLE	0.042	0.000	1	6-		98,889	98,889				
122	(0928;01) CROWNED RIDGE 1	CROWNED RIDGE 2	230.0	230.0	SINGLE POLE	4.763	0.000	1	3- ACSR		3,173,402	3,173,402				
123	(0927;01) FOXTAIL	FOXTAIL	230.0	230.0	SINGLE POLE	0.115	0.000	1	3-795 ACSR		48,277	48,277				
124	(0924;01) MCHENRY (GRE)	MAGIC CITY	230.0	230.0	SINGLE POLE	20.573	0.000	1	3-477 ACSR/VR2	844,717	26,291,840	27,136,557				
125	(0923;01) CASS LAKE (OTP)	WILTON (MPC)	230.0	230.0	SINGLE POLE	19.318	0.000	1	3-795 ACSS	884,508	9,194,724	10,079,232				
126	(0922;01) BOSWELL (MINNESOTA POWER)	CASS LAKE (OTP)	230.0	230.0	SINGLE POLE	51.461	0.000	1	3-795 ACSS	1,023,124	23,387,110	24,410,234				
127	(0920;01) GLENBORO (MHEB)	PEACE GARDEN	230.0	230.0	H-FRAME	1.985	0.000	1	3-954 ACSR	1,288,507	12,521,625	13,810,132				
128	(0920;01) PEACE GARDEN	RUGBY (OTP)	230.0	230.0	H-FRAME	54.672	0.000	1	3-954 ACSR		326,714	326,714				
129	(0919;01) PAYNESVILLE TRANS. S	WILLMAR (GRE)	230.0	230.0	H-FRAME	2.181	0.000	1	3-795 ACSR	302,577	7,615,686	7,918,263				
130	(0919;01) PAYNESVILLE TRANS. S	WILLMAR (GRE)	230.0	230.0	SINGLE POLE	27.554	0.000		3-795 ACSR							
131	(0918;01) SIOUX FALLS (WAPA)	SPLIT ROCK	230.0	230.0	3 POLE	0.938	0.000	1	3-795 ACSS	531,676	605,867	1,137,543				
132	(0916;01) GRAND FORKS (WAPA)	PRAIRIE	230.0	230.0	H-FRAME	6.321	0.000	1	3-954 ACSR	24,662	1,531,625	1,556,287				
133	(0916;01) GRAND FORKS (WAPA)	PRAIRIE	230.0	230.0	SINGLE POLE	0.476	0.000		3-954 ACSR							
134	(0915;01) FARGO (WAPA)	SHEYENNE	230.0	230.0	H-FRAME	4.093	0.152	1	3-795 ACSR	21,223	1,900,567	1,921,790				
135	(0912;01) DRAYTON (MINNKOTA)	LETELLIER (MANITOBA HYDRO)	230.0	230.0	3 POLE	0.028	0.000	1	3-954 ACSR	57,281	3,010,357	3,067,638				
136	(0912;01) DRAYTON (MINNKOTA)	LETELLIER (MANITOBA HYDRO)	230.0	230.0	H-FRAME	28.660	0.000		3-954 ACSR							
137	(0912;01) DRAYTON (MINNKOTA)	LETELLIER (MANITOBA HYDRO)	230.0	230.0	SINGLE POLE	0.040			3-954 ACSR							
138	(0911;01) AUDUBON (OTP)	SHEYENNE	230.0	230.0	H-FRAME	1.409	0.000	1	3-795 ACSR	10,733	237,425	248,158				
139	(0911;01) MAPLE RIVER	SHEYENNE	230.0	230.0	H-FRAME	2.801	0.000	1	3-795 ACSR	21,002	597,200	618,202				
140	(0911;01) MAPLE RIVER	SHEYENNE	230.0	230.0	TOWER	0.047	3.734		3-795 ACSR							
141	(0910;01) MAPLE RIVER	WAHPETON (MINNKOTA)	230.0	230.0	TOWER	3.604	0.000	1	3-795 ACSR	55,625	283,964	339,589				

142	(0909;01) AUDUBON (OTP)	HUBBARD (GRE)	230.0	230.0	H-FRAME	38.557	0.000	1	3-795 ACSR	57,863	7,828,503	7,886,366				
143	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	H-FRAME	0.922	0.000	1	3-795 ACSR	407,857	7,873,513	8,281,370				
144	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	K-FRAME	52.990	0.000		3-795 ACSR							
145	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	SINGLE POLE	10.887	0.098		3-1272 ACSR							
146	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	TOWER	2.783	0.000		3-1272 ACSR							
147	(0902;01) BEAR CREEK (GRE)	ROCK CREEK	230.0	230.0	SINGLE POLE	12.551	0.000	1	3-795 ACSR	29,881	1,250,116	1,279,997				
148	(0900;01) BLUE LAKE	MCLEOD (MUNI)	230.0	230.0	H-FRAME	1.340	0.000	1	3-795 ACSR	371,590	5,207,737	5,579,327				
149	(0900;01) BLUE LAKE	MCLEOD (MUNI)	230.0	230.0	TOWER	45.150	0.000	1	3-795 ACSR							
150	(0900;02) GRANITE FALLS (WAPA)	PANTHER (GRE)	230.0	230.0	TOWER	32.809	0.000	1	3-795 ACSR	5,902	1,880,562	1,886,464				
151	(0900;01) MCLEOD (MUNI)	PANTHER (GRE)	230.0	230.0	TOWER	28.490	0.000	1	3-795 ACSR	59,673	1,519,137	1,578,810				
152	(5313;01) FREEBORN	GLENWORTH (ITC)	161.0	161.0	SINGLE POLE	7.121	0.000	1	3-1272 ACSR		6,203,947	6,203,947				
153	(5312;01) ADAMS	MOWER CO. WIND FARM	161.0	161.0	2 POLE	0.203	0.000	1	3-477 ACSR		1,288,029	1,288,029				
154	(5312;01) ADAMS	MOWER CO. WIND FARM	161.0	161.0	SINGLE POLE	7.729	0.000		3-477 ACSR							
155	(5311;01) PLEASANT VALLEY (GRE)	PLEASANT VALLEY WIND FARM	161.0	161.0	SINGLE POLE	4.982	0.000	1	3-954 ACSR		2,268,717	2,268,717				
156	(5310;01) NORTHERN HILLS	NORTH ROCHESTER	161.0	161.0	SINGLE POLE	15.507	0.000	1	3-795 ACSS	1,314,415	9,559,156	10,873,571				
157	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.0	161.0	SINGLE POLE	11.408	0.000	1	3-397.5 TACSR/TW	567,003	12,379,705	12,946,708				
158	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.0	161.0	SINGLE POLE	1.145	15.108		6-954 ACSS/TW							
159	(5308;01) GRAND MEADOW	PLEASANT VALLEY (GRE)	161.0	161.0	SINGLE POLE	5.703	0.000	1	6-795 ACSS		1,399,017	1,399,017				
160	(5306;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	161.0	161.0	SINGLE POLE	16.604	0.000	1	3-795 ACSS	477,246	6,134,098	6,611,344				
161	(5305-MN;01) LAWRENCE CREEK	ST CROIX FALLS	161.0	161.0	SINGLE POLE	1.454	0.000	1	3-795 ACSS	69,801	10,278,048	10,347,849				
162	(5305-MN;01) LAWRENCE CREEK	ST CROIX FALLS	161.0	161.0	UNDERGROUND	0.579	0.000		3-3000 CU							
163	(5305-MN;01) LAWRENCE CREEK	ST CROIX FALLS	161.0	161.0	H-FRAME	0.113	0.000		3-795 ACSS							
164	(5301;01) ELK (ALLIANT)	ROCK CO.	161.0	161.0	H-FRAME	5.253	0.135	1	3-477 ACSR	16,110	650,733	666,843				
165	(5301-MN;01) ROCK CO.	SPLIT ROCK	161.0	161.0	H-FRAME	3.453	0.000	1	3-477 ACSR	17,390	603,450	620,840				
166	(5301-MN;01) ROCK CO.	SPLIT ROCK	161.0	161.0	SINGLE POLE	0.081	0.000		3-477 ACSR							
167	(5301-SD;01) ROCK CO.	SPLIT ROCK	161.0	161.0	H-FRAME	10.274	0.000	1	3-477 ACSR	25,772	1,548,304	1,574,076				

168	(5301-SD;01) ROCK CO.	SPLIT ROCK	161.0	161.0	SINGLE POLE	0.867	0.000		3-2312 ACSR							
169	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.0	161.0	H-FRAME	29.952	0.200	1	3-477 ACSR	143,079	1,968,800	2,111,879				
170	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.0	161.0	SINGLE POLE	0.000	1.364		3-565.3 ACSS/TW							
171	SUMMARY OF 115 KV SYSTEM		115.0	115.0	Overhead	1,480.393	152.328			23,693,855	778,239,361	801,933,216				
172	SUMMARY OF 115 KV SYSTEM		115.0	115.0	Underground	13.221	0.000									
173	SUMMARY OF 69 KV SYSTEM		69.0	69.0	Overhead	1,489.069	98.222			6,809,203	458,675,948	465,485,151				
174	SUMMARY OF 69 KV SYSTEM		69.0	69.0	Underground	1.532	0.000									
175	SUMMARY OF 34.5 KV SYSTEM		34.5	34.5	Overhead	60.119	32.471			436,068	29,622,717	30,058,785				
176	SUMMARY OF 34.5 KV SYSTEM		34.5	34.5	Underground	0.590	0.000									
177	Expenses, except depreciation and taxes												373,137	5,543,700	1,273,660	7,190,497
36	TOTAL					5,226.266	629.756	109		151,471,277	2,649,445,345	2,800,916,622	373,137	5,543,700	1,273,660	7,190,497

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: LengthForStandAloneTransmissionLines NSM ((0973;01) MONTICELLO SUB-QUARRY) : Xcel Energy owns 36.1%(10.84 miles) of 30.04 miles of this circuit: remaining 63.9%(19.19 miles) is owned by other members of a joint venture partnership
(b) Concept: LengthForStandAloneTransmissionLines NSM ((0972-MN;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.01 miles) of 8.86 miles of this circuit: remaining 32.2%(2.85 miles) is owned by other members of a joint venture partnership
(c) Concept: LengthForStandAloneTransmissionLines NSM ((0972-SD;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.91 miles) of 10.19 miles of this circuit: remaining 32.2%(3.28 miles) is owned by other members of a joint venture partnership
(d) Concept: LengthForStandAloneTransmissionLines NSM ((0972;01) HAWKS NEST LAKE-LYON CO.) : Xcel Energy owns 67.8%(20.71 miles) of 30.55 miles of this circuit: remaining 32.2%(9.84 miles) is owned by other members of a joint venture partnership
(e) Concept: LengthForStandAloneTransmissionLines NSM ((0972;01) HAWKS NEST LAKE-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.75 miles) of 9.96 miles of this circuit: remaining 32.2%(3.21 miles) is owned by other members of a joint venture partnership
(f) Concept: LengthForStandAloneTransmissionLines NSM ((0967;01) HUNTLEY (ITC)-WILMARTH) : Xcel Energy owns 50.0%(26.01 miles) of 52.03 miles of this circuit: remaining 50.0%(26.01 miles) is owned by other operating companies
(g) Concept: LengthForStandAloneTransmissionLines NSM ((0966;01) BROOKINGS CO.-BIG STONE SOUTH) : Xcel Energy owns 50.0%(35.99 miles) of 71.98 miles of this circuit: remaining 50.0%(35.99 miles) is owned by other members of a joint venture partnership
(h) Concept: LengthForStandAloneTransmissionLines NSM ((0965-MN;01) BRIGGS ROAD-NORTH ROCHESTER) : Xcel Energy owns 64.0%(27.64 miles) of 43.19 miles of this circuit: remaining 36.0%(15.55 miles) is owned by other members of a joint venture partnership
(i) Concept: LengthForStandAloneTransmissionLines NSM ((0965-MN;01) BRIGGS ROAD-NORTH ROCHESTER) : Xcel Energy owns 64.0%(27.64 miles) of 43.19 miles of this circuit: remaining 36.0%(15.55 miles) is owned by other members of a joint venture partnership
(j) Concept: LengthForStandAloneTransmissionLines NSM ((0964;01) HAMPTON-NORTH ROCHESTER) : Xcel Energy owns 64.0%(24.22 miles) of 37.85 miles of this circuit: remaining 36.0%(13.63 miles) is owned by other members of a joint venture partnership
(k) Concept: LengthForStandAloneTransmissionLines NSM ((0962;01) HAZEL CREEK-LYON CO.) : Xcel Energy owns 67.8%(16.64 miles) of 24.54 miles of this circuit: remaining 32.2%(7.9 miles) is owned by other members of a joint venture partnership
(l) Concept: LengthForStandAloneTransmissionLines NSM ((0961;01) CHUB LAKE (GRE)-HAMPTON) : Xcel Energy owns 67.8%(12.27 miles) of 18.1 miles of this circuit: remaining 32.2%(5.83 miles) is owned by other members of a joint venture partnership
(m) Concept: LengthForStandAloneTransmissionLines NSM ((0960;01) CHUB LAKE (GRE)-HELENA) : Xcel Energy owns 67.8%(14.15 miles) of 20.87 miles of this circuit: remaining 32.2%(6.72 miles) is owned by other members of a joint venture partnership
(n) Concept: LengthForStandAloneTransmissionLines NSM ((0959;02) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.53 miles) of 73.06 miles of this circuit: remaining 32.2%(23.53 miles) is owned by other members of a joint venture partnership
(o) Concept: LengthForStandAloneTransmissionLines NSM ((0959;02) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.53 miles) of 73.06 miles of this circuit: remaining 32.2%(23.53 miles) is owned by other members of a joint venture partnership
(p) Concept: LengthForStandAloneTransmissionLines NSM ((0958;01) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.56 miles) of 73.1 miles of this circuit: remaining 32.2%(23.54 miles) is owned by other members of a joint venture partnership

(g) Concept: LengthForStandAloneTransmissionLines
NSM ((0958;01) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.56 miles) of 73.1 miles of this circuit: remaining 32.2%(23.54 miles) is owned by other members of a joint venture partnership
(r) Concept: LengthForStandAloneTransmissionLines
NSM ((0957;02) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8%(33.55 miles) of 49.49 miles of this circuit: remaining 32.2%(15.94 miles) is owned by other members of a joint venture partnership
(s) Concept: LengthForStandAloneTransmissionLines
NSM ((0956;01) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8%(33.55 miles) of 49.49 miles of this circuit: remaining 32.2%(15.94 miles) is owned by other members of a joint venture partnership
(t) Concept: LengthForStandAloneTransmissionLines
NSM ((0955-MN;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(37.69 miles) of 104.39 miles of this circuit: remaining 63.9%(66.71 miles) is owned by other members of a joint venture partnership
(u) Concept: LengthForStandAloneTransmissionLines
NSM ((0955-MN;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(37.69 miles) of 104.39 miles of this circuit: remaining 63.9%(66.71 miles) is owned by other members of a joint venture partnership
(v) Concept: LengthForStandAloneTransmissionLines
NSM ((0955-ND;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(12.41 miles) of 34.38 miles of this circuit: remaining 63.9%(21.97 miles) is owned by other members of a joint venture partnership
(w) Concept: LengthForStandAloneTransmissionLines
NSM ((0954;01) ALEXANDRIA SW. ST.-RIVERVIEW (GRE)) : Xcel Energy owns 36.1%(16.3 miles) of 45.16 miles of this circuit: remaining 63.9%(28.86 miles) is owned by other members of a joint venture partnership
(x) Concept: LengthForStandAloneTransmissionLines
NSM ((0954;01) QUARRY-RIVERVIEW (GRE)) : Xcel Energy owns 36.1%(13.03 miles) of 36.09 miles of this circuit: remaining 63.9%(23.06 miles) is owned by other members of a joint venture partnership
(y) Concept: LengthForStandAloneTransmissionLines
NSM ((0963;01) HAZEL CREEK-MINNESOTA VALLEY) : Xcel Energy owns 67.8%(3.37 miles) of 4.97 miles of this circuit: remaining 32.2%(1.6 miles) is owned by other members of a joint venture partnership
(z) Concept: LengthForStandAloneTransmissionLines
NSM ((0923;01) CASS LAKE (OTP)-WILTON (MPC)) : Xcel Energy owns 26.2%(5.06 miles) of 19.32 miles of this circuit: remaining 73.8%(14.26 miles) is owned by other members of a joint venture partnership
(aa) Concept: LengthForStandAloneTransmissionLines
NSM ((0922;01) BOSWELL (MINNESOTA POWER)-CASS LAKE (OTP)) : Xcel Energy owns 26.2%(13.48 miles) of 51.46 miles of this circuit: remaining 73.8%(37.98 miles) is owned by other members of a joint venture partnership
(ab) Concept: LengthForStandAloneTransmissionLines
NSM ((5310;01) NORTHERN HILLS-NORTH ROCHESTER) : Xcel Energy owns 64.0%(9.92 miles) of 15.51 miles of this circuit: remaining 36.0%(5.58 miles) is owned by other members of a joint venture partnership
(ac) Concept: LengthForStandAloneTransmissionLines
NSM ((5309;01) CHESTER (RPU)-NORTH ROCHESTER) : Xcel Energy owns 64.0%(17.7 miles) of 27.66 miles of this circuit: remaining 36.0%(9.96 miles) is owned by other members of a joint venture partnership
(ad) Concept: LengthForStandAloneTransmissionLines
NSM ((5309;01) CHESTER (RPU)-NORTH ROCHESTER) : Xcel Energy owns 64.0%(17.7 miles) of 27.66 miles of this circuit: remaining 36.0%(9.96 miles) is owned by other members of a joint venture partnership
(ae) Concept: LengthForStandAloneTransmissionLines
NSM ((5558;01) CEDAR MTN. (GRE)-FRANKLIN) : Xcel Energy owns 67.8%(2.92 miles) of 4.3 miles of this circuit: remaining 32.2%(1.39 miles) is owned by other members of a joint venture partnership
(af) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0973;01) MONTICELLO SUB-QUARRY) : Xcel Energy owns 36.1%(10.84 miles) of 30.04 miles of this circuit: remaining 63.9%(19.19 miles) is owned by other members of a joint venture partnership
(ag) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0972-MN;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.01 miles) of 8.86 miles of this circuit: remaining 32.2%(2.85 miles) is owned by other members of a joint venture partnership
(ah) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0972-SD;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.91 miles) of 10.19 miles of this circuit: remaining 32.2%(3.28 miles) is owned by other members of a joint venture partnership
(ai) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0972;01) HAWKS NEST LAKE-LYON CO.) : Xcel Energy owns 67.8%(20.71 miles) of 30.55 miles of this circuit: remaining 32.2%(9.84 miles) is owned by other members of a joint venture partnership

(aj) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0972;01) HAWKS NEST LAKE-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.75 miles) of 9.96 miles of this circuit: remaining 32.2%(3.21 miles) is owned by other members of a joint venture partnership
(ak) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0967;01) HUNTLEY (ITC)-WILMARTH) : Xcel Energy owns 50.0%(26.01 miles) of 52.03 miles of this circuit: remaining 50.0%(26.01 miles) is owned by other operating companies
(al) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0966;01) BROOKINGS CO.-BIG STONE SOUTH) : Xcel Energy owns 50.0%(35.99 miles) of 71.98 miles of this circuit: remaining 50.0%(35.99 miles) is owned by other members of a joint venture partnership
(am) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0965-MN;01) BRIGGS ROAD-NORTH ROCHESTER) : Xcel Energy owns 64.0%(27.64 miles) of 43.19 miles of this circuit: remaining 36.0%(15.55 miles) is owned by other members of a joint venture partnership
(an) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0965-MN;01) BRIGGS ROAD-NORTH ROCHESTER) : Xcel Energy owns 64.0%(27.64 miles) of 43.19 miles of this circuit: remaining 36.0%(15.55 miles) is owned by other members of a joint venture partnership
(ao) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0964;01) HAMPTON-NORTH ROCHESTER) : Xcel Energy owns 64.0%(24.22 miles) of 37.85 miles of this circuit: remaining 36.0%(13.63 miles) is owned by other members of a joint venture partnership
(ap) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0962;01) HAZEL CREEK-LYON CO.) : Xcel Energy owns 67.8%(16.64 miles) of 24.54 miles of this circuit: remaining 32.2%(7.9 miles) is owned by other members of a joint venture partnership
(aq) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0961;01) CHUB LAKE (GRE)-HAMPTON) : Xcel Energy owns 67.8%(12.27 miles) of 18.1 miles of this circuit: remaining 32.2%(5.83 miles) is owned by other members of a joint venture partnership
(ar) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0960;01) CHUB LAKE (GRE)-HELENA) : Xcel Energy owns 67.8%(14.15 miles) of 20.87 miles of this circuit: remaining 32.2%(6.72 miles) is owned by other members of a joint venture partnership
(as) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0959;02) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.53 miles) of 73.06 miles of this circuit: remaining 32.2%(23.53 miles) is owned by other members of a joint venture partnership
(at) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0959;02) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.53 miles) of 73.06 miles of this circuit: remaining 32.2%(23.53 miles) is owned by other members of a joint venture partnership
(au) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0958;01) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.56 miles) of 73.1 miles of this circuit: remaining 32.2%(23.54 miles) is owned by other members of a joint venture partnership
(av) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0958;01) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.56 miles) of 73.1 miles of this circuit: remaining 32.2%(23.54 miles) is owned by other members of a joint venture partnership
(aw) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0957;02) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8%(33.55 miles) of 49.49 miles of this circuit: remaining 32.2%(15.94 miles) is owned by other members of a joint venture partnership
(ax) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0956;01) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8%(33.55 miles) of 49.49 miles of this circuit: remaining 32.2%(15.94 miles) is owned by other members of a joint venture partnership
(ay) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0955-MN;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(37.69 miles) of 104.39 miles of this circuit: remaining 63.9%(66.71 miles) is owned by other members of a joint venture partnership
(az) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0955-MN;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(37.69 miles) of 104.39 miles of this circuit: remaining 63.9%(66.71 miles) is owned by other members of a joint venture partnership
(ba) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0955-ND;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(12.41 miles) of 34.38 miles of this circuit: remaining 63.9%(21.97 miles) is owned by other members of a joint venture partnership
(bb) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0954;01) ALEXANDRIA SW. ST.-RIVERVIEW (GRE)) : Xcel Energy owns 36.1%(16.3 miles) of 45.16 miles of this circuit: remaining 63.9%(28.86 miles) is owned by other members of a joint venture partnership

(bc) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures

NSM ((0954;01) QUARRY-RIVERVIEW (GRE)) : Xcel Energy owns 36.1%(13.03 miles) of 36.09 miles of this circuit: remaining 63.9%(23.06 miles) is owned by other members of a joint venture partnership

(bd) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures

NSM ((0963;01) HAZEL CREEK-MINNESOTA VALLEY) : Xcel Energy owns 67.8%(3.37 miles) of 4.97 miles of this circuit: remaining 32.2%(1.6 miles) is owned by other members of a joint venture partnership

(be) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures

NSM ((0923;01) CASS LAKE (OTP)-WILTON (MPC)) : Xcel Energy owns 26.2%(5.06 miles) of 19.32 miles of this circuit: remaining 73.8%(14.26 miles) is owned by other members of a joint venture partnership

(bf) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures

NSM ((0922;01) BOSWELL (MINNESOTA POWER)-CASS LAKE (OTP)) : Xcel Energy owns 26.2%(13.48 miles) of 51.46 miles of this circuit: remaining 73.8%(37.98 miles) is owned by other members of a joint venture partnership

(bg) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures

NSM ((5310;01) NORTHERN HILLS-NORTH ROCHESTER) : Xcel Energy owns 64.0%(9.92 miles) of 15.51 miles of this circuit: remaining 36.0%(5.58 miles) is owned by other members of a joint venture partnership

(bh) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures

NSM ((5309;01) CHESTER (RPU)-NORTH ROCHESTER) : Xcel Energy owns 64.0%(17.7 miles) of 27.66 miles of this circuit: remaining 36.0%(9.96 miles) is owned by other members of a joint venture partnership

(bi) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures

NSM ((5309;01) CHESTER (RPU)-NORTH ROCHESTER) : Xcel Energy owns 64.0%(17.7 miles) of 27.66 miles of this circuit: remaining 36.0%(9.96 miles) is owned by other members of a joint venture partnership

(bj) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures

NSM ((5558;01) CEDAR MTN. (GRE)-FRANKLIN) : Xcel Energy owns 67.8%(2.92 miles) of 4.3 miles of this circuit: remaining 32.2%(1.39 miles) is owned by other members of a joint venture partnership

FERC FORM NO. 1 (ED. 12-87)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)	Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1	(5503;01) CHERRY CREEK	WEST SIOUX FALLS	0.092	SINGLE POLE	21	1	1	3-477	ACSS	24/7	115.0		233,191	324,928		558,119	
2	(5506,5522;01) CROOKED LAKE	WEST COON RAPIDS	0.072	SINGLE POLE	13	1	1	3-795	ACSS	26/7	115.0		533,172	75,648		608,820	
3	(0898;01) DEAN LAKE	SCOTT CO.	0.013	SINGLE POLE	7	2	2	3-795	ACSR	26/7	115.0		388,184	212,710		600,894	
4	(0898;01) DEAN LAKE	SCOTT CO.	0.036	TOWER	7	1	1	3-795	ACSR	26/7	115.0						
5	(0808;01) HIGH BRIDGE SUB	ROGERS LAKE	0.06	H-FRAME	9	1	1	3-795	ACSS	26/7	115.0		420,120	99,425		519,545	
6	(0755,0756;01) FIESTA CITY	MINNESOTA VALLEY	0.02	3WAY NONSWITCH	19	1	1	3-4/0	ACSR	6/1	69.0		292,919	318,136		611,055	
44	TOTAL		0		76	7	7						1,867,586	1,030,847		2,898,433	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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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).
5. Show in columns (l), (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.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1	ADAMS-TR09	Transmission	Unattended	345.00	161.00	13.80	300.00	1				
2	ADA-TR01	Distribution	Unattended	69.00	23.00	4.16	14.00	1				
3	AFTON-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
4	AFTON-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
5	AIR LAKE-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
6	AIR LAKE-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
7	AIRPORT-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
8	AIRPORT-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
9	ALBANY-TR02	Distribution	Unattended	69.00	12.50		10.50	1				
10	ALDRICH-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
11	ALDRICH-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
12	ALDRICH-TR04	Distribution	Unattended	115.00	13.80		70.00	1				

13	ALEXANDRIA-TR01ABC	Distribution	Unattended	34.50	4.16		2.00	3				
14	ALTURA-TR01	Distribution	Unattended	69.00	13.80		7.00	1				
15	ANNANDALE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
16	APACHE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
17	APACHE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
18	ARDEN HILLS-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
19	ARDEN HILLS-TR02	Transmission	Unattended	115.00	69.00	13.80	70.00	1				
20	ARLINGTON-TR01	Distribution	Unattended	69.00	4.16		6.00	1				
21	AS KING-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
22	AS KING-TR91	Distribution	Unattended	115.00	34.50		25.00	1				
23	ATWATER-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
24	AVERILL-TR01	Distribution	Unattended	69.00	23.00	4.00	14.00	1				
25	AVON-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
26	BASSETT CREEK-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
27	BASSETT CREEK-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
28	BATTLE CREEK-TR01	Distribution	Unattended	115.00	13.80		48.00	1				
29	BATTLE CREEK-TR02	Distribution	Unattended	115.00	13.80		48.00	1				
30	BAYTOWN-TR01	Distribution	Unattended	118.00	13.80		28.00	1				
31	BECKER-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
32	BECKER-TR02	Distribution	Unattended	69.00	34.50		4.70	1				
33	BELGRADE-TR01	Distribution	Unattended	69.00	4.16		3.50	1				
34	BELLE PLAINE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
35	BIRCH-TR01	Distribution	Unattended	69.00	34.50		14.00	1				
36	BIRD ISLAND-TR02	Distribution	Unattended	69.00	4.16		2.50	1				
37	BLUE HERON-TR01	Distribution	Unattended	69.00	13.80		9.40	1				
38	BLUE LAKE-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
39	BLUE LAKE-TR02	Distribution	Unattended	115.00	13.80		25.00	1				

40	BLUE LAKE-TR07	Transmission	Unattended	230.00	115.00	13.80	336.00	1				
41	BLUE LAKE-TR09	Transmission	Unattended	345.00	115.00	14.00	336.00	1				
42	BLUFF CREEK-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
43	BLUFF CREEK-TR05	Transmission	Unattended	115.00	69.00	13.80	112.00	1				
44	BROOKINGS COUNTY-TR09	Transmission	Unattended	345.00	115.00	34.50	448.00	1				
45	BROOKINGS COUNTY-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
46	BROOKLYN PARK-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
47	BROOKLYN PARK-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
48	BROOTEN-TR01	Distribution	Unattended	69.00	12.50		6.00	1				
49	BROWNTON-TR01	Distribution	Unattended	69.00	2.40		1.40	1				
50	BUFFALO LAKE-TR01	Distribution	Unattended	69.00	12.50		5.60	1				
51	BUFFALO RIDGE-TR01	Distribution	Unattended	115.00	34.50	13.80	120.00	1				
52	BUFFALO RIDGE-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
53	BURNSIDE-TR01	Distribution	Unattended	69.00	12.50		28.00	1				
54	BURNSIDE-TR02	Distribution	Unattended	69.00	12.50		10.50	1				
55	BUTTERFIELD-TR01	Distribution	Unattended	69.00	4.16		1.50	1				
56	CANISTOTA JCT-TR01	Distribution	Unattended	69.00	13.80		8.00	1				
57	CANISTOTA-TR01ABC	Distribution	Unattended	69.00	4.16		3.00	3				
58	CANNON FALLS XMSN-TR06	Transmission	Unattended	115.00	69.00	13.80	112.00	1				
59	CANNON FALLS XMSN-TR07	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
60	CANNON FALLS-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
61	CANTON-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
62	CANTON-TR02	Distribution	Unattended	69.00	13.80		14.00	1				

63	CARVER COUNTY-TR01	Transmission	Unattended	115.00	69.00	35.00	70.00	1				
64	CARVER COUNTY-TR02	Transmission	Unattended	115.00	69.00	35.00	70.00	1				
65	CASS COUNTY-TR01XY	Distribution	Unattended	115.00	23.00	3.00	50.00	2				
66	CASS COUNTY-TR02	Distribution	Unattended	115.00	23.00		47.00	1				
67	CASS COUNTY-TR03	Distribution	Unattended	115.00	23.00	14.00	46.70	1				
68	CASTLE ROCK-TR01	Distribution	Unattended	69.00	4.00		1.00	1				
69	CEDAR LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
70	CEDAR LAKE-TR02	Distribution	Unattended	115.00	13.80		50.00	1				
71	CEDARVALE-TR01	Distribution	Unattended	115.00	13.80		20.00	1				
72	CEDARVALE-TR02	Distribution	Unattended	115.00	13.80		23.00	1				
73	CENTERVILLE-TR01	Distribution	Unattended	69.00	13.80		7.00	1				
74	CHANARAMBIE-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
75	CHANARAMBIE-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
76	CHANARAMBIE-TR04	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
77	CHEMOLITE-TR01	Distribution	Unattended	115.00	13.80		50.00	1				
78	CHEMOLITE-TR02	Distribution	Unattended	115.00	13.80		50.00	1				
79	CHERRY CREEK-TR01	Distribution	Unattended	115.00	13.80		37.00	1				
80	CHERRY CREEK-TR03	Distribution	Unattended	115.00	34.50		70.00	1				
81	CHISAGO COUNTY-TR02	Distribution	Unattended	115.00	34.50		47.00	1				
82	CHISAGO COUNTY-TR05	Transmission	Unattended	345.00	115.00	35.00	448.00	1				
83	CHISAGO COUNTY-TR06	Transmission	Unattended	345.00	115.00	35.00	448.00	1				
84	CHISAGO COUNTY-TR09ABC	Transmission	Unattended	500.00	345.00	35.00	1203.00	3				
85	CHISAGO COUNTY-TR10ABC	Transmission	Unattended	500.00	345.00	35.00	1203.00	3				

86	CLARA CITY-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
87	CLARA CITY-TR02	Distribution	Unattended	69.00	23.00		14.00	1				
88	CLARKS GROVE-TR01	Distribution	Unattended	69.00	7.20		2.00	1				
89	CLIFF AVENUE-TR01	Distribution	Unattended	69.00	4.16		7.00	1				
90	CLIFF AVENUE-TR02	Distribution	Unattended	69.00	13.80		10.50	1				
91	COKATO-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
92	COLVILL-TR04	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
93	COLVILL-TR05	Transmission	Unattended	161.00	115.00	14.00	187.00	1				
94	COON CREEK-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
95	COON CREEK-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
96	COON CREEK-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
97	COON CREEK-TR10	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
98	COTTAGE GROVE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
99	COTTAGE GROVE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
100	CREDIT RIVER-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
101	CREDIT RIVER-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
102	CROOKED LAKE-TR01	Distribution	Unattended	119.00	13.80		46.70	1				
103	CROOKED LAKE-TR02	Distribution	Unattended	119.00	13.80		46.70	1				
104	CROOKED LAKE-TR03	Distribution	Unattended	115.00	12.50		28.00	1				
105	CROOKED LAKE-TR65ABC	Distribution	Unattended	13.80	12.50		10.00	3				
106	CROSSROADS-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
107	CROSSROADS-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
108	CROSSROADS-TR03	Distribution	Unattended	115.00	13.80		22.00	1				
109	CRYSTAL FOODS-TR01	Distribution	Unattended	69.00	13.80		14.00	1				

110	DAHLGREN-TR01	Distribution	Unattended	115.00	13.80		14.00	1				
111	DANUBE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
112	DASSEL-TR01	Distribution	Unattended	69.00	13.80		6.00	1				
113	DAYTONS BLUFF-TR01	Distribution	Unattended	115.00	13.80		63.00	1				
114	DAYTONS BLUFF-TR02	Distribution	Unattended	115.00	13.80		63.00	1				
115	DAYTONS BLUFF-TR03	Distribution	Unattended	115.00	13.80		63.00	1				
116	DEEPHAVEN-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
117	DEEPHAVEN-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
118	DELANO-TR01XY	Distribution	Unattended	69.00	7.20		0.40	2				
119	DELL RAPIDS-TR02	Distribution	Unattended	34.50	12.50		10.50	1				
120	DODGE CENTER-TR01	Distribution	Unattended	69.00	23.00		5.00	1				
121	DODGE CENTER-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
122	DODGE CENTER-TR03	Distribution	Unattended	69.00	12.50		10.50	1				
123	DOME PIPELINE-TR01	Distribution	Unattended	115.00	4.16		8.00	1				
124	DOUGLAS COUNTY-TR01	Transmission	Unattended	115.00	69.00	35.00	46.70	1				
125	DOUGLAS COUNTY-TR02	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
126	DOUGLAS COUNTY-TR03	Distribution	Unattended	69.00	13.80		7.20	1				
127	DUNDAS-TR01	Distribution	Unattended	69.00	13.80		20.00	1				
128	DUNDAS-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
129	EAGLE LAKE-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
130	EAST BLOOMINGTON-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
131	EAST BLOOMINGTON-TR02	Distribution	Unattended	115.00	13.80		46.70	1				

132	EAST BLOOMINGTON-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
133	EAST WINONA-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
134	EASTWOOD-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
135	EASTWOOD-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
136	EASTWOOD-TR03	Distribution	Unattended	115.00	13.80		52.50	1				
137	EDEN PRAIRIE-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
138	EDEN PRAIRIE-TR03	Distribution	Unattended	115.00	13.80		47.00	1				
139	EDEN PRAIRIE-TR04	Distribution	Unattended	115.00	13.80		51.00	1				
140	EDEN PRAIRIE-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
141	EDEN PRAIRIE-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
142	EDGERTON-TR01	Distribution	Unattended	23.00	4.16		2.00	1				
143	EDINA-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
144	EDINA-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
145	EDINA-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
146	ELLIOT PARK-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
147	ELLIOT PARK-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
148	ELLIOT PARK-TR03	Distribution	Unattended	115.00	13.80		72.50	1				
149	ELM CREEK-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
150	ELM CREEK-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
151	ELM CREEK-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
152	ELM CREEK-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
153	EMERY-TR01ABC	Distribution	Unattended	34.50	4.16		1.50	3				
154	ESSIG-TR01ABC	Distribution	Unattended	69.00	2.40		0.45	3				
155	EXCELSIOR-TR01	Distribution	Unattended	69.00	13.80		19.00	1				
156	FAIR PARK-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
157	FAIR PARK-TR02	Distribution	Unattended	69.00	13.80		14.00	1				
158	FALLS-TR01	Distribution	Unattended	115.00	13.80		62.60	1				

159	FALLS-TR02	Distribution	Unattended	115.00	13.80		62.60	1				
160	FARIBAULT-TR01	Distribution	Unattended	69.00	13.80		22.40	1				
161	FARIBAULT-TR02	Distribution	Unattended	69.00	13.80		14.00	1				
162	FARMINGTON-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
163	FARMINGTON-TR02	Distribution	Unattended	69.00	13.80		10.50	1				
164	FENTON-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
165	FENTON-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
166	FENTON-TR05	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
167	FIESTA CITY-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
168	FIESTA CITY-TR02	Distribution	Unattended	69.00	12.50		28.00	1				
169	FIFTH STREET-TR01	Distribution	Unattended	115.00	13.80		84.00	1				
170	FIFTH STREET-TR02	Distribution	Unattended	115.00	13.80		84.00	1				
171	FIFTH STREET-TR03	Distribution	Unattended	115.00	13.80		84.00	1				
172	FIFTH STREET-TR04	Distribution	Unattended	115.00	13.80		84.00	1				
173	FIRST LAKE-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
174	FOLEY-TR01	Distribution	Unattended	34.50	4.16		3.00	1				
175	FORBES-TR09	Distribution	Unattended	500.00	20.00		168.00	1				
176	FORT RIDGELY-TR05	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
177	FRANKLIN-TR04	Distribution	Unattended	69.00	23.00		7.00	1				
178	FRANKLIN-TR05	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
179	FRANKLIN-TR06	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
180	FRANKLIN-TR07	Distribution	Unattended	69.00	4.16		2.00	1				
181	FRONTENAC-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
182	GATEWAY-TR01	Distribution	Unattended	69.00	12.50		28.00	1				
183	GATEWAY-TR02	Distribution	Unattended	69.00	12.50		28.00	1				
184	GAYLORD-TR01	Distribution	Unattended	69.00	4.00		5.00	1				
185	GIBBON-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
186	GLEASON LAKE-TR01	Transmission	Unattended	115.00	69.00	14.00	112.00	1				

187	GLEASON LAKE-TR03	Distribution	Unattended	34.50	13.80		28.00	1				
188	GLEASON LAKE-TR04	Distribution	Unattended	115.00	34.50		70.00	1				
189	GLEASON LAKE-TR07	Distribution	Unattended	115.00	13.80		47.00	1				
190	GLEASON LAKE-TR08	Distribution	Unattended	115.00	13.80		70.00	1				
191	GLEN LAKE-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
192	GLEN LAKE-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
193	GLENWOOD-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
194	GLENWOOD-TR02	Distribution	Unattended	69.00	12.50		5.00	1				
195	GOODVIEW-TR01	Distribution	Unattended	69.00	12.50		28.00	1				
196	GOODVIEW-TR02	Distribution	Unattended	69.00	12.50		28.00	1				
197	GOOSE LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
198	GOOSE LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
199	GOPHER-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
200	GOPHER-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
201	GRANITE CITY-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
202	GRANITE CITY-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
203	GRANITE CITY-TR03	Distribution	Unattended	115.00	34.50		70.00	1				
204	GRANT-TR01	Transmission	Unattended	115.00	69.00	14.00	25.00	1				
205	GRANT-TR03	Distribution	Unattended	115.00	34.50		46.70	1				
206	GREAT PLAINS-TR01	Distribution	Unattended	115.00	14.30		50.00	1				
207	GREEN ISLE-TR01	Distribution	Unattended	69.00	4.16		2.00	1				
208	GREENFIELD-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
209	HADLEY-TR01	Distribution	Unattended	69.00	13.80		2.80	1				
210	HASSAN-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
211	HASSAN-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
212	HASTINGS-TR01	Distribution	Unattended	69.00	12.50		28.00	1				

213	HASTINGS-TR02	Distribution	Unattended	69.00	12.50		28.00	1				
214	HATFIELD-TR01ABC	Distribution	Unattended	23.00	12.50		2.00	3				
215	HATTON-TR01	Distribution	Unattended	69.00	4.16		2.00	1				
216	HAZEL CREEK-TR09	Transmission	Unattended	345.00	230.00	14.00	336.00	1				
217	HECTOR-TR01	Distribution	Unattended	69.00	4.16		3.00	1				
218	HENDERSON-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
219	HIAWATHA WEST-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
220	HIGH BRIDGE-TR04	Distribution	Unattended	115.00	13.80		46.70	1				
221	HOLLYDALE-TR01	Distribution	Unattended	69.00	13.80		25.00	1				
222	HOLLYDALE-TR02	Distribution	Unattended	34.50	13.80		28.00	1				
223	HOWARD LAKE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
224	HUGO-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
225	HUGO-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
226	HYLAND LAKE-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
227	HYLAND LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
228	INDIANA-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
229	INDIANA-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
230	INVER GROVE-TR01	Transmission	Unattended	115.00	69.00	14.00	63.00	1				
231	INVER GROVE-TR02	Transmission	Unattended	115.00	69.00	14.00	63.00	1				
232	INVER HILLS-PLTSDU	Distribution	Unattended	34.50	13.80		1.00	1				
233	INVER HILLS-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
234	JAMAICA-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
235	JORDAN-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
236	KASSON-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
237	KASSON-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
238	KEGAN LAKE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
239	KENYON-TR01	Distribution	Unattended	69.00	12.50		3.00	1				

240	KIMBALL-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
241	KOCH REFINERY-TR11	Distribution	Unattended	115.00	13.80		46.70	1				
242	KOCH REFINERY-TR12	Distribution	Unattended	115.00	13.80		46.70	1				
243	KOCH REFINERY-TR13	Distribution	Unattended	115.00	13.80		46.70	1				
244	KOCH REFINERY-TR14	Distribution	Unattended	115.00	13.80		46.70	1				
245	KOCH REFINERY-TR15	Distribution	Unattended	115.00	13.80		46.70	1				
246	KOCH REFINERY-TR16	Distribution	Unattended	115.00	13.80		46.70	1				
247	KOHLMAN LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
248	KOHLMAN LAKE-TR02	Distribution	Unattended	115.00	13.80		50.00	1				
249	KOHLMAN LAKE-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
250	KOHLMAN LAKE-TR10	Transmission	Unattended	345.00	115.00	14.00	450.00	1				
251	LA CRESCENT-TR01	Distribution	Unattended	69.00	13.80		16.00	1				
252	LAFAYETTE-TR01	Distribution	Unattended	69.00	4.16		1.00	1				
253	LAKE BAVARIA-TR01	Distribution	Unattended	115.00	34.50		73.50	1				
254	LAKE EMILY-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
255	LAKE LILLIAN-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
256	LAKE PULASKI-TR03	Distribution	Unattended	115.00	34.50		28.00	1				
257	LAKE PULASKI-TR05	Transmission	Unattended	115.00	69.00	35.00	46.70	1				
258	LAKE PULASKI-TR06	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
259	LAKE YANKTON-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
260	LAKE YANKTON-TR02	Transmission	Unattended	115.00	69.00	14.00	15.00	1				
261	LAKE YANKTON-TR03	Distribution	Unattended	69.00	13.80		10.50	1				

262	LARIMORE-TR01	Distribution	Unattended	69.00	4.16		4.00	1				
263	LAWRENCE CREEK-TR01	Distribution	Unattended	115.00	34.50		28.00	1				
264	LAWRENCE CREEK-TR04	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
265	LAWRENCE CREEK-TR05	Transmission	Unattended	161.00	115.00	14.00	336.00	1				
266	LAWRENCE-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
267	LAWRENCE-TR07	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
268	LAWRENCE-TR08	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
269	LENNOX-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
270	LESTER PRAIRIE-TR01	Distribution	Unattended	69.00	13.80		9.00	1				
271	LEXINGTON-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
272	LEXINGTON-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
273	LEXINGTON-TR03	Distribution	Unattended	115.00	34.50		70.00	1				
274	LEXINGTON-TR04	Distribution	Unattended	34.50	13.80		46.70	1				
275	LINCOLN COUNTY-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
276	LINCOLN COUNTY-TR07	Distribution	Unattended	115.00	13.80		50.00	1				
277	LINCOLN COUNTY-TR08	Distribution	Unattended	115.00	13.80		50.00	1				
278	LINDE-TR01	Distribution	Unattended	115.00	13.80		50.00	1				
279	LINDSTROM-TR01	Distribution	Unattended	115.00	12.50		28.70	1				
280	LINDSTROM-TR02	Distribution	Unattended	115.00	12.50		28.70	1				
281	LINN STREET-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
282	LINN STREET-TR02	Distribution	Unattended	69.00	12.50		10.50	1				
283	LONE OAK-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
284	LONE OAK-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
285	LONG LAKE-TR01	Distribution	Unattended	115.00	13.80		12.00	1				
286	LONG LAKE-TR02	Distribution	Unattended	115.00	13.80		28.00	1				

287	LOUISE-TR01	Distribution	Unattended	115.00	13.80		51.50	1				
288	LOWRY-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
289	LYON COUNTY-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
290	LYON COUNTY-TR09	Transmission	Unattended	345.00	115.00	35.00	270.00	1				
291	M E INTERNATIONAL- TR01	Distribution	Unattended	115.00	13.80		46.70	1				
292	M E INTERNATIONAL- TR02	Distribution	Unattended	115.00	13.80		46.70	1				
293	MAIN STREET-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
294	MAIN STREET-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
295	MAPLE LAKE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
296	MAPLE RIVER-TR05	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
297	MAPLE RIVER-TR06	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
298	MAPLETON-TR01	Distribution	Unattended	69.00	13.80		6.00	1				
299	MARION-TR01	Distribution	Unattended	23.00	4.16		4.00	1				
300	MAYHEW LAKE-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
301	MAYNARD TRANSMISSION- TR01	Transmission	Unattended	115.00	69.00		46.70	1				
302	MAYNARD-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
303	MAYVILLE-TR01	Distribution	Unattended	69.00	4.16		6.00	1				
304	MAYVILLE-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
305	MAZEPPA-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
306	MEDFORD JUNCTION-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
307	MEDICINE LAKE- TR01	Distribution	Unattended	115.00	13.80		70.00	1				
308	MEDICINE LAKE- TR02	Distribution	Unattended	115.00	13.80		70.00	1				
309	MEDICINE LAKE- TR03	Distribution	Unattended	115.00	13.80		70.00	1				

310	MEIRE GROVE-TR01	Distribution	Unattended	69.00	12.50		2.00	1				
311	MERIDEN-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
312	MERRIAM PARK-TR01	Distribution	Unattended	115.00	13.80		63.00	1				
313	MERRIAM PARK-TR02	Distribution	Unattended	115.00	13.80		72.00	1				
314	MERRIAM PARK-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
315	MIDTOWN-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
316	MINNEHAHA-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
317	MINNEHAHA-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
318	MINNESOTA LAKE-TR01	Distribution	Unattended	69.00	4.16		2.00	1				
319	MINNESOTA PIPELINE-TR01	Distribution	Unattended	115.00	4.16		8.00	1				
320	MINNESOTA VALLEY-TR02	Distribution	Unattended	69.00	23.00		14.00	1				
321	MINNESOTA VALLEY-TR05	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
322	MINNESOTA VALLEY-TR06	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
323	MINNESOTA VALLEY-TR11	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
324	MINNESOTA VALLEY-TR12	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
325	MONTEVIDEO-TR01	Distribution	Unattended	69.00	4.16		6.00	1				
326	MONTEVIDEO-TR02	Distribution	Unattended	69.00	12.50		5.00	1				
327	MONTICELLO-TR06	Transmission	Unattended	345.00	230.00	14.00	336.00	1				
328	MONTICELLO-TR10	Transmission	Unattended	345.00	115.00	14.00	345.00	1				
329	MONTROSE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
330	MOORE LAKE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
331	MOORE LAKE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
332	MOORE LAKE-TR03	Distribution	Unattended	115.00	13.80		46.70	1				

333	MORGAN-TR01	Distribution	Unattended	69.00	23.00		14.00	1				
334	MORRISTOWN-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
335	MOUND-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
336	MOUND-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
337	NERSTRAND-TR01XY	Distribution	Unattended	69.00	12.50		3.00	2				
338	NINE MILE CREEK-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
339	NINE MILE CREEK-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
340	NOBLES COUNTY-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
341	NOBLES COUNTY-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
342	NOBLES COUNTY-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
343	NOBLES COUNTY-TR10	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
344	NORDIC-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
345	NORDIC-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
346	NORTH BROADWAY-TR01	Distribution	Unattended	23.00	4.16		5.00	1				
347	NORTH BROADWAY-TR02	Distribution	Unattended	23.00	4.16		5.00	1				
348	NORTH ROCHESTER-TR09	Transmission	Unattended	345.00	161.00	35.00	672.00	1				
349	NORTHFIELD-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
350	NORTHFIELD-TR02	Distribution	Unattended	69.00	13.80		17.00	1				
351	OAK PARK-TR01	Distribution	Unattended	115.00	23.00	14.00	28.00	1				
352	OAK PARK-TR07	Distribution	Unattended	115.00	13.80		46.70	1				
353	OAK PARK-TR08	Distribution	Unattended	115.00	13.80		46.70	1				
354	OAKDALE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
355	OAKDALE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				

356	ORONO-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
357	OSSEO-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
358	OSSEO-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
359	PARKERS LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
360	PARKERS LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
361	PARKERS LAKE-TR03	Distribution	Unattended	115.00	13.80		50.00	1				
362	PARKERS LAKE-TR09ABC	Transmission	Unattended	345.00	115.00	14.00	450.00	3				
363	PARKERS LAKE-TR10ABC	Transmission	Unattended	345.00	115.00	14.00	450.00	3				
364	PAYNESVILLE XMSN-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
365	PAYNESVILLE XMSN-TR02	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
366	PAYNESVILLE XMSN-TR04	Distribution	Unattended	115.00	34.50		28.00	1				
367	PAYNESVILLE XMSN-TR09	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
368	PINE BEND-TR03	Distribution	Unattended	69.00	13.80		14.00	1				
369	PINE ISLAND-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
370	PINE ISLAND-TR02	Distribution	Unattended	69.00	12.50		7.00	1				
371	PIPESTONE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
372	PIPESTONE-TR02	Distribution	Unattended	69.00	4.16		9.00	1				
373	PIPESTONE-TR03	Distribution	Unattended	69.00	25.00		6.00	1				
374	PIPESTONE-TR05	Transmission	Unattended	115.00	69.00	3.00	25.00	1				
375	PIPESTONE-TR06	Transmission	Unattended	115.00	69.00	14.00	25.00	1				
376	PLATO-TR01	Distribution	Unattended	115.00	12.50		15.00	1				
377	PRAIRIE ISLAND-TR10	Transmission	Unattended	345.00	161.00	14.00	224.00	1				
378	PRAIRIE-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				

379	PRAIRIE-TR03	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
380	PRAIRIE-TR05	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
381	PRAIRIE-TR07	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
382	PRAIRIE-TR08	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
383	PRIOR-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
384	QUARRY-TR09	Transmission	Unattended	345.00	115.00	35.00	448.00	1				
385	RAMSEY-TR01	Distribution	Unattended	115.00	13.80		50.00	1				
386	RAMSEY-TR02	Distribution	Unattended	115.00	13.80		50.00	1				
387	RAPIDAN-TR01	Distribution	Unattended	69.00	13.80		3.00	1				
388	RED RIVER-TR01	Distribution	Unattended	115.00	23.00	14.00	91.00	1				
389	RED RIVER-TR02	Distribution	Unattended	115.00	23.00	14.00	91.00	1				
390	RED RIVER-TR03	Distribution	Unattended	115.00	23.00	5.00	91.00	1				
391	RED ROCK-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
392	RED ROCK-TR02	Distribution	Unattended	115.00	13.80		20.00	1				
393	RED ROCK-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
394	RED ROCK-TR05	Transmission	Unattended	345.00	230.00	14.00	336.00	1				
395	RED ROCK-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
396	RED ROCK-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
397	RED WING-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
398	RED WING-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
399	RENVILLE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
400	REYNOLDS-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
401	RICH SPRING-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
402	RICH VALLEY-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
403	RICHMOND-TR01	Distribution	Unattended	69.00	13.80		5.00	1				
404	RIVERSIDE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
405	RIVERSIDE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
406	RIVERWOOD-TR01	Distribution	Unattended	115.00	13.80		25.00	1				

407	RIVERWOOD-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
408	ROCK RIVER-TR01	Distribution	Unattended	69.00	23.00		8.00	1				
409	ROGERS LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
410	ROGERS LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
411	ROSE PLACE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
412	ROSE PLACE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
413	ROSEMOUNT-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
414	SACRED HEART-TR01	Distribution	Unattended	69.00	13.80	4.00	5.00	1				
415	SALEM-TR01ABC	Distribution	Unattended	69.00	34.50	3.00	4.00	3				
416	SALEM-TR02	Distribution	Unattended	69.00	13.80		7.00	1				
417	SALIDA CROSSING-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
418	SALIDA CROSSING-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
419	SARTELL-TR01	Distribution	Unattended	34.50	12.50	2.00	7.00	1				
420	SAUK RIVER-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
421	SAUK RIVER-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
422	SAVAGE-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
423	SAVAGE-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
424	SCANDIA-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
425	SCOTT COUNTY-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
426	SCOTT COUNTY-TR02	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
427	SCOTT COUNTY-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
428	SCOTT COUNTY-TR10	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
429	SEDAN-TR01 AB	Distribution	Unattended	69.00	7.20		0.30	1				
430	SHEAS LAKE-TR05	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
431	SHEAS LAKE-TR09	Transmission	Unattended	345.00	115.00	35.00	336.00	1				

432	SHEPARD-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
433	SHEPARD-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
434	SHERBURNE COUNTY-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
435	SHEYENNE-TR05	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
436	SHEYENNE-TR06	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
437	SIBLEY PARK-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
438	SIBLEY PARK-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
439	SLAYTON WEST-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
440	SOURIS-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
441	SOURIS-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
442	SOURIS-TR03	Distribution	Unattended	115.00	13.80		52.50	1				
443	SOUTH BEND-TR05	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
444	SOUTH BEND-TR06	Transmission	Unattended	161.00	115.00	14.00	187.00	1				
445	SOUTH HAVEN-TR01	Distribution	Unattended	69.00	34.50		1.00	1				
446	SOUTH RENNER-TR01	Distribution	Unattended	115.00	34.50		73.50	1				
447	SOUTH RIDGE-TR01	Distribution	Unattended	69.00	23.00		5.00	1				
448	SOUTH SIOUX FALLS-TR01	Distribution	Unattended	69.00	4.16		6.70	1				
449	SOUTH SIOUX FALLS-TR02	Distribution	Unattended	69.00	4.16		6.00	1				
450	SOUTH SIOUX FALLS-TR03	Distribution	Unattended	69.00	13.80		28.00	1				
451	SOUTH SIOUX FALLS-TR04	Distribution	Unattended	69.00	13.80		28.00	1				
452	SOUTHTOWN-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
453	SOUTHTOWN-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
454	SOUTHTOWN-TR03	Distribution	Unattended	115.00	13.80		62.50	1				
455	SOUTH-TR01ABC	Distribution	Unattended	69.00	2.40		1.00	3				
456	SPLIT ROCK-TR06	Transmission	Unattended	161.00	115.00	35.00	187.00	1				

457	SPLIT ROCK-TR07	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
458	SPLIT ROCK-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
459	SPLIT ROCK-TR11	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
460	ST CLOUD-TR01	Distribution	Unattended	115.00	34.50		42.00	1				
461	ST CLOUD-TR02	Distribution	Unattended	115.00	34.50		42.00	1				
462	ST JAMES MUNICIPAL-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
463	ST JOHNS-TR01	Distribution	Unattended	69.00	4.16		4.00	1				
464	ST JOSEPH-TR01	Distribution	Unattended	69.00	4.16		7.00	1				
465	ST LOUIS PARK- TR02	Distribution	Unattended	115.00	34.50		70.00	1				
466	ST LOUIS PARK- TR04	Distribution	Unattended	115.00	13.80		70.00	1				
467	ST LOUIS PARK- TR05	Distribution	Unattended	115.00	13.80		70.00	1				
468	ST LOUIS PARK- TR06	Distribution	Unattended	115.00	13.80		70.00	1				
469	ST. PAUL WATER- TR01	Distribution	Unattended	13.80	4.16		5.00	1				
470	STEWART-TR01	Distribution	Unattended	69.00	12.50		6.00	1				
471	STOCKYARDS-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
472	STOCKYARDS-TR02	Distribution	Unattended	118.00	13.80		46.70	1				
473	SUMMIT AVENUE- TR01	Distribution	Unattended	115.00	13.80		46.70	1				
474	SUMMIT AVENUE- TR02	Distribution	Unattended	115.00	13.80		46.70	1				
475	SWAN LAKE-TR01	Distribution	Unattended	115.00	12.50		10.50	1				
476	TANNERS LAKE- TR01	Distribution	Unattended	115.00	13.80		70.00	1				
477	TANNERS LAKE- TR02	Distribution	Unattended	115.00	13.80		70.00	1				
478	TANNERS LAKE- TR23A1B1C1	Distribution	Unattended	13.80	12.50		10.00	3				

479	TANNERS LAKE-TR23A2B2C2	Distribution	Unattended	13.80	12.50		10.00	3				
480	TANNERS LAKE-TR32A1B1C1	Distribution	Unattended	13.80	12.50		10.00	3				
481	TANNERS LAKE-TR32A2B2C2	Distribution	Unattended	13.80	12.50		10.00	3				
482	TANNERS LAKE-TR34A1B1C1	Distribution	Unattended	13.80	12.50		10.00	3				
483	TANNERS LAKE-TR34A2B2C2	Distribution	Unattended	13.80	12.50		10.00	3				
484	TERMINAL-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
485	TERMINAL-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
486	TERMINAL-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
487	TERMINAL-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
488	TERMINAL-TR10	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
489	THOMPSON-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
490	TRACY SWITCHING-TR01	Distribution	Unattended	69.00	13.80		5.00	1				
491	TRACY-TR01	Distribution	Unattended	69.00	4.16	2.00	5.00	1				
492	TWIN LAKES-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
493	TWIN LAKES-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
494	TWIN LAKES-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
495	UPPER LEVEE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
496	UPPER LEVEE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
497	UPPER LEVEE-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
498	VERMILLION RIVER-TR03	Distribution	Unattended	115.00	13.80		28.00	1				
499	VESELI-TR01	Distribution	Unattended	69.00	12.50		8.00	1				
500	VIKING-TR01	Distribution	Unattended	115.00	13.80		72.50	1				
501	VILLARD-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
502	WABASHA-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
503	WABASHA-TR02	Distribution	Unattended	69.00	2.40		20.00	1				

504	WACONIA-TR01	Distribution	Unattended	69.00	13.80		22.00	1				
505	WAKEFIELD-TR02	Distribution	Unattended	115.00	34.50	14.00	10.00	1				
506	WAKEFIELD-TR02ABC	Distribution	Unattended	34.50	13.80		2.00	3				
507	WAKEFIELD-TR06	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
508	WASECA-TR02	Distribution	Unattended	69.00	23.00		14.00	1				
509	WASECA-TR03	Distribution	Unattended	69.00	23.00		28.00	1				
510	WASECA-TR04	Distribution	Unattended	69.00	23.00		28.00	1				
511	WATAB RIVER-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
512	WATERTOWN-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
513	WATERVILLE-TR01	Distribution	Unattended	69.00	23.00		14.00	1				
514	WATERVILLE-TR02	Distribution	Unattended	69.00	4.16		1.50	1				
515	WATERVILLE-TR03	Distribution	Unattended	69.00	12.50		3.50	1				
516	WATKINS-TR01	Distribution	Unattended	69.00	4.16		3.50	1				
517	WAVERLY-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
518	WELLS CREEK-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
519	WESCOTT PROPANE PLANT-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
520	WEST BYRON-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
521	WEST COON RAPIDS-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
522	WEST COON RAPIDS-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
523	WEST COON RAPIDS-TR03	Distribution	Unattended	34.50	13.80		28.00	1				
524	WEST FARIBAULT-TR01	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
525	WEST FARIBAULT-TR02	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
526	WEST FARIBAULT-TR03	Distribution	Unattended	69.00	13.80		22.00	1				
527	WEST FARIBAULT-TR07	Distribution	Unattended	69.00	13.80		7.00	1				

528	WEST HASTINGS-TR01	Distribution	Unattended	115.00	12.50		28.00	1				
529	WEST HASTINGS-TR05	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
530	WEST NEW ULM-TR05	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
531	WEST RIVER ROAD-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
532	WEST RIVER ROAD-TR02	Distribution	Unattended	115.00	13.80		72.50	1				
533	WEST RIVER ROAD-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
534	WEST SIOUX FALLS-TR05	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
535	WEST SIOUX FALLS-TR07	Distribution	Unattended	115.00	13.80		70.00	1				
536	WEST SIOUX FALLS-TR08	Distribution	Unattended	115.00	13.80		70.00	1				
537	WEST WACONIA-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
538	WEST WACONIA-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
539	WESTERN-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
540	WESTERN-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
541	WESTGATE-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
542	WESTGATE-TR02	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
543	WESTGATE-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
544	WESTGATE-TR04	Distribution	Unattended	115.00	13.80		70.00	1				
545	WESTGATE-TR05	Distribution	Unattended	115.00	34.50		70.00	1				
546	WESTGATE-TR06	Distribution	Unattended	115.00	34.50		70.00	1				
547	WESTPORT-TR01X AB,Y CB	Distribution	Unattended	69.00	7.20		0.40	2				
548	WILMARTH-TR06	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
549	WILMARTH-TR07	Transmission	Unattended	115.00	69.00	14.00	70.00	1				

550	WILMARTH-TR08	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
551	WILMARTH-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
552	WILMARTH-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
553	WINONA-TR01	Distribution	Unattended	69.00	13.80		22.00	1				
554	WINONA-TR02	Distribution	Unattended	69.00	13.80		22.00	1				
555	WINONA-TR03	Distribution	Unattended	69.00	13.80		25.00	1				
556	WINSTED-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
557	WINTHROP-TR01	Distribution	Unattended	69.00	4.16		6.25	1				
558	WOBEGON TRAIL-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
559	WOODBURY-TR01	Distribution	Unattended	115.00	34.50		47.00	1				
560	WOODBURY-TR02	Distribution	Unattended	115.00	34.50		46.70	1				
561	WYOMING-TR01	Distribution	Unattended	115.00	12.50		28.00	1				
562	WYOMING-TR02	Distribution	Unattended	115.00	12.50		28.00	1				
563	YANKEE-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
564	YANKEE-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
565	YELLOW MEDICINE-TR01	Distribution	Unattended	69.00	23.00		14.00	1				
566	YOUNG AMERICA-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
567	YOUNG AMERICA-TR02	Distribution	Unattended	69.00	13.80		10.50	1				
568	ZUMBRO FALLS-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
569	ZUMBROTA-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
570	569						44698	617				
571	Count TTL Transformer Banks							569				
572	Count TTL Transformers In Service							617				
573	TTL MVA In Service							44698				

574	Count TTL Substations with Transformers							306			
575	Count TTL Substations without Transformer							48			
576	Count TTL Substations							354			
577	Count TTL Spares							44			
578	Spare Transformers										
579	Alexandria-B67606			36	2		0		1		
580	Canistota Junc-2741803			23	13		5		1		
581	Chanarambie-T040N00142701			118	34		120		1		
582	Clarks Grove-8975520			69	8		2		1		
583	Emery sub-B67608			36	2		0		1		
584	Falls Sub-P660522			69	14		28		1		
585	Hazel Creek sub-10008553_C001			345	230	14	336		1		
586	Hugo Trg Ctr-242601941			118	14		14		1		
587	Inver Hills sub-10075845-001			345	115	35	672		1		
588	MGRV-TP80279701			345	165	14	336		1		
589	MGRV-8779073			345	118	35	448		1		
590	MGRV-WT02255			345	118	35	672		1		
591	MGRV-WT-03820			230	118	14	336		1		
592	MGRV-TP80240801			161	118	14	187		1		
593	MGRV-WT02258			118	71	14	112		1		
594	MGRV-13623/2			118			102		1		
595	MGRV-N2261			118	71	14	50		1		
596	MGRV-E5074			118	71	14	70		1		
597	MGRV-E4976			118	36		70		1		
598	MGRV-E4990			118	25		90		1		

599	MGRV-WTO4771			118	14		70		1		
600	MGRV-WTO4921			118	14		70		1		
601	MGRV-50939-1			118	14		47		1		
602	MGRV-N2219			118	34		70		1		
603	MGRV-91F0693			71	36		17		1		
604	MGRV-J9E1054			69	35		5		1		
605	MGRV-282210982			70	24		14		1		
606	MGRV-GT-3547			71	14		14		1		
607	MGRV-C184245			69	14		10		1		
608	MGRV-H881493			69	14		8		1		
609	MGRV-C0301051			69	14		7		1		
610	MGRV-1174820415			71	14		7		1		
611	MGRV-249834			69	14		4		1		
612	MGRV-249866			69	14		4		1		
613	MGRV-G852083B			69	12		4		1		
614	MGRV-9F1025			69	14		25		1		
615	MGRV-236578			69	13		4		1		
616	MGRV-6993529			69	4		10		1		
617	MGRV-47011MA014-D221A			69	14		14		1		
618	MGRV-4089204			14	4		5		1		
619	MGRV-N2264			69	13		7		1		
620	Portal Pipeline (Minot)-4088687			14	2		5		1		
621	Prairie Island-C0665551			345	20		866		1		
622	Red River-D590633			115	24		47		1		
623	Total								44		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Interchange agreement	NSP-Wisconsin	see note	^(a) 204,649,391
3	Repayments from Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	243,000,000
4	Services provided by Xcel Energy Services Inc.	Xcel Energy Services Inc.	see note	^(b) 718,736,224
5	Contribution of Capital	Xcel Energy Inc.	211	351,337,196
6	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	302,000,000
7	Wind farm materials, financing charges, storage fees	Capital Services LLC	107	7,709,732
8	Company labor, benefits, and related payments	NSP-Wisconsin	see note	^(c) 356,300
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Interchange agreement	NSP-Wisconsin	see note	^(d) 493,321,316
22	Gas dispatch and SCADA system agreement	NSP-Wisconsin	G495	542,290
23	Vehicle and equipment use	NSP-Wisconsin	see note	^(e) 7,115,380
24	Company labor, benefits, and related payments	NSP-Wisconsin	see note	^(f) 18,073,956
25	Repayments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	302,000,000
26	Investments in Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	300,000,000
27	Dividends on Common Stock	Xcel Energy Inc.	216	647,252,975
28	Inventory Transfer	NSP-Wisconsin	154	391,773
42				

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/04/2024	Year/Period of Report End of: 2023/ Q4
FOOTNOTE DATA			

(a) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

557	\$	62,582,431
565		142,066,960
	\$	204,649,391

(b) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Service Function Group	Updated FERC Group	Total
Accounting, Financial Reporting & Taxes	107-CWIP	\$3,923,588
	130-176-Current and Accrued Assets	556
	408-409-Taxes	457,440
	416-Costs and Expenses of Jobbing and Contracting	814
	417-421-Other Income	(2,609,151)
	426.1-426.5-Other Income Deductions	(62,351)
	427-432-Interest Charges	57,669
	500-514-Steam Power Generation	16,676
	517-532-Nuclear Power Generation	74,999
	546-557-Other Power Generation	563,720
	560-573-Transmission Expenses	664,481
	580-598-Distribution Expenses	344,439
	800-813-Other Gas Supply Expenses	22,254
	850-870-Transmission Expenses	144,516
	871-893-Distribution Expenses	5,717
	901-905-Customer Accounts Expenses	1,417,076
	911-916-Sales Expense	919,122
	920-935-Administrative and General Expense	38,921,342
Accounting, Financial Reporting & Taxes Total		44,862,907
Aviation Services	426.1-426.5-Other Income Deductions	290
	920-935-Administrative and General Expense	2,014,939
Aviation Services Total		2,015,229

Business Systems	107-CWIP	171,533,479
	130-176-Current and Accrued Assets	1,230
	181-190-Deferred Debits	213,349
	252-283-Deferred Credits	226
	408-409-Taxes	407
	416-Costs and Expenses of Jobbing and Contracting	59
	417-421-Other Income	358
	426.1-426.5-Other Income Deductions	36,946
	500-514-Steam Power Generation	104,222
	517-532-Nuclear Power Generation	1,711,349
	535-545-Hydraulic Power Generation	621
	546-557-Other Power Generation	557,295
	560-573-Transmission Expenses	5,878,631
	575.1-575.8-Regional Market Expenses	2
	580-598-Distribution Expenses	2,991,030
	725-742-Gas Raw Materials	73
	750-769-Natural Gas Production	-
	800-813-Other Gas Supply Expenses	104,233
	814-837-Underground Storage Expenses	-
	840-843-Other Storage Expense	(530)
	844-847-Liquefied Natural Gas Terminating Expenses	94
	850-870-Transmission Expenses	24,268
	871-893-Distribution Expenses	511,052
	901-905-Customer Accounts Expenses	10,373,611
	908-910-Customer Service and Informational Expenses	169
	911-916-Sales Expense	72,500
	920-935-Administrative and General Expense	142,617,214
Business Systems Total		336,731,888
Claims Services	426.1-426.5-Other Income Deductions	-
	920-935-Administrative and General Expense	591,681
Claims Services Total		591,681
Corporate Communications	181-190-Deferred Debits	3,387,325
	426.1-426.5-Other Income Deductions	340,998
	908-910-Customer Service and Informational Expenses	427,889
	920-935-Administrative and General Expense	3,880,776
Corporate Communications Total		8,036,988
Corporate Strategy & Business Development	181-190-Deferred Debits	87,145
	417-421-Other Income	4,783
	426.1-426.5-Other Income Deductions	98,259
	908-910-Customer Service and Informational Expenses	7,113
	920-935-Administrative and General Expense	2,188,655
Corporate Strategy & Business Development Total		2,385,955
Customer Service	107-CWIP	447,370
	181-190-Deferred Debits	723,409

	252-283-Deferred Credits	197,805
	417-421-Other Income	42,013
	426.1-426.5-Other Income Deductions	2,544
	580-598-Distribution Expenses	56
	901-905-Customer Accounts Expenses	15,031,610
	908-910-Customer Service and Informational Expenses	263,320
	911-916-Sales Expense	55,981
	920-935-Administrative and General Expense	5,276
Customer Service Total		16,769,384
Employee Communications	426.1-426.5-Other Income Deductions	199
	517-532-Nuclear Power Generation	12,365
	920-935-Administrative and General Expense	527,958
Employee Communications Total		540,522
Energy Delivery - Engineering/Design	107-CWIP	33,839,830
	130-176-Current and Accrued Assets	28,845
	181-190-Deferred Debits	(18,010)
	408-409-Taxes	1,827
	426.1-426.5-Other Income Deductions	60,737
	500-514-Steam Power Generation	167,850
	535-545-Hydraulic Power Generation	1,008
	546-557-Other Power Generation	786,584
	560-573-Transmission Expenses	7,404,523
	580-598-Distribution Expenses	2,312,047
	725-742-Gas Raw Materials	207
	814-837-Underground Storage Expenses	259
	840-843-Other Storage Expense	42,196
	844-847-Liquified Natural Gas Terminaling Expenses	1,032
	850-870-Transmission Expenses	1,857,555
	871-893-Distribution Expenses	591,891
	920-935-Administrative and General Expense	2,854,812
Energy Delivery - Engineering/Design Total		49,933,193
Energy Delivery Construction, Operations & Maintenance (COM)	107-CWIP	52,483
	408-409-Taxes	(484)
	417-421-Other Income	-
	426.1-426.5-Other Income Deductions	24,633
	560-573-Transmission Expenses	50,407
	580-598-Distribution Expenses	2,521,917
	814-837-Underground Storage Expenses	98,287
	840-843-Other Storage Expense	1,284,805
	844-847-Liquified Natural Gas Terminaling Expenses	21,414
	850-870-Transmission Expenses	463,519
	871-893-Distribution Expenses	326,999
	908-910-Customer Service and Informational Expenses	15
	920-935-Administrative and General Expense	563,191

Energy Delivery Construction, Operations & Maintenance (COM) Total		5,407,186
Energy Markets - Fuel Procurement	426.1-426.5-Other Income Deductions	96
	500-514-Steam Power Generation	927,586
	920-935-Administrative and General Expense	121,665
Energy Markets - Fuel Procurement Total		1,049,347
Energy Markets Regulated Trading & Marketing	426.1-426.5-Other Income Deductions	4,101
	546-557-Other Power Generation	3,065,642
	560-573-Transmission Expenses	428,089
	575.1-575.8-Regional Market Expenses	418,171
	800-813-Other Gas Supply Expenses	178,459
	920-935-Administrative and General Expense	1,006,085
Energy Markets Regulated Trading & Marketing Total		5,100,547
Energy Supply Business Resources	107-CWIP	1,142,666
	181-190-Deferred Debits	3,199
	426.1-426.5-Other Income Deductions	4,087
	500-514-Steam Power Generation	3,948,731
	517-532-Nuclear Power Generation	844,122
	535-545-Hydraulic Power Generation	77,703
	546-557-Other Power Generation	5,013,851
	920-935-Administrative and General Expense	100,560
Energy Supply Business Resources Total		11,134,919
Energy Supply Engineering & Environmental	107-CWIP	8,883,043
	181-190-Deferred Debits	73,161
	408-409-Taxes	171
	426.1-426.5-Other Income Deductions	9,576
	500-514-Steam Power Generation	4,346,856
	517-532-Nuclear Power Generation	109,976
	535-545-Hydraulic Power Generation	20,110
	546-557-Other Power Generation	453,218
	560-573-Transmission Expenses	24,902
	580-598-Distribution Expenses	1,844
	850-870-Transmission Expenses	603
	871-893-Distribution Expenses	255,453
	920-935-Administrative and General Expense	2,018,061
Energy Supply Engineering & Environmental Total		16,196,974
Executive Management Services	426.1-426.5-Other Income Deductions	204,378
	580-598-Distribution Expenses	563
	850-870-Transmission Expenses	93,416
	871-893-Distribution Expenses	459
	920-935-Administrative and General Expense	5,922,570
Executive Management Services Total		6,221,386
Facilities & Real Estate	107-CWIP	2,591,695
	130-176-Current and Accrued Assets	4,183
	181-190-Deferred Debits	18,412

	252-283-Deferred Credits	482
	416-Costs and Expenses of Jobbing and Contracting	365
	417-421-Other Income	259,680
	426.1-426.5-Other Income Deductions	29,396
	500-514-Steam Power Generation	1,877,775
	517-532-Nuclear Power Generation	7,299,670
	535-545-Hydraulic Power Generation	29,631
	546-557-Other Power Generation	1,375,915
	560-573-Transmission Expenses	1,567,669
	575.1-575.8-Regional Market Expenses	23,016
	580-598-Distribution Expenses	3,395,913
	725-742-Gas Raw Materials	207
	750-769-Natural Gas Production	-
	800-813-Other Gas Supply Expenses	7,503
	814-837-Underground Storage Expenses	6,119
	840-843-Other Storage Expense	85,066
	844-847-Liquified Natural Gas Terminaling Expenses	116,517
	850-870-Transmission Expenses	84,742
	871-893-Distribution Expenses	1,710,111
	901-905-Customer Accounts Expenses	351,055
	908-910-Customer Service and Informational Expenses	38,300
	911-916-Sales Expense	42,264
	920-935-Administrative and General Expense	16,233,586
Facilities & Real Estate Total		37,149,272
Facilities Administrative Services	107-CWIP	109,055
Facilities Administrative Services Total		109,055
Finance & Treasury	107-CWIP	22,786,306
	130-176-Current and Accrued Assets	10,750
	181-190-Deferred Debits	4,569,239
	252-283-Deferred Credits	129,935
	408-409-Taxes	10,297,779
	416-Costs and Expenses of Jobbing and Contracting	604
	417-421-Other Income	(195,369)
	426.1-426.5-Other Income Deductions	104,979
	427-432-Interest Charges	4,908,964
	500-514-Steam Power Generation	741,268
	517-532-Nuclear Power Generation	551,387
	535-545-Hydraulic Power Generation	10,271
	546-557-Other Power Generation	1,246,268
	560-573-Transmission Expenses	744,958
	575.1-575.8-Regional Market Expenses	35,434
	580-598-Distribution Expenses	474,443
	725-742-Gas Raw Materials	203
	750-769-Natural Gas Production	-

	800-813-Other Gas Supply Expenses	12,648
	814-837-Underground Storage Expenses	7,183
	840-843-Other Storage Expense	84,378
	844-847-Liquified Natural Gas Terminating Expenses	4,122
	850-870-Transmission Expenses	165,847
	871-893-Distribution Expenses	133,428
	901-905-Customer Accounts Expenses	1,310,333
	908-910-Customer Service and Informational Expenses	71,423
	911-916-Sales Expense	183,781
	920-935-Administrative and General Expense	46,651,263
Finance & Treasury Total		95,041,825
Fleet	107-CWIP	715,088
	130-176-Current and Accrued Assets	37
	181-190-Deferred Debits	8
	252-283-Deferred Credits	5
	416-Costs and Expenses of Jobbing and Contracting	-
	417-421-Other Income	194
	426.1-426.5-Other Income Deductions	1
	500-514-Steam Power Generation	11,214
	517-532-Nuclear Power Generation	3,662
	535-545-Hydraulic Power Generation	4
	546-557-Other Power Generation	2,586
	560-573-Transmission Expenses	9,304
	575.1-575.8-Regional Market Expenses	2
	580-598-Distribution Expenses	66,972
	725-742-Gas Raw Materials	-
	800-813-Other Gas Supply Expenses	1
	814-837-Underground Storage Expenses	1
	840-843-Other Storage Expense	7
	844-847-Liquified Natural Gas Terminating Expenses	856
	850-870-Transmission Expenses	19,135
	871-893-Distribution Expenses	12,329
	901-905-Customer Accounts Expenses	2,666
	908-910-Customer Service and Informational Expenses	12
	911-916-Sales Expense	6
	920-935-Administrative and General Expense	2,284
Fleet Total		846,374
Government Affairs	426.1-426.5-Other Income Deductions	552,273
	920-935-Administrative and General Expense	1,160,895
Government Affairs Total		1,713,168
Human Resources	107-CWIP	454,360
	130-176-Current and Accrued Assets	694
	181-190-Deferred Debits	10,064
	227-230-Other Noncurrent Liabilities	1,333,157

	231-245-Current and Accrued Liabilities	22,470,662
	252-283-Deferred Credits	132
	408-409-Taxes	(61)
	416-Costs and Expenses of Jobbing and Contracting	120
	417-421-Other Income	1,402
	426.1-426.5-Other Income Deductions	33,879
	500-514-Steam Power Generation	8,365
	517-532-Nuclear Power Generation	417,530
	535-545-Hydraulic Power Generation	62
	546-557-Other Power Generation	854,936
	560-573-Transmission Expenses	243,801
	575.1-575.8-Regional Market Expenses	1
	580-598-Distribution Expenses	240,382
	725-742-Gas Raw Materials	17
	750-769-Natural Gas Production	-
	800-813-Other Gas Supply Expenses	245
	814-837-Underground Storage Expenses	-
	840-843-Other Storage Expense	469
	844-847-Liquified Natural Gas Terminating Expenses	366
	850-870-Transmission Expenses	3,932
	871-893-Distribution Expenses	1,005
	901-905-Customer Accounts Expenses	7,290
	908-910-Customer Service and Informational Expenses	183,048
	911-916-Sales Expense	1,191
	920-935-Administrative and General Expense	11,299,035
Human Resources Total		37,566,084
Internal Audit	426.1-426.5-Other Income Deductions	335
	920-935-Administrative and General Expense	958,299
Internal Audit Total		958,634
Investor Relations	426.1-426.5-Other Income Deductions	106
	920-935-Administrative and General Expense	809,949
Investor Relations Total		810,055
Legal	107-CWIP	7,688
	181-190-Deferred Debits	18,576
	408-409-Taxes	-
	417-421-Other Income	47
	426.1-426.5-Other Income Deductions	35,052
	517-532-Nuclear Power Generation	201,457
	560-573-Transmission Expenses	34,935
	725-742-Gas Raw Materials	2,247
	920-935-Administrative and General Expense	4,970,192
Legal Total		5,270,194
Marketing & Sales	107-CWIP	11,033
	181-190-Deferred Debits	8,957,992

	252-283-Deferred Credits	345,573
	417-421-Other Income	2,798,687
	426.1-426.5-Other Income Deductions	15,147
	908-910-Customer Service and Informational Expenses	712,267
	911-916-Sales Expense	3,895,792
	920-935-Administrative and General Expense	4,757,270
Marketing & Sales Total		21,493,761
Payment & Reporting	920-935-Administrative and General Expense	472,093
Payment & Reporting Total		472,093
Payroll	920-935-Administrative and General Expense	782,198
Payroll Total		782,198
Rates & Regulation	181-190-Deferred Debits	3,721
	426.1-426.5-Other Income Deductions	71
	920-935-Administrative and General Expense	1,540,183
Rates & Regulation Total		1,543,975
Receipts Processing	426.1-426.5-Other Income Deductions	1,527
	901-905-Customer Accounts Expenses	355,590
	920-935-Administrative and General Expense	362,661
Receipts Processing Total		719,778
Supply Chain	107-CWIP	5,922,175
	130-176-Current and Accrued Assets	18,170
	181-190-Deferred Debits	136,005
	252-283-Deferred Credits	3,063
	408-409-Taxes	-
	416-Costs and Expenses of Jobbing and Contracting	2,404
	417-421-Other Income	4,989
	426.1-426.5-Other Income Deductions	19,183
	500-514-Steam Power Generation	87,319
	517-532-Nuclear Power Generation	379,415
	535-545-Hydraulic Power Generation	1,026
	546-557-Other Power Generation	246,415
	560-573-Transmission Expenses	75,701
	575.1-575.8-Regional Market Expenses	20
	580-598-Distribution Expenses	266,634
	725-742-Gas Raw Materials	338
	750-769-Natural Gas Production	0
	800-813-Other Gas Supply Expenses	3,420
	814-837-Underground Storage Expenses	5
	840-843-Other Storage Expense	5,787
	844-847-Liquefied Natural Gas Terminaling Expenses	8,193
	850-870-Transmission Expenses	33,757
	871-893-Distribution Expenses	37,148
	901-905-Customer Accounts Expenses	122,287
	908-910-Customer Service and Informational Expenses	2,622
	911-916-Sales Expense	21,526
	920-935-Administrative and General Expense	(115,950)
Supply Chain Total		7,281,652
Grand Total		718,736,224

(c) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

107		\$	131,805
108			10,581
184			13,666
531			1,483
538			438
539			1,077
542			478
543			52,115
544			106,603
552			646
553			313
562			470
584			53
586			2,876
587			266
588			112
593			21,286
594			8
846.2			8,552
856			92
857			92
874			2,427
877			46
879			714
892			56
893			45
		\$	<u>356,300</u>
(d) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies			
456		\$	434,100,943
456.1			59,220,373
		\$	<u>493,321,316</u>
(e) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies			

107	\$ 6,442,829
108	485,112
184	1,723
502	324
511	384
537	196
539	6,054
562	140
563	2,533
570	373
571	687
583	36,538
584	209
588	1,887
592	678
593	129,191
594	2,377
596	2,787
846.2	196
847.3	43
865	27
874	403
887	70
889	194
892	33
921	392
	<u>\$ 7,115,380</u>

(f) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

107	\$ 16,140,647
108	1,116,318
163	168,407
184	22,161
417.1	125
501	124,012
502	144,218
505	10,571
506	636
511	29,717
512	75,776
513	39

537	197
539	4,988
542	568
543	3,203
549	2,176
553	339
561.2	839
562	1,755
563	2,912
566	1,081
571	6,187
582	12,805
583	7,873
584	2,984
585	112
586	3,262
587	468
588	10,156
592	11,679
593	33,299
594	1,981
844.3	103,426
846.2	2,888
856	1,204
865	980
874	1,337
878	1,775
879	1,337
887	10,979
889	5,762
892	1,724
893	152
903	142
920	759
	\$ 18,073,956