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: 2024/ Q4

3 PU-25-176 Filed 05/01/2025 Pages: 336
2024 FERC Financial Report

Northern States Power Company
Alex Nisbet, Reg. Policy Specialist

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

a. 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.

b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

c. 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

d. 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:

a. 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

b. 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.)

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

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

VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

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

IX. 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.

X. 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

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

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:

a. FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b. 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)).

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

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

EXCERPTS FROM THE LAW

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

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

3. ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;
5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......
11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or 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

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

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may 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.

"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 field..."

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: 2024/ 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 Melissa L. Ostrom		06 Title of Contact Person Senior Vice President, Controller
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) 330-5500	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/04/2025
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 Melissa L. Ostrom 02 Title Senior Vice President, Controller	03 Signature Melissa L. Ostrom	04 Date Signed (Mo, Da, Yr) 04/04/2025
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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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".

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	

70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☑ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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.

Melissa Ostrom

Senior Vice President, Controller

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 2024, 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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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%	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	541,808	[(a)] 2024-01-01	2024-12-31
2	Senior Vice President, Chief Nuclear Officer	Christpher Church	480,000	2024-01-01	2024-12-31
3	President	Ryan Long	480,000	2024-01-01	2024-12-31
4	Executive Vice President, Chief Operations Officer	Timothy J. O'Connor	309,605	2024-01-01	2024-12-31
5	Executive Vice President, Chief Financial Officer	Brian Van Abel	309,605	2024-01-01	2024-12-31
6	Senior Vice President, Chief Human Resources Officer	Patricia Correa	259,663	2024-01-01	2024-12-31
7	Executive Vice President, Group President, Utilities and Chief Customer Officer and Interim General Counsel	Amanda J. Rome	103,908	2024-01-01	2024-05-20
8	Executive Vice President, Chief Legal and Compliance Officer	Rob Berntsen	141,141	2024-05-20	2024-12-31
9	Vice President, Corporate Secretary and Securities	Amy L. Schneider	129,704	2024-01-01	2024-12-31
10	Executive Vice President, Group President, Utilities and Chief Customer Officer	Amanda J. Rome	166,996	2024-05-20	2024-12-31
11	Vice President, Controller	Melissa Ostrom	99,407	2024-01-01	2024-09-03
12	Vice President, Treasurer	Paul A. Johnson	97,377	2024-01-01	2024-09-08
13	Senior Vice President, Controller	Melissa Ostrom	52,892	2024-09-03	2024-12-31
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.				

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DateOfficerIncumbencyStarted

Ryan Long was appointed NSP-Minnesota President effective January 1, 2024.
Amanda J. Rome was appointed Director and Executive Vice President, Chief Customer Officer and Interim General Counsel effective January 1, 2024. Amanda resigned as Interim General Counsel effective May 20, 2024.
Rob Berntsen was appointed Executive Vice President, Chief Legal and Compliance Officer effective May 20, 2024.
Melissa Ostrom was appointed Senior Vice President, Controller effective September 3, 2024.
Paul A. Johnson resigned as Vice President, Treasurer effective September 8, 2024.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. 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	Ryan Long, 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	Amanda J. Rome, Executive Vice President, and Chief Customer Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	false

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

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
17	FERC Electric Tariff updated effective 01-01-2025 (Midwest Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment GG-NSP)	ER25-323-000 Approval of Tariff Revisions to Attachment GG-NSP, Issued November 1, 2024 Accession No. 20241101-5066

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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)
9	20250314-5363	03/14/2025	ER25-1723-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin	FERC Electric Tariff updated effective 01-01-2025 (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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	151
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	26
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	24
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	29
17	300	Electric Operating Revenues (Acct 400)	b	19
18	310-311	Sales for Resale (Acct 447)	a	41

19	320-323	Electric Operation and Maintenance Expenses	b	112
20	328	Transmission of Electricity for Others	a	17
21	356	Common Utility Plant and Expenses	n/a	n/a

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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 capital ratio.

1. Franchise
City, State - Utility - Expiration
St Martin, MN - Electric - December 10, 2043
Sedan, MN - Electric - December 12, 2043
Wanamingo, MN - Electric - January 7, 2043
Elko New Market, MN - Electric - February 8, 2044
Greenwald, MN - Electric - February 27, 2044
Clements, MN - Electric - March 11, 2044
New Richland, MN - Electric - March 24, 2044
Cottonwood, MN - Electric - April 15, 2044
Minneapolis, MN - Electric - April 17, 2025
West St Paul, MN - Electric - May 12, 2044
Maplewood, MN - Electric - May 27, 2044
Lake Henry, MN - Electric - May 28, 2044
Afton, MN - Electric - June 17, 2044
Afton, MN - Gas - June 17, 2044
New London, MN - Electric - June 21, 2044
New London, MN - Gas - June 21, 2044
Brooten, MN - Electric - July 21, 2044
Foley, MN - Electric - August 5, 2044
Foley, MN - Gas - August 5, 2044
Delhi, MN - Electric - September 4, 2044
Coates, MN - Electric - September 8, 2044
Zumbro Falls, MN - Electric - October 8, 2044
Arden Hills, MN - Electric - October 27, 2044
Arden Hills, MN - Gas - October 27, 2044
Rogers, MN - Electric - November 25, 2044
Stewart, MN - Electric - December 8, 2044
Mapleton, MN - Electric - December 9, 2044

2. Acquisitions
None.

3. Purchase or sale of an operating unit or system
None.

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

Certain Union Employees — 4.00 percent increase effective Jan. 1, 2024.
Certain Union Employees — hourly wage scale increase between $1-$3 effective March 31, 2024.
Certain Union Employees — 4.00 percent increase effective June 15, 2024.
Certain Union Employees — 4.00 percent increase effective August 1, 2024.
Certain Union Employees — 3.00 percent increase effective September 1, 2024.

Non-Union Employees — Merit based increase of 3.50 percent, effective March 16, 2024.

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 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.
Effective May 20, 2024, Amanda J. Rome resigned as Interim General Counsel.
Effective May 20, 2024 Robert Berntsen elected EVP, Chief Legal and Compliance Officer.
Effective September 3, 2024, Melissa Ostrom elected SVP, Controller.
Effective September 9, 2024, Paul Johnson resigned as VP, Treasurer.
Effective September 9, 2024, Todd Wehner elected VP, Treasurer.

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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	[(a)]29,859,480,554	[(d)]27,485,045,414
3	Construction Work in Progress (107)	200	1,531,616,544	1,091,213,892
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		31,391,097,098	28,576,259,306
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	11,315,978,537	10,464,116,598
6	Net Utility Plant (Enter Total of line 4 less 5)		20,075,118,561	18,112,142,708
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	208,557,507	121,049,448
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		66,773,660	74,022,472
9	Nuclear Fuel Assemblies in Reactor (120.3)		557,340,356	557,940,914
10	Spent Nuclear Fuel (120.4)		2,658,192,690	2,583,569,659
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	3,093,699,820	2,987,981,986
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		397,164,393	348,600,507
14	Net Utility Plant (Enter Total of lines 6 and 13)		20,472,282,954	18,460,743,215
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		33,656,610	25,896,733
19	(Less) Accum. Prov. for Depr. and Amort. (122)		13,475,444	12,174,890
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	15,859,609	3,501,594
23	Noncurrent Portion of Allowances	228		

24	Other Investments (124)		54,689,426	51,733,913
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		3,493,594,277	3,209,781,663
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		66,725,895	61,239,193
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,651,050,373	3,339,978,206
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		4,437,525	1,569,984
36	Special Deposits (132-134)		3,281,822	2,898,490
37	Working Fund (135)		159,347	119,200
38	Temporary Cash Investments (136)		51,373,345	29,418,710
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		503,402,450	481,790,307
41	Other Accounts Receivable (143)		147,275,778	104,006,781
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		43,602,395	49,402,649
43	Notes Receivable from Associated Companies (145)		33,000,000	57,000,000
44	Accounts Receivable from Assoc. Companies (146)		7,210,542	15,660,663
45	Fuel Stock (151)	227	81,648,991	106,828,966
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	231,709,713	217,884,396
49	Merchandise (155)	227	1,331,042	1,088,329
50	Other Materials and Supplies (156)	227		

51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	200,000	200,000
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)		20,785,341	27,166,326
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		2,928,480	2,381,847
57	Prepayments (165)		(b)40,901,800	24,748,689
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		2,257,102	1,414,765
60	Rents Receivable (172)		1,147,731	952,252
61	Accrued Utility Revenues (173)		273,564,152	291,363,874
62	Miscellaneous Current and Accrued Assets (174)		1,352	6
63	Derivative Instrument Assets (175)		103,213,684	111,174,145
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		66,725,895	61,239,193
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		1,399,501,907	1,367,025,888
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		79,690,543	73,395,427
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	55,351,360	63,952,628
72	Other Regulatory Assets (182.3)	232	4,128,101,094	3,883,635,158
73	Prelim. Survey and Investigation Charges (Electric) (183)		4,399,957	1,439,654
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			746
77	Temporary Facilities (185)			

78	Miscellaneous Deferred Debits (186)	233	37,542,020	43,354,022
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		9,054,665	10,036,019
82	Accumulated Deferred Income Taxes (190)	234	[c]1,458,301,719	1,403,283,654
83	Unrecovered Purchased Gas Costs (191)		76,107,452	74,547,804
84	Total Deferred Debits (lines 69 through 83)		5,848,548,810	5,553,645,112
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		31,371,384,044	28,721,392,421

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: UtilityPlant
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.
(b) 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.
(c) Concept: AccumulatedDeferredIncomeTaxes
Refer to FERC page 232 for NSPM's regulatory asset related to nonplant excess ADIT.
(d) Concept: UtilityPlant
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	5,920,268,234	5,206,742,091
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	2,870,730,559	2,543,428,084
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	10,127,458	(2,230,631)
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(8,019,595)	(19,876,201)
16	Total Proprietary Capital (lines 2 through 15)		9,272,399,185	8,207,355,872
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	7,984,000,000	7,450,000,000
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256	166,000,000	
21	Other Long-Term Debt (224)	256	2,032,176	2,376,908
22	Unamortized Premium on Long-Term Debt (225)			

23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		49,452,185	49,067,939
24	Total Long-Term Debt (lines 18 through 23)		8,102,579,991	7,403,308,969
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		[(a)]316,531,702	[(d)]371,741,428
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)			
29	Accumulated Provision for Pensions and Benefits (228.3)		127,399,436	144,038,000
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		3,172,988	187,228,510
32	Long-Term Portion of Derivative Instrument Liabilities		76,544,979	85,606,340
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		3,073,005,377	2,657,859,157
35	Total Other Noncurrent Liabilities (lines 26 through 34)		3,596,654,482	3,446,473,435
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		195,000,000	165,000,000
38	Accounts Payable (232)		644,799,783	601,268,902
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		100,939,378	91,119,845
41	Customer Deposits (235)		30,960,151	34,938,292
42	Taxes Accrued (236)	262	220,546,958	223,266,353
43	Interest Accrued (237)		90,432,205	79,305,747
44	Dividends Declared (238)		80,177,000	121,278,150
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		46,159,875	43,016,985
48	Miscellaneous Current and Accrued Liabilities (242)		9,022,701	15,271,819
49	Obligations Under Capital Leases-Current (243)		[(b)]97,162,928	[(e)]91,284,357

50	Derivative Instrument Liabilities (244)		107,290,057	122,538,659
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		76,544,979	85,606,340
52	Derivative Instrument Liabilities - Hedges (245)			7,537,298
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,545,946,057	1,510,220,067
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		17,023,097	17,851,733
57	Accumulated Deferred Investment Tax Credits (255)	266	12,739,706	14,069,823
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	338,795,040	320,809,377
60	Other Regulatory Liabilities (254)	278	4,805,645,856	4,423,262,055
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	17,911,074	19,763,973
63	Accum. Deferred Income Taxes-Other Property (282)		3,096,333,381	2,854,781,587
64	Accum. Deferred Income Taxes-Other (283)		[c]565,356,175	503,495,530
65	Total Deferred Credits (lines 56 through 64)		8,853,804,329	8,154,034,078
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		31,371,384,044	28,721,392,421

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ 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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF INCOME

Quarterly

1. 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.
2. 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.
3. 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.
4. 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.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. 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.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. 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.
11. 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.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. 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.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. 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 Utiity 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	5,485,916,739	5,924,063,546			4,833,673,433	5,162,301,320	652,243,306	761,762,226		
3	Operating Expenses											
4	Operation Expenses (401)	320	3,338,698,469	3,570,549,911			2,922,826,716	2,992,602,087	415,871,753	577,947,824		

5	Maintenance Expenses (402)	320	250,699,804	236,257,800			233,617,771	217,894,147	17,082,033	18,363,653		
6	Depreciation Expense (403)	336	941,031,562	831,238,367			872,997,922	770,935,123	68,033,640	60,303,244		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	32,037,466	(18,543,930)			31,904,416	(18,921,399)	133,050	377,469		
8	Amort. & Depl. of Utility Plant (404-405)	336	106,749,887	95,971,422			95,206,680	85,647,339	11,543,207	10,324,083		
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	9,185,658			9,185,658	9,185,658				
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		[a]103,137,826	[d]171,346,201			96,011,647	165,581,053	7,126,179	5,765,148		
13	(Less) Regulatory Credits (407.4)		[b]355,328,082	[e]189,531,027			329,980,524	177,345,261	25,347,558	12,185,766		
14	Taxes Other Than Income Taxes (408.1)	262	215,600,258	239,339,559			188,508,414	215,415,677	27,091,844	23,923,882		
15	Income Taxes - Federal (409.1)	262	(147,738,680)	(176,734,294)			(150,828,526)	(194,438,348)	3,089,846	17,704,054		
16	Income Taxes - Other (409.1)	262	(24,826,643)	(1,957,168)			(26,420,715)	(9,297,456)	1,594,072	7,340,288		
17	Provision for Deferred Income Taxes (410.1)	234, 272	534,169,731	671,806,784			491,840,592	642,643,760	42,329,139	29,163,024		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	725,543,304	608,853,796			704,037,492	565,153,568	21,505,812	43,700,228		
19	Investment Tax Credit Adj. - Net (411.4)	266	(1,330,117)	(1,338,553)			(1,223,533)	(1,231,734)	(106,584)	(106,819)		
20	(Less) Gains from Disp. of Utility Plant (411.6)											

21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)		2,821,031	1,718,646			2,821,031	1,718,646				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		128,161,889	126,069,386			126,665,339	123,487,013	1,496,550	2,582,373		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,404,978,086	4,956,181,067			3,856,546,727	4,258,378,838	548,431,359	697,802,229		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		1,080,938,653	967,882,479			977,126,706	903,922,482	103,811,947	63,959,997		
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,591,349	2,007,454								
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,539,009	1,832,026								
33	Revenues From Nonutility Operations (417)		15,317,085	47,639,745								
34	(Less) Expenses of Nonutility Operations (417.1)		19,011,733	42,750,894								
35	Nonoperating Rental Income (418)											
36	Equity in Earnings of Subsidiary Companies (418.1)	119	12,358,089	(94,942)								

37	Interest and Dividend Income (419)		13,754,712	7,814,741								
38	Allowance for Other Funds Used During Construction (419.1)		53,396,561	35,651,456								
39	Miscellaneous Nonoperating Income (421)		5,746,783	10,048,269								
40	Gain on Disposition of Property (421.1)		13,067,088	18,949,087								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		94,680,925	77,432,890								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		908,300	19,634								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		5,261,615	2,410,834								
46	Life Insurance (426.2)		[c](3,666,010)	[f](3,000,911)								
47	Penalties (426.3)		404,365	1,016,182								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,012,856	1,721,033								
49	Other Deductions (426.5)		4,958,778	5,686,339								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		9,879,904	7,853,111								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	237,140	402,827								
53	Income Taxes-Federal (409.2)	262	(3,443,526)	10,286,563								

54	Income Taxes-Other (409.2)	262	(1,618,422)	4,345,569									
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	13,569,202	(511,219)									
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	4,359,374	6,352,466									
57	Investment Tax Credit Adj.-Net (411.5)												
58	(Less) Investment Tax Credits (420)												
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		4,385,020	8,171,274									
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		80,416,001	61,408,505									
61	Interest Charges												
62	Interest on Long-Term Debt (427)		345,767,911	303,837,737									
63	Amort. of Debt Disc. and Expense (428)		6,247,772	5,873,531									
64	Amortization of Loss on Reaquired Debt (428.1)		981,354	978,673									
65	(Less) Amort. of Premium on Debt-Credit (429)												
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)												
67	Interest on Debt to Assoc. Companies (430)		4,775,571	4,908,964									
68	Other Interest Expense (431)		36,304,624	27,171,063									

69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		25,563,142	20,712,776									
70	Net Interest Charges (Total of lines 62 thru 69)		368,514,090	322,057,192									
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		792,840,564	707,233,792									
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)		792,840,564	707,233,792									

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: RegulatoryDebits

	Electric	Gas
Minnesota Renewable Development Fund Rider	$ 38,373,757	$ —
Minnesota Electric Property Tax Tracker	23,226,620	—
Minnesota Renewable Energy Standard Rider	11,759,866	—
Theoretical Depreciation Reserve Surplus	8,892,617	—
Minnesota Transmission Cost Recovery Rider	6,447,903	—
Minnesota Incentive Compensation Refund	4,523,334	32,479
South Dakota Infrastructure Rider	1,293,208	—
Minnesota Business Incentive and Sustainability Rider	871,192	—
Sherco Unit 3 Depreciation Deferral	503,130	—
Minnesota LED Streetlighting	120,020	—
Minnesota Gas Utility Infrastructure Rider	—	7,093,700
	$ 96,011,647	$ 7,126,179

(b) Concept: RegulatoryCredits

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	$ 158,569,756	$ 1,629,600
Minnesota Capacity Revenue Tracker	107,423,187	—
Minnesota Electric Capital True-up	37,218,277	—
Minnesota Electric Sales True-up	20,776,376	—
Minnesota Net Operating Loss	1,526,909	—
North Dakota AGIS Deferral	1,345,999	—
Minnesota State Energy Policy Rider	1,248,328	—
North Dakota Renewable Energy Rider	858,793	—
North Dakota Transmission Cost Recovery Rider	578,863	—
South Dakota Transmission Cost Recovery Rider	383,634	—
South Dakota Electric Property Tax Tracker	50,402	—
Minnesota Gas Decoupling	—	21,634,245
Minnesota Gas Property Tax Tracker	—	2,083,713
	$ 329,980,524	$ 25,347,558

(c) Concept: LifeInsurance

Income on Company Owned Life Insurance.

(d) Concept: RegulatoryDebits

	Electric	Gas
Minnesota Electric Sales True-Up	$ 62,838,993	$ —
Minnesota Electric 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

(e) 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

(f) Concept: LifeInsurance

Income on Company Owned Life Insurance.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		2,543,350,461	2,482,104,827
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Rounding			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		780,482,475	707,328,734
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Dividends Declared-Common Stock (Account 438)	238	(453,180,000)	(646,083,100)

36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(453,180,000)	(646,083,100)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,870,652,936	2,543,350,461
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)		2,870,730,559	2,543,428,084
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(2,230,631)	(2,135,689)
50	Equity in Earnings for Year (Credit) (Account 418.1)		12,358,089	(94,942)
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)		10,127,458	(2,230,631)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF CASH FLOWS

1. 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.
2. 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.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. 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)	792,840,564	707,233,792
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	990,645,501	877,128,073
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Nuclear Fuel	105,717,834	96,379,479
5.2	Amortization of Premium, Discount and Debt Expense	7,229,126	6,852,204
5.3	Amortization of Software and Other	114,123,083	102,017,308
8	Deferred Income Taxes (Net)	142,685,569	205,965,274
9	Investment Tax Credit Adjustment (Net)	(1,330,117)	(1,338,553)
10	Net (Increase) Decrease in Receivables	(62,334,929)	34,162,091
11	Net (Increase) Decrease in Inventory	(23,761,231)	(26,471,753)
12	Net (Increase) Decrease in Allowances Inventory		(50,000)
13	Net Increase (Decrease) in Payables and Accrued Expenses	58,358,319	(113,809,609)
14	Net (Increase) Decrease in Other Regulatory Assets	(182,498,249)	6,434,568
15	Net Increase (Decrease) in Other Regulatory Liabilities	317,162,228	299,610,321
16	(Less) Allowance for Other Funds Used During Construction	53,396,561	35,651,456

17	(Less) Undistributed Earnings from Subsidiary Companies	12,358,015	(95,004)
18	Other (provide details in footnote):		
18.1	Other: Decrease (Increase) in Accrued Utility Revenues	17,799,722	82,140,193
18.2	Other: Net Realized and Unrealized Hedging and Derivative Transactions	15,853,194	(3,861,842)
18.3	Other: Changes in Other Current Assets and Liabilities	(34,877,024)	(16,553,624)
18.4	Other: Changes in Noncurrent Liabilities and Deferred Amounts	[(a)](269,335,180)	[(d)]98,610,487
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	1,922,523,834	2,318,891,957
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(2,537,280,652)	(1,894,631,631)
27	Gross Additions to Nuclear Fuel	(154,281,720)	(153,823,515)
28	Gross Additions to Common Utility Plant	(172,770,036)	(280,811,385)
29	Gross Additions to Nonutility Plant	(7,947,854)	(3,769,123)
30	(Less) Allowance for Other Funds Used During Construction	(53,396,561)	(35,651,456)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(2,818,883,701)	(2,297,384,198)
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		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
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	(390,000,000)	(300,000,000)
53.2	Repayments from Utility Money Pool Arrangement	414,000,000	243,000,000
53.3	Other: Miscellaneous Other Investing Activities	(2,955,515)	(4,481,614)
53.4	Other: Purchase of Investments in External Decommissioning Fund	(997,887,846)	(993,862,798)
53.5	Other: Proceeds from Sale of Investments in External Decomissioning Fund	961,228,946	958,739,195
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(2,834,498,116)	(2,393,989,415)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	687,072,867	782,509,833
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other: Capital Contributions (to) from Parent	714,772,952	351,337,196
64.2	Other: Borrowings under Utility Money Pool Arrangement	271,000,000	302,000,000
66	Net Increase in Short-Term Debt (c)	30,000,000	
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,702,845,819	1,435,847,029
72	Payments for Retirement of:		
73	Long-term Debt (b)	(344,732)	(400,403,566)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		

76.1	Other: Repayments under Utility Money Pool Arrangement	(271,000,000)	(302,000,000)
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	(494,281,150)	(647,252,975)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	937,219,937	44,190,488
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)	25,245,655	(30,906,970)
88	Cash and Cash Equivalents at Beginning of Period	[(b)]34,006,384	64,913,354
90	Cash and Cash Equivalents at End of Period	[(c)]59,252,039	[(e)]34,006,384

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Changes in Noncurrent Liabilities and Deferred Amounts		
Change in pension and employee benefit obligation	$	(41,963,102)
Change in deferred debits		(4,167,501)
Change in deferred credits		(39,148,982)
Change in noncurrent liabilities		(184,055,595)
	$	(269,335,180)

(b) 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

(c) Concept: CashAndCashEquivalents

Cash (131)	$	4,437,525
Special Deposits (132-134)		3,281,822
Working Fund (135)		159,347
Temporary Cash Investments (136)		51,373,345
Cash and Cash Equivalents at End of Period	$	59,252,039

(d) 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

(e) 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

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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 4Q 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.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

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 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.

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	$	388
Current assets		385
Current liabilities		842
Other long-term assets		(4,661)
Long-term debt and other long-term liabilities		(4,729)
Statement of Income:		
Operating revenue	$	281
Operating expenses		652
Other income and deductions		(16)
Net Interest charges		(32)

Subsequent Events - Management has evaluated the impact of events occurring after Dec. 31, 2024 up to Feb. 27, 2025, the date NSP-Minnesota’s GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of the draft. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

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.

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 3.9% for 2024, 3.7% for 2023.

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. The latest decommissioning study was deferred one year and completed in 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 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 generally 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. When separate mechanisms are expected to provide cost recovery or when changes in projected costs occur near the end of a facility's useful life, regulatory accounting may be applied.

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.

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.

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.

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)	2024	2023
Current assets	$ 15	$ 6
Other assets	1	(2)
Total assets	$ 16	$ 4
Equity	$ 16	$ 4
Total liabilities and equity	$ 16	$ 4

(Millions of Dollars)	2024	2023
Operating income	$ 17	$ —
Income taxes	(5)	—
Net income	$ 12	$ —

3. Joint Ownership of Generation, Transmission and Gas Facilities

Jointly owned assets as of Dec. 31, 2024:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
Electric generation:			
Sherco Unit 3	$ 636	$ 499	59 %
Sherco common facilities	189	128	80
Sherco substation	5	4	59
Electric transmission:			
Grand Meadow	11	4	50
Huntley Wilmarth	49	3	50
CapX2020	855	160	51
Total (a)	$ 1,745	$ 798	

(a) Projects additionally include $10 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.

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, 2024	Dec. 31, 2023
Other Regulatory Assets		
Asset retirement recovery	$ 2,926	$ 2,772
Pension and retiree medical obligations	336	339
Theoretical deprecation reserve surplus	211	220
Recoverable deferred taxes on AFUDC recorded in plant	137	127
MISO Capacity Revenue Tracker	107	62
Excess deferred taxes - TCJA	97	106
Sales true-up and revenue decoupling	83	9
Nuclear refueling outage costs	71	62
Renewable resources and environmental initiatives	37	38
Contract valuation adjustments [(a)]	23	31
PPA termination	18	24
Purchased power contracts costs	17	21
Other	65	73
Total other regulatory assets	$ 4,128	$ 3,884

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

Components of regulatory liabilities:

(Millions of Dollars)	Dec. 31, 2024	Dec. 31, 2023
Other Regulatory Liabilities		
Plant removal costs	$ 2,104	$ 2,028
Deferred income tax adjustments and TCJA refunds [(a)]	1,109	1,161
Nuclear Decommissioning Trust Investments	984	835
Deferred natural gas and electric energy/fuel costs [(c)]	360	143
Conservation Programs	41	27
Contract valuation adjustments [(b)]	21	16
Investment tax credit deferrals	14	13
Other	173	200
Total other regulatory liabilities	$ 4,806	$ 4,423

(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 FTR instruments utilized/intended to offset the impacts of transmission system congestion.

(c) Includes Nuclear PTCs.

NSP-Minnesota's regulatory assets not earning a return include past expenditures of $562 million and $479 million at Dec. 31, 2024 and 2023, respectively, which predominately relate to purchased natural gas (including certain costs related to Winter Storm Uri), sales true-up and revenue decoupling, various renewable resources/environmental initiatives and certain prepaid pension amounts. Additionally, the unfunded portion of pension and retiree medical obligations and net AROs (i.e. deferrals for which cash has not been disbursed) do not earn a return.

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.

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 2024	2023
Borrowing limit	$ 250	$ 250
Amount outstanding at period end	—	—
Average amount outstanding	10	17
Maximum amount outstanding	139	135
Weighted average interest rate, computed on a daily basis	4.82 %	4.97 %
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 2024	2023
Borrowing limit	$ 700	$ 700
Amount outstanding at period end	195	165
Average amount outstanding	54	92
Maximum amount outstanding	400	441
Weighted average interest rate, computed on a daily basis	5.39 %	4.99 %
Weighted average interest rate at end of period	4.63	5.47

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, 2024 and 2023, there were $12 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)] 2024	2023	Amount Facility May Be Increased (Millions)	Additional Periods for Which a One-Year Extension May Be Requested [(b)]
47.0 %	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, 2024, 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, 2024 (in millions of dollars):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 700	$ 207	$ 493

(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, 2024 and 2023.

Bilateral Credit Agreement — In April 2024, 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, 2024, and 2023 NSP-Minnesota had $74 million and $65 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	2024	2023
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 (a)	2.60	June 1, 2051	700	700
First mortgage bonds	3.20	April 1, 2052	425	425
First mortgage bonds	4.50	June 1, 2052	500	500
First mortgage bonds (b)	5.10	May 15, 2053	800	800
First mortgage bonds (c)	5.40	Mar 15, 2054	700	—
Other long-term debt			2	2
Unamortized discount			(49)	(49)
Total long-term debt			$ 8,103	$ 7,403

(a) During 2024, Xcel Energy Inc. purchased a portion of these NSP-Minnesota first mortgage bonds for $105 million. Interest expense related to these repurchased bonds was immaterial for the year ended Dec. 31, 2024.

(b) 2023 financing.

(c) 2024 financing.

Maturities of long-term debt are as follows:

(Millions of Dollars)	
2025	$ 250
2026	—
2027	—
2028	150
2029	—

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, 2024:

Equity to Total Capitalization Ratio Required Range	Equity to Total Capitalization Ratio Actual

Low	High	2024
47.6 %	58.2 %	53.0 %

Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
$ 1,809 million	$ 17,490 million	$ 17,800 million

6. Income Taxes

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense.

Effective income tax rate for years ended Dec. 31:

	2024	2023
Federal statutory rate	21.0 %	21.0 %
State income tax on pretax income, net of federal tax effect	7.1	7.0
Increases (decreases) in tax from:		
Production tax credits [a]	(100.5)	(39.5)
Plant regulatory differences [b]	(9.3)	(5.7)
Other tax credits, net of net operating loss (NOL) & tax credit allowances	(1.9)	(1.3)
Other, net	—	0.2
Effective income tax rate	(83.6)%	(18.3)%

(a) Wind, Solar and Nuclear Production Tax Credits (net of estimated transfer discounts) are generally credited to customers (reduction to revenue) and do not materially impact earnings. Nuclear Production Tax Credits, newly available in 2024, resulted in benefits of 40.0% to the effective tax rate for the year ended Dec. 31, 2024.

(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 taxes are offset by corresponding revenue reductions.

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

(Millions of Dollars)	2024	2023
Current federal tax benefit	$ (153)	$ (154)
Current state tax (benefit) expense	(27)	3
Current change in unrecognized tax expense (benefit)	2	(13)
Deferred federal tax (benefit) expense	(243)	5
Deferred state tax expense	61	51
Deferred investment tax credits	(1)	(1)
Other	—	—
Total income tax benefit	$ (361)	$ (109)

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

(Millions of Dollars)	2024	2023
Deferred tax expense (benefit) excluding items below	$ 247	$ 319
Adjustments to deferred income taxes for tax credit cash transfers [a]	(325)	(150)
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(99)	(114)
Tax (expense) benefit allocated to other comprehensive income, and other	(5)	1
Deferred tax (benefit) expense	$ (182)	$ 56

(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)	2024	2023
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 3,579	$ 3,343
Regulatory assets	(125)	(205)
Operating lease assets	115	129
Pension expense	67	64
Deferred fuel costs	21	20
Other	23	10

Total deferred tax liabilities	$ 3,680	$ 3,361
Deferred tax assets:		
Tax credit carryforward	$ 892	$ 850
Differences between book and tax bases of property	405	374
Operating lease liabilities	115	129
Rate refund	10	59
Regulatory liabilities	(1)	(72)
NOL and Tax credit valuation allowances	(68)	(57)
Other employee benefits	28	31
Deferred investment tax credits	4	4
Other	73	68
Total deferred tax assets	$ 1,458	$ 1,386
Net deferred tax liability	$ 2,222	$ 1,975

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)	2024	2023
Federal tax credit carryforwards	831	794
Valuation allowances for federal credit carryforwards	(11)	(5)
State NOL carryforwards	—	2
State tax credit carryforwards, net of federal detriment	61	56
Valuation allowances for state credit carryforwards, net of federal benefit	(57)	(52)

Federal carryforward periods expire between 2038 and 2044. State carryforward periods, not including those with indefinite carryforward periods, expire starting between 2025 and 2036.

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
2021	October 2025

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. In 2023, the Internal Revenue Service 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 2023.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state tax returns based on income in its major operating jurisdictions and various other state income-based returns. As of Dec. 31, 2024, NSP-Minnesota's earliest open tax years (subject to examination by state taxing authorities in its major operating jurisdictions) were as follows:

State	Tax Year(s)	Expiration
Minnesota	2014-2016	September 2025
Minnesota	2020	June 2025

There are currently no state income tax audits in progress.

Unrecognized tax benefit balance may include permanent tax positions, which if recognized would affect the effective tax rate (ETR). In addition, the unrecognized tax benefit balance may include temporary tax positions for which deductibility is highly certain, but for which there is uncertainty about the timing. A change in the period 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, 2024	Dec. 31, 2023
Unrecognized tax benefit — Permanent tax positions	$ 20	$ 18
Unrecognized tax benefit — Temporary tax positions	—	—
Total unrecognized tax benefit	$ 20	$ 18

Changes in unrecognized tax benefits:

(Millions of Dollars)	2024	2023
Balance at Jan. 1	$ 18	$ 34
Additions based on tax positions related to the current year	3	2
Additions for tax positions of prior years	—	1
Reductions for tax positions of prior years	(1)	(18)
Reductions for tax positions related to settlements with taxing authorities	—	(1)
Balance at Dec. 31	$ 20	$ 18

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2024	Dec. 31, 2023
NOL and tax credit carryforwards	$ (17)	$ (18)

There exists approximately $20 million of noncurrent liabilities related to unrecognized tax benefits for which there is uncertainty about if or when these liabilities will significantly increase or decrease.

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)	2024	2023
Receivable (payable) for interest related to unrecognized tax benefits at Jan. 1	$ 1	$ (3)
Interest (expense) benefit related to unrecognized tax benefits	$ (1)	$ 4
Receivable (payable) for interest related to unrecognized tax benefits at Dec. 31	$ —	$ 1

No penalties were accrued related to unrecognized tax benefits as of Dec. 31, 2024 or 2023.

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, 2024 and 2023 is reflected below.

	Dec. 31, 2024		Dec. 31, 2023	
(Millions of Dollars)	Account 182.3	Account 254	Account 182.3	Account 254
Protected				
Plant	$ —	$ 981	$ —	$ 1,021
Nonplant	87	—	92	—
Unprotected				
Plant	—	114	—	121
Nonplant	9	14	12	19
Total				
Plant	$ —	$ 1,095	$ —	$ 1,142
Nonplant	$ 96	$ 14	$ 104	$ 19

Excess and deficient ADITs in 2024 were amortized in the Statement of Income as follows:

(Millions of Dollars)		Dec. 31, 2024
Protected		
Plant	$	(29)
Nonplant		4
Unprotected		
Plant		(6)
Nonplant		(1)
Total		
Plant	$	(35)
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.

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 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 $1.4 billion and $1.2 billion as of Dec. 31, 2024 and 2023, respectively, and unrealized losses were $49 million and $29 million as of Dec. 31, 2024 and 2023, respectively.

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

	Dec. 31, 2024					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund						
Cash equivalents	$ 39	$ 39	$ —	$ —	$ —	$ 39
Commingled funds	703	—	—	—	1,025	1,025
Debt securities	866	—	832	14	—	846
Equity securities	522	1,583	1	—	—	1,584
Total	$ 2,130	$ 1,622	$ 833	$ 14	$ 1,025	$ 3,494

	Dec. 31, 2023					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund						
Cash equivalents	$ 41	$ 41	$ —	$ —	$ —	$ 41
Commingled funds	721	—	—	—	1,049	1,049
Debt securities	784	—	771	9	—	780
Equity securities	508	1,339	2	—	—	1,341
Total	$ 2,054	$ 1,380	$ 773	$ 9	$ 1,049	$ 3,211

For the years ended Dec. 31, 2024 and 2023, 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, 2024:

	Final Contractual Maturity				
(Millions of Dollars)	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	$ 7	$ 308	$ 269	$ 262	$ 846

Derivative Activities and Fair Value Measurements

NSP-Minnesota enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates and utility commodity prices.

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, 2024, accumulated other comprehensive loss related to interest rate derivatives included immaterial of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings. As of Dec. 31, 2024, NSP-Minnesota had no unsettled interest rate swaps outstanding.

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 10.

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.

Results of derivative instrument transactions 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, 2024 and 2023 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.

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, 2024, 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, 2024**	**Dec. 31, 2023**
Megawatt hours of electricity	31	38
Million British thermal units of natural gas	57	64

(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 often has significant concentrations of credit risk with particular entities or industries in its wholesale, trading and non-trading commodity activities.

As of Dec. 31, 2024, six of NSP-Minnesota's ten most significant counterparties for these activities, comprising $20 million or 22% of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings.

One of the ten most significant counterparties, comprising $27 million or 29% 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 $43 million or 47% of this credit exposure, had credit quality less than investment grade, based on internal analysis.

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

Credit Related Contingent Features — Contract provisions for derivative instruments that NSP-Minnesota enters into, 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, 2024 and 2023, there were $11 million and $12 million, respectively, of derivative liabilities with such underlying contract provisions, respectively.

Certain contracts also 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, 2024 and 2023, there were approximately $63 million and $80 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. NSP-Minnesota had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2024 and 2023.

Recurring Derivative Fair Value Measurements *—*

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, 2024		
Derivatives designated as cash flow hedges		
Interest rate	$ 16	$ —
Total	$ 16	$ —
Other derivative instruments		
Electric commodity	$ —	$ (18)
Natural gas commodity	—	2
Total	$ —	$ (16)
Year Ended Dec. 31, 2023		
Derivatives designated as cash flow hedges		
Interest rate	$ (3)	$ —
Total	$ (3)	$ —
Other derivative instruments		
Electric commodity	$ —	$ (48)
Natural gas commodity	—	(1)
Total	$ —	$ (49)

(Millions of Dollars)	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive	Regulatory Assets and	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2024			
Derivatives designated as cash flow hedges			
Interest rate	$ 1 (a)	$ —	$ —
Total	$ 1	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ (10) (b)
Electric commodity	—	21 (c)	—
Natural gas commodity	—	—	(7) (d)(e)
Total	$ —	$ 21	$ (17)
Year Ended Dec. 31, 2023			
Derivatives designated as cash flow hedges			
Interest rate	$ 1 (a)	$ —	$ —
Total	$ 1	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ (2) (b)
Electric commodity	—	45 (c)	—
Natural gas commodity	—	—	(8) (d)(e)
Total	$ —	$ 45	$ (10)

(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, 2024 and 2023.

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

(Millions of Dollars)	Dec. 31, 2024 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Netting [a]	Total	Dec. 31, 2023 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Netting [a]	Total
Current derivative assets												
Other derivative instruments:												
Commodity trading	$ 5	$ 20	$ 8	$ 33	$ (22)	$ 11	$ 7	$ 32	$ 32	$ 71	$ (42)	$ 29
Electric commodity	—	—	23	23	(2)	21	—	—	23	23	(7)	16
Natural gas commodity	—	4	—	4	—	4	—	5	—	5	—	5
Total current derivative assets	$ 5	$ 24	$ 31	$ 60	$ (24)	$ 36	$ 7	$ 37	$ 55	$ 99	$ (49)	$ 50
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 3	$ 33	$ 47	$ 83	$ (16)	$ 67	$ 7	$ 43	$ 45	$ 95	$ (34)	$ 61
Total noncurrent derivative assets	$ 3	$ 33	$ 47	$ 83	$ (16)	$ 67	$ 7	$ 43	$ 45	$ 95	$ (34)	$ 61

(Millions of Dollars)	Dec. 31, 2024 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Netting [a]	Total	Dec. 31, 2023 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Netting [a]	Total
Current derivative liabilities												
Derivatives designated as cash flow hedges:												
Interest rate	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 7	$ —	$ 7	$ —	$ 7
Other derivative instruments:												
Commodity trading	6	35	5	46	(22)	24	6	60	5	71	(43)	28
Electric commodity	—	—	1	1	(1)	—	—	—	7	7	(7)	—
Natural gas commodity	—	1	—	1	—	1	—	3	—	3	—	3
Total current derivative liabilities	$ 6	$ 36	$ 6	$ 48	$ (23)	25	$ 6	$ 70	$ 12	$ 88	$ (50)	38
PPAs [b]						6						6
Current derivative instruments						$ 31						$ 44
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 9	$ 30	$ 40	$ 79	$ (18)	$ 61	$ 14	$ 49	$ 37	$ 100	$ (36)	$ 64
Total noncurrent derivative liabilities	$ 9	$ 30	$ 40	$ 79	$ (18)	61	$ 14	$ 49	$ 37	$ 100	$ (36)	64
PPAs [b]						16						22
Noncurrent derivative instruments						$ 77						$ 86

(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, 2024 and 2023, derivative assets and liabilities include no obligations to return cash collateral. At Dec. 31, 2024 and 2023, derivative assets and liabilities include rights to reclaim cash collateral of $1 million and $3 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 2024	2023
Balance at Jan. 1	$ 51	$ (107)
Purchases [(a)]	72	98
Settlements [(a)]	(61)	(65)
Net transactions recorded during the period:		
(Losses) gains recognized in earnings [(b)]	(9)	15
Net losses recognized as regulatory assets and liabilities [(a)]	(21)	(104)
Balance at Dec. 31	$ 32	$ 51

(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:

	2024		2023	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 8,103	$ 6,755	$ 7,403	$ 6,561
Long-term debt - related parties	166	99	—	—

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, 2024 and 2023, 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 4.89% and 4.67% in 2024 and 2023, 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.

Obligations of the SERP and nonqualified plan as of Dec. 31, 2024 and 2023 were $13 million and $12 million, respectively, of which an immaterial amount was 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 2024 were below the assumed level of 7.25%.
- Investment returns in 2023 were above the assumed level of 7.25%.
- In 2025, 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:

	Dec. 31, 2024 (a)					Dec. 31, 2023 (a)				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 24	$ —	$ —	$ —	$ 24	$ 46	$ —	$ —	$ —	$ 46
Commingled	—	—	—	373	373	110	—	—	265	375
Debt securities	—	123	1	—	124	—	127	1	—	128
Equity securities	6	—	—	—	6	8	—	—	—	8
Other	—	1	—	—	1	—	5	—	—	5
Total	$ 30	$ 124	$ 1	$ 373	$ 528	$ 164	$ 132	$ 1	$ 265	$ 562

(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:

	Dec. 31, 2024 (a)					Dec. 31, 2023 (a)				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Commingled funds	$ —	$ —	$ —	$ 1	$ 1	$ —	$ —	$ —	$ 1	$ 1
Debt securities	—	1	—	—	1	—	2	—	—	2
Total	$ —	$ 1	$ —	$ 1	$ 2	$ —	$ 2	$ —	$ 1	$ 3

(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 2024. No assets were transferred in or out of Level 3 for 2023.

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:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2024**	**2023**	**2024**	**2023**
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 660	$ 657	$ 42	$ 48
Service cost	22	21	1	—
Interest cost	34	36	2	3
Plan amendments	—	1	—	—
Actuarial (gain) loss	(22)	30	1	(2)
Benefit payments	(82)	(83)	(5)	(7)
Obligation at Dec. 31	$ 612	$ 660	$ 41	$ 42
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 562	$ 570	$ 3	$ 5
Actual return on plan assets	7	52	—	—
Employer contributions	41	23	4	5
Benefit payments	(82)	(83)	(5)	(7)
Fair value of plan assets at Dec. 31	$ 528	$ 562	$ 2	$ 3
Funded status of plans at Dec. 31	$ (84)	$ (98)	$ (39)	$ (39)
Amounts recognized in the Balance Sheet at Dec. 31:				
Current liabilities	$ —	$ —	$ (3)	$ (2)
Noncurrent liabilities	(84)	(98)	(36)	(37)
Net amounts recognized	$ (84)	$ (98)	$ (39)	$ (39)

	Pension Benefits		Postretirement Benefits	
Significant Assumptions Used to Measure Benefit Obligations:	**2024**	**2023**	**2024**	**2023**
Discount rate for year-end valuation	5.88 %	5.49 %	5.88 %	5.54 %
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	7.00 %	6.50 %
Health care costs trend rate — initial: Post-65	N/A	N/A	7.50 %	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	9	6

Accumulated benefit obligation for the pension plan was $557 million and $599 million as of Dec. 31, 2024 and 2023, 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:

(Millions of Dollars)	Pension Benefits 2024	Pension Benefits 2023	Pension Benefits 2022	Postretirement Benefits 2024	Postretirement Benefits 2023	Postretirement Benefits 2022
Service cost	$ 22	$ 21	$ 27	$ 1	$ —	$ —
Interest cost	34	36	25	2	3	2
Expected return on plan assets	(46)	(46)	(48)	—	—	—
Amortization of prior service cost	—	—	—	—	(1)	(3)
Amortization of net loss	13	11	24	—	—	1
Settlement charge (a)	37	—	38	—	—	—
Net periodic pension cost	60	22	66	3	2	—
Effects of regulation	(30)	16	(32)	—	—	—
Net benefit cost recognized for financial reporting	$ 30	$ 38	$ 34	$ 3	$ 2	$ —
Significant Assumptions Used to Measure Costs:						
Discount rate	5.49 %	5.80 %	3.08 %	5.54 %	5.80 %	3.09 %
Expected average long-term increase in compensation level	4.25	4.25	3.75	—	—	—
Expected average long-term rate of return on assets	7.25	7.25	6.60	5.00	5.00	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 2024, as a result of lump-sum distributions during each plan year, NSP-Minnesota recorded a total pension settlement charge of $37 million, 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 2024	Pension Benefits 2023	Postretirement Benefits 2024	Postretirement Benefits 2023
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 289	$ 321	$ 14	$ 15
Total	$ 289	$ 321	$ 14	$ 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	$ 14	$ 11	$ —	$ —
Noncurrent regulatory assets	275	310	13	14
Net-of-tax accumulated other comprehensive income	—	—	1	1
Total	$ 289	$ 321	$ 14	$ 15
Measurement date	Dec 31, 2024	Dec 31, 2023	Dec 31, 2024	Dec 31, 2023

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 2022 - 2025 to meet minimum funding requirements.

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

- $125 million in January 2025, of which $54 million is attributable to NSP-Minnesota.
- $100 million in 2024, of which $41 million was attributable to NSP-Minnesota.
- $50 million in 2023, of which $23 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:

- $8 million expected in 2025, of which $5 million is attributable to NSP-Minnesota.
- $11 million during 2024, of which $4 million, was attributable to NSP-Minnesota.
- $11 million during 2023, of which $5 million was attributable to NSP-Minnesota.

Targeted asset allocations:

	Pension Benefits 2024	Pension Benefits 2023	Postretirement Benefits 2024	Postretirement Benefits 2023
Long-duration fixed income and interest rate swap securities	38 %	38 %	— %	— %
Domestic and international equity securities	31	31	25	9
Alternative investments	20	20	11	13
Short-to-intermediate fixed income securities	9	9	61	77

Cash	2	2	3	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 — There were no significant plan amendments made in 2024 and 2022 which affected the pension or postretirement benefit obligation.

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.

Projected Benefit Payments

NSP-Minnesota's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Net Projected Postretirement Health Care Benefit Payments (a)
2025	$ 63	$ 5
2026	59	5
2027	58	4
2028	56	4
2029	57	4
2030-2034	269	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, unfunded obligations of $7 million and $8 million for health plan subsidies and $1 million and $1 million for other medical benefits are presented in other current liabilities and noncurrent pension and employee benefit obligations in the balance sheets as of Dec. 31, 2024 and 2023, respectively.

Significant Assumptions to Measure Benefit Obligations:	2024	2023
Discount rate for year-end valuation	5.00 %	5.50 %
Mortality table	PRI-2012	PRI-2012
Health care costs trend rate	7.00 %	7.00 %
Ultimate trend assumption	4.50 %	N/A
Years until ultimate trend is reached	9	N/A

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, $14 million, and $13 million in 2024, 2023 and 2022, 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.

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 consolidated financial statements.

Sherco — In 2018, NSP-Minnesota and SMMPA (Co-owner of Sherco Unit 3) reached a settlement with 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 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 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 May 2024, the ALJ recommended a customer refund of $34 million (less a portion of the proceeds received from the settlement with GE). The ALJ indicated that consideration of the $22 million of previously disallowed costs was not in the scope of their recommendation. In 2024, following contested case procedures, the NSP-Minnesota recognized a customer refund of $47 million for replacement power incurred during the outage.

Minnesota 2023 Fuel Clause Adjustment — In March 2024, NSP-Minnesota filed its annual FCA true-up petition to the MPUC. In 2024, the DOC recommended customer refunds for 2023 replacement power costs incurred during an outage at the Prairie Island generating station (October 2023 through February 2024). NSP-Minnesota estimates that customer refunds would be approximately $22 million if the DOC recommendations are applied to both 2023 and 2024.

In September 2024, the MPUC ruled NSP-Minnesota was imprudent in the operation of the Prairie Island nuclear plant based on an incident that resulted in the extended outage. The MPUC did not quantify the refund and referred the determination of the refund amount to the Office of Administrative Hearings. NSP-Minnesota has recorded an estimated liability for a customer refund. The procedural schedule is as follows:

- Xcel Energy testimony: May 1, 2025
- Intervenor direct testimony: July 2, 2025
- Rebuttal testimony: August 13, 2025
- ALJ Report: March 16, 2026

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 for resolution of these issues, however, the final 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 is subject to the CCR Rule, which imposes requirements for handling, storage, treatment and disposal of coal ash and other solid waste.

In May 2024, final amendments to the CCR Rule were published, widening its scope to include legacy CCR surface impoundments at inactive facilities and previously exempt areas where CCR was placed directly on land at CCR-regulated facilities, including areas of beneficial use.

As a requirement of the CCR Rule, utilities must complete facility evaluations and groundwater sampling around their subject landfills, surface impoundments and certain other areas where coal ash was placed on land.

If certain impacts to groundwater are detected, utilities may be required to perform additional groundwater investigations and/or perform corrective actions, typically beginning with an Assessment of Corrective Measures.

NSP-Minnesota expects to incur $6 million for investigations through 2028 to perform required reporting and assess whether corrective actions are necessary. AROs have been recorded for each of these activities, and amounts are expected to be recoverable through regulatory mechanisms.

NSP-Minnesota has also identified coal ash that is expected to be required to be removed from certain closed coal-fueled generating facilities at estimated costs totaling approximately $60 million. AROs have been recorded, with the costs expected to be recoverable through regulatory mechanisms.

NSP-Minnesota continues to evaluate the 2024 updates to the CCR Rule, the interpretations of those updates and how they will apply to specific sites. Assessment of the recent updates to the CCR Rule and corresponding site investigation activities may result in updates to estimated costs as well as identification of additional required corrective actions.

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 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.

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. In June 2024, the U.S. Supreme Court issued an order granting a stay of the final rule. In response, the EPA issued a nationwide an administrative stay of the rule. Depending on the outcomes of the underlying legal challenges, the regulation may become applicable in the future.

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 $3.5 billion and $3.2 billion at Dec. 31, 2024 and 2023, respectively.

NSP-Minnesota's AROs were as follows:

(Millions of Dollars)	2024 Jan. 1, 2024	Amounts Incurred (a)	Amounts Settled	Accretion	Cash Flow Revisions (b)	Dec. 31, 2024
Electric						
Nuclear	$ 2,107	$ —	$ —	$ 106	$ 263	$ 2,476
Wind	424	—	—	15	(33)	406
Steam and other production	77	61	(6)	4	3	139
Distribution	17	—	—	1	—	18
Natural gas						
Transmission and distribution	32	—	—	2	(1)	33
Other						
Miscellaneous	1	—	—	—	—	1
Total liability	$ 2,658	$ 61	$ (6)	$ 128	$ 232	$ 3,073

(a) Amounts incurred pertain to CCR coal ash regulations and Sherco Solar 1 being placed in service.

(b) In 2024, AROs were revised for changes in timing and estimates of cash flows. Changes in the nuclear AROs were driven by updated assumptions in the nuclear triennial filing coupled with discount rate and escalation rate changes. Wind, steam, and other production AROs were revised due to the results of 2024 dismantling studies.

(Millions of Dollars)	2023 Jan. 1, 2023	Amounts Incurred	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	—	(1)	3	—	77
Distribution	16	—	—	1	—	17
Natural gas						
Transmission and distribution	59	—	—	2	(29)	32
Other						
Miscellaneous	1	—	—	—	—	1
Total liability	$ 2,727	$ 10	$ (1)	$ 126	$ (204)	$ 2,658

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

(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.

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, 2024. 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 $16.3 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has $500 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.

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 $19 million for business interruption insurance and $34 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 extended operations to 2040.

The PI dry-cask storage facility currently stores 52 of the 64 authorized casks. In February 2024, NSP-Minnesota filed a CON with the MPUC for additional storage at Prairie Island 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 2050 and its Prairie Island nuclear plant until 2033 for Unit 1 and 2034 for Unit 2. NSP-Minnesota's authorized retirement dates are 2040 for Monticello, 2033 for PI Unit 1 and 2034 for PI Unit 2. In February 2025, the MPUC approved a settlement agreement which extends the retirement dates for planning purposes to 2050, 2053, and 2054 for Monticello, PI Unit 1, and PI Unit 2, respectively. Requests to update the authorized retirement dates are expected to be submitted to the MPUC in 2025.

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 most recent triennial decommissioning study was filed in December 2024.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. NSP-Minnesota had $3.5 billion and $3.2 billion of assets held in external decommissioning trusts at Dec. 31, 2024, and 2023, 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 4.7%). 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, 2024	Dec. 31, 2023
PPAs	$ 709	$ 709
Other	166	125
Gross operating lease ROU assets	875	834
Accumulated amortization	(482)	(395)
Net operating lease ROU assets	$ 393	$ 439

Components of lease expense:

(Millions of Dollars)	2024	2023	2022
Operating leases			
PPA capacity payments	$ 96	$ 100	$ 98
Other operating leases (a)	15	13	9
Total operating lease expense (b)	$ 111	$ 113	$ 107

(a) Includes immaterial short-term lease expense for 2024 and 2023.

(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, 2024 in Accounts 227 and 243:

(Millions of Dollars)	PPA [a] [b] Operating Leases	Other Operating Leases	Total Operating Leases
2025	$ 101	$ 13	$ 114
2026	89	13	102
2027	72	13	85
2028	40	13	53
2029	—	12	12
Thereafter	—	195	195
Total minimum obligation	302	259	561
Interest component of obligation	(22)	(125)	(147)
Present value of minimum obligation	$ 280	$ 134	414
Less current portion			(97)
Noncurrent operating lease liabilities			$ 311
Weighted-average remaining lease term in years			11.9

(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 2041, contain minimum energy purchase commitments. Total energy payments on those contracts were $186 million, $185 million, and $182 million in 2024, 2023 and 2022, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $64 million, $62 million and $60 million in 2024, 2023 and 2022, 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, 2024, 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]
2025	$ 32	$ 53
2026	15	21
2027	13	21
2028	6	22
2029	6	22
Thereafter	2	—
Total (b)	$ 74	$ 139

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

(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 2025 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, 2024:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and
2025	$ 104	$ 168	$ 84	$ 141
2026	40	62	—	140
2027	4	133	—	108
2028	—	19	—	41
2029	—	67	—	21
Thereafter	—	49	—	29
Total (a)	$ 148	$ 498	$ 84	$ 480

(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:

	2024		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (18)	$ (2)	$ (20)
Other comprehensive loss before reclassifications	12	—	12
Accumulated other comprehensive loss at Dec. 31	$ (6)	$ (2)	$ (8)

	2023		
(Millions of Dollars)	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.

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.

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)	2024	2023
Operating revenues:		
Electric	$ 460	$ 493
Gas	1	1
Operating expenses:		
Purchased power	65	63
Transmission expense	151	142
Other operating expenses — paid to Xcel Energy Services Inc.	710	719
Interest income	5	1
Interest expense	2	5

Accounts receivable and payable with affiliates at Dec. 31:

	2024		2023	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	$ —	$ 28	$ 9	$ —
PSCo	—	7	5	—
SPS	—	2	—	4
Other subsidiaries of Xcel Energy Inc.	1	62	1	85
	$ 1	$ 99	$ 15	$ 89

During 2024, Xcel Energy Inc. repurchased certain of NSP-Minnesota's first mortgage bonds. For more information about these repurchases, see Note 5.

12. Supplementary Cash Flow Data

	Year Ended Dec. 31	
(Millions of Dollars)	2024	2023
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (350)	$ (311)
Cash received for income taxes, net	451	256
Supplemental disclosure of non-cash investing transactions:		
Accrued utility plant additions	$ 500	$ 218
Inventory transfers to utility plant	41	55
Operating lease right-of-use assets	39	216
Allowances for funds used during construction	53	36

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.

No such activities occurred in 2024.

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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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			(2,013,231)	(17,158,126)		(18,428,482)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				(84,639)	691,591		606,952		
3	Preceding Quarter/Year to Date Changes in Fair Value	(742,875)			669,178	(1,980,974)		(2,054,671)		
4	Total (lines 2 and 3)	(742,875)			584,539	(1,289,383)		(1,447,719)	707,233,792	705,786,073
5	Balance of Account 219 at End of Preceding Quarter/Year				(1,428,692)	(18,447,509)		(19,876,201)		
6	Balance of Account 219 at Beginning of Current Year				(1,428,692)	(18,447,509)		(19,876,201)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				(76,249)	687,223		610,974		
8	Current Quarter/Year to Date Changes in Fair Value				(88,836)	11,334,468		11,245,632		
9	Total (lines 7 and 8)				(165,085)	12,021,691		11,856,606	792,840,564	804,697,170
10	Balance of Account 219 at End of Current Quarter/Year				(1,593,777)	(6,425,818)		(8,019,595)		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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)	26,065,903,522	22,965,709,422	2,115,672,746				984,521,354
4	Property Under Capital Leases	[(a)]393,496,324	131,900,742					261,595,582
5	Plant Purchased or Sold							
6	Completed Construction not Classified	3,300,767,797	2,511,642,130	360,242,679				428,882,988
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	29,760,167,643	25,609,252,294	2,475,915,425				1,674,999,924
9	Leased to Others							
10	Held for Future Use	21,785,658	8,893,189					12,892,469
11	Construction Work in Progress	1,531,616,544	1,285,135,833	78,210,876				168,269,835
12	Acquisition Adjustments	77,527,253	77,527,253					
13	Total Utility Plant (8 thru 12)	31,391,097,098	26,980,808,569	2,554,126,301				1,856,162,228
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	11,315,978,537	9,878,523,481	841,465,644				595,989,412
15	Net Utility Plant (13 less 14)	20,075,118,561	17,102,285,088	1,712,660,657				1,260,172,816
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							

18	Depreciation	10,576,739,320	9,533,095,160	829,671,956				213,972,204
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	726,727,190	[(b)]332,916,294	11,793,688				382,017,208
22	Total in Service (18 thru 21)	11,303,466,510	9,866,011,454	841,465,644				595,989,412
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	12,512,027	[(c)]12,512,027					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	11,315,978,537	9,878,523,481	841,465,644				595,989,412

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ 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		393,496,324
Total	$	393,496,324

(b) Concept: AmortizationOfOtherUtilityPlantUtilityPlantInService

The amortization of other utility plant within account 111 includes the following:

Intangible Plant	$	168,728,684
Nuclear Production Plant		152,357,179
Other Production		8,717,587
Hydraulic Production Plant-Conventional		3,112,844
Total Amort of Other Utility Plant - Electric	$	332,916,294

(c) Concept: AmortizationOfPlantAcquisitionAdjustment

The amortization of plant acquisition adjustment within account 115 includes the following:

Other Production	$	12,421,557
Transmission		90,470
Total Amort of Plant Acquisition Adj - Electric	$	12,512,027

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	778,124	12,597,297		[b]11,917,664	1,457,757
3	Nuclear Materials	112,028,894	128,942,805		[c]50,842,521	190,129,178
4	Allowance for Funds Used during Construction	8,109,998	12,455,969		[d]3,906,125	16,659,842
5	(Other Overhead Construction Costs, provide details in footnote)	132,432	285,564		[e]107,266	[i]310,730
6	SUBTOTAL (Total 2 thru 5)	121,049,448	154,281,635		66,773,576	208,557,507
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)	74,022,472	[a]66,773,660		[f]74,022,472	66,773,660
9	In Reactor (120.3)	557,940,914	75,485,126		[g]76,085,684	[j]557,340,356
10	SUBTOTAL (Total 8 & 9)	631,963,386	142,258,786		150,108,156	624,114,016
11	Spent Nuclear Fuel (120.4)	2,583,569,659	76,085,685		[h]1,462,654	[k]2,658,192,690
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,987,981,986		(105,717,834)		3,093,699,820
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	348,600,507				397,164,393
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)					

FOOTNOTE DATA

(a) Concept: NuclearFuelMaterialsAndAssembliesInStockAdditions
Consists of transfers from 120.1 , and direct trailing charges to asset after in-service
(b) Concept: FabricationCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Classified to Account 120.2 and 120.3
(c) Concept: NuclearMaterialsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Classified to Account 120.2 and 120.3
(d) Concept: AllowanceForFundsConstructionNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Classified to Account 120.2 and 120.3
(e) Concept: OtherOverheadConstructionCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
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: OtherOverheadConstructionCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabrication
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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. 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.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. 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.
7. 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.
8. 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.
9. 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	263,674,221	2,333,583				266,007,804
4	(303) Miscellaneous Intangible Plant	240,184,501	41,876,321	341,965			281,718,857
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	503,858,722	44,209,904	341,965			(g)547,726,661
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	10,111,545	6,732,036	155,223			16,688,358
9	(311) Structures and Improvements	299,694,704	11,828,286	538,376			310,984,614
10	(312) Boiler Plant Equipment	1,380,104,217	16,892,637	6,311,407			1,390,685,447
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	279,528,774	1,110,457	1,069,568			279,569,663

13	(315) Accessory Electric Equipment	184,479,274	1,210,078	66,804			185,622,548
14	(316) Misc. Power Plant Equipment	53,320,537	1,818,773	11,666			55,127,644
15	(317) Asset Retirement Costs for Steam Production	20,240,869	58,137,688				78,378,557
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,227,479,920	97,729,955	8,153,044			2,317,056,831
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	1,757,711		76,955			1,680,756
19	(321) Structures and Improvements	636,072,136	38,352,950				674,425,086
20	(322) Reactor Plant Equipment	2,059,775,435	102,454,120	743,761			2,161,485,794
21	(323) Turbogenerator Units	680,872,645	2,401,574				683,274,219
22	(324) Accessory Electric Equipment	561,070,279	2,802,406				563,872,685
23	(325) Misc. Power Plant Equipment	212,352,752	1,065,245				213,417,997
24	(326) Asset Retirement Costs for Nuclear Production	(380,870,212)	263,182,499				(117,687,713)
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	3,771,030,746	410,258,794	820,716			4,180,468,824
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	1,693,076					1,693,076
28	(331) Structures and Improvements	1,557,753		4,566			1,553,187
29	(332) Reservoirs, Dams, and Waterways	11,312,518	618,713	164,003			11,767,228
30	(333) Water Wheels, Turbines, and Generators	10,156,576					10,156,576
31	(334) Accessory Electric Equipment	3,295,922		12,015			3,283,907
32	(335) Misc. Power Plant Equipment	134,001					134,001
33	(336) Roads, Railroads, and Bridges	152,109	215,279				367,388
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	28,301,955	833,992	180,584			28,955,363
36	D. Other Production Plant						
37	(340) Land and Land Rights	36,388,142	788,866				37,177,008

38	(341) Structures and Improvements	522,814,460	8,189,381	360,875			530,642,966
39	(342) Fuel Holders, Products, and Accessories	30,314,461	1,926,427	59,808			32,181,080
40	(343) Prime Movers	147,619,370	5,219,164	18,868			152,819,666
41	(344) Generators	4,236,052,372	312,327,812	8,471,666			4,539,908,518
42	(345) Accessory Electric Equipment	367,147,868	75,351,534	15,630,421			426,868,981
43	(346) Misc. Power Plant Equipment	64,776,249	13,255,508	244,012		(10,262,356)	67,525,389
44	(347) Asset Retirement Costs for Other Production	354,104,101	6,376,703	5,885,320	(33,247,531)		321,347,953
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)	5,763,345,925	423,435,395	34,799,872	(33,247,531)	(10,262,356)	6,108,471,561
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	11,790,158,546	932,258,136	43,954,216	(33,247,531)	(10,262,356)	[(d)] 12,634,952,579
47	3. Transmission Plant						
48	(350) Land and Land Rights	172,863,055	2,894,063				175,757,118
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	169,263,207	4,991,994	1,165,583			173,089,618
50	(353) Station Equipment	1,587,179,440	101,384,780	6,239,907		1,065,771	1,683,390,084
51	(354) Towers and Fixtures	127,675,939	499,606				128,175,545
52	(355) Poles and Fixtures	1,685,276,228	120,049,612				1,805,325,840
53	(356) Overhead Conductors and Devices	764,363,245	94,620,975				858,984,220
54	(357) Underground Conduit	32,181,582					32,181,582
55	(358) Underground Conductors and Devices	35,616,310	25,378				35,641,688
56	(359) Roads and Trails	3,157,183	1,279,979				4,437,162
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)] 4,577,749,618	325,746,387	7,405,490		1,065,771	[(e)] 4,897,156,286
59	4. Distribution Plant						

60	(360) Land and Land Rights	20,131,641	387,998				20,519,639
61	(361) Structures and Improvements	66,798,568	4,867,994	166,802			71,499,760
62	(362) Station Equipment	809,027,221	76,230,735	2,528,289		(1,065,771)	881,663,896
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	744,678,539	123,381,696	660,103			867,400,132
65	(365) Overhead Conductors and Devices	721,100,006	71,570,803	2,344,836			790,325,973
66	(366) Underground Conduit	413,181,083	25,703,609	762,660			438,122,032
67	(367) Underground Conductors and Devices	1,485,454,805	89,940,053	4,831,033			1,570,563,825
68	(368) Line Transformers	569,016,156	114,943,014	73,425			683,885,745
69	(369) Services	456,431,285	28,868,036	336,301			484,963,020
70	(370) Meters	190,699,177	125,613,380				316,312,557
71	(371) Installations on Customer Premises	12,879,192	4,875,656				17,754,848
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	100,218,571	6,827,127	74,613			106,971,085
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)	[(b)]5,601,847,282	673,210,101	11,778,062		(1,065,771)	[(f)]6,262,213,550
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	20,032,304	1,393,602				21,425,906
87	(390) Structures and Improvements	98,354,566	73,030,744				171,385,310
88	(391) Office Furniture and Equipment	132,503,400	(12,196,960)	8,263,049			112,043,391
89	(392) Transportation Equipment	248,279,588	18,086,224				266,365,812
90	(393) Stores Equipment	1,949,332	35,488				1,984,820
91	(394) Tools, Shop and Garage Equipment	150,904,086	13,792,023	160,156			164,535,953
92	(395) Laboratory Equipment	2,965,829		301,973			2,663,856
93	(396) Power Operated Equipment	70,779,266	26,606,706				97,385,972
94	(397) Communication Equipment	228,714,586	56,985,475	336,533		10,262,356	295,625,884
95	(398) Miscellaneous Equipment	1,888,676		3,104			1,885,572
96	SUBTOTAL (Enter Total of lines 86 thru 95)	956,371,633	177,733,302	9,064,815		10,262,356	1,135,302,476
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)	956,371,633	177,733,302	9,064,815		10,262,356	1,135,302,476[(g)]
100	TOTAL (Accounts 101 and 106)	23,429,985,801	2,153,157,830	72,544,548	(33,247,531)		25,477,351,552
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)	23,429,985,801	2,153,157,830	72,544,548	(33,247,531)		25,477,351,552

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	22,236,471		4,412	—	—	$ 22,232,059
Account 353 - Station Equipment	131,382,246	11,997,461	119,657	—	—	$ 143,260,050
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	13,816,165		—	—	—	$ 13,816,165

(b) Concept: DistributionPlant

Distribution Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 361 - Structures & Improvements	$ 838,281	$ —	$ 11,450	$ —	$ —	$ 826,831
Account 362 - Station Equipment	4,224,690	—	—	—	(1,561,531)	$ 2,663,159

(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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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			
3				
21	Other Property:			
22	Sfwr-General B-MN	09/01/2024	02/28/2025	8,893,189
47	TOTAL			8,893,189

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.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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 #2	313,284,474
2	SHC Solar Gen Plant III New-25233	88,329,699
3	PVW Pleasant Valley Repower	52,505,080
4	BWF Border Wind Repower	39,613,411
5	Chanhassen New SC	36,180,855
6	BLL0 - Black Start Conversion	35,949,416
7	PI TN-40 Casks (48-64)	30,983,838
8	Sioux Falls Renovation	25,979,944
9	MT 2nd License Renewal	22,411,386
10	ELR MN Sub Feeder Breakers	18,871,463
11	0980 -Str 2 -27A (Phase 2)	18,533,677
12	5300 Huntley-South Bend	15,456,035
13	MN-Dist Fleet NewUnit Prchse El Ops	14,682,608
14	SHC SS East Collector Sub	11,730,969
15	MN Energy Connection Pre-Con	10,967,357
16	Envis Switching Station	10,806,104
17	Hennepin South Relocation	8,390,122
18	MT 2028 DFS Cask Campaign	8,385,012
19	MN Transportation Units Over 50K	8,212,004
20	ITC-VOIP Ref Prairie Island NP MNx	8,122,181
21	SHC to SSE Line 5652 T-Line	7,886,219

22	SHC Solar II SSE-SHC Interconn Line	7,493,573
23	LINE Convert Larimore LAR 4kV	7,370,201
24	LINE Install Louise LOU TR2	7,208,797
25	ITC-ADMS-OMS Merge Upgrade CE MN	7,076,816
26	Rebuild Downtown St. Paul Manholes	6,576,683
27	Mallard TR1 TR2 and BKR 5T7	6,556,568
28	SUB MN Feeder Load Monitoring	6,262,171
29	MT - WRGM Replacement	6,237,248
30	Parkers Lake TR09	6,105,143
31	Install Network Monitoring Mpls	5,559,711
32	RIV9 - Hot Gas Path - 22487	5,442,852
33	LYC - Add 345kV Brkr	5,058,997
34	ITC ISO Intrfc & Stlmt Rpl SW MN-20	5,055,351
35	Pot Parallel Removal Parkers Lake 1	4,712,612
36	MISO LRTP4 pre-con MN	4,583,956
37	SUB Install South Renner SRN TR02	4,537,967
38	BDS5C Unit 5 Major Inspection	4,531,530
39	Rebuild Daytons Bluff DBL Manholes	4,468,327
40	SUB ELR Install Gaiter Lake Sub	4,432,578
41	0980 - Str 50 - 79 (Phase 3)	4,404,931
42	RIV10 Hot Gas Path-22488	4,307,096
43	Reinforce Twin Lakes TWL081	4,146,279
44	PI 2nd License Renewal	4,033,369
45	SUB Rebuild Averill AVR Substation	3,799,900
46	ADM - 345kV MTC Shunt Reactor	3,777,040
47	FERC 881 ? Data Compliance	3,743,017
48	PI Water Treatment Mod	3,657,460
49	HNA - HMP 2nd CKT 39Mi	3,607,153

50	MN - Pole Replacement Blanket		3,518,601
51	ITC-Solar Garden Portal SW MN		3,492,305
52	Sheyenne 230kV NERC Order 754 Upgra		3,477,798
53	NSM0992 CNC SHC REPL STRS PH5		3,423,215
54	T PIP090 feeder underbuild 2nd		3,366,560
55	Install Edina EDA063 Feeder		3,328,179
56	RRK - 115kV Ampacity Upgrade		3,277,392
57	ITC-AOM Servers HW MN		3,097,535
58	SHC2 Synch Condenser		3,035,355
59	0729 CLF LCO SOS RELO STRS 222-228		2,986,173
60	ITC-FERC 881 AAR Solution SW 200118		2,901,369
61	0736 SCA-LCR 69kV REBLD 9mi		2,871,053
62	Rebuild Red River RED Feeders		2,822,073
63	Relocate STP Tunnel Feeders		2,790,999
64	Reserve TR 115-13.8 kV 50 MVA		2,731,808
65	Inver Grove Sub Upgrades		2,687,922
66	NSP0714 WAW- SJE Tap Rebuild		2,654,742
67	SUB Install La Crescent LAC TR2		2,588,803
68	Pot Parallel Prairie Island 345kV		2,510,879
69	C Install Elm Creek ECK342 Feeder		2,467,815
70	ITC-Wildfire Risk FS SW MN		2,463,565
71	Reserve TR 115-13 kV 28 MVA		2,462,551
72	MT Replace Stator Connection Ring		2,406,283
73	MN Failed Sub Equip Replacement		2,388,983
74	NSPM Priority Defects 69kV, Line		2,367,004
75	ELR MPLS Network Protectors		2,335,634
76	COMM MN Fiber Buildout		2,317,233
77	ITC-CAP Nuc Admin Panel SW MN		2,296,436

78	Pot Parallel Red Rock 345kV	2,277,764
79	NSM0984 CNC SHC REPL STRS PH5	2,223,893
80	Carver County - Oil Breaker - 5M100	2,188,971
81	LINE Convert North Broadway NBY 4kV	2,127,893
82	MT 2026 ISFSI Expansion	2,093,818
83	MT #12 EDG Voltage Regulator	2,084,403
84	MT RFO32 Rplc Turbine Stop Valves	2,078,324
85	COMM MN Feeder Load Monitoring	2,049,700
86	ITC-PI Sec Comp Refresh NP MN	2,030,284
87	MN-Dist Fleet ADD Unit Purchase E >	1,969,570
88	JT Extension Umore	1,953,244
89	NSPM S&E 345kV Line	1,944,952
90	PI SR Inverter Replacement	1,876,046
91	NSPM PHEV >$50K Distribution Electr	1,864,664
92	0749 69kV Rebuild Waseca to ITC Tap	1,857,958
93	Relocate RED091 8th ST	1,853,120
94	SUB Install Stockyards STY TR03	1,831,888
95	ITC-MEC 2.0 SW 200117 MN	1,749,010
96	Relocate for I-494 expansion	1,709,148
97	Eidswold Sub Interconnection	1,698,772
98	Prairie Island Physical Security In	1,668,633
99	PI 2023 Capital Maintenance	1,666,357
100	PI Equipment Sensors (A/I)	1,648,033
101	PI NI Drawer Replacement	1,633,219
102	ELR MN Sub RTUs	1,607,592
103	SD - FPIP Blanket	1,594,000
104	MT T-2 T-3 TRB Bearing	1,584,573
105	MN SUB Analog Circuit Retirements	1,569,046

106	MT #11 EDG Voltage Regulator	1,564,060
107	Replace FLS064 8th-10th S Phillips	1,535,612
108	0726 Curie tap-Tracy Switch St rebu	1,525,363
109	MT AST SSR Isolation	1,513,917
110	C Relocate 3900 MNTNKA BLVD OH-UG	1,498,875
111	Parkers Lake 115kV NERC Order 754	1,481,111
112	MT CRD Rebuild and Rplc (RFO32)	1,479,508
113	SE Region Reliability Initiative	1,476,468
114	RRK - 115kV ELR Breakers	1,468,952
115	NSPM S&E 69kV Line	1,463,004
116	SUB Reinf Daytons Bluff DBL Sub Ph2	1,460,750
117	LYC - Inst 3 - 345kV Brkrs	1,391,954
118	PI U2 Rod Control	1,380,257
119	MN EV Public DCFC (XEO) EVSI	1,358,317
120	SHC FE Long Duration Battery-26451	1,324,994
121	Install Feeder Tie SDX312-FSL311	1,322,900
122	MN Electric Vehicle Program FLEET	1,322,600
123	NSPM 0795 St. John's - Watab River	1,320,303
124	PI-NMC RD Rad Monitor Repl	1,319,179
125	T DLO-WTN-STB Del to St Boni	1,305,283
126	ELR MPLS Vault Tops	1,300,211
127	NSM0859 Str. 16 to Chemolite Rebuil	1,294,851
128	HMP - Add 345kV Brkr	1,286,774
129	HNA - Add 345kV Brkr	1,263,810
130	5400 STR 182 ? RCH Rebuild	1,259,255
131	Stockyards DCP TR3 Sub	1,234,322
132	0827 (SCL - SHC) - Private Comm Net	1,234,270
133	0721 Rebuild STR 71 to STR 476	1,202,234

134	ELR MN Sub Switches	1,200,450
135	Astro Substation TAM	1,187,463
136	0760 WAB LAK STR181-217 RBLD	1,185,015
137	NSPM Priority Defects 115kV, Line	1,184,271
138	South Bend Substation	1,164,062
139	MINNESOTA MAJOR STORM RECOVERY	1,149,922
140	Relocation MPLS SWLRT Road Project	1,119,541
141	SUB Install Prior PRR TR2	1,108,290
142	NSPM Week4 SES Accrual	1,100,532
143	ITC-ECMS Nuclear SW MN	1,082,221
144	MN SES Accruals	1,068,583
145	RRK - 115kV Cap Breakers	1,049,330
146	NSP0714 SJE Tap- MDE Rebuild	1,045,517
147	PI DFS +20yr incl CON	1,033,521
148	NSM0782 GNL-GSL Rebuild	1,009,028
149	LINE ELR Install Gaiter Lake Sub	1,007,441
150	Minor Projects	165,319,192
151	[(a)] (footnote to page 106)	
43	Total	1,285,135,833

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.

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Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	8,874,406,430	8,874,406,430		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	789,618,547	789,618,547		
4	(403.1) Depreciation Expense for Asset Retirement Costs	31,904,416	31,904,416		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	19,711,395	19,711,395		
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)	841,391,930	841,391,930		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(66,317,263)	(66,317,263)		
13	Cost of Removal	(62,772,510)	(62,772,510)		
14	Salvage (Credit)	14,167,758	14,167,758		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(114,922,015)	(114,922,015)		

16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	(61,895,865)	[a](61,895,865)		
18	Book Cost or Asset Retirement Costs Retired	(5,885,320)	(5,885,320)		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	[b]9,533,095,160	9,533,095,160		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	1,838,462,165	[c]1,838,462,165		
21	Nuclear Production	2,554,998,823	[d]2,554,998,823		
22	Hydraulic Production-Conventional	20,707,009	[e]20,707,009		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,281,596,915	[f]1,281,596,915		
25	Transmission	1,246,728,896	[g],[h]1,246,728,896		
26	Distribution	2,116,566,124	[i],[j]2,116,566,124		
27	Regional Transmission and Market Operation				
28	General	474,035,228	[k]474,035,228		
29	TOTAL (Enter Total of lines 20 thru 28)	[l]9,533,095,160	9,533,095,160		

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToAccumulatedDepreciation

Net change in RWIP	$	(54,091,060)
Net Transfers and Adjustments		494
(Gain)/Loss		(7,801,821)
Common Expense Allocation		(3,478)
Total	$	(61,895,865)

(b) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

		Cost of Removal Reserve
Steam Production	$	169,451,593
Nuclear Production		(62,761,377)
Hydraulic Production-Conventional		3,899,472
Other Production		116,759,712
Transmission		205,122,099
Distribution		258,126,545
General		1,064,963
Total	$	691,663,007

(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	$	53,442,160

(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	$	2,933,259

(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.

(l) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

		Cost of Removal Reserve
Steam Production	$	169,451,593
Nuclear Production		(62,761,377)
Hydraulic Production-Conventional		3,899,472
Other Production		116,759,712
Transmission		205,122,099
Distribution		258,126,545
General		1,064,963
Total	$	691,663,007

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. 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.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between 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).
8. 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.			1,921,868	12,358,427	135	14,280,160	
2	UNITED POWER & LAND CO. - Capital Stock			4,020,000			4,020,000	
3	UNITED POWER & LAND CO. - Paid-In-Capital			749,511		[(a)]135	749,376	
4	UNITED POWER & LAND CO. - Unappropriated Undistributed Subsidiary Earnings			(2,847,643)	12,358,427		9,510,784	
5	NSP NUCLEAR CO.			1,579,726	(338)	(61)	1,579,449	
6	NSP NUCLEAR CO. - Capital Contribution			962,713		[(b)](61)	962,774	
7	NSP NUCLEAR CO. - Unappropriated Undistributed Subsidiary Earnings			617,013	(338)		616,675	
42	Total Cost of Account 123.1 $ 5,732,150.00		Total	3,501,594	12,358,089	74	15,859,609	

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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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)	106,828,966	81,648,991	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]60,783,380	[b]71,606,663	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	157,395,060	165,226,526	Electric
8	Transmission Plant (Estimated)	921,173	1,100,272	Electric
9	Distribution Plant (Estimated)	4,125,403	4,632,023	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[c](5,340,620)	[d](10,855,771)	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	217,884,396	231,709,713	
13	Merchandise (Account 155)	1,088,329	1,331,042	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	[e] (footnote to page 106)			
20	TOTAL Materials and Supplies	325,801,691	314,689,746	

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction

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

(b) Concept: PlantMaterialsAndOperatingSuppliesConstruction

	Electric	Gas
Production	$ 25,748,613	$ —
Transmission	17,054,201	—
Distribution	26,540,163	2,263,686
Total	$ 69,342,977	$ 2,263,686

(c) 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.

(d) Concept: PlantMaterialsAndOperatingSuppliesOther

Includes a credit of $2,777,165 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of $8,078,606 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).

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	1,300,466		69,262		69,262		69,262		1,800,812		3,309,064	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)									69,262		69,262	
5	Returned by EPA	[(c)] 3										3	
6													
7													
8	Purchases/Transfers:												
9	[(a)] Allow transfer to SMMPA(CSAPR)												
10	[(b)] Transfer to SMMPA (ARP)												
11													
12													
13													

14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	(6,406)										(6,406)	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Beginning Balance Adj.	4										4	
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	1,294,067		69,262		69,262		69,262		1,870,074		3,371,927	
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		36,989		40,693	
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		36,063		38,841	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)	926	19							926	18	1,852	37
45	Gains		19								18		37
46	Losses												

FOOTNOTE DATA

(a) Concept: AllowancesInventoryPurchasesTransfersDescription

Information not available at time of filing.

(b) Concept: AllowancesInventoryPurchasesTransfersDescription

Information not available at time of filing.

(c) Concept: AllowancesReturnedByEnvironmentalProtectionAgencyNumber

Information not available at time of filing, estimate used. Amount to be finalized by EPA in first half of 2025.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	87,644										87,644	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)			16,253								16,253	
5	Returned by EPA	[(b)]78										78	
6													
7													
8	Purchase/Transfer												
9	[(a)] Transfer to SMMPA												
10													
11													
12													
13													

14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	(5,277)										(5,277)	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Beginning Balance Adj.	3										3	
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	82,448		16,253								98,701	
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												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												

40	Balance-End of Year												
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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AllowancesInventoryPurchasesTransfersDescription
Information not available at time of filing.
(b) Concept: AllowancesReturnedByEnvironmentalProtectionAgencyNumber
Information not available at time of filing, estimate used. Amount to be finalized by EPA in first half of 2025.

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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	[a] Prairie Island Extended Power Uprate Project MN Docket E-002/CN-08-509	[c] 78,884,915		[d] Various	3,923,369	37,862,067
22	[b] 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	17,489,293
49	TOTAL	126,929,210			8,601,268	55,351,360

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, NDPSC 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	$	4,217,515
Account No. 426.5 - accretion		(294,146)
	$	3,923,369

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	Sauk Centre Facilities Study Agmt-600101762359	176	561.6,408.1,925,926		
3	OTP Lake Preston Interconnection Req-600101768858	259	561.6,408.1,925,926	45,741	561.6, 242
4	GRE Century Interc Req-600101775373	15,154	561.6,408.1,925,926	3	561.6
5	Kimley Horn Interconnection Requests-600101775410	160,819	561.6,408.1,925,926	100,000	561.6
6	East Shakopee-600101775409	19,402	561.6,408.1,925,926	55,000	561.6, 242
7	NorthPoint Development-600101775426			15,000	242
8	RGA Holdings - Rosemount SISA-600101775419	18,580	561.6,408.1,925,926	30,000	561.6, 242
9	Ryan Companies - Pine Island SISA-600101775420			50,000	242
10	GRE Slayton Interc Req-600101775416	19,409	561.6,408.1,925,926	55,000	561.6, 242
11	Microsoft Corporation - Kodiak SISA-600101775425	5,396	561.6,408.1,925,926	50,000	561.6, 242
12	Slayton-600101775375	3,715	561.6,408.1,925,926		
20	Total	242,910		400,744	
21	**Generation Studies**				
22	J1445 Mayhew Lake Sub Solar-600101746865	105	561.7	1	561.7
23	S1013 Surplus Interconn Facilities Study-600101774911	28,567	561.7		
24	J2104 Facility Study-600101775453	168,567	561.7		
25	J2087 Facility Study-600101775446	96,416	561.7		

26	J2309 Facility Study-600101775452	103,898	561.7	64,897	561.7
27	J2065 Facility Study-600101775458	93,320	561.7		
28	J2199 Facility Study-600101775454	139,232	561.7		
29	J1898 Facility Study-600101775463	6,781	561.7		
30	J2053 Facility Study-600101775451	4,924	561.7		
31	J2199 Short Circuit Study-600101775450	954	561.7		
32	Byron - GRE PL Valley NU Facility Study-600101775885	428	561.7	2	561.7
39	Total	643,192		64,900	
40	Grand Total	886,102		465,644	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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 Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Asset Retirement Recovery	2,772,264,090	154,121,067			2,926,385,157
2	Benefit Cost Recovery Deficit	338,837,600	18,505,671	184	20,848,270	336,495,001
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	23,296,896		557	4,913,132	18,383,764
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	590,072	691,257	142	419,107	862,222
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	62,183,211	[(a)]57,925,275	[(b)] Various	48,703,733	71,404,753
6	Deferred Tax Collected in Rates in Excess of Current Tax Accrual Levels	713,133		282	341,063	372,070
7	Derivatives & Hedging – Retail Electric & Gas	2,934,716		244	2,193,059	741,657
8	Laurentian Biomass PPA Termination - SD Docket EL 22-017	1,031,745		557	1,031,745	
9	Load Flexibility Tracker - MN Docket E-002/M-21-101	50,013	311,999	908	362,012	
10	Mankato/Cannon Falls Lease Normalization	20,761,607	414,000	101.1	4,004,046	17,171,561
11	Minnesota Business Incentive and Sustainability Rider - MN Docket E-002/M-20-436 - MN Docket E-002/GR-21-630 - Amortized through 2024	871,192		407.3	871,192	

12	Minnesota Capacity Revenue Tracker- MN Docket E-002/GR-21-630	62,252,909	107,423,187	182.3	62,252,909	107,423,187
13	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	882,068		912	880,436	1,632
14	Minnesota Electric Sales True-Up - 2023- MN Docket E-002/GR-21-630		32,345,935	407.4	19,798,505	12,547,430
15	Minnesota Electric Sales True-Up - 2024 - MN Docket E-002/GR-21-630		39,590,623			39,590,623
16	Minnesota Electric State Energy Policy Rider - MN Docket E-002/M-23-465		7,265,556	407.4	6,017,228	1,248,328
17	Minnesota Gas Utility Infrastructure Cost Rider - MN Docket G-002/M-24-369	36,633,097	17,162,617	407.3	24,256,317	29,539,397
18	Minnesota LED Streetlighting - MN Docket E-002/GR-15-826 - MN Docket E-002/GR-21-630 - Amortized through 2024	120,020		407.3	120,020	
19	Minnesota Deferred Gas Property Tax - 2022 - MN Docket G-002/GR-21-678	24,841				24,841
20	Minnesota Deferred Gas Property Tax - 2023 - MN Docket G-002/GR-21-678	2,071,777	49,322	408.1	887,866	1,233,233
21	Minnesota Deferred Gas Property Tax - 2024 - MN Docket G-002/GR-21-678		2,083,713			2,083,713
22	Minnesota Gas Conservation and Energy Management Program Costs - MN Docket G-002/M-24-147 - Generally amortized over 12 month period following the expenditure		33,490,082	[(c)] Various	30,533,992	2,956,090
23	Minnesota Gas Decoupling - MN Docket G-002/GR-21-678	9,225,924	25,859,013	407.4	4,224,768	30,860,169
24	Minnesota Renewable Development Fund Rider - MN Docket E-002/M-24-326	37,886,413	32,788,699	407.3	38,412,456	32,262,656
25	Net of Tax AFUDC in Plant Adjustments	127,073,599	9,540,929			136,614,528
26	Nonplant Excess ADIT	104,222,053		283	8,467,222	[(f)] 95,754,831
27	North Dakota AGIS Deferral - ND Docket PU-20-441	2,389,661	1,948,623			4,338,284
28	North Dakota Environmental Cleanup - ND Docket PU-17-894	3,140,114		[(d)] Various	3,140,114	

29	North Dakota Renewable Energy Rider - ND Docket PU-24-341		5,194,538	407.4	4,883,760	310,778
30	North Dakota PI Payments - ND Docket PU-23-364		517,435			517,435
31	North Dakota Transmission Cost Recovery Rider - ND Docket PU-24-349		3,614,332	407.4	3,081,727	532,605
32	Power Contract Valuation Adjustment - Generally amortized over term of related contract	28,259,882		244	6,101,888	22,157,994
33	Renewable*Connect Off-Peak - MN Docket E-002/M-19-33 - MN Docket E-002/M-21-222	210,832	8,547,198	142	7,649,639	1,108,391
34	Renewable*Connect Standard - MN Docket E-002/M-19-33 - MN Docket E-002/M-21-222	38,803	4,339,713	142	3,619,601	758,915
35	Sherco 3 Depreciation Deferral - MN Docket E-002/GR-15-826 - Amortized over 21 years (01/2014-12/2035)	5,534,425		407.3	503,130	5,031,295
36	South Dakota Electric Conservation and Energy Management Program Costs - SD Docket EL 24-016 - Generally amortized over 12 month period following the expenditure		1,143,694	(e) Various	1,043,497	100,197
37	South Dakota Infrastructure - SD Docket EL 24-029	628,756		254	628,756	
38	South Dakota PI Payments		596,282			596,282
39	South Dakota Ratemaking Differences - SD Docket F-3382 - SD Docket F-3422 - Amortized over plant lives	2,903,250	433,000	405	453,000	2,883,250
40	South Dakota Transmission Cost Recovery Rider - SD Docket EL 24-030	479,531	881,603	407.4	464,524	896,610
41	Theoretical Depreciation Reserve Surplus - MN Docket E-002/GR-17-147 - Amortized over plant lives	219,716,840		407.3	8,892,617	210,824,223
42	Transmission Formula Rates	16,406,088	5,313,162	565	7,631,258	14,087,992
44	TOTAL	3,883,635,158	572,098,525		327,632,589	4,128,101,094

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: IncreaseDecreaseInOtherRegulatoryAssets

Accounts charged:		
517	$	2,014,098
519		1,819,222
520		13,182,157
523		728,699
524		2,855,905
528		506,969
530		8,140,453
531		5,136,398
532		23,541,374
Total	$	57,925,275

(b) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:		
517	$	1,827,011
519		1,079,452
520		9,562,364
523		324,476
524		2,342,361
528		489,241
530		6,069,649
531		4,295,623
532		22,713,556
Total	$	48,703,733

(c) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:		
421	$	5,724,809
495		3,756,712
908		21,052,471
Total	$	30,533,992

(d) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:		
142	$	1,436,787
254		538,066
431		27,037
735		1,138,224
Total	$	3,140,114

(e) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:

254	$ 55,628
142	987,869
Total	$ 1,043,497

(f) Concept: OtherRegulatoryAssets

	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Total
Electric	$ 66,516,630	$ 25,915,720	$ 92,432,350
Gas	2,390,940	931,541	3,322,481
Total	$ 68,907,570	$ 26,847,261	$ 95,754,831

*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 12/31/2023	Amortization 2024	Excess Balance 12/31/2024
Federal Net Operating Loss	$ 71,309,566	$ (4,194,680)	$ 67,114,886
Post Employment Benefits - Long Term Disability	1,151,061	(127,896)	1,023,165
Post Employment Benefits - Retiree Medical	3,691,742	(410,193)	3,281,549
Total Electric	$ 76,152,369	$ (4,732,769)	$ 71,419,600

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Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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-24-50)	22,952,517	14,714,318	182.3	22,952,518	14,714,317
2	Conservation and Energy Management Program Costs Minnesota Gas Incentive (Docket G-002/M-24-47)	2,633,533	5,279,617	182.3	2,633,532	5,279,618
3	Federal and State Income Taxes Interest Receivable	90,696	134,931	171	90,696	134,931
4	Federal and State Income Tax Receivable	818	3,421,328			3,422,146
5	IPP Power Contract Billing Adjustments	532,056				532,056
6	JOA & Rate Payer Share MTM	10,502,369		557	3,453,288	7,049,081
7	Notes Receivable - 3rd Party	1,937,877		143	1,937,877	
8	Prepaids - Facility Fees	1,512,472		431	411,368	1,101,104
9	Minnesota Electric Retail Rate Case Expenses (Docket E-002/GR-21-630) - Amortized through Dec. 2024	831,686	793,050	928	1,624,736	
10	Minnesota Electric Retail Rate Case Expenses (Docket E-002/GR-24-320)		971,467			971,467
11	Minnesota Gas Retail Rate Case Expenses (Docket G-002/GR-23-413) - Amortized through Dec. 2026	726,175	1,200,794	928	1,104,968	822,001
12	North Dakota Electric Retail Rate Case Expenses (Docket PU-12-813) - Amortized through June 2024	22,899		928	22,899	
13	North Dakota Electric Retail Rate Case Expenses (Docket PU-24-376)		488,680			488,680

14	North Dakota Gas Retail Rate Case Expenses (Docket PU-23-367) - Amortized through Feb. 2027	499,668	386,457	928	339,293	546,832
15	South Dakota Electric Retail Rate Case Expenses (Docket EL 22-017) - Amortized through Dec. 2025	476,974	156	928	238,487	238,643
16	Recovery of Legislative Costs - Community Solar Garden (Docket E002/CI-23-335)		961,000			961,000
17	Loan Receivable - 3rd Party	633,889	1,497,938	143	1,063,457	1,068,370
18	Debt Issuance Expense	393	211,381			211,774
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	43,354,022				37,542,020

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	257,779,311	[(a)]288,374,097
3	Electric - Non-Plant	1,092,733,812	1,117,406,725
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,350,513,123	[(b)]1,405,780,822
9	Gas		
10		40,080,146	[(c)]40,413,397
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	40,080,146	[(d)]40,413,397
17.1	Other (Specify)	12,690,385	[(e)]12,107,500
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,403,283,654	[(f)]1,458,301,719

Notes

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Decommissioning	$ —	$ —
Electric Distribution Plant	162,444,561	182,271,996
Electric General Plant	1,418,573	(4,907,489)
Electric Intangible Plant	3,265,435	2,675,781
Electric Nuclear Fuel	29,931,181	30,242,381
Electric Nuclear Production Plant	40,101,848	36,745,222
Electric Production Plant	48,370,717	56,632,519
Electric Transmission Plant	57,875,333	68,267,378
Electric Transmission-Production Plant	2,309,061	—
Common (Allocation to Electric)	2,441,981	2,484,989
Regulatory Differences - Effect of Rate Changes	(95,898,029)	(91,055,269)
Regulatory Differences - Investment Tax Credit Gross-Up	5,518,650	5,016,589
Total Electric Plant Related Only	$ 257,779,311	$ 288,374,097

(b) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Electric:		
Avoided Tax Interest	$136,774,207	$140,589,043
Bad Debts	12,526,166	11,121,114
Customer Advances	6,130,593	5,771,405
Deferred Connection Fees	159,256,354	175,606,865
Deferred Rent	2,108,609	1,852,657
Deferred Revenue	430,451	56,564
Economic Development Securities - Write-Off	100,746	101,345
Employee Incentive Plans	3,987,185	2,491,890
Employee Stock Ownership Program Dividends	7,533,930	7,638,739
End of Life Nuclear Fuel Amortization	29,899,366	38,172,211
Environmental Remediation	1,740,791	17,217,022
Excess Nonplant Accumulated Deferred Income Taxes	4,921,074	3,721,419
Fuel Tax Credit - Income Addback	6,911	5,994

Interest Income/Expense on Disputed Tax	(362,952)	—
Inventory Reserve	649,969	647,190
Mark to Market Adjustment	385,477	254,530
Medical Deductions - Self Insured	1,323,632	1,258,340
Minnesota Net Operating Loss	121,304	24,943
Monticello Extended Power Uprate Writedown	8,564,240	6,634,514
North Dakota Investment Tax Credit	55,496,566	60,665,008
North Dakota Investment Tax Credit - Valuation Allowance	(52,493,545)	(56,452,612)
North Dakota Investment Tax Credit - Federal Gross-Up	1,517,941	1,809,650
North Dakota Net Operating Loss	1,840	—
North Dakota Production Tax Credit - Levelization	5,776,021	8,322,539
Nuclear Production Tax Credit	—	172,681,247
Operating Lease Liabilities	118,245,506	105,140,838
Performance Recognition Awards	124,754	117,984
Post Employment Benefits - Retiree Medical	6,399,475	6,083,782
Post Employment Benefits - Long Term Disability	2,007,700	1,846,597
Post Employment Benefits - Voluntary Retirement Program	2,162,019	1,872,011
Public Utility Conservation Investment Programs	—	7,455,228
Rate Refund	59,479,067	9,285,202
Regulatory Asset/Liability - Decoupling	8,659,430	—
Regulatory Asset/Liability - Minnesota Credit Card Fees	—	1,014,715
Regulatory Asset/Liability - Miscellaneous	11,435,958	—
Regulatory Asset/Liability - Net Operating Loss Tracker	458,131	1,261,688
Regulatory Asset/Liability - Nuclear Production Tax Credit	—	56,395,797
Regulatory Asset/Liability - Renewable Energy Standard Rider	8,215,066	14,203,253
Regulatory Asset/Liability - Transmission Attach O	257,766	304,115
Regulatory Asset/Liability - Transmission Cost Recovery Rider	7,632,653	8,220,776
Regulatory Asset/Liability - Windsource	2,034,005	243,201
Regulatory Difference - Effect of Rate Changes	(95,898,029)	(91,055,269)
Regulatory Difference - Investment Tax Credit Gross-Up	5,518,650	5,016,589
Research and Experimentation Credit	35,765,466	36,126,740
Section 174 - Section 59(e) Adjustment	28,177,705	22,181,980
Severance Accrual	542,918	9,096
Solar Production Tax Credit	—	719,691
Solar Rewards Program	3,028,829	2,682,959
South Dakota Infrastructure Tracker	—	309,543
State Tax Deduction Cash vs. Accrual	609,996	665,589
Texas Gross Margin Tax	307	7,203
Vacation Accrual	6,576,950	6,627,299
Wind Production Tax Credit	752,432,964	608,827,937
Workers Compensation	248,961	24,661
Total Electric	$ 1,350,513,123	$ 1,405,780,822

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 $2,831,749 for 2023 and $2,695,598 for 2024.

	2023 ARAM	2024 ARAM
Unprotected ARAM:		
Decommissioning	$ —	$ 75.00
Electric Distribution Plant	977,529	1,079,048
Electric General Plant	34,439	32,524
Electric Intangible Plant	(135,178)	109,480
Electric Nuclear Fuel	(13,967)	—
Electric Production Plant	1,761,885	1,220,727
Electric Transmission Plant	194,558	243,770
Electric Transmission-Production Plant	5,354	3,560
Common (Allocation to Electric)	7,101	6,414
Total Electric	$ 2,831,721	$ 2,695,598

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

	2023 ARAM	2024 ARAM
Common (Unallocated)	$ 7,858	$ 7,098

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.

Excess (Electric only)	12/31/2024 Excess	12/31/2024 Gross up	12/31/2024 Total Regulatory
Flow Through	$ 491,390	$ 191,452	$ 682,842
Other Basis Differences (Unprotected)	(66,017,038)	(25,721,072)	$ (91,738,110)
	$ (65,525,648)	$ (25,529,620)	$ (91,055,268)

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

	12/31/2024 Excess	12/31/2024 Gross up	12/31/2024 Total Regulatory
Non-utility			
Other Basis Differences (Unprotected)	$ (8)	$ (3)	$ (11)
	$ (8)	$ (3)	$ (11)
Common (allocated)			
Other Basis Differences (Unprotected)	$ 196,489	$ 76,555	$ 273,044
	$ 196,489	$ 76,555	$ 273,044
Common (unallocated)			
Other Basis Differences (Unprotected)	$ (285,324)	$ (111,166)	$ (396,490)
	$ (285,324)	$ (111,166)	$ (396,490)

(c) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Gas:		
Avoided Tax Interest	$ 4,227,295	$ 5,109,508
Bad Debts	1,322,384	1,103,907
Deferred Connection Fees	18,803,666	18,482,496
Deferred Rent	190,104	176,096
Economic Development Securities - Write-Off	10,636	10,059
Employee Incentive Plans	412,186	257,005
Employee Stock Ownership Program Dividends	2,800,084	2,807,280
Environmental Remediation	65,051	75,889
Excess Nonplant Accumulated Deferred Income Taxes	320,999	258,653
Fuel Tax Credit - Income Addback	623	570
Interest Income/Expense on Disputed Tax	(38,317)	—
Inventory Reserve	58,599	61,515
Lower of Cost or Market on Gas Inventories	44,893	417,066
Medical Deduction - Self Insured	136,834	129,781
Minnesota Net Operating Loss	6,384	1,313
North Dakota Net Operating Loss	97	—
Operating Lease Liabilities	10,660,529	9,993,676
Performance Recognition Awards	12,897	12,168
Post Employment Benefits - Retiree Medical	661,563	627,461
Post Employment Benefits - Long Term Disability	207,551	190,452
Post Employment Benefits - Voluntary Retirement Program	223,504	193,073
Public Utility Conservation Investment Programs	827,847	—
Rate Refund	18,534	353,052
Regulatory Asset/Liability - Minnesota Credit Card Fees	—	897,086
Regulatory Asset/Liability - Miscellaneous	—	15,344
Regulatory Difference - Effect of Rate Changes	(5,687,206)	(5,512,324)
Regulatory Difference - Investment Tax Credit Gross-Up	259,015	217,559
Research and Experimentation Credit	1,213,010	1,713,046
Section 174 - Section 59(e) Adjustment	2,540,386	2,108,405
Severance Accrual	56,126	938
State Tax Deduction Cash vs. Accrual	19,225	26,263
Vacation Accrual	679,910	683,517
Workers Compensation	25,737	2,543
Total Gas	$ 40,080,146	$ 40,413,397

(d) Concept: AccumulatedDeferredIncomeTaxes

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

(e) Concept: AccumulatedDeferredIncomeTaxes

Other:	Balance at Beginning of Year	Balance at End of Year
Avoided Tax Interest	$ 79	$ 3,498,659
Deferred Compensation Plan Reserve	4,189,308	4,490,967
Deferred Connection Fees and CIAC	—	274,281
Minnesota Net Operating Loss	86	86
North Dakota Net Operating Loss	850	—
Nonqualified Pension Plans	190,550	85,373
Other Comprehensive Income	7,752,111	3,134,149
Partnership Passthrough	364,436	366,464
Performance Share Plan	188,927	257,536
Regulatory Difference - Effect of Rate Changes	(16)	(15)
State Tax Deduction Cash vs. Accrual	4,054	—
Total Other	$ 12,690,385	$ 12,107,500

(f) Concept: AccumulatedDeferredIncomeTaxes

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

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Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	All NSP-Minnesota common stock is owned by parent, Xcel Energy Inc.	5,000,000	0.01		1,000,000	10,000				
7	Total	5,000,000			1,000,000	10,000				
8	Preferred Stock (Account 204)									
9										
10										
11										
12	Total									

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-04	Year/Period of Report End of: 2024/ Q4

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	5,206,742,091
15.1	Increases (Decreases) due to contribution of capital by parent	713,526,143
16	Ending Balance Amount	5,920,268,234
17	**Other Paid in Capital**	

18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	5,920,268,234

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	[b] 18,500,579
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	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	[c] 24,453,968
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	534,000,000	18,200,000
12	4.50% Jun 1, 2052 First Mortgage Bonds		500,000,000		7,596,315		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	[a] 5.40% Mar 15, 2054 First Mortgage Bonds		700,000,000		10,217,694		2,709,000	02/29/2024	03/15/2054	02/29/2024	03/15/2054	700,000,000	[d] 31,483,675
16	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
17	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
18	5.10% May 15, 2053 First Mortage Bonds		800,000,000		11,417,666		5,968,000	05/08/2023	05/15/2053	05/08/2023	05/15/2053	800,000,000	[e] 40,640,090
19	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	[f] 16,157,286
20	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
21	Subtotal		8,150,000,000		109,930,533		67,295,751					7,984,000,000	345,585,598
22	Reacquired Bonds (Account 222)												
23													
24													
25													
26	Subtotal												
27	Advances from Associated Companies (Account 223)												
28	[g] 2.60% Jun 1, 2051 First Mortgage Bonds							12/17/2024	06/01/2051			166,000,000	166,000,000
29	Subtotal											166,000,000	166,000,000
30	Other Long Term Debt (Account 224)												
31	Right of Way Debt											[h] 2,032,176	182,313
32	Interest on Debt to Associated Companies												[i] 4,775,571
33	Subtotal											2,032,176	4,957,884
33	TOTAL		8,150,000,000									8,152,032,176	516,543,482

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription

Minnesota Public Utilities Commission Docket No. E, G-002/M-23-463. Order dated January 17, 2024.

In February 2024, NSPM issued $700,000,000 of 5.40 percent Green First Mortgage Bonds, due March 15, 2054. NSPM used the net proceeds to finance or refinance existing or future Eligible Green Expenditures and may temporarily repay short-term borrowings.

(b) Concept: InterestExpenseBonds

Interest at stated rate	$	17,000,000
Interest at swap loss		1,500,579
	$	18,500,579

(c) Concept: InterestExpenseBonds

Interest at stated rate	$	25,000,000
Interest at swap gain		(546,032)
	$	24,453,968

(d) Concept: InterestExpenseBonds

Interest at stated rate	$	31,710,000
Interest at swap gain		(226,325)
	$	31,483,675

(e) Concept: InterestExpenseBonds

Interest at stated rate	$	40,800,000
Interest at swap gain		(159,910)
	$	40,640,090

(f) Concept: InterestExpenseBonds

Interest at stated rate	$	16,050,000
Interest at swap loss		107,286
	$	16,157,286

(g) Concept: ClassAndSeriesOfObligationCouponRateDescription

Intercompany Note 2.60% Jun 1, 2051 First Mortgage Bonds issued 12/17/2024.

(h) Concept: OtherLongTermDebt

	Balance Dec. 31, 2023	Additions	Reductions	Balance Dec. 31, 2024
Right of Way Debt	$2,376,909	$—	$(344,733)	$2,032,176

(i) Concept: InterestExpenseOtherLongTermDebt

Xcel Energy Service Inc	$	4,336,408
Money Pool		439,163
	$	4,775,571

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Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	792,840,564
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		[(a)]78,009,296
9	Deductions Recorded on Books Not Deducted for Return	
10		[(b)]1,692,588,646
14	Income Recorded on Books Not Included in Return	
15		[(c)](124,038,748)
19	Deductions on Return Not Charged Against Book Income	
20		[(d)](2,329,499,573)
21	Equity in Earnings of Subsidiary Companies	(12,358,089)
22	Total Income Tax Expense	(361,121,133)
27	Federal Tax Net Income	(263,579,037)
28	Show Computation of Tax:	
29	Federal Income Tax at 21 percent	(55,351,598)
30	Other	(95,830,608)
31	Total Federal Income Tax Payable	[(e)](151,182,206)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: TaxableIncomeNotReportedOnBooks

TAXABLE INCOME NOT REPORTED ON BOOKS:		
Contributions in Aid of Construction	$	78,009,296
	$	78,009,296

(b) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

DEDUCTIONS RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:		
Avoided Cost Interest	$	54,906,396
Book Amortization - Acquisition Adjustments		14,976
Book Amortization - Computer Software		104,023,256
Book Amortization - Electric Vehicle Regulatory Assets		503,130
Book Amortization - Other		14,494,817
Book Depreciation		917,844,600
Book Income - Wisconsin/South Dakota Allowance for Funds During Construction		257,000
Book Unamortized Cost of Reacquired Debt		981,354
Clearing Account Book Expense		34,467,336
Deferred Compensation Plan Reserve		1,072,979
Electric Vehicle Charging Tariff		880,436
Employee Retention		145,628
Employee Stock Ownership Plan Dividends		1,585,921
Environmental Remediation		55,235,722
(Gain)/Loss on Dispositions (Book)		95,783
Lobbying Expenses		1,922,000
Low Income Discount Program		308,000
Meals & Entertainment		2,139,000
Nuclear Decommissioning		35,891,249
Nuclear Fuel Expense		110,712,471
Operating Lease Assets		49,208,430
Penalties		294,108
Pension and Benefit Capitalized		6,539,538
Pension Expense		29,833,994
Performance Share Plan		244,572
Prairie Island Extended Power Uprate Writedown Amortization		3,561,965
Public Utility Conservation Investments Programs Adjustment		17,054,346
Regulatory Asset - Gas Safety Deferrals		7,093,700
Regulatory Asset/Liability - Cancellation		4,383,753
Regulatory Asset/Liability - Minnesota Credit Card Fees		6,818,728
Regulatory Asset/Liability - Net Operating Loss Tracker		2,865,686
Regulatory Asset/Liability - Nuclear Production Tax Credit		201,144,170
Regulatory Asset/Liability - Renewable Energy Standard Rider		21,352,026
Regulatory Asset/Liability - Transmission Attach O		165,133
Regulatory Asset/Liability - Transmission Cost Recovery Rider		2,092,288
South Dakota Infrastructure Tracker		1,732,790
Suite and Entertainment Tickets		534,000
Vacation Accrual		187,365
	$	1,692,588,646

(c) Concept: IncomeRecordedOnBooksNotIncludedInReturn

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:		
Allowance for Funds During Construction - Equity (Non-Conservation Improvement Program)		(58,000,938)
Deferred Revenue		(1,333,825)
Deferred Revenue - Investment Tax Credit Grant		(68,945)
Insurance Fund Income (Cash Value)		(2,813,512)
Interest Income/Expense on Disputed Tax		(658,231)
Operating Lease Liabilities		(49,208,430)
Rate Surcharge		(11,954,867)
	$	(124,038,748)

(d) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:	
Allowance for Funds During Construction - Debt (Non-Conservation Improvement Program)	(26,954,399)
Bad Debts	(5,800,254)
Book Amortization - Monticello Extended Power Uprate Writedown Amortization	(6,896,832)
Deferred Fuel Costs	(4,100,829)
Deferred Rent	(964,462)
Employee Incentive Plans	(5,889,748)
Executive Officer Nondeductible Compensation	(103,022)
External Qualified Nuclear Decommissioning Fund	(35,891,246)
Gain/(Loss) on Dispositions (Tax)	(10,592,978)
Mark to Market Adjustment	(467,313)
Medical Deductions - Self Insured	(1,059,381)
Nonqualified Pension Plan	(375,260)
Performance Recognition Awards	(26,839)
Post Employment Benefits - Long Term Disability	(637,140)
Post Employment Benefits - Retiree Medical	(1,252,538)
Post Employment Benefits - Voluntary Retirement Program	(1,144,564)
Prepaid Advertising	(139,323)
Prepaid Insurance	(10,670,009)
Rate Case/Restructuring Expense	(30,334,807)
Rate Refund	(177,872,567)
Regulatory Asset - Miscellaneous	(45,079,637)
Regulatory Asset - Nuclear Refueling Outage Costs	(9,221,542)
Regulatory Asset - Property Tax	(11,937)
Regulatory Asset/Liability - Decoupling	(104,663,530)
Regulatory Asset/Liability - Windsource	(6,388,597)
Regulatory Reserve - Environmental	(52,951,216)
Repair Expenditures	(163,812,086)
Section 174	(37,500,000)
Section 174 - Section 59(e) Adjustment	(22,946,881)
Severance Accrual	(2,101,209)
State Tax Deduction	(27,789,573)
Solar Rewards Program	(1,235,717)
Tax Amortization - Monticello Rerate	(6,160,471)
Tax Amortization - Computer Software	(122,964,354)
Tax Depreciation	(1,274,623,295)
Tax Expense - Spent Fuel Isolation Devices	(16,750,551)
Tax Removal Cost Over Book	(113,242,551)
Workers Compensation	(882,915)
	$ (2,329,499,573)

(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 2024. The other members of the affiliated group and the federal income tax provision of each are:

Xcel Energy Inc.	(53,763,717)
NSP Nuclear Corporation	(86)
United Power and Land Company	3,282,988
Northern States Power Company (Wisconsin) and Subsidiaries	28,552,265
Public Service Company of Colorado and Subsidiaries	192,101,968
Southwestern Public Service Company	41,720,709
Nicollet Holdings Company, LLC and Subsidiaries	(357,587)
Nicollet Project Holdings LLC and Subsidiaries	(13,612,895)
Xcel Energy Communications Group Inc. and Subsidiaries	(113,409)
Xcel Energy Markets Holdings Inc. and Subsidiaries	395,664
Xcel Energy International Inc.	332
Xcel Energy Nuclear Services, Inc.	(9,265)
Xcel Energy Retail Holdings Inc. and Subsidiaries	5,079
Xcel Energy Transmission Holding Company, LLC and Subsidiaries	(87,128)
Xcel Energy Ventures Inc. and Subsidiaries	118,696
Xcel Energy Venture Holdings, Inc. and Subsidiaries	(4,355,056)
Xcel Energy Wholesale Group Inc. and Subsidiaries	74,954
Xcel Energy WYCO Inc.	3,995,529
WestGas Interstate, Inc.	13,915
Xcel Energy Services Inc.	(10,007,237)

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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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					(152,835,720)	(154,190,744)	(d)(1,355,024)			(152,352,577)			(l)(483,143)
2	Income Tax Adjustment	Federal Tax					1,653,514		(e)(1,653,514)			1,524,051			(m)129,463
3	FICA	Federal Tax		2023	2,999,501			2,999,501							
4	FICA	Federal Tax		2024			41,152,731	39,549,162		1,603,569		28,942,928			(n)12,209,803
5	Unemployment	Federal Tax		2023	4,485			4,485							
6	Unemployment	Federal Tax		2024			191,990	190,434		1,556		149,398			(o)42,592
7	**Subtotal Federal Tax**				3,003,986		(109,837,485)	(111,447,162)	(3,008,538)	1,605,125		(121,736,200)			11,898,715
8	Income	State Tax	Minnesota				(26,302,135)	26,761,104	(f)53,063,239			(26,260,818)			(p)(41,317)
9	Income Tax Adjustment	State Tax	Minnesota				294,954		(g)(294,954)			278,817			(q)16,137
10	Unemployment	State Tax	Minnesota	2023	44,190			44,190							
11	Unemployment	State Tax	Minnesota	2024			2,943,292	2,829,999		113,293		1,678,647			(r)1,264,645
12	Property Tax	State Tax	Minnesota	2022			(12,146)	(12,146)				(10,946)			(s)(1,200)
13	Property Tax	State Tax	Minnesota	2023	202,068,000		(8,611,598)	193,456,402				(7,692,922)			(t)(918,676)
14	Property Tax	State Tax	Minnesota	2024			199,128,000			199,128,000		178,110,000			(u)21,018,000
15	Property Tax MN Settlement	State Tax	Minnesota	2024			(25,544,541)		25,544,541			(26,432,408)			(v)887,867
16	Income	State Tax	North Dakota				(422,479)	1,075,364	(h)1,497,843			(413,979)			(w)(8,500)

17	Income Tax Adjustment	State Tax	North Dakota				(442)		[i]442						[x](442)
18	Unemployment	State Tax	North Dakota	2023	196			196							
19	Unemployment	State Tax	North Dakota	2024			4,038	3,994		44		2,012			[y]2,026
20	Property Tax	State Tax	North Dakota	2023	8,094,000		141,962	8,235,962				91,523			[z]50,439
21	Property Tax	State Tax	North Dakota	2024			8,599,099	31,099		8,568,000		6,832,699			[aa]1,766,400
22	Unemployment	State Tax	South Dakota	2024			3,865	4,683		(818)		1,925			[ab]1,940
23	Property Tax	State Tax	South Dakota	2022			1,337	1,337				1,337			
24	Property Tax	State Tax	South Dakota	2023	5,916,000		(154,002)	5,761,998				(154,002)			
25	Property Tax	State Tax	South Dakota	2024			6,462,000			6,462,000		6,462,000			
26	[a]Personal Property FCA	State Tax	South Dakota	2024			32,071	32,071				32,071			
27	Personal Property	State Tax	Iowa	2023	204,000		(31,772)	172,228				(31,772)			
28	Personal Property	State Tax	Iowa	2024			396,000			396,000		396,000			
29	Personal Property	State Tax	Kansas	2024			696,040	696,040							[ac]696,040
30	Income	State Tax	Wisconsin		17,000		23,254	(87,419)	[j](91,673)	36,000		23,252			[ad]2
31	Unemployment	State Tax	Wisconsin	2024			3,273	3,590		(317)		1,630			[ae]1,643
32	Income	State Tax	Texas		205,935		(39,114)	39,627	[k](54,564)	72,630		(47,987)			[af]8,873
33	Unemployment	State Tax	Georgia	2024	11		10			21		5			[ag]5
34	Unemployment	State Tax	Colorado	2024	20					20					
35	**Subtotal State Tax**				216,549,352		157,610,966	239,050,319	79,664,874	214,774,873		132,867,084			24,743,882
36	Denver Occ'l Privilege	Other Taxes		2023								15,166			[ah](15,166)
37	Miscellaneous Income	Other Taxes					897	897							[ai]897
38	[b]Property Tax on Rail Car	Other Taxes		2023	2,400		(675)	1,725							[aj](675)
39	[c]Property Tax on Rail Car	Other Taxes		2024			2,400			2,400					[ak]2,400
40	Other	Other Taxes		2024			121,675	121,675				113,123			[al]8,552
41	Use	Other Taxes		2024	3,710,615		33,787,968	33,334,023		4,164,560					[am]33,787,968
42	**Subtotal Other Tax**				3,713,015		33,912,265	33,458,320		4,166,960		128,289			33,783,976
40	TOTAL				223,266,353		81,685,746	161,061,477	76,656,336	220,546,958		11,259,173			70,426,573

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ 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)	$	730,614
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (211)		(3,508,002)
Federal income tax expense (409.1 and 409.2) accrued for long term income tax receiveable (186)		2,414,497
Federal income tax benefit (accrual and Cash) in other accounts receivable (143)		(992,133)
Total	$	(1,355,024)

(e) Concept: TaxAdjustments

Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)		3,936,539
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)		(5,590,053)
Total	$	(1,653,514)

(f) Concept: TaxAdjustments

Annual allocation of unitary benefit/detriment for Minnesota income taxes accrued as additional paid in capital (211)	$	16,113,868
State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)		987,805
State income tax benefit (accrual and cash) in other accounts receivable (143)		35,961,566
Total	$	53,063,239

(g) Concept: TaxAdjustments

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	$	707,535
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)		(1,002,489)
Total	$	(294,954)

(h) Concept: TaxAdjustments

Annual allocation of unitary benefit/detriment for North Dakota income taxes accrued as additional paid in capital (211)	$	737,139
State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)		19,026
State income tax benefit (accrual and cash) in other accounts receivable		741,678
Total	$	1,497,843

(i) Concept: TaxAdjustments

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	$	442
Total	$	442

(j) Concept: TaxAdjustments

Annual allocation of unitary benefit/detriment for Wisconsin income taxes accrued as additional paid in capital (211)	$	(91,673)

(k) Concept: TaxAdjustments

Annual allocation of unitary benefit/detriment for Texas income tax accrued as additional paid in capital (211)	$	(54,564)

(l) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	2,914,834
Other income and deductions (Account No. 409.2)		(3,397,977)
Total	$	(483,143)

(m) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	175,012
Other Income and deductions (Account No. 409.2)		(45,549)
Total	$	129,463

(n) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	3,426,548
Other income and deductions (Account No. 408.2)		164,815
Other		8,618,440
Total	$	12,209,803

(o) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	17,605
Other income and deductions (Account No. 408.2)		902
Other		24,085
Total	$	42,592

(p) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	1,518,127
Other income and deductions (Account No. 409.2)		(1,559,445)
Rounding		1
Total	$	(41,317)

(q) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	35,001
Other income and deductions (Account No. 409.2)		(18,864)
Total	$	16,137

(r) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	200,974
Other income and deductions (Account No. 408.2)		8,174
Other		1,055,497
Total	$	1,264,645

(s) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	(1,196)
Other income and deductions (Account No. 408.2)		(4)
Total	$	(1,200)

(t) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	(915,766)
Other income and deductions (Account No. 408.2)		(2,910)
Total	$	(918,676)

(u) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	20,952,000
Other income and deductions (Account No. 408.2)		66,000
Total	$	21,018,000

(v) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	887,867

(w) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	32,068
Other income and deductions (Account No. 409.2)		(40,568)
Total	$	(8,500)

(x) Concept: TaxesIncurredOther

Other income and deductions (Account No. 409.2)	$	(442)

(y) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	243
Other income and deductions (Account No. 408.2)		9
Other		1,774
Total	$	2,026

(z) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	50,439

(aa) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	1,766,400

(ab) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	232
Other income and deductions (Account No. 408.2)		8
Other		1,700
Total	$	1,940

(ac) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	696,040

(ad) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	2

(ae) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	197
Other income and deductions (Account No. 408.2)		7
Other		1,439
Total	$	1,643

(af) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	8,873
Total	$	8,873

(ag) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	1
Other		4
Total	$	5

(ah) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	1,709
Other income and deductions (Account No. 408.2)		140
Other		(17,015)
Total	$	(15,166)

(ai) Concept: TaxesIncurredOther

Other income and deductions (Account No. 409.2)	$	897

(aj) Concept: TaxesIncurredOther

Other	$	(675)

(ak) Concept: TaxesIncurredOther

Other	$	2,400

(al) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	8,551
Rounding		1
Total	$	8,552

(am) Concept: TaxesIncurredOther

Other	$	33,787,968

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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%	28,788			411.4	4,718		24,070	58 Years	
4	7%									
5	10%	12,327,959			411.4	1,114,870		11,213,089	57 Years	
6	30%	992,582			411.4	97,312		895,270	22 Years	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	13,349,329				1,216,900		[(a)] 12,132,429		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
11	Gas Utility									
12	4%	1,236			411.4	63		1,173	70 Years	
13	10%	658,284			411.4	106,071		552,213	50 Years	
14	TOTAL Gas Utility	659,520				106,134		553,386		
15	Common Utility									
16	4%	696			411.4	518		178	50 Years	
17	10%	60,278			411.4	6,565		53,713	50 Years	

18	TOTAL Common Utility	60,974				7,083		[(b)] 53,891		
47	OTHER TOTAL									
48	GRAND TOTAL	14,069,823				1,330,117		12,739,706		

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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 - 93.65%	$	50,469
Gas - 6.35%		3,422
	$	53,891

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Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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 Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	CapX2020 Promissory Notes	1,193	232	1,193		
2	Customer Prepayments	55,000			1,816,500	1,871,500
3	Deferred Compensation - Employees	11,579,609	131	2,005,218	3,218,706	12,793,097
4	Deferred Compensation - Employees (Wealth Op)	3,365,126	232	339,793	199,285	3,224,618
5	401 Nicollet Lease Credit	5,557,910	101	757,896		4,800,014
6	Deferred Revenue	1,535,569	(b) Various	1,503,980	170,155	201,744
7	Deferred Revenue-ITC Grant - Amortized over plant lives	763,487	405	68,945		694,542
8	Environmental & Regulatory Reserves	1,974,333	242	2,169,072	1,554,102	1,359,363
9	Executive PSP - Long Term	725,479	232	367,794	242,293	599,978
10	Long-Term Income Tax & Interest Payable	13,880,763	(c) Various	773,783	6,871,385	19,978,365
11	Unfunded Nonqualified Pension Benefit Costs	1,793,999	232	94,000		1,699,999
12	Nuclear Waste Strategy Coalition	37,495	253	44,542	71,000	63,953
13	Postemployment Benefit-Injury Compensation	7,902,581	(d) Various	1,545,665	908,525	7,265,441
14	Pre-Funded AFUDC: Metro Emissions Reduction Rider	43,473,074	405	2,226,732		41,246,342
15	Pre-Funded AFUDC: Mercury Emission Reduction Rider	218,851	405	96,073		122,778
16	Pre-Funded AFUDC: Minnesota Transmission Cost Recovery Rider	36,429,221	(e) Various	1,222,220	2,103,407	37,310,408

17	Pre-Funded AFUDC: FERC Transmission	35,706,255	405	[h]684,489	[i]50,549	35,072,315
18	Pre-Funded AFUDC: Renewable Energy Standards Rider	105,728,349	405	3,554,505	24,476,898	126,650,742
19	Pre-Funded AFUDC: South Dakota Transmission Cost Recovery Rider	2,063,367	[f] Various	2,229	377,694	2,438,832
20	Pre-Funded AFUDC: North Dakota Transmission Cost Recovery Rider	1,608,469	[g] Various	4,664	932,678	2,536,483
21	Coal Car Residual Value Deficit	3,302,461	151	3,302,461		
22	Renewable Development Fund Obligations	42,227,101	232	36,935,199	32,750,000	38,041,902
23	Shared Network Upgrade	879,685	565	57,061		822,624
24	[a] **Footnote from page 106b					
47	TOTAL	320,809,377		57,757,514	75,743,177	338,795,040

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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	$	960,078
456		543,902
Total	$	1,503,980

(c) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:		
236	$	730,614
431		43,169
Total	$	773,783

(d) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:		
131	$	241,815
232		1,303,850
Total	$	1,545,665

(e) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:		
405	$	1,195,452
432		11,292
419.1		15,476
Total	$	1,222,220

(f) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:		
432	$	940
419.1		1,289
Total	$	2,229

(g) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:		
432	$	1,712
419.1		2,952
Total	$	4,664

(h) 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 $996,157.
(i) 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 $243,371.

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
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)
							Debits		Credits		
			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)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	19,763,973	(1,852,899)						Various		[(a)] 17,911,074
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	19,763,973	(1,852,899)								[(b)] 17,911,074
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										

16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	19,763,973	(1,852,899)								17,911,074
18	Classification of TOTAL										
19	Federal Income Tax	15,393,235	(1,440,140)								13,953,095
20	State Income Tax	4,370,738	(412,759)								3,957,979
21	Local Income Tax										

FOOTNOTE DATA

(a) 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.
(b) Concept: AccumulatedDeferredIncomeTaxesAcceleratedAmortizationProperty
All amounts in columns b - k are related to Electric Steam Production Plant

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Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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)
							Debits		Credits		
			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)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	2,693,622,080	105,690,747					141,605,171		248,066,038	[(a)] 2,905,773,694
3	Gas	168,055,150	12,440,758					165,002		3,681,646	184,012,552
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	2,861,677,230	118,131,505					141,770,173		251,747,684	3,089,786,246
6	Other (Non-Operating)	(6,895,643)			13,442,778						6,547,135
9	TOTAL Account 282 (Total of Lines 5 thru 8)	2,854,781,587	118,131,505		13,442,778			141,770,173		251,747,684	3,096,333,381
10	Classification of TOTAL										
11	Federal Income Tax	1,934,689,339	68,933,697		9,173,016			91,483,072		175,845,526	2,097,158,506
12	State Income Tax	920,092,248	49,197,808		4,269,762			50,287,101		75,902,158	999,174,875
13	Local Income Tax										

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

	Dec. 31, 2023	410.1 & Adjustments	Dec. 31, 2024
Decommissioning Nonqualified	$ —	$ —	$ —
Electric Distribution Plant	823,337,847	18,830,584	842,168,431
Electric General Plant	93,140,075	3,186,743	96,326,818
Electric Intangible Plant	11,255,085	1,996,872	13,251,957
Electric Nuclear Fuel	22,662,137	1,960,910	24,623,047
Electric Nuclear Production Plant	479,786,421	(11,249,548)	468,536,873
Electric Production Plant	1,108,416,024	65,134,432	1,173,550,456
Electric Transmission Plant	924,105,001	54,081,927	978,186,928
Electric Transmission-Production Plant	25,789,699	(25,789,699)	—
Common (Allocation to Electric)	43,699,493	(2,461,477)	41,238,016
Regulatory Differences - Prior Flow Thru / Rate Change	(1,160,539,360)	48,842,332	(1,111,697,028)
Regulatory Differences - AFUDC Equity	—	—	—
Decommissioning Qualified	321,969,658	57,618,538	379,588,196
Total Electric Plant Related Only	$ 2,693,622,080	$ 212,151,614	$ 2,905,773,694

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 $33,014,789 for 2023 and $35,299,297 for 2024.

	2023 ARAM	2024 ARAM
Protected ARAM:		
Decommissioning	$ —	$ —
Electric Distribution Plant	4,771,727	4,282,485
Electric General Plant	2,091,087	2,441,013
Electric Intangible Plant	67,815	59,554
Electric Nuclear Fuel	(15,435)	(6,563)
Electric Production Plant	11,388,555	15,052,143
Electric Transmission Plant	2,462,803	3,564,893
Electric Transmission-Production Plant	70,139	81,380
Common (Allocation to Electric)	2,593,042	1,252,524
Total Protected ARAM	23,429,733	26,727,429
Unprotected ARAM:		
Decommissioning	—	—
Electric Distribution Plant	2,295,548	2,142,028
Electric General Plant	40,115	40,252
Electric Intangible Plant	(28,906)	113,808
Electric Nuclear Fuel	(3,273)	(2,188)
Electric Production Plant	6,423,364	5,232,616
Electric Transmission Plant	712,547	887,487
Electric Transmission-Production Plant	(25,020)	8,208
Common (Allocation to Electric)	171,269	149,717
Total Unprotected ARAM	9,585,644	8,571,928
Non Utility	(588)	(60)
Total Electric	$ 33,014,789	$ 35,299,297

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

Common (Unallocated)	$ 3,059,163	$ 1,551,810

For 2024, the flowback of permanent items included in 410.1 are included in 283.

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.

Excess (Electric only)	12/31/2024 Excess	12/31/2024 Gross up	12/31/2024 Total Regulatory
Flow Through	$ 1,024,165	$ 399,027	$ 1,423,192
Method Life (Protected)	(658,852,983)	(256,697,454)	(915,550,437)
Other Basis Differences (Unprotected)	(142,176,155)	(55,393,628)	(197,569,783)
	$ (800,004,973)	$ (311,692,055)	$ (1,111,697,028)

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	$ 99,810	$ 38,887	$ 138,697
Method Life (Protected)	1,064	415	1,479
Other Basis Differences (Unprotected)	—	—	—
	$ 100,874	$ 39,302	$ 140,176
Common (allocated)			
Flow Through	$ 14,041	$ 5,470	$ 19,511
Method Life (Protected)	(4,854,350)	(1,891,316)	(6,745,666)
Other Basis Differences (Unprotected)	(216,670)	(84,418)	(301,088)
	$ (5,056,979)	$ (1,970,264)	$ (7,027,243)
Common (unallocated)			
Flow Through	$ 17,380	$ 6,771	$ 24,151
Method Life (Protected)	(6,008,821)	(2,341,112)	(8,349,933)
Other Basis Differences (Unprotected)	(268,199)	(104,495)	(372,694)
	$ (6,259,640)	$ (2,438,836)	$ (8,698,476)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR: Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR: Amounts Credited to Account 411.2 (f)	ADJUSTMENTS: Debits: Account Credited (g)	ADJUSTMENTS: Debits: Amount (h)	ADJUSTMENTS: Credits: Account Debited (i)	ADJUSTMENTS: Credits: Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Electric - Plant	171,975,637	2,933,747					257,714		8,779,045	183,430,715 [(a)]
4	Electric - Non-Plant	265,738,315	137,163,296	87,919,024			182.3	11,618,481	182.3	3,644,822	307,008,928
5											0
9	TOTAL Electric (Total of lines 3 thru 8)	437,713,952	140,097,043	87,919,024				11,876,195		12,423,867	490,439,643 [(b)]
10	Gas										
11	Gas	65,869,819	23,776,861	14,970,070				720,107		1,246,142	75,202,645
17	TOTAL Gas (Total of lines 11 thru 16)	65,869,819	23,776,861	14,970,070				720,107		1,246,142	75,202,645
18	TOTAL Other	(88,241)			(197,872)						(286,113)
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	503,495,530	163,873,904	102,889,094	(197,872)			12,596,302		13,670,009	565,356,175 [(c)]
20	Classification of TOTAL										
21	Federal Income Tax	346,659,384	116,206,724	71,017,657	(135,042)			11,388,090		10,153,580	390,478,899
22	State Income Tax	156,836,146	47,667,180	31,871,437	(62,830)			1,208,212		3,516,429	174,877,276

23	Local Income Tax										
NOTES											

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

	Balance at Beginning of Year	410.1 & Adjustments	Balance at End of Year
Electric Distribution Plant	$ 154,645	$ (4,666)	$ 149,979
Electric General Plant	465,606	(67,163)	398,443
Electric Intangible Plant	7,255,788	2,869,382	10,125,170
Electric Nuclear Production Plant	1,686,698	(419,792)	1,266,906
Electric Production Plant	—	—	—
Electric Transmission Plant	(109,820)	159,620	49,800
Common (Allocation to Electric)	41,016,362	396,366	41,412,728
Regulatory Differences - AFUDC Equity	121,506,358	8,521,331	130,027,689
Total Electric Plant Related Only	$ 171,975,637	$ 11,455,078	$ 183,430,715

The flowback of permanent items included in FERC 283 is $7,618,214 for 2023 and $8,430,244 for 2024 .

(b) 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.

(c) Concept: AccumulatedDeferredIncomeTaxesOther

Refer to FERC Page 278 for NSPM's regulatory liability related to nonplant excess ADIT

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	1,142,649,679	282	47,682,393		1,094,967,286
2	Department of Energy Settlement Payment - MN Docket E-002/M-21-815	12,273,507	[(a)] Various	20,306,590	8,033,731	648
3	Derivatives and Hedging - Retail Electric & Gas	15,773,269			5,678,313	21,451,582
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	9,531,829	[(b)] Various	28,240,797	34,386,439	15,677,471
5	Gain on Sale of Assets		142	5,644,132	6,064,853	420,721
6	Gas Low Income Discount Program - MN Docket G-002/GR-06-1429	2,585,518	[(c)] Various	4,173,297	2,491,875	904,096
7	ITC Gross-Up to Pre-Tax Rate Levels	5,777,665	190	543,517		5,234,148
8	Minnesota Electric Automatic Bill Credit Rider - MN Docket E-002/M-24-173				5,400,000	5,400,000
9	Minnesota Deferred Electric Commodity Costs - MN Docket E-002/GR-21-630 - MN Docket E-002/AA-22-179 - MN Docket E-002/AA-23-153	126,274,697	557	1,020,258,190	1,176,173,943	282,190,450
10	Minnesota Deferred Electric Property Tax - 2022- MN Docket E-002/GR-21-630	11,398,314	142	11,903,762	505,448	
11	Minnesota Deferred Electric Property Tax - 2023 - MN Docket E-002/GR-21-630	15,085,743	142	21,810,493	6,724,750	
12	Minnesota Deferred Electric Property Tax - 2024 - MN Docket E-002/GR-21-630				23,226,621	23,226,621
13	Minnesota Electric Capital True-Up - 2022- MN Docket E-002/GR-21-630	13,579,811	407.4	14,181,996	602,185	

14	Minnesota Electric Capital True-Up - 2023- MN Docket E-002/GR-21-630	23,700,000	407.4	24,560,029	860,029	
15	Minnesota Credit Card Fee Tracker - Electric- MN Docket E-002/GR-21-630				5,428,703	5,428,703
16	Minnesota Credit Card Fee Tracker - Gas - MN Docket G-002/GR-21-678				1,390,025	1,390,025
17	Minnesota Electric Sales True-Up - 2023- MN Docket E-002/GR-21-630	30,891,232	[(d)] Various	31,128,640	237,408	
18	Minnesota Electric Conservation and Energy Management Program Costs - MN Docket E-002/M-24-148 - Generally amortized over 12 month period following the expenditure	20,872,820	232	164,634,683	185,166,580	41,404,717
19	Minnesota Gas Conservation and Energy Management Program Costs - MN Docket G-002/M-24-147 - Generally amortized over 12 month period following the expenditure	5,586,756	232	5,586,756		
20	Minnesota Gas Rate Case Deferral - MN Docket G-002/GR-09-1153 - MN Docket G-002/GR-21-678 - Amortized through 2024	1,053,937	928	1,053,937		
21	Minnesota Incentive Compensation Refund- MN Docket E-002/M-23-468	1,694,041	407.3	3,233,104	7,783,816	6,244,753
22	Minnesota Participant Compensation- MN Docket G-002/GR-23-413				54,729	54,729
23	Minnesota Net Operating Loss - MN Docket E-002/GR-21-630	6,034,314	407.4	12,064,885	10,530,571	4,500,000
24	Minnesota Service Quality Program - MN Docket E,G-002/CI-02-2034 - MN Docket E,G-002/M-12-383	1,775,002	456	1,172,063	2,572,063	3,175,002
25	Minnesota Renewable Energy Standard Rider- MN Docket E-002/M-24-353	1,382,901	407.3	13,973,120	25,749,486	13,159,267
26	Minnesota Transmission Cost Recovery Rider- MN Docket E-002/GR-24-371	1,075,338	407.3	55,549,676	61,997,580	7,523,242
27	Minnesota Winter Storm Uri Refund Accrual	394,425	142	394,425		
28	NNG Refund	554,234	[(e)] Various	554,234		
29	Nonplant Excess ADIT	18,700,318	190	4,504,797		[(h)] 14,195,521
30	North Dakota Deferred Electric Commodity Costs - ND Docket PU-24-011	3,034,178	557	58,661,470	59,608,741	3,981,449
31	North Dakota Earnings Sharing - ND Docket PU-20-441 - ND Docket PU-21-160 - ND Docket PU-22-183	14,541,425				14,541,425

32	North Dakota Environmental Cleanup - ND Docket PU-17-894				10,584	10,584
33	North Dakota ITC	7,228,288			1,389,092	8,617,380
34	North Dakota Nuclear PTCs				12,396,629	12,396,629
35	North Dakota Production Tax Credit Levelization - ND Docket PU-20-441 - ND Docket PU-23-312	27,375,115			10,434,453	37,809,568
36	North Dakota Purchased Gas Cost - ND Docket PU-24-008	2,541,183	805.1	28,616,867	26,075,684	
37	North Dakota Renewable Energy Rider - ND Docket PU-24-341	548,015	407.4	548,015		
38	North Dakota Retail Asset and Non-Asset Margin Sharing - ND Docket PU-10-657	4,543,586	557	7,732,895	7,654,880	4,465,571
39	North Dakota Transmission Cost Recovery Rider - ND Docket PU-24-349	46,258	407.4	46,258		
40	Power Purchase Agreement	532,056				532,056
41	Pre-ARO Decommissioning	2,027,614,634			76,081,821	2,103,696,455
42	Renewable*Connect Classic - MN Docket E-002/GR-24-147	1,125,199	[f] Various	4,170,662	4,248,128	1,202,665
43	Renewable*Connect Government - MN Docket E-002/GR-24-147	83,982	555	361,157	293,895	16,720
44	Renewable*Connect Flex - MN Docket E-002/GR-24-147	451,846	[g] Various	20,513,270	21,574,944	1,513,520
45	Sherco 3 Replacement Costs - MN Docket E-002/AA-18-373				47,068,747	47,068,747
46	South Dakota Deferred Electric Commodity Costs - SD Docket EL 14-058 - SD Docket EL 22-017	4,964,519	557	60,637,188	76,605,899	20,933,230
47	South Dakota Electric Conservation and Energy Management Program Costs - SD Docket EL 24-016 - Generally amortized over 12 month period following the expenditure	55,628	232	55,628		
48	South Dakota Infrastructure - SD Docket EL 24-029		407.3	925,828	2,029,861	1,104,033
49	South Dakota Property Tax Collected in the Fuel Clause Adjustment - SD Docket EL 14-058 - SD Docket EL 22-017	1,378,659	407.4	671,218	652,887	1,360,328
50	South Dakota Retail Asset and Non-Asset Margin Sharing - SD Docket EL 14-058 - SD Docket EL 22-017	851,325	557	5,283,837	5,829,470	1,396,958

51	Transmission Formula Rates	17,325,631	456	8,403,546	5,650,495	14,572,580
52	Unrealized Gains on Decommissioning Trust	834,530,556			149,344,603	983,875,159
53	Windsource - MN Docket E-002/M-01-1479 - MN Docket E-002/GR-13-868	5,844,622	142	6,261,980	419,175	1,817
41	TOTAL	4,423,262,055		1,696,045,335	2,078,429,136	4,805,645,856

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Accounts charged:		
142	$	14,906,590
254		5,400,000
Total	$	20,306,590

(b) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Accounts charged:		
142	$	27,787,508
232		453,289
Total	$	28,240,797

(c) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

142	$	4,071,058
232		102,239
Total	$	4,173,297

(d) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

182.3	$	29,906,974
407.4		1,221,666
Total	$	31,128,640

(e) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Accounts charged:		
182.3	$	548,649
912		5,585
Total	$	554,234

(f) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Accounts charged:		
555	$	4,145,407
912		25,255
Total	$	4,170,662

(g) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Accounts charged:		
555	$	20,368,018
912		145,252
Total	$	20,513,270

(h) Concept: OtherRegulatoryLiabilities

	Excess Nonplant ADIT - Regulatory Liability*	Gross-Up	Total
Electric	$ 9,551,586	$ 3,721,419	$ 13,273,005
Gas	663,866	258,650	922,516
Total	$ 10,215,452	$ 3,980,069	$ 14,195,521

*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 12/31/2023	Amortization 2024	Excess Balance 12/31/2024
Pension Expense	$ 13,599,096	$ (1,511,011)	$ 12,088,085
Total Electric	$ 13,599,096	$ (1,511,011)	$ 12,088,085

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Electric Operating Revenues

1. 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.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. 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.
4. 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.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. 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.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. 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	1,616,662,430	1,679,937,185	10,232,245	10,669,105	1,405,248	1,385,188
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	1,567,900,546	1,846,623,840	14,019,794	14,404,301	163,166	162,224
5	Large (or Ind.) (See Instr. 4)	[(a)]736,896,153	[(g)]797,945,464	7,628,739	7,830,382	531	531
6	(444) Public Street and Highway Lighting	27,155,316	29,280,614	106,083	108,934	6,940	6,767
7	(445) Other Sales to Public Authorities	9,733,875	11,748,486	75,986	83,243	1,591	1,591
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales	759,663	717,395	6,552	5,646		
10	TOTAL Sales to Ultimate Consumers	3,959,107,983	4,366,252,984	32,069,399	33,101,611	1,577,476	1,556,301
11	(447) Sales for Resale	143,353,969	209,055,131	17,275,121	14,923,743		
12	TOTAL Sales of Electricity	4,102,461,952	4,575,308,115	49,344,520	48,025,354	1,577,476	1,556,301
13	(Less) (449.1) Provision for Rate Refunds	[(b)](168,890,426)	107,583,434				

14	TOTAL Revenues Before Prov. for Refunds	4,271,352,378	4,467,724,681	49,344,520	48,025,354	1,577,476	1,556,301
15	Other Operating Revenues						
16	(450) Forfeited Discounts	8,464,271	9,368,336				
17	(451) Miscellaneous Service Revenues	[c]2,477,216	[h]2,498,086				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	[d]5,549,762	5,268,969				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[e]212,744,480	[i]345,150,398				
22	(456.1) Revenues from Transmission of Electricity of Others	[f]333,085,326	[j]332,290,850				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	562,321,055	694,576,639				
27	TOTAL Electric Operating Revenues	4,833,673,433	5,162,301,320				

Line12, column (b) includes $ (38,273,338) of unbilled revenues.
Line12, column (d) includes (303,946) MWH relating to unbilled revenues

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ 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.

(b) Concept: ProvisionForRateRefunds

Credit balance due to accrual reversal.

(c) Concept: MiscellaneousServiceRevenues

Connection charges	$	2,653,053
NSF Check Fees		450,811
Billing Concessions		(722,214)
Other, less than $250,000 each		95,566
	$	2,477,216

(d) 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.

(e) 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	$	204,632,199
Variable Production Expense		188,152,416
Total Interchange Agreement	$	392,784,615

Also includes the following items:

Renewable*Connect	$	29,436,218
Fees charged to burn Refuse Derived Fuel		8,368,039
Net distribution of commodity trading margins under Joint Operating Agreement		3,681,903
Purchased Power Reimbursement		865,890
Distribution Facility Fixed Charges		694,619
Manitoba Hydro Energy Service Agreement		593,293
Solar Gardens-Subscribed		480,838
Work on Customers' Equipment		271,991
Transmission Owner's Interconnection Facilities (TOIF) Billings		263,035
Facilities Agreement		212,410
Windsource Program		(53,677)
Solar Energy Standard Exclusion		(1,702,012)
Service Quality Plans		(2,419,250)
Minnesota Credit Card Fee Tracker		(5,428,703)
Conservation Improvement Program incentive, net of accruals and recoveries		(6,492,873)
Change in net over-recovered electric commodity costs		(8,511,852)
Nuclear Production Tax Credits Deferral		(201,144,170)
Other less than $250,000 each		844,166
	$	212,744,480

(f) Concept: RevenuesFromTransmissionOfElectricityOfOthers

Includes $67,116,676 reimbursement from NSP-Wisconsin for transmission costs shared under the FERC-approved Interchange Agreement between the companies. See Note 1 to the Financial Statements.

(g) 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.

(h) Concept: MiscellaneousServiceRevenues

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

(i) 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	$	434,100,943
Also includes the following items:		
Windsource 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
	$	345,150,398

(j) 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.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Minnesota					
2	A00 Water Heating	129	20,777	34	3,794	0.1611
3	A01 Residential	4,799,119	791,774,374	796,923	6,022	0.1650
4	A02 Residential Time of Day	7,475	1,078,513	943	7,927	0.1443
5	A03 Residential Underground	3,746,345	606,087,738	418,851	8,944	0.1618
6	A04 Residential TOD Underground	7,395	1,093,992	566	13,065	0.1479
7	A05 Energy Control	31,227	3,403,539	3,131	9,973	0.1090
8	A06 Limited Off Peak	2,062	258,707	356	5,792	0.1255
9	A07 Auto Protective Lighting	4,707	1,300,683			0.2763
10	A08 Residential Electric Vehicle	6,323	789,026			0.1248
11	A72 Resid TOU Pilot-Overhead	27,088	4,570,038	5,552	4,879	0.1687
12	A74 Resid TOU Pilot-Underground	29,370	4,939,007	3,464	8,479	0.1682
13	A79 Resid EV Pay-As-You-Go	808	85,196	236	3,424	0.1054
14	A80 Resid EV Pilot Bundled	9,036	1,287,880			0.1425
15	A81 Resid EV Pilot Pre-Pay	3,063	334,215			0.1091
16	A82 Resid EV Pilot Bundled Subs	447	53,061			0.1187
17	A83 Resid EV Pilot Pre-Pay Subs	67	7,379			0.1101

18	A92 Multi-Dwelling EV Pilot	28	5,837			0.2085
19	Unbilled-MN-Residential Sales	1,950	(3,306,974)			(1.6959)
20	North Dakota					
21	D01 Residential	564,308	69,334,449	69,523	8,117	0.1229
22	D02 Residential Time of Day	735	75,479	31	23,710	0.1027
23	D03 Residential Underground	158,260	18,296,138	13,043	12,134	0.1156
24	D04 Residential TOD Underground	163	17,156	11	14,818	0.1053
25	D05 Energy Control	2,496	214,834	285	8,758	0.0861
26	D10 Limited Off Peak	543	43,625	95	5,716	0.0803
27	D11 Auto Protective Lighting	279	58,952			0.2113
28	Unbilled-ND-Residential Sales	4,300	512,352			0.1192
29	South Dakota					
30	E01 Residential	348,403	48,631,782	48,896	7,125	0.1396
31	E02 Residential Time of Day	166	18,695	11	15,091	0.1126
32	E03 Residential Underground	470,068	64,343,357	43,080	10,912	0.1369
33	E04 Residential Time of Day	204	26,070	14	14,571	0.1278
34	E06 Residential Heat Pump	1,549	158,117	100	15,490	0.1021
35	E10 Energy Control	1,080	97,185	102	10,588	0.0900
36	E11 Limited Off Peak	7	568	1	7,000	0.0811
37	E12 Auto Protective Lighting	307	65,513			0.2134
38	Unbilled-SD-Residential Sales	2,738	985,170			0.3598
41	TOTAL Billed Residential Sales	10,223,257	1,618,471,882	1,405,248	7,275	0.1583
42	TOTAL Unbilled Rev. (See Instr. 6)	8,988	(1,809,452)			(0.2013)
43	TOTAL	10,232,245	1,616,662,430	1,405,248	7,281	0.1580

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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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	1,508	157,643	111	13,586	0.1045
4	A06 Limited Off Peak	1,143	207,614	80	14,288	0.1816
5	A07 Auto Protective Lighting	22,082	4,041,076			0.1830
6	A09 Small General Service	25	10,910	100	250	0.4364
7	A10 Small General Service	701,005	108,281,493	76,899	9,116	0.1545
8	A11 Water Heating	183	27,253	70	2,614	0.1489
9	A12 Small General TOD Service	37,633	5,290,051	3,021	12,457	0.1406
10	A13 Direct Current	115	24,306	1	115,000	0.2114
11	A14 General Service	7,700,555	884,249,423	43,418	177,359	0.1148
12	A15 General TOD Service	2,547,725	212,288,100	4,652	547,662	0.0833
13	A16 Small General kWh metered	16,264	2,446,054	3,118	5,216	0.1504
14	A18 Small General TOD Service	26,016	3,870,064	4,212	6,177	0.1488
15	A22 Small General TOD Low Wattage	901	137,419	2	450,500	0.1525
16	A23 Peak Control Tiered	908,771	115,766,208	1,266	717,829	0.1274
17	A24 Peak Control Time of Day	432,288	45,492,636	203	2,129,498	0.1052

18	A25 General TOU - Pilot	608	333,827	2	304,000	0.5491
19	A26 General TOU - Pilot CPP	610	56,416			0.0925
20	A27 Tier 1 Energy Control	14,056	1,321,943	4	3,514,000	0.0940
21	A29 Hiawatha Light Rail	27,854	3,515,064	30	928,467	0.1262
22	A85 Solar Photo Voltaic		151,068			
23	A86 Solar Photo Voltaic		32,428			
24	A87 - EV Fleet Pilot Service	423	117,402			0.2775
25	A90 - EV Public Charging Pilot	1,190	348,890			0.2932
26	Unbilled-MN-Commercial Sales	(387,978)	(38,945,991)			0.1004
27	North Dakota					
28	D05 Energy Control	993	82,617	50	19,860	0.0832
29	D10 Limited Off Peak	359	46,699	35	10,257	0.1301
30	D11 Auto Protective Lighting	2,392	360,484			0.1507
31	D12 Small General Service	87,285	10,697,799	8,126	10,741	0.1226
32	D14 Small General TOD Service	2,583	294,236	191	13,524	0.1139
33	D16 General Service	633,380	70,686,259	3,989	158,782	0.1116
34	D17 General TOD Service	93,061	8,792,230	193	482,181	0.0945
35	D18 Small General TOD Service	548	69,279	99	5,535	0.1264
36	D19 Small General kWh metered	1,095	145,472	206	5,316	0.1329
37	D20 Peak Control	28,061	2,959,476	46	610,022	0.1055
38	D21 Peak Control Time of Day	9,652	900,172	9	1,072,444	0.0933
39	D22 Tier 1 Energy Control	98,354	8,268,484	52	1,891,423	0.0841
40	D34 Sm General TOD Low Wattage	50	4,781	5	10,000	0.0956
41	Unbilled-ND-Commercial Sales	778	204,779			0.2632
42	South Dakota					
43	E10 Energy Control	121	11,022	13	9,308	0.0911
44	E11 Limited Off Peak	245	21,774	7	35,000	0.0889
45	E12 Auto Protective Lighting	2,174	384,583			0.1769

46	E13 Small General Service	81,738	10,791,941	7,997	10,221	0.1320
47	E14 Small General TOD Service	2,720	350,704	376	7,234	0.1289
48	E15 General Service	678,228	78,027,318	4,248	159,658	0.1150
49	E16 General TOD Service	173,369	16,931,144	241	719,373	0.0977
50	E20 Peak Control	40,545	4,974,390	73	555,411	0.1227
51	E21 Peak Control Time of Day	12,726	1,228,888	10	1,272,600	0.0966
52	E22 Energy Control	16,230	1,447,492	11	1,475,455	0.0892
53	Unbilled-SD-Commercial Sales	130	997,226			7.6710
41	TOTAL Billed Small or Commercial	14,406,864	1,605,644,532	163,166		
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(387,070)	(37,743,986)			
43	TOTAL Small or Commercial	14,019,794	1,567,900,546	163,166		

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SALES OF ELECTRICITY BY RATE SCHEDULES

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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	189,070	23,369,238	64	2,954,219	0.1236
4	A15 General TOD Service	4,725,490	466,044,835	293	16,127,952	0.0986
5	A23 Peak Control Tiered	29,038	3,229,606	9	3,226,444	0.1112
6	A24 Peak Control Time of Day	1,531,314	151,851,295	106	14,446,358	0.0992
7	A25 General TOU - Pilot	57,819	4,861,276	2	28,909,500	0.0841
8	A27 Tier 1 Energy Control	243,945	17,172,074	6	40,657,500	0.0704
9	A62 - Firm Real Time Pricing	2,070	195,430			0.0944
10	Unbilled-MN-Commercial Sales	59,969	(482,548)			(0.0080)
11	North Dakota					
12	D16 General Service	44,079	4,910,903	6	7,346,500	0.1114
13	D17 General TOD Service	97,010	8,612,102	5	19,402,000	0.0888
14	D21 Peak Control Time of Day	118,961	9,368,219	5	23,792,200	0.0788
15	D22 Tier 1 Energy Control	115,303	8,920,675	8	14,412,875	0.0774
16	Unbilled-ND-Commercial Sales	12,127	1,108,982			0.0914
17	South Dakota					

18	E15 General Service	22,279	2,346,256	6	3,713,167	0.1053
19	E16 General TOD Service	318,895	29,184,187	14	22,778,214	0.0915
20	E20 Peak Control	13,310	1,550,567	4	3,327,500	0.1165
21	E21 Peak Control Time of Day	46,218	3,949,867	3	15,406,000	0.0855
22	Unbilled-SD-Commercial Sales	1,842	703,189			0.3818
41	TOTAL Billed Large (or Ind.) Sales	7,554,801	735,566,530	531		
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	73,938	1,329,623			
43	TOTAL Large (or Ind.)	7,628,739	[(a)]736,896,153	531		

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.

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1	Minnesota					
2	A30 Street Lighting Company Owned	29,175	18,208,428	2,196	13,286	0.6241
3	A32 Street Lighting Customer Owned	20,396	2,016,551	422	48,332	0.0989
4	A34 Street Lighting Metered	34,558	3,484,892	3,466	9,971	0.1008
5	A37 Street Lighting St Paul	934	158,936	1	934,000	0.1702
6	Unbilled-MN-Street Lighting Sales	(146)	(39,260)			0.2689
7	North Dakota					
8	D30 Street Lighting Company Owned	660	522,102	63	10,476	0.7911
9	D31 Street Lighting Customer Owned	9,483	880,314	37	256,297	0.0928
10	D32 Street Lighting Ornamental	19	1,448	2	9,500	0.0762
11	D33 Street Lighting Metered	2,528	200,511	162	15,605	0.0793
12	Unbilled-ND-Street Lighting Sales	144	20,739			0.1440
13	South Dakota					
14	E30 Street Lighting Company Owned	782	903,574	132	5,924	1.1555
15	E31 Street Lighting Customer Owned	1,929	223,635	15	128,600	0.1159
16	E32 Street Lighting Metered	5,312	539,242	355	14,963	0.1015
17	E33 Street Lighting Ornamental	406	41,163	89	4,562	0.1014

18	Unbilled-SD-Street Lighting Sales	(97)	(6,959)			0.0717
41	TOTAL Billed Public Street and Highway Lighting	106,182	27,180,796	6,940	15,300	0.2560
42	TOTAL Unbilled Rev. (See Instr. 6)	(99)	(25,480)			0.2574
43	TOTAL	106,083	27,155,316	6,940	15,286	0.2560

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1	Minnesota					
2	A40 Small Municipal Pumping	5,668	887,389	874	6,485	0.1566
3	A41 Municipal Pumping	56,301	7,262,623	568	99,121	0.1290
4	A42 Fire Siren		34,898			
5	Unbilled-MN-Other Sales	423	(12,750)			(0.0301)
6	North Dakota					
7	D40 Small Municipal Pumping	618	76,286	60	10,300	0.1234
8	D41 Municipal Pumping	13,102	1,492,556	89	147,213	0.1139
9	D42 Fire Siren		1,156			
10	Unbilled-ND-Other Sales	(126)	(11,293)			0.0896
11	South Dakota					
12	E40 Fire Siren		3,010			
41	TOTAL Billed Other Sales to Public Authorities	75,689	9,757,918	1,591	47,573	0.1289
42	TOTAL Unbilled Rev. (See Instr. 6)	297	(24,043)			(0.0810)
43	TOTAL	75,986	9,733,875	1,591	47,760	0.1281

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1	Interdepartmental					
2	Interdepartmental Sales	6,552	759,663			0.1159
41	TOTAL Billed Interdepartmental Sales	6,552	759,663			0.1159
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	6,552	759,663			0.1159

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1	(Footnote for Instruction 5)					
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		[a](168,890,426)			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: ProvisionForRateRefunds
Credit balance due to accrual reversal.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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)
41	TOTAL Billed - All Accounts	32,373,345	3,997,381,321	1,577,476	20,522	0.1235
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(303,946)	(38,273,338)			0.1259
43	TOTAL - All Accounts	32,069,399	(a)3,959,107,983	1,577,476	20,522	0.1235

FOOTNOTE DATA

(a) Concept: RevenueFromSalesOfElectricityByRateSchedulesIncludingUnbilledRevenue

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

A00	$	4,330
A01		156,434,281
A02		219,544
A03		123,305,679
A04		232,343
A05		1,052,057
A06		103,276
A07		663,755
A08		197,791
A09		817
A10		23,144,722
A11		6,142
A12		1,246,095
A13		4,231
A14		258,674,527
A15		219,775,193

A16		540,003
A18		879,068
A22		30,470
A23		30,681,647
A24		61,186,479
A25		1,497,083
A26		21,790
A27		7,853,507
A29		921,914
A30		721,339
A32		506,783
A34		843,251
A37		23,375
A40		184,357
A41		1,789,226
A62		64,755
A72		829,560
A74		955,854
A79		24,715
A80		297,957
A81		100,974
A82		771
A83		54
A85		31,791
A87		14,145
A90		29,615
Minnesota jurisdiction	$	895,095,266

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

D01	$	14,062,829
D02		18,594
D03		3,943,272
D04		4,134
D05		90,107
D10		23,601
D11		51,788
D12		2,182,052
D14		64,770
D16		17,378,631
D17		4,457,470
D18		13,592
D19		27,257
D20		692,068
D21		2,473,473
D22		5,119,532
D30		12,795
D31		183,806
D32		368
D33		48,876
D34		1,259
D40		15,404

D41		320,658
North Dakota jurisdiction	$	51,186,336
Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:		
E01		8,865,098
E02		4,208
E03		11,899,938
E04		5,179
E06		40,218
E10		31,373
E11		6,577
E12		50,496
E13		2,027,344
E14		64,887
E15		17,449,715
E16		11,866,388
E20		1,343,874
E21		1,426,872
E22		390,616
E30		15,747
E31		38,784
E32		105,246
E33		8,257
South Dakota jurisdiction		55640817
Total Company	$	1,001,922,419

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

					ACTUAL DEMAND (MW)			REVENUE			

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)	Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	Megawatt Hours Sold (g)	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	NSP- Wisconsin	RQ									[(b)]0
2	AEP Energy Partners, Inc.	SF	V6				21,760		989,040		[(c)]989,040
3	Citigroup Energy, Inc.	OS	V6				174,000			4,449,320	[(d)]4,449,320
4	Citigroup Energy, Inc.	SF	V6				16,400		659,987		[(e)]659,987
5	City of Ada, MN	OS	V6					58,926			58,926
6	City of Ada, MN	LF	V6				4,239		365,797		365,797
7	City of Ada, MN	AD	V6				(28)	2,475		(17,579)	[(f)](15,104)
8	City of Kasota, MN	OS	V6					29,506			29,506
9	City of Kasota, MN	LF	V6				3,805		225,491		225,491
10	City of Kasota, MN	AD	V6				(15)	225		(3,735)	[(g)](3,510)
11	Dahlberg Light and Power Co	OS	V6				6,114	1,352,335	69,082		1,421,417
12	Dahlberg Light and Power Co	SF	V6				100,362		5,055,566		5,055,566
13	Dahlberg Light and Power Co	AD	V6				292	23,329		(23,229)	[(h)]100
14	Direct Energy Marketing	SF	V6				2,160		63,364		[(i)]63,364
15	Direct Energy Marketing	OS	V6				28,712			530,546	[(j)]530,546
16	East Texas Electric Cooperative, Inc.	SF	V6				131,760		2,594,354		[(k)]2,594,354
17	EDF Trading North America, LLC	OS	V6				107,000			1,792,630	[(l)]1,792,630
18	EDF Trading North America, LLC	SF	V6				10,200		271,221		[(m)]271,221
19	Great River Energy	OS	V6					875,000			[(n)]875,000
20	Great River Energy	SF	V6				60,000		1,862,480		[(o)]1,862,480
21	J. Aron & Company LLC	SF	V6				10,200		208,228		[(p)]208,228
22	J. Aron & Company LLC	OS	V6				107,000			1,376,278	[(q)]1,376,278

23	JPMorgan Chase Bank	SF	V6				8,400		317,024		[r]317,024
24	JPMorgan Chase Bank	OS	V6				94,000			2,237,778	[s]2,237,778
25	ICE NGX Canada Inc	OS	V6				201,000			3,619,630	[t]3,619,630
26	ICE NGX Canada Inc	SF	V6				238,200		5,654,147		[u]5,654,147
27	Mercuria Energy American Inc.	AD	V6							(465,000)	[v](465,000)
28	Merrill Lynch Commodities, Inc.	SF	V6				8,400		367,461		[w]367,461
29	Merrill Lynch Commodities, Inc.	OS	V6				94,000			2,593,792	[x]2,593,792
30	Midcontinent Independent System Operator	OS	V6				14,845,463	3,809,551	71,986,195	6,440,490	[y]82,236,236
31	Midcontinent Independent System Operator	AD	V6				20,897	175,671		(518,481)	[z](342,810)
32	NextEra Energy Power Marketing, LLC	OS	V6				201,000			3,593,459	[aa]3,593,459
33	NextEra Energy Power Marketing, LLC	SF	V6				677,400		16,048,523		[ab]16,048,523
34	North Central Power Company, Inc.	OS	V6					199,548	17,586		217,134
35	North Central Power Company, Inc.	AD	V6					6,460			[ac]6,460
36	Northwestern Wisconsin Electric Company	OS	V6					1,229,591			1,229,591
37	Northwestern Wisconsin Electric Company	AD	V6				0	27,994			[ad]27,994
38	Ohio Power Company	AD	V6				0			20,023	[ae]20,023
39	Shelleneno	OS	V6				94,000			2,787,051	[af]2,787,051
40	Shelleneno	SF	V6				8,400		394,839		[ag]394,839
41	[a]Footnote for 106b										
15	Subtotal - RQ						6,152,554				
16	Subtotal-Non-RQ						17,275,121	7,790,611	107,150,385	28,412,973	143,353,969
17	Total						17,275,121	7,790,611	107,150,385	28,412,973	143,353,969

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ 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 6,152,554 Mwh in column G, $327,748,997 in column I, and $327,748,997 in column K. See Note 1 to the Financial Statements.

(c) Concept: RevenueFromSalesOfElectricityForResale

Financial Trading

(d) Concept: RevenueFromSalesOfElectricityForResale

Financial Trading

(e) Concept: RevenueFromSalesOfElectricityForResale

Financial Trading

(f) Concept: RevenueFromSalesOfElectricityForResale

Prior Period Adjustment

(g) Concept: RevenueFromSalesOfElectricityForResale

Prior Period Adjustment

(h) Concept: RevenueFromSalesOfElectricityForResale

Prior Period Adjustment

(i) Concept: RevenueFromSalesOfElectricityForResale

Financial Trading

(j) Concept: RevenueFromSalesOfElectricityForResale

Financial Trading

(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
Financial Trading
(s) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(t) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(u) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(v) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(w) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(x) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(y) Concept: RevenueFromSalesOfElectricityForResale
Demand - Resource Adequacy Auction, Other - Ancillary Services
(z) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(aa) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(ab) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(ac) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(ad) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(ae) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(af) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(ag) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	2,834,215	3,041,499
5	(501) Fuel	175,428,485	218,422,593
6	(502) Steam Expenses	14,821,179	17,270,080
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	4,730,394	5,105,422
10	(506) Miscellaneous Steam Power Expenses	12,113,123	13,264,376
11	(507) Rents	1,720,279	1,456,294
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	211,647,675	258,560,264
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,437,329	1,459,264
16	(511) Maintenance of Structures	5,132,920	4,931,738
17	(512) Maintenance of Boiler Plant	16,892,810	19,449,464
18	(513) Maintenance of Electric Plant	5,822,855	6,754,263
19	(514) Maintenance of Miscellaneous Steam Plant	6,340,754	6,419,880
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	35,626,668	39,014,609

21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	247,274,343	297,574,873
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	27,343,822	34,613,674
25	(518) Fuel	105,717,834	96,379,479
26	(519) Coolants and Water	8,507,254	9,208,027
27	(520) Steam Expenses	58,888,601	54,394,215
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,551,012	2,607,515
31	(524) Miscellaneous Nuclear Power Expenses	137,959,211	123,893,804
32	(525) Rents	6,476,187	5,763,152
33	TOTAL Operation (Enter Total of lines 24 thru 32)	347,443,921	326,859,866
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	6,485,604	7,891,172
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment	22,674,197	26,005,094
38	(531) Maintenance of Electric Plant	14,232,679	13,295,965
39	(532) Maintenance of Miscellaneous Nuclear Plant	39,747,996	33,726,695
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	83,140,476	80,918,926
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	430,584,397	407,778,792
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	16,269	13,110
45	(536) Water for Power	49,506	24,494
46	(537) Hydraulic Expenses	228,899	243,134
47	(538) Electric Expenses	12,087	17,569

48	(539) Miscellaneous Hydraulic Power Generation Expenses	115,662	152,762
49	(540) Rents	29,040	35,806
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	451,463	486,875
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	53	78,063
54	(542) Maintenance of Structures	18,191	16,314
55	(543) Maintenance of Reservoirs, Dams, and Waterways	171,879	362,900
56	(544) Maintenance of Electric Plant	39,913	158,594
57	(545) Maintenance of Miscellaneous Hydraulic Plant	137	5,728
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	230,173	621,599
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	681,636	1,108,474
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	3,880,128	3,837,111
63	(547) Fuel	191,809,638	186,652,908
64	(548) Generation Expenses	8,059,153	8,044,508
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	21,360,535	20,689,590
66	(550) Rents	18,983,020	17,750,890
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	244,092,474	236,975,007
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,473,105	1,368,379
70	(552) Maintenance of Structures	7,697,271	7,661,502
71	(553) Maintenance of Generating and Electric Plant	13,941,038	9,730,564
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	14,395,528	11,100,501

73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	37,506,942	29,860,946
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	281,599,416	266,835,953
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,043,810,933	1,082,622,299
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	1,326,160	1,368,668
78	(557) Other Expenses	[(a)]74,599,323	[(e)]119,789,935
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	1,119,736,416	1,203,780,902
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	2,079,876,208	2,177,078,994
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,422,164	8,166,252
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	5,109,568	4,799,300
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	7,906,015	7,119,039
89	(561.5) Reliability, Planning and Standards Development	32,541	166,074
90	(561.6) Transmission Service Studies	[(b)](90,961)	76,321
91	(561.7) Generation Interconnection Studies	497,991	460,319
92	(561.8) Reliability, Planning and Standards Development Services	3,619,872	3,190,294
93	(562) Station Expenses	5,363,869	5,662,676
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	785,882	356,017
95	(564) Underground Lines Expenses		17,120
96	(565) Transmission of Electricity by Others	[(c)]363,054,825	[(f)]351,948,780
97	(566) Miscellaneous Transmission Expenses	9,800,404	8,215,403
98	(567) Rents	1,426,373	1,273,660

99	TOTAL Operation (Enter Total of Lines 83 thru 98)	404,928,543	391,451,255
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	2,520,984	2,395,430
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	6,305,878	5,543,700
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	8,826,862	7,939,130
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	[d]413,755,405	399,390,385
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	74,910	177,776
116	(575.2) Day-Ahead and Real-Time Market Facilitation	243,791	275,727
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	52,274	17,040
121	(575.7) Market Facilitation, Monitoring and Compliance Services	10,929,696	10,589,583
122	(575.8) Rents	18,261	17,978
123	Total Operation (Lines 115 thru 122)	11,318,932	11,078,104
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)	11,318,932	11,078,104
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	17,166,234	17,280,225
135	(581) Load Dispatching	816,721	757,288
136	(582) Station Expenses	3,041,592	3,032,286
137	(583) Overhead Line Expenses	5,981,809	6,170,008
138	(584) Underground Line Expenses	9,202,149	7,834,722
138.1	(584.1) Operation of Energy Storage Equipment		571
139	(585) Street Lighting and Signal System Expenses	523,567	664,430
140	(586) Meter Expenses	1,151,242	150,285
141	(587) Customer Installations Expenses	2,912,475	2,271,257
142	(588) Miscellaneous Expenses	11,699,392	13,925,838
143	(589) Rents	3,489,118	3,110,938
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	55,984,299	55,197,848
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	158,310	101,855
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	1,056,055	1,690,316
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	58,159,954	47,801,680

150	(594) Maintenance of Underground Lines	5,285,043	6,737,175
151	(595) Maintenance of Line Transformers		3,116
152	(596) Maintenance of Street Lighting and Signal Systems	2,060,462	1,635,241
153	(597) Maintenance of Meters	597,625	512,933
154	(598) Maintenance of Miscellaneous Distribution Plant	164,040	216,677
155	TOTAL Maintenance (Total of Lines 146 thru 154)	67,481,489	58,698,993
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	123,465,788	113,896,841
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	128,313	123,803
160	(902) Meter Reading Expenses	20,966,417	19,848,846
161	(903) Customer Records and Collection Expenses	26,996,944	25,493,999
162	(904) Uncollectible Accounts	18,041,849	24,400,214
163	(905) Miscellaneous Customer Accounts Expenses	231,692	251,300
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	66,365,215	70,118,162
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	161,795,106	99,581,455
169	(909) Informational and Instructional Expenses	1,226,524	1,207,479
170	(910) Miscellaneous Customer Service and Informational Expenses	305,379	417,386
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	163,327,009	101,206,320
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	4,709,981	8,303,773
176	(913) Advertising Expenses		

177	(916) Miscellaneous Sales Expenses	37,615	60,624
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	4,747,596	8,364,397
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	94,316,697	108,131,814
182	(921) Office Supplies and Expenses	69,308,765	71,918,981
183	(Less) (922) Administrative Expenses Transferred-Credit	80,134,456	66,472,499
184	(923) Outside Services Employed	24,528,067	20,801,187
185	(924) Property Insurance	10,139,893	7,393,588
186	(925) Injuries and Damages	17,066,397	14,655,916
187	(926) Employee Pensions and Benefits	84,636,871	108,296,100
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	11,928,463	11,989,354
190	(929) (Less) Duplicate Charges-Cr.	6,417,105	6,619,698
191	(930.1) General Advertising Expenses	3,359,124	3,602,887
192	(930.2) Miscellaneous General Expenses	5,108,965	4,820,648
193	(931) Rents	58,941,492	50,004,809
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	292,783,173	328,523,087
195	Maintenance		
196	(935) Maintenance of General Plant	805,161	839,944
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	293,588,334	329,363,031
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	3,156,444,487	3,210,496,234

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: OtherExpensesOtherPowerSupplyExpenses

Includes $50,648,189 of fixed costs and $14,387,429 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: TransmissionServiceStudies

Credit balance due to timing difference between period that cost is incurred and reimbursement.

(c) Concept: TransmissionOfElectricityByOthers

Includes $151,156,475 of fixed costs reimbursed to NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

(d) 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.

(e) 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.

(f) 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.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, 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): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES: MegaWatt Hours Received (i)	POWER EXCHANGES: MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER: Demand Charges ($) (k)	COST/SETTLEMENT OF POWER: Energy Charges ($) (l)	COST/SETTLEMENT OF POWER: Other Charges ($) (m)	COST/SETTLEMENT OF POWER: Total (k+l+m) of Settlement ($) (n)
1	ACE Lincoln Heights Wind Holdings, LLC	AD					(34)					[a](1,114)		(1,114)
2	ACE Lincoln Heights Wind Holdings, LLC	LU					16,687					550,667		550,667
3	Adams Wind Generations	LU					46,464					3,089,849		3,089,849
4	AEP Energy Partners, Inc.	LU					1,600					69,600		69,600

5	Agassiz Beach, LLC	LU					4,426					132,767		132,767
6	Aurora Distributed Solar, LLC	LU					191,308					21,376,768		21,376,768
7	Best Power International LLC	LU					1,850					191,647		191,647
8	Big Blue Wind Farm, LLC	AD										[b]2,240		2,240
9	Big Blue Wind Farm, LLC	LU					71,029					7,223,090		7,223,090
10	Bisson Windfarm, LLC	AD					53					[c]1,788		1,788
11	Bisson Windfarm, LLC	LU					4,268					145,137		145,137
12	Boeve Windfarm, L.L.C.	AD					3					[d]112		112
13	Boeve Windfarm, L.L.C.	LU					5,270					176,523		176,523
14	Cannon Falls Energy Center	AD					4,851				334	[e](336,048)		(335,714)
15	Cannon Falls Energy Center	LU		357			864,536				30,274,734	27,556,589		57,831,323
16	Carleton College	AD					11					[f]361		361
17	Carleton College	LU					4,432					146,271		146,271
18	CG Windfarm, LLC	AD					(135)					[g](4,607)		(4,607)
19	CG Windfarm, LLC	LU					2,298					78,146		78,146
20	Cisco Wind Energy, L.L.C.	AD										[h]8,892		8,892
21	Cisco Wind Energy, L.L.C.	LU					9,087					646,690		646,690
22	Citigroup Energy, Inc.	OS											[ay]2,914,799	2,914,799
23	Covanta Hennepin Energy Resource Co LP	AD										[i](463)		(463)
24	Covanta Hennepin Energy Resource Co LP	LU					202,420					5,430,564		5,430,564
25	Crowned Ridge Wind, LLC	AD										[j]835,052		835,052
26	Crowned Ridge Wind, LLC	LU					761,930					17,329,146		17,329,146
27	Dairyland Electric Cooperative Incorporated	LU					16,528					385,433		385,433
28	Dakota Range III, LLC	AD					(4,487)					[k](70,128)		(70,128)
29	Dakota Range III, LLC	LU					524,794					11,496,729		11,496,729
30	Danielson Wind Farms, LLC	LU					46,744					3,108,486		3,108,486
31	Deuel Harvest Wind Energy LLC	AD					3,810					[l]61,238		61,238
32	Deuel Harvest Wind Energy LLC	LU					332,948					5,911,901		5,911,901
33	East Ridge group	AD					12					[m]390		390
34	East Ridge group	LU					18,572					612,892		612,892
35	EDF Trading North America LLC	OS											[az]3	3

36	Electric Reliability Council of Texas	AD					(2)					[(n)](31,675)		(31,675)
37	Electric Reliability Council of Texas	SF					38,425					5,547,999		5,547,999
38	Ewington Energy Systems, LLC	AD					5					[(o)]171		171
39	Ewington Energy Systems, LLC	LU					85,592					3,031,347		3,031,347
40	Fenton Power Partners I, L.L.C.	AD										[(p)]54,663		54,663
41	Fenton Power Partners I, L.L.C.	LU					271,992					37,696,105		37,696,105
42	Fey Windfarm, L.L.C.	AD					(5)					[(q)](185)		(185)
43	Fey Windfarm, L.L.C.	LU					4,939					172,884		172,884
44	Fillmore County Solar Project, LLC	LU					60,219					3,396,007		3,396,007
45	Garwin McNeilus	AD					474					[(r)]22,106		22,106
46	Garwin McNeilus	LU					81,325					2,582,448		2,582,448
47	Grant County Windfarm, LLC	LU					55,491					3,773,361		3,773,361
48	Great American West Wind, LLC	AD										[(s)](14)		(14)
49	Great American West Wind, LLC	LU					432,217					5,873,992		5,873,992
50	Hastings Lock & Dam	LU		2			13,243				411,963	192,238		604,201
51	Heartland Divide Wind II, LLC	AD					10					[(t)]196		196
52	Heartland Divide Wind II, LLC	LU					811,523					16,831,121		16,831,121
53	Hilltop Power, L.L.C.	LU					4,091					179,995		179,995
54	J. Aron & Company LLC	OS											1,819,872[(ba)]	1,819,872
55	JJN Windfarm, LLC	AD					31					[(u)]1,033		1,033
56	JJN Windfarm, LLC	LU					4,055					135,843		135,843
57	JPMorgan Chase Bank New York	OS											10,151,063[(bb)]	10,151,063
58	Karbone Energy, LLC	AD											[(bc)] [(bd)]3,705	3,705
59	Karbone Energy, LLC	LU					279					879,600		879,600
60	Karbone Energy, LLC	OS											[(be)]7,170	7,170
61	Kas Brothers Windfarm, L.L.C.	AD										[(v)](16)		(16)
62	Kas Brothers Windfarm, L.L.C.	LU					1,739					70,498		70,498
63	K-Brink Windfarm, L.L.C.	AD					1					[(w)]27		27
64	K-Brink Windfarm, L.L.C.	LU					3,294					110,353		110,353
65	Keller Paving & Landscaping, Inc.	LU					201					6,219		6,219
66	KODA Energy, LLC	AD					(216)					[(x)](1,741)		(1,741)
67	KODA Energy, LLC	LU					1,992					68,297		68,297

68	Lake Benton Power Partners, L.L.C.	AD										[y]1,887		1,887
69	Lake Benton Power Partners, L.L.C.	LU					243,845					7,171,200		7,171,200
70	Louise Solar Project, LLC	LU					102,764					5,770,716		5,770,716
71	LPS Futures LLC	AD											[bf] [bg]2,190	2,190
72	LSP Cottage Grove Incorporated	LU		245			1,273,338				8,495,591	28,778,778		37,274,369
73	Manitoba Hydro	AD									(1,516,677)	[z]254,016		(1,262,661)
74	Manitoba Hydro	LU		476			2,106,324				55,575,975	176,118,205		231,694,180
75	Mankato Energy Center I, L.L.C.	AD					(712)				(134,725)	[aa](651,935)		(786,660)
76	Mankato Energy Center I, L.L.C.	LU		375			1,305,546				37,994,809	57,371,484		95,366,293
77	Mankato Energy Center II, L.L.C.	AD					326				(114,551)	[ab](85,163)		(199,714)
78	Mankato Energy Center II, L.L.C.	LU		345			1,408,733				28,197,693	5,640,030		33,837,723
79	Marshall Solar	LU					87,434					7,495,533		7,495,533
80	Metro Wind LLC	AD					(30)					[ac](910)		(910)
81	Metro Wind LLC	LU					779					23,384		23,384
82	MidAmerican Energy Company	LU		158							573,600			573,600
83	Midcontinental ISO	AD					(14,959)					(5,138,423)[ad]		(5,138,423)
84	Midcontinental ISO	SF					5,382,771					27,798,684		27,798,684
85	MinnDakota Wind LLC	LU	NAEMA				281,199					6,701,674		6,701,674
86	Miscellaneous	AD											576,960[bh] [bi]	576,960
87	Miscellaneous	OS											(8,064,988)[bj]	(8,064,988)
88	Moraine Wind, L.L.C.	AD										[ae](92)		(92)
89	Moraine Wind, L.L.C.	LU					73,053					3,019,051		3,019,051
90	N A E Lakota Ridge, LLC	AD					(1)					[af](11)		(11)
91	N A E Lakota Ridge, LLC	LU					16,617					182,784		182,784
92	N A E Shaokatan Hills, LLC	AD					(1)					[ag](10)		(10)
93	N A E Shaokatan Hills, LLC	LU					12,040					132,437		132,437
94	NAE Shaokatan, LLC	AD										[ah]10		10
95	NAE Shaokatan, LLC	LU					22,303					669,075		669,075
96	Natural Gas Exchange Inc.	OS											16,620,273[bk]	16,620,273
97	NextEra Energy Power Marketing, LLC	AD											[bl] [bm]1,384	1,384
98	NextEra Energy Power Marketing, LLC	OS											10,219,281[bn]	10,219,281

99	North Star Solar	LU					187,422					13,726,391		13,726,391
100	NSP-M Solar Gardens	AD					(6,954)					[(ai)]7,903,794		7,903,794
101	NSP-M Solar Gardens	LU					1,593,333					217,383,729		217,383,729
102	Odell Wind Farm, LLC	LU					773,060					23,175,672		23,175,672
103	Olsen Wind Farm	AD					(4)					[(aj)](143)		(143)
104	Olsen Wind Farm	LU					245					9,848		9,848
105	Pipestone	AD					86					[(ak)]2,828		2,828
106	Pipestone	LU					13,503					445,617		445,617
107	PJM Interconnection LLC	OS											[(bo)]6,500	6,500
108	Poet, LLC	LU					370					7,482		7,482
109	Prairie Rose Wind, LLC	AD										[(al)]38,363		38,363
110	Prairie Rose Wind, LLC	LU					403,103					29,564,461		29,564,461
111	Restore Renewables, LLC	AD					242					[(am)]412		412
112	Restore Renewables, LLC	LU					1,413					102,096		102,096
113	Ridgewind Power Partners, LLC	AD					9							
114	Ridgewind Power Partners, LLC	LU					82,054					5,328,364		5,328,364
115	Rock Ridge Power Partners LLC	AD										[(an)]20		20
116	Rock Ridge Power Partners LLC	LU					4,231					59,414		59,414
117	Ruthton Ridge	LU					38,068					1,142,028		1,142,028
118	SAF Hydroelectric, L.L.C.	LU					29,026					1,656,224		1,656,224
119	Shane's Wind Machine LLC	LU					6,761					223,100		223,100
120	Slayton Solar, LLC	LU					1,973					203,245		203,245
121	South Ridge Power Partners, LLC	AD										[(ao)](19)		(19)
122	South Ridge Power Partners, LLC	LU					3,696					47,653		47,653
123	Southwest Power Pool, Inc.	AD					(146)					[(ap)](11,386)		(11,386)
124	Southwest Power Pool, Inc.	OS					4,677					182,867		182,867
125	City of St Cloud	LU					50,581					1,910,441		1,910,441
126	St. Olaf College	LU					5					168		168
127	St. Paul Cogeneration	LU					151,068					14,804,671		14,804,671
128	Taygete Energy Project, LLC	SF					386,847					9,864,713		9,864,713
129	TG Windfarm, LLC	AD					53					[(aq)]1,788		1,788
130	TG Windfarm, LLC	LU					4,268					145,137		145,137

131	Tholen Transmission-Trust	AD					42					[(ar)]1,397		1,397
132	Tholen Transmission-Trust	LU					41,043					1,354,394		1,354,394
133	Tofteland Windfarm, LLC	AD					53					[(as)]1,788		1,788
134	Tofteland Windfarm, LLC	LU					4,268					145,137		145,137
135	Uilk Wind Farm, LLC	LU					8,616					633,597		633,597
136	University of Minnesota	LU					2,564					53,568		53,568
137	Valley View Transmission	AD										[(at)]29,962		29,962
138	Valley View Transmission	LU					9,097					1,198,911		1,198,911
139	Velva Windfarm, LLC	LU					25,531					842,530		842,530
140	Western Area Power Administration	LU					10,751					300,060		300,060
141	Westridge Windfarm, LLC	AD					(135)					[(au)](4,607)		(4,607)
142	Westridge Windfarm, LLC	LU					4,268					145,137		145,137
143	Windcurrent Farms, L.L.C.	LU					5,036					176,245		176,245
144	Windvest Power Partners, LLC	AD										[(av)](95)		(95)
145	Windvest Power Partners, LLC	LU					3,641					48,280		48,280
146	Winona County Wind LLC	LU					4,724					315,963		315,963
147	Woodstock Hills, L.L.C.	AD										[(aw)]8		8
148	Woodstock Hills, L.L.C.	LU					34,890					763,310		763,310
149	Woodstock Municipal Wind, LLC	LU					1,534					102,619		102,619
150	Zephyr Wind LLC	AD										[(ax)]91,919		91,919
151	Zephyr Wind LLC	LU					61,176					7,672,990		7,672,990
15	TOTAL						21,249,648	0	0	0	159,758,746	849,793,975	34,258,212	1,043,810,933

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: EnergyChargesOfPurchasedPower
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

(q) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(r) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(s) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(t) 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: OtherChargesOfPurchasedPower
Financial Trading
(az) Concept: OtherChargesOfPurchasedPower
Financial Trading
(ba) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bb) Concept: OtherChargesOfPurchasedPower
Financial Trading

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. 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.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: 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.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. 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.
10. 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.
11. 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: Megawatt Hours Received (i)	TRANSFER OF ENERGY: Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS: Demand Charges ($) (k)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS: Energy Charges ($) (l)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS: Other Charges ($) (m)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS: Total Revenues ($) (k+l+m) (n)
1	Buffalo Ridge Wind	Buffalo Ridge Wind	MISO	OS	3751	Buffalo Ridge	Buffalo Ridge						(h)(4,636)	(4,636)
2	Great River Energy	Various	Various	FNO	(f) Various	Various	Various				56,885,417		(i)126,983	57,012,400
3	Marshall Solar	Marshall Solar	MISO	OS	3514	Lyon County	Lyon County						(j)141,090	141,090
4	MidAmerican Energy Company	Palo Alto	MISO	OS	3721	Palo Alto	Palo Alto						(k)327,060	327,060
5	Midcontinent ISO (MISO)	Various	Various	(e) FNO	MISO OATT	Various	Various				116,805,820	(g) 72,066,030		188,871,850
6	Missouri River Energy Services (MRES)	Various	Various	FNO	304	Various	Various				7,122,626			7,122,626
7	North Star Solar PV LLC	North Star Solar	MISO	OS	2871	Chisago County	Chisago County						(l)255,793	255,793
8	(a) Northern States Power-Minnesota	Blazing Star 2	MISO	OS	3418	Steep Bank Lake	Steep Bank Lake						(m) 913,783	913,783
9	Sioux Falls, City of	Western Area Power Administration (WAPA)	Sioux Falls, City of	OS	484	WAPA	Sioux Falls, City of						(n)210,362	210,362
10	South Dakota State Penitentiary (SDSP)	WAPA	SDSP	OS	385	WAPA	SDSP						(o)15,545	15,545
11	Southern MN Municipal Power Agency	Various	Various	FNO	304	Various	Various				8,532,907			8,532,907

12	Stoneray Power	Stoneray Power Partners	MISO	OS	3513	Chanarambie	Chanarambie						[p]290,547	290,547
13	Tenaska Nobles 2 Holdings LLC	Nobles 2 Wind Farm	MISO	OS	3347	Zephyr	Zephyr						[q]1,622,345	1,622,345
14	University of North Dakota (UND)	WAPA	University of North Dakota	OS	440	WAPA	UND						[r]61,021	61,021
15	Walleye Wind, LLC	Walleye Wind	MISO	OS	1495	Rock County	Rock County						[s]555,637	555,637
16	Wisconsin Public Power, Inc. (WPPI)	Minnesota Power Authority	WPPI	OS	466								[t]40,320	40,320
17	[b]Northern States Power-Wisconsin	[d]Various	Various	OS	437	Various	Various				67,116,676			67,116,676
18	[c]Footnote from page 106b													
35	TOTAL							0	0	0	256,463,446	72,066,030	4,555,850	333,085,326

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ 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

(q) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Interconnection Network Upgrade revenue
(r) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Facilities Charge
(s) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Interconnection Network Upgrade revenue
(t) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Meter Charge

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. 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.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. 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.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. 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.
6. Enter ""TOTAL"" in column (a) as the last line.
7. 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					[j]2,400	2,400
2	Central MN Municipal Pw	FNS			1,414,753			1,414,753
3	Dairyland Power	OS					[k]18,099	18,099
4	Great River Energy	FNS			36,189,257			36,189,257
5	ITC Midwest	OS					[l]738,527	738,527
6	McLeod Coop Power	[c]OLF			23,213			23,213
7	Midcontinent ISO (MISO)	[d]LFP			75,444,651	[i]73,646,108	[m]1,000	149,091,759
8	MN Municipal Pwr Agy	FNS			1,341,636			1,341,636
9	Minnkota Power Coop	[e]OLF				18,705	[n]780,000	798,705
10	Missouri Riv Engy Serv	FNS			1,521,512		[o]61,569	1,583,081
11	Montana-Dakota Util Co	OS					[p]1,270,254	1,270,254
12	Northwestern Wis Elect	FNS			569,875			569,875

13	[a] Northern States Pwr-MN	OS					[q] 913,783	913,783
14	Otter Tail Pwr Co	OS					1,883,355 [r]	1,883,355
15	Rochester Public Util	FNS			1,352,830			1,352,830
16	Southern MN Muncipl Pwr	FNS			14,470,756			14,470,756
17	Southwest Power Pool	FNS			102,451	492		102,943
18	Stearns Coop Electric	[f] OS				2,796	[s] 463	3,259
19	Verendrye Electric Coop	[g] OLF				129,865		129,865
20	[b] Northern States Pwr-WI	[h] OLF			151,156,475			151,156,475
	TOTAL		0	0	283,587,409	73,797,966	5,669,450	363,054,825

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
MISO Excess Congestion Fund distribution
(n) Concept: OtherChargesTransmissionOfElectricityByOthers
Fixed Transmission Service Charge
(o) Concept: OtherChargesTransmissionOfElectricityByOthers
Interconnection upgrade charge
(p) Concept: OtherChargesTransmissionOfElectricityByOthers
Interconnection upgrade charge
(q) Concept: OtherChargesTransmissionOfElectricityByOthers
Affiliate - Interconnection upgrade charge
(r) Concept: OtherChargesTransmissionOfElectricityByOthers
Interconnection upgrade charge

(s) Concept: OtherChargesTransmissionOfElectricityByOthers
Fixed Facility Charge

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,414,470
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	398,909
7	Director Fees and Expenses	1,776,545
8	SEC Filing Expense	47,765
9	Research and Development Expense	471,276
46	TOTAL	5,108,965

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

1. 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).
2. 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.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type 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.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	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			[(a)]31,906,028	(123,209)	31,782,819
2	Steam Production Plant	103,932,687	53,442,723		(1,107,767)	156,267,643
3	Nuclear Production Plant	178,856,756	(32,365,251)			146,491,505
4	Hydraulic Production Plant-Conventional	1,550,545			(67,064)	1,483,481
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	206,967,317	10,584,152	424,976	(4,378,699)	213,597,746
7	Transmission Plant	[(b)]100,005,496	5,255		(1,184,505)	98,826,246
8	Distribution Plant	[(c)]190,789,408	234,059		(3,839)	191,019,628
9	Regional Transmission and Market Operation					
10	General Plant	43,407,587			(507,073)	42,900,514
11	Common Plant-Electric	[(d)]47,488,126	3,478	70,248,801	(969)	117,739,436
12	TOTAL	872,997,922	31,904,416	102,579,805	(7,373,125)	1,000,109,018

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. ACCOUNT 405 Column (e) Prefunded AFUDC recorded as Other Deferred Credits (Account 253) is amortized over the life of the property, and thus appears as a credit to expense.

Line No.	C. Factors Used in Estimating Depreciation Charges						
	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	13,400					0 years
14	311	305,340		(16.56)%			9 years, 8 months, 22 days
15	312	1,385,395		(15.18)%			7 years, 7 months, 25 days
16	314	279,549		(15.44)%			6 years, 8 months, 29 days
17	315	185,051		(15.27)%			7 years, 6 months, 20 days
18	316	54,224		(16.29)%			7 years, 3 months, 25 days
19	317	49,310					0 years
20	Subtotal Steam Prod	2,272,269					
21	Nuclear Production						
22	320	1,719					0 years
23	321	655,249					11 years, 8 months, 10 days
24	322	2,110,631					10 years, 10 months, 1 day
25	323	682,073					11 years, 2 months, 20 days
26	324	562,471					11 years, 10 months, 13 days
27	325	212,885					11 years, 1 month
28	326	(249,279)					0 years
29	Subtotal Nuclear Prod	3,975,749					
30	Hydro Production						
31	330	1,693					0 years
32	331	1,555		(28.61)%			48 years, 6 months, 5 days
33	332	11,540		(30.4)%			37 years, 11 months

34	333	10,157		(28.35)%			49 years, 2 months, 13 days
35	334	3,290		(28.35)%			49 years, 2 months, 13 days
36	335	134		(28.35)%			49 years, 2 months, 13 days
37	336	260					0 years
38	337						
39	Subtotal Hydro Prod	28,629					
40	Other Production						
41	340	36,783					20 years, 7 months, 20 days
42	341	510,401		(11.85)%			27 years, 7 months, 20 days
43	342	31,248		(15.85)%			23 years, 8 months, 5 days
44	343	150,220		(9.82)%			23 years
45	344	4,404,308		(11.45)%			25 years, 9 months, 8 days
46	345	397,008		(12.02)%			23 years, 10 months, 5 days
47	346	66,151		(12.36)%			25 years, 8 months, 16 days
48	347	337,726					0 years
49	348	2,064		(29.3)%			0 years
50	Subtotal Other Prod	5,935,909					
51	Transmission						
52	350	174,310					
53	352	171,176	65 years	(15)%	1.82%	R4	53 years, 2 months, 27 days
54	353	1,635,285	56 years	(20)%	2.18%	R2	43 years, 3 months, 10 days
55	354	127,926	75 years	(50)%	2.11%	R4	39 years, 3 months, 2 days
56	355	1,745,301	60 years	(55)%	2.61%	R2	50 years, 2 months, 22 days
57	356	811,674	67 years	(40)%	2.09%	R0.5	58 years, 6 months, 25 days
58	357	32,182	74 years	(5)%	1.44%	R4	58 years, 6 months, 25 days
59	358	35,629	50 years	(5)%	2.16%	R3	35 years, 1 month, 28 days
60	359	3,797	60 years		1.68%	SQ	59 years, 2 months, 23 days

61	359.1	173					
62	Subtotal Transmission	4,737,453					
63	Distribution						
64	360	20,326					
65	361	69,149	63 years	(40)%	2.29%	R2.5	46 years, 10 months, 16 days
66	362	845,346	51 years	(30)%	2.64%	R2	36 years, 4 months, 13 days
67	364	806,039	44 years	(135)%	5.48%	R1.5	36 years, 8 months
68	365	755,713	37 years	(30)%	3.56%	L0	29 years, 8 months, 5 days
69	366	425,652	67 years	(30)%	1.99%	R2.5	52 years, 8 months, 22 days
70	367	1,528,009	51 years	(20)%	2.42%	R2.5	35 years, 6 months, 8 days
71	[e] 368	593,674	32 years	(5)%	3.29%	SQ	19 years, 5 months, 20 days
72	[f] 368	32,777	25 years	(10)%	3.97%	SQ	16 years, 3 months, 5 days
73	[g] 369	115,595	42 years	(100)%	5%	R1.5	25 years, 9 months, 10 days
74	[h] 369	355,102	44 years	(10)%	2.62%	R4	27 years, 8 months, 20 days
75	370	253,506	15 years	(5)%	5.82%		8 years, 5 months, 22 days
76	371		10 years		10.1%	SQ	9 years, 1 month, 7 days
77	373	103,595	29 years	(50)%	5.18%	L0	23 years, 2 months, 8 days
78	374	12,231					
79	Subtotal Distribution	5,916,714					
80	General						
81	389	20,729					
82	[i] 390	133,795	55 years	(20)%	2.76%	R1.5	40 years, 2 months, 6 days
83	[j] 390	1,075				SQ	[w] 0 years
84	[k] 391	29,627	20 years		5.03%	SQ	8 years, 5 months, 14 days
85	[l] 391	92,647	6 years		17.19%	SQ	3 years, 11 months, 28 days

86	[m] 392	8,277	10 years	6%	9.19%	SQ	4 years, 1 month, 27 days
87	[n] 392	61,765	10 years	12%	9.17%	SQ	6 years, 5 months, 28 days
88	[o] 392	32,091	12 years	15%	7.88%	SQ	6 years, 1 month, 2 days
89	[p] 392	155,191	12 years	10%	8%	SQ	5 years, 11 months, 8 days
90	393	1,967	20 years		5.06%	SQ	8 years, 3 months, 18 days
91	394	157,720	15 years		6.7%	SQ	8 years, 8 months, 26 days
92	395	2,815	10 years		9.87%	SQ	4 years, 2 months, 13 days
93	396	84,083	12 years	25%	7.53%	SQ	6 years, 2 months, 8 days
94	[q] 397	5,952	10 years		13.59%	SQ	3 years, 9 months, 10 days
95	[r] 397	67.847	10 years	0%	0%	SQ	3 years, 9 months
96	[s] 397	7,104	15 years		10.7%	SQ	3 years, 4 months, 25 days
97	[t] 397	104,765	15 years		6.69%	SQ	9 years, 7 months
98	[u] 397	76,502	20 years		4.62%	SQ	17 years, 9 months, 10 days
99	398	1,887	15 years		6.66%	SQ	9 years, 2 months, 4 days
100	Subtotal General	978,060					
101	TOTAL	[v] 23,844,783					

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AmortizationOfLimitedTermPlantOrProperty

The Amortization of Limited Term Electric Plant within Account 404 includes the following:

Intangible Plant	$	20,930,905
Nuclear Production Plant		10,868,295
Hydraulic Production Plant - Conventional		106,828
Total	$	31,906,028

(b) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

Transmission Serving Production	$	3,902,119

(c) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

Distribution Serving Production	$	122,540

(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	$	(4,633,264)
Transmission Plant		(4,171,205)
General Plant		(88,148)
Total	$	(8,892,617)

(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).

	Charged to Clearing Accounts	Depreciable Plant Base
392 Transportation Equipment	$ 15,608,723	$ 257,324,000
396 Power Operated Equipment	4,102,672	84,083,000
Total	$ 19,711,395	$ 341,407,000

(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 E002-GR-21-630_2022 MN Elec Rate Case, with with no change to net salvage percentages. Grand Meadows and Nobles wind farms were repowers. South Dakota also approved this via settlement, docket EL22-17_2022 Elec Rate Case.

For 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.

(w) Concept: UtilityPlantWeightedAverageRemainingLife
Account 390 Structures and Improvements - Leasehold Improvements is computed using an end of life method rather than a specific rate.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
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)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	MINNESOTA PUBLIC UTILITIES COMMISSION											
2	Electric Assessments	9,697,772		9,697,772		Elec	928	8,813,670				
3	Gas Assessments					Gas	928	884,102				
4	G002/GR-09-1153 2010 Natural Gas Rate Increase - Amortized through 2024	(1,053,937)		(1,053,937)		Gas	928			254	(1,053,937)	
5	G002/GR-21-678 2022 Natural Gas Rate Increase	12,269		12,269		Gas	928	12,269				
6	E002/GR-21-630 2022 Electric Rate Increase - Amortized through 2024	1,624,735	4,903	1,629,638		Elec	928	4,903		186	1,624,735	
7	G002/GR-23-413 2024 Natural Gas Rate Increase - Amortized through 2026	1,104,968		1,104,968		Gas	928			186	1,104,968	

8	E999/AA-18-373 Sherco Unit 3		171,655	171,655		Elec	928	171,655					
9	IP-6946/WS-17-410 Freeborn Wind Site Permit		170	170		Elec	928	170					
10	E002/GR-13-868 Sherco 3 Fuel Recovery 2012 Turbine Failure	89,604		89,604		Elec	928	89,604					
11	E002/C-23-424 Technical Planning Standards Appeal	6,974	22,378	29,352		Elec	928	29,352					
12	G002/M-23-518 Natural Gas Innovation Plan		2,691	2,691		Gas	928	2,691					
13	E002/AA-22-179 2023 Prairie Island Outage Prudence Case		3,639	3,639		Elec	928	3,639					
14	E002/M-13-867 Community Solar Garden Bill Credit Change		18,401	18,401		Elec	928	18,401					
15	NSPM Hinshaw Pipeline		58,120	58,120		Elec	928	58,120					
16	Integrated Resource Plan Advertisement	149,994		149,994		Elec	928	149,994					
17	Electric Miscellaneous - Minnesota	46,275	340	46,615		Elec	928	46,719					
18	Gas Miscellaneous - Minnesota					Gas	928	(104)					
19	NORTH DAKOTA PUBLIC SERVICE COMMISSION												
20	Gross Receipts Tax Assessment Electric	54,094		54,094		Elec	928	37,547					
21	Gross Receipts Tax Assessment Gas					Gas	928	16,547					
22	PU-24-349 2025 TCR Rider Rate Adjustment Petition	10,000		10,000		Elec	928	10,000					
23	PU-22-410 Advance Prudence – 150 MW PPA	(29,616)		(29,616)		Elec	928	(29,616)					

24	PU-21-152 Advance Prudence - 460MW Sherco Solar	(49,137)		(49,137)		Elec	928	(49,137)				
25	PU-12-813 ND Electric Future Rate Case - Amortized through 2024	22,899		22,899		Elec	928			186	22,899	
26	PU-23-367 2024 Natural Gas Rate Increase - Amortized through 2027	267,884		267,884		Gas	928			186	267,884	
27	PU-24-160 Integrated Resource Plan 2024-2040	250,000		250,000		Elec	928	250,000				
28	SOUTH DAKOTA PUBLIC UTILITIES COMMISSION											
29	Gross Receipts Tax Assessment	368,626		368,626		Elec	928	368,626				
30	EL24-030 2025 TCR Eligibility and Rate Adjustment	5,177		5,177		Elec	928	5,177				
31	EL24-029 Infrastructure Rider	33,029		33,029		Elec	928	33,029				
32	EL22-017 2022 SD Electric Rate Increase - Amortized through 2025	238,487		238,487		Elec	928			186	238,487	
33	Other	1,726		1,726		Elec	928	1,726				
34	FEDERAL ENERGY REGULATORY COMMISSION											
35	EL22-78 MISO Complaint	2,325	11,968	14,293		Elec	928	14,293				
36	Miscellaneous - Electric	7,410	7,499	14,909		Elec	928	14,470				
37	Miscellaneous - Gas					Gas	928	439				
46	TOTAL	12,861,558	301,764	13,163,322				10,958,286			2,205,036	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	B(1)	Electric Power Research Institute		262,004	588	262,004	
2				481,934	930.2	481,934	
3	B(4)	Other, 1 item under $50,000		23,284	930.2	23,284	
4	B(5)	Total		767,222		767,222	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	180,689,634		
4	Transmission	16,471,893		
5	Regional Market	356,594		
6	Distribution	33,986,627		
7	Customer Accounts	13,893,909		
8	Customer Service and Informational	1,545,844		
9	Sales	1,409,120		
10	Administrative and General	94,026,571		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	342,380,192		
12	Maintenance			
13	Production	75,632,709		
14	Transmission	2,073,089		
15	Regional Market			
16	Distribution	22,476,919		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	100,182,717		
19	Total Operation and Maintenance			

20	Production (Enter Total of lines 3 and 13)	256,322,343		
21	Transmission (Enter Total of lines 4 and 14)	18,544,982		
22	Regional Market (Enter Total of Lines 5 and 15)	356,594		
23	Distribution (Enter Total of lines 6 and 16)	56,463,546		
24	Customer Accounts (Transcribe from line 7)	13,893,909		
25	Customer Service and Informational (Transcribe from line 8)	1,545,844		
26	Sales (Transcribe from line 9)	1,409,120		
27	Administrative and General (Enter Total of lines 10 and 17)	94,026,571		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	442,562,909	7,391,865	449,954,774
29	Gas			
30	Operation			
31	Production - Manufactured Gas	3,125		
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	174,739		
34	Storage, LNG Terminaling and Processing	1,613,697		
35	Transmission	751,814		
36	Distribution	19,701,908		
37	Customer Accounts	3,443,004		
38	Customer Service and Informational	868,164		
39	Sales			
40	Administrative and General	8,555,821		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	35,112,272		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	2,387,111		

47	Transmission	240,555		
48	Distribution	7,794,956		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	10,422,622		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	3,125		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	174,739		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	4,000,808		
56	Transmission (Lines 35 and 47)	992,369		
57	Distribution (Lines 36 and 48)	27,496,864		
58	Customer Accounts (Line 37)	3,443,004		
59	Customer Service and Informational (Line 38)	868,164		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	8,555,821		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	45,534,894	1,469,464	47,004,358
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	488,097,803	8,861,329	496,959,132
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	213,644,895	58,555,794	272,200,689
69	Gas Plant	21,673,176	11,491,928	33,165,104
70	Other (provide details in footnote):	[(a)]816,115		816,115
71	TOTAL Construction (Total of lines 68 thru 70)	236,134,186	70,047,722	306,181,908
72	Plant Removal (By Utility Departments)			
73	Electric Plant	16,244,982	4,171,730	20,416,712

74	Gas Plant	578,083	818,727	1,396,810
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	16,823,065	4,990,457	21,813,522
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Merchandise (Acct No. 155)		45,787	45,787
80	Prepayments (Acct No. 165)		45,539	45,539
81	Regulatory Assets (Acct No. 182.3)	11,706,497	280,736	11,987,233
82	Preliminary Survey and Investigation (Acct No. 183)	464,364	(295)	464,069
83	Miscellaneous Deferred Debits (Acct No. 186)		13,758	13,758
84	Miscellaneous Deferred Credits (Acct No. 253)	186,202	1,808	188,010
85	Regulatory Liabilities (Acct No. 254)	210,929	1,720	212,649
86	Non-utility (Accts No. 416-417.1)	2,074,996	26,252	2,101,248
87	Miscellaneous Income and Deductions (Accts No. 426.1-426.5)	567,547	2,953	570,500
88	Non-utility CWP and RWP	2,660,025	37,774	2,697,799
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	17,870,560	456,032	18,326,592
96	TOTAL SALARIES AND WAGES	758,925,614	84,355,540	843,281,154

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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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:

Account		Allocated to Utility Departments Electric	Gas	Cost at Dec. 31, 2024
COMMON UTILITY PLANT IN SERVICE AND COMPLETED NOT CLASSIFIED (ACCOUNTS 101 AND 106)				
301	Organization	91,365	9,243	100,608
303	Computer Software	676,295,274	68,419,968	744,715,242
Total intangible plant		676,386,639	68,429,211	744,815,850
389	Land and land rights	14,829,262	1,123,540	15,952,802
390	Structures and improvements	278,446,329	21,096,502	299,542,831
391	Office furniture and equipment	289,077,510	21,901,974	310,979,484
392	Transportation equipment	14,879,121	2,817,288	17,696,409
393	Stores equipment	228,825	17,337	246,162
394	Tools/shop/garage equipment	18,760,890	1,428,337	20,189,227
395	Laboratory equipment	—	—	—
396	Power operated equipment	2,186,309	261,263	2,447,572
397	Communications equipment	1,066,295	80,788	1,147,083
398	Miscellaneous equipment	41,727	3,161	44,888
399.1	Asset retirement costs for general plant	317,945	24,089	342,034
Total		1,296,220,852	117,183,490	1,413,404,342
COMMON UTILITY PLANT HELD FOR FUTURE USE (ACCOUNT 105)				
	General Plant	11,727,013	1,165,456	12,892,469
COMMON UTILITY PLANT CONSTRUCTION WORK IN PROGRESS (ACCOUNT 107)				
	General Plant	154,704,339	13,565,496	168,269,835

Instruction 2:

COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (ACCOUNT 108 AND 111)				
	General Plant	544,907,254	51,082,158	595,989,412

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.

	Cost of Removal Reserve
Common General	$ 2,648,618
Common Intangible	—
Total Common	2,648,618

Instruction 3:

Common Utility Plant Expenses

		Electric	Gas	Total
403	Depreciation Expense	47,488,126	3,417,566	50,905,692
403.1	Depreciation Expense - ARC	3,478	262	3,740
404	Amortization of limited term plant	70,248,801	8,117,017	78,365,818
405	Amortization of other plant	(969)	(71)	(1,040)
407.4	Amortization of regulatory credits	(24,689)	(1,855)	(26,544)
411.1	Accretion expense	21,210	1,594	22,804

411.1	Accretion expense	[illegible]	[illegible]	[illegible]
Total		117,735,957	11,534,513	129,270,470

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.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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)	23,816,422	32,364,730	48,515,358	67,518,061
9	MISO - Net Sales (Account 447)	(17,784,766)	(20,769,289)	(73,012,970)	(81,893,426)
10	MISO - Transmission Rights	(14,014,033)	(34,727,642)	(39,513,492)	(45,210,337)
11	MISO - Ancillary Services	505,521	995,611	2,410,911	2,899,629
12	MISO - Uplift Charges	(4,934,108)	(4,607,039)	(4,137,785)	(2,547,092)
13	Electric Reliability Council of TX (ERCOT)				
14	ERCOT - Net Purchases (Account 555)	564,531	2,050,981	4,292,519	5,522,040
15	ERCOT - Net Sales (Account 447)				
16	ERCOT - Transmission Rights				
17	ERCOT - Ancillary Services				
18	ERCOT - Uplift Charges	287	839	1,717	(5,716)
19	PJM Interconnection				

20	PJM - Net Purchases (Account 555)				
21	PJM - Net Sales (Account 447)				
22	PJM - Transmission Rights				
23	PJM - Ancillary Services				
24	PJM - Uplift Charges				6,500
25	Southwest Power Pool (SPP)				
26	SPP - Net Purchases (Account 555)	55,414	74,782	108,318	162,500
27	SPP - Net Sales (Account 447)				
28	SPP - Transmission Rights				
29	SPP - Ancillary Services	496	868	1,231	1,894
30	SPP - Uplift Charges	1,518	2,459	4,860	7,087
46	TOTAL	(11,788,718)	(24,613,700)	(61,329,333)	(53,538,860)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	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	[(a)] 0	[(b)] 0	8,258,685	[(c)] 0	[(d)] 0	824,543
2	Reactive Supply and Voltage	[(e)] 0	[(f)] 0	27	[(g)] 0	[(h)] 0	126,983
3	Regulation and Frequency Response	[(i)] 0	[(j)] 0	2,067,143	[(k)] 0	[(l)] 0	5,671,609
4	Energy Imbalance	0	0		0	0	
5	Operating Reserve - Spinning	[(m)] 0	[(n)] 0	1,496,224	[(o)] 0	[(p)] 0	2,076,489
6	Operating Reserve - Supplement	[(q)] 0	[(r)] 0	272,749	[(s)] 0	[(t)] 0	146,522
7	Other	[(u)] 0	[(v)] 0	[(w)] 2,764,904	[(x)] 0	[(y)] 0	[(z)] 2,222,196
8	Total (Lines 1 thru 7)			14,859,732			11,068,342

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ 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: AncillaryServicesSoldNumberOfUnits

Volume of units is not available

(h) Concept: AncillaryServicesSoldUnitsOfMeasure

Unit of measure is not available

(i) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of units is not available

(j) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Unit of measure is not available

(k) Concept: AncillaryServicesSoldNumberOfUnits

Volume of units is not available

(l) Concept: AncillaryServicesSoldUnitsOfMeasure

Unit of measure is not available

(m) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of units is not available

(n) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Unit of measure is not available

(o) Concept: AncillaryServicesSoldNumberOfUnits

Volume of units is not available

(p) Concept: AncillaryServicesSoldUnitsOfMeasure

Unit of measure is not available

(q) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of units is not available

(r) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Unit of measure is not available

(s) Concept: AncillaryServicesSoldNumberOfUnits

Volume of units is not available

(t) Concept: AncillaryServicesSoldUnitsOfMeasure

Unit of measure is not available

(u) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of units is not available

(v) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Unit of measure is not available

(w) Concept: AncillaryServicesPurchasedAmount

NSPP Real-Time Short-Term Reserve Cost Distribution Amount	$	2,764,904

(x) Concept: AncillaryServicesSoldNumberOfUnits

Volume of units is not available

(y) Concept: AncillaryServicesSoldUnitsOfMeasure

Unit of measure is not available

(z) Concept: AncillaryServicesSoldAmount

NSPP Real-Time Ramp Capability Amount	$	53,993
NSPP Day-Ahead Ramp Capability Amount	$	172,631
NSPP Day-Ahead Short-Term Reserve Amount	$	2,032,146
NSPP Real-Time Short-Term Reserve Amount	$	(36,574)
	$	2,222,196

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	[a]7,347	15	18	[b]6,040	1,615				
2	February	6,601	29	8	5,378	1,489				
3	March	6,525	26	11	5,383	1,400				
4	Total for Quarter 1				16,801	4,504	0			0
5	April	5,768	2	12	4,667	1,332				
6	May	6,845	17	17	5,596	1,453				
7	June	8,572	24	18	6,991	1,805				
8	Total for Quarter 2				17,254	4,590	0			0
9	July	9,912	31	15	8,129	2,122				
10	August	10,477	26	17	8,612	2,183				
11	September	9,042	16	16	7,420	1,954				
12	Total for Quarter 3				24,161	6,259	0			0
13	October	6,875	21	16	5,606	1,473				
14	November	6,433	20	18	5,329	1,360				
15	December	7,368	11	18	6,060	1,605				

16	Total for Quarter 4				16,995	4,438	0			0
17	Total				75,211	19,791	0	0	0	0

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	325
February	280
March	273
April	244
May	217
June	241
July	360
August	340
September	352
October	219
November	271
December	313
Total	3,435

"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	68
February	56
March	53
April	46
May	39
June	60
July	67
August	45
September	55
October	42
November	57
December	54
Total	642

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Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-04	Year/Period of Report End of: 2024/ Q4

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)	32,069,399
3	Steam	5,763,171	23	Requirements Sales for Resale (See instruction 4, page 311.)	6,152,554
4	Nuclear	11,955,794	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	17,275,121
5	Hydro-Conventional	43,519	25	Energy Furnished Without Charge	206
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	48,138
7	Other	18,463,070	27	Total Energy Losses	1,929,783
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	36,225,554	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	57,475,201
10	Purchases (other than for Energy Storage)	21,249,648			
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)	57,475,202

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	[(a)]4,572,438	1,201,190	5,216	15	18
30	February	4,140,852	1,131,860	4,604	28	8
31	March	4,708,888	1,409,218	4,612	26	11
32	April	5,072,262	1,512,970	4,324	2	12
33	May	4,940,469	1,531,084	4,932	17	17
34	June	4,940,735	1,578,596	6,162	24	18
35	July	5,521,214	1,836,046	7,048	31	15
36	August	5,416,236	1,924,855	7,444	26	17
37	September	4,854,981	1,399,604	6,448	17	17
38	October	4,256,367	1,267,231	4,892	21	17
39	November	4,147,417	1,144,841	4,509	20	18
40	December	4,903,342	1,337,626	5,204	11	18
41	Total	57,475,201	17,275,121			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ 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.

				Northern States Power Co. (a Minnesota corporation)		Northern States Power Co. (a Wisconsin corporation)	
Day	Hour	Integrated System	Minnesota	North Dakota	South Dakota	Wisconsin	Michigan
15-Jan	1800	6,270	4,457	388	371	1,030	24
28-Feb	800	5,584	3,947	338	319	957	22
26-Mar	1100	5,565	3,992	315	305	932	20
2-Apr	1200	5,247	3,784	262	278	906	18
17-May	1700	5,779	4,238	302	392	831	16
24-Jun	1800	7,306	5,268	384	510	1,124	20
31-Jul	1500	8,316	6,205	342	501	1,246	21
26-Aug	1700	8,822	6,589	327	528	1,355	23
17-Sep	1700	7,614	5,619	390	439	1,143	22
21-Oct	1700	5,798	4,286	275	331	888	18
20-Nov	1800	5,490	3,897	307	305	962	20
11-Dec	1800	6,264	4,489	372	343	1,037	22

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	1,319.10	25.00
6	Net Peak Demand on Plant - MW (60 minutes)	511	377	557	345	629	351	665	1,120	508	1,202	24
7	Plant Hours Connected to Load	1,367	1,493	7,240	1,643	6,594	670	8,577	7,759	6,820	8,607	7,988
8	Net Continuous Plant Capability (Megawatts)	511	401	523	545	580	357	646	1,092	502	1,197	18
9	When Not Limited by Condenser Water	511	401	523	545	580	357	646	1,092	500	1,197	18
10	When Limited by Condenser Water	511	343	491	454	530	272	617	1,040	454	1,197	18
11	Average Number of Employees	70	7	24	5	26	7	322	442	24	212	26
12	Net Generation, Exclusive of Plant Use - kWh	536,033,000	233,913,332	2,305,693,000	316,181,000	3,046,086,000	65,279,000	5,512,189,000	6,443,605,000	2,774,508,000	4,977,798,871	106,345,000
13	Cost of Plant: Land and Land Rights	1,335,100	1,155,578	952,692	141,878	523,582	351,801	778,651	892,327	450,132	17,630,288	499,773
14	Structures and Improvements	41,802,368	8,581,808	58,373,850	2,619,682	71,766,691	1,913,277	315,655,816	358,769,271	58,557,461	246,181,138	12,946,435
15	Equipment Costs	673,361,079	148,734,779	318,258,564	125,597,619	384,720,343	64,599,906	1,379,363,381	2,242,687,318	279,101,903	1,421,245,204	69,411,409

16	Asset Retirement Costs	5,718,453	712,520	49,621,834	170,055	20,138	26,851	59,466,115	(177,153,829)	1,060,162	21,070,327	3,302,516
17	Total cost (total 13 thru 20)	722,217,000	159,184,685	427,206,940	128,529,234	457,030,754	66,891,835	1,755,263,963	2,425,195,087	339,169,658	1,706,126,957	86,160,133
18	Cost per KW of Installed Capacity (line 17/5) Including	1,206.9134	392.3704	770.7143	229.8037	709.5649	238.4736	2,562.4291	2,044.5077	578.8866	1,293.4023	3,446.4053
19	Production Expenses: Oper, Supv, & Engr	674,821	83,261	178,223	97,011	212,714	95,862	11,920,147	15,423,676	218,789	1,589,527	376,567
20	Fuel	19,302,847	7,274,414	54,713,533	10,942,537	63,090,579	3,590,459	43,835,519	61,882,315	61,960,407	137,747,402	4,003,841
21	Coolants and Water (Nuclear Plants Only)							3,655,763	4,851,491			
22	Steam Expenses	3,799,043						25,257,089	33,631,512		7,145,020	2,152,160
23	Steam From Other Sources											
24	Steam Transferred (Cr)											
25	Electric Expenses	733,586	191,297	1,965,287	362,114	1,967,292	260,294	202,411	2,348,601	2,349,606	3,901,875	78,116
26	Misc Steam (or Nuclear) Power Expenses	3,114,656	527,161	1,217,545	145,810	1,394,527	136,647	55,522,020	82,437,191	1,118,121	7,021,629	1,133,239
27	Rents	343,219	45,985	100,265	35,512	119,668	34,699	2,612,639	3,863,548	115,773	1,054,655	174,669
28	Allowances											
29	Maintenance Supervision and Engineering	484,648	149,003	91,038	67,483	108,656	53,090	3,169,115	3,316,489	105,119	777,783	7,139
30	Maintenance of Structures	834,231	450,313	1,815,908	234,678	1,007,582	103,691			1,308,357	3,505,984	213,589
31	Maintenance of Boiler (or reactor) Plant	2,366,392						8,680,543	13,993,654		11,795,713	1,111,573
32	Maintenance of Electric Plant	853,420	1,729,206	1,520,171	1,463,543	3,331,180	1,351,793	3,556,644	10,676,035	2,647,628	3,546,794	1,294,603
33	Maintenance of Misc Steam (or Nuclear) Plant	1,134,816	15,109	69,938	58,359	163,371	372,058	14,668,905	25,079,092	171,279	3,721,893	742,020
34	Total Production Expenses	33,641,679	10,465,749	61,671,908	13,407,047	71,395,569	5,998,593	173,080,795	257,503,604	69,995,079	181,808,275	11,287,516
35	Expenses per Net kWh	0.0628	0.0447	0.0267	0.0424	0.0234	0.0919	0.0314	0.0400	0.0252	0.0365	0.1061

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	357,810	80,230	30	2,807,121	3,936	20,250,191	3,498,596	4,177	22,184,580	962,449	2,222	479,480	646,852	20,055,060	2	2,950,303	14,924	29,972	175,270	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	(e)8,171	310	83,528	1,012	134,887	936	965	138,228	1,657	1,161	130,706	121,069	107,002	1,922	25,212	(f)(g)8,946	138,019	667	6,069	0

40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	36.544	6.332	106.884	2.460	93.476	2.744	2.994	111.849	2.844	3.240	212.560			3.090	69.557	45.052	109.590	4.934	2.255	
41	Average Cost of Fuel per Unit Burned	53.881	6.332	106.884	2.460	93.476	2.744	2.994	111.849	2.844	3.240	212.560			3.090	69.557	46.231	109.590	4.934	24.137	
42	Average Cost of Fuel Burned per Million BTU	[(b)]3.297	20.457	30.476	2.432	16.500	2.931	3.101	19.266	1.716	2.790	38.720	0.760	0.896	1.608	65.688	[(i)]2.584	18.905	7.392	1.989	
43	Average Cost of Fuel Burned per kWh Net Gen		0.035			0.030	0.024		0.033	0.023	0.053		0.010	0.010	0.021			0.028	0.041		
44	Average BTU per kWh Net Generation		10,389.32			11,986.55	8,122.07		10,350.56	13,235.21	16,672.79		10,466.36	11,148.88	13,311			10,622.00	20,051.59		

FOOTNOTE DATA

(a) Concept: PlantKind

Black Dog Unit 2 & 5 are combined cycle plants. Black Dog Unit 6 is a gas turbine.

(b) Concept: PlantKind

Instruction 12 - Monticello Nuclear Generating Plant (p. 403.1)

(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.

(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.

(c) The Monticello Plant is a General Electric BWR-3 Nuclear Power Plant. Fuel material is U02 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 85 metric tons of uranium metal with a nominal U-235 enrichment of 4.1 weight percent in the fresh fuel. The reactor is licensed to operate at 2,004 MWt.

(c) Concept: PlantKind

Instruction 12 - Prairie Island Nuclear Generating Plant (p. 403)

(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.

(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.

(c) The Prairie Island Plant has two identical Westinghouse 2 loop PWR Nuclear Power Plants. Fuel material is U02 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 47 metric tons of uranium metal with a nominal U-235 enrichment of 4.91 weight percent in the fresh fuel. The reactor is licensed to operate at 1677 MWt.

(d) Concept: PlantKind

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.

(e) Concept: FuelBurnedAverageHeatContent

The Coal BTU numbers for the AS King and Sherburne plant are estimates

(f) Concept: FuelBurnedAverageHeatContent

The "Average Heat Content of Fuel Burned" is calculated as:

Coal: Btu/pound
Oil: BTU/gallons
Gas: Btu/cubic ft

(g) Concept: FuelBurnedAverageHeatContent

The Coal BTU numbers for the AS King and Sherburne plant are estimates

(h) Concept: AverageCostOfFuelBurnedPerMillionBritishThermalUnit

The Coal BTU numbers for the AS King and Sherburne plant are estimates

(i) Concept: AverageCostOfFuelBurnedPerMillionBritishThermalUnit

The Coal BTU numbers for the AS King and Sherburne plant are estimates

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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)		9
7	Plant Hours Connect to Load		8,462
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		43,519,000
13	**Cost of Plant**		
14	Land and Land Rights		1,548,707
15	Structures and Improvements		1,515,263
16	Reservoirs, Dams, and Waterways		9,570,950

17	Equipment Costs		13,574,484
18	Roads, Railroads, and Bridges		367,389
19	Asset Retirement Costs		
20	Total cost (total 13 thru 20)		26,576,793
21	Cost per KW of Installed Capacity (line 20 / 5)		1,911.999
22	**Production Expenses**		
23	Operation Supervision and Engineering		16,269
24	Water for Power		49,506
25	Hydraulic Expenses		228,899
26	Electric Expenses		12,087
27	Misc Hydraulic Power Generation Expenses		115,662
28	Rents		29,040
29	Maintenance Supervision and Engineering		53
30	Maintenance of Structures		18,191
31	Maintenance of Reservoirs, Dams, and Waterways		171,879
32	Maintenance of Electric Plant		39,913
33	Maintenance of Misc Hydraulic Plant		136
34	Total Production Expenses (total 23 thru 33)		681,635
35	Expenses per net kWh		0.0157

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

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: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
1	STEAM PLANTS												
2	Red Wing	1949	23.00	23	142,994,000	87,102,167	3,787,051	2,926,408	615,324	3,236,070	RDF, Gas	8.56	Steam
3	WIND TURBINES												
4	Blazing Star Wind 1	2020	218.00	200	815,587,345	346,260,797	1,588,352	3,497,904		1,745,533			Wind
5	Lake Benton Wind	2019	100.20	101	437,777,649	181,900,222	1,815,371	1,242,097		981,548			Wind
6	Ben Fowke Wind Energy Center	2008	107.50	101	376,785,251	150,589,073	1,400,829	1,818,078		1,150,364			Wind
7	Nobles Wind	2010	212.80	198	752,467,138	295,489,320	1,388,578	3,353,765		1,734,648			Wind
8	Borders Wind	2015	150.00	147	613,002,383	282,383,568	1,882,557	2,201,890		984,258			Wind
9	Pleasant Valley Wind	2015	200.00	194	769,311,312	366,306,906	1,831,535	3,493,019		1,595,716			Wind
10	Courtenay Wind	2016	200.00	193	737,303,273	304,992,162	1,524,961	3,230,730		1,468,200			Wind
11	Foxtail Wind	2019	163.60	151	585,966,826	249,979,540	1,527,992	1,402,342		438,282			Wind
12	Blazing Star Wind 2	2020	218.00	200	839,652,520	382,865,505	1,756,264	3,584,068		1,495,663			Wind

13	Community Wind North	2020	26.40	26	114,604,850	36,646,173	1,388,113	446,938		218,481			Wind
14	Crowned Ridge	2020	200.60	196	830,337,297	348,993,519	1,739,748	2,260,067		1,825,252			Wind
15	Jeffers	2020	44.00	44	194,508,232	52,401,598	1,190,945	773,456		470,564			Wind
16	Mower County	2020	98.90	91	341,825,841	224,870,437	2,273,715	2,101,359		490,511			Wind
17	Freeborn	2021	218.00	199	749,676,624	360,233,470	1,652,447	4,966,328		1,456,318			Wind
18	Dakota Range 1 & 2	2022	304.00	296	1,038,227,418	422,301,383	1,389,149	3,301,510		2,043,212			Wind
19	Northern Wind CV	2023	100.20	91	369,615,539	188,160,790	1,877,852	1,508,097		907,169			Wind
20	Rock Aetna	2022	21.60	20	82,161,830	36,616,205	1,695,195						Wind
21	SOLAR FARMS												
22	Sherco Solar	2024	264.60	210	72,598,156	349,788,615	1,321,952	127,726		112,671			Solar

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. 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.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. 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.
5. 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.
6. 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).
7. 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.
8. 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.
9. 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 (a)	To (b)	Operating (c)	Designated (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)	(i)	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (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	REIL (MN)	500.0	500.0	TOWER	203.628	0.000	1	9-1192.5 ACSR	1,723,645	90,274,300	91,997,945				
3	(5653;01) LYON CO.	STEEP BANK LAKE	345.0	345.0	SINGLE[(a)] POLE	5.681	34.682	1	6-397.5 ZTACSR-VR2		24,334,632	24,334,632				
4	(5653-SD;01) BROOKINGS CO.	STEEP BANK LAKE	345.0	345.0	SINGLE[(b)] POLE	7.250	2.942	1	6-397.5 ZTACSR-VR2		3,055,038	3,055,038				
5	(5653-MN;01) BROOKINGS CO.	STEEP BANK LAKE	345.0	345.0	SINGLE[(c)] POLE	4.037	4.825	1	6-397.5 ZTACSR-VR2		5,480,682	5,480,682				
6	(5651;01) SHERBURNE CO.	SHERCO SOLAR WEST	345.0	345.0	SINGLE POLE	3.247	0.000	1	3-556.5 ACSR		11,297,789	11,297,789				
7	(5650;01) DAKOTA RANGE WIND	TWIN BROOKS SW. ST.	345.0	345.0	SINGLE POLE	0.091	0.000	1	6-795 ACSR							
8	(0998;01) SIOUX CITY (WAPA)	SPLIT ROCK	345.0	345.0	SINGLE POLE	0.000	4.432	1	6-954 ACSS		670,200	670,200				
9	(0998;01) SIOUX CITY (WAPA)	SPLIT ROCK	345.0	345.0	SINGLE POLE	0.049	0.580		6-954 ACSS/TW							

10	(0997;01) SPLIT ROCK	WHITE (WAPA)	345.0	345.0	SINGLE POLE	5.152	0.000	1	6-954 ACSS/TW	139,860	8,455,822	8,595,682					
11	(0996;01) DICKINSON SW STA (GRE)	PARKERS LAKE	345.0	345.0	TOWER	0.148	9.578	1	6-954 ACSR		576,104	576,104					
12	(0994;01) ALLEN S KING	CHISAGO CO.	345.0	345.0	SINGLE POLE	0.088	31.458	1	6-954 ACSR		1,648,291	1,648,291					
13	(0994;01) ALLEN S KING	CHISAGO CO.	345.0	345.0	TOWER	0.056	6.604		6-795 ACSR								
14	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	H-FRAME	5.160	0.000	1	6-954 ACSR	472,775	15,293,675	15,766,450					
15	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	6.623	0.000		6-954 ACSR								
16	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	5.170	14.789		6-954 ACSR								
17	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	0.364	11.336		6-954 ACSR								
18	(0991;01) MONTICELLO SUB	SHERBURNE CO.	345.0	345.0	TOWER	0.128	5.697	1	6-954 ACSR		196,978	196,978					
19	(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					
20	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	SINGLE POLE	0.111	0.730		6-795 ACSR								
21	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	TOWER	4.064	16.627		6-795 ACSR								
22	(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					
23	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	K-FRAME	1.997	0.000		6-795 ACSR								
24	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	TOWER	4.408	1.613		6-795 ACSR								
25	(0988;01) BLUE LAKE	PARKERS LAKE	345.0	345.0	SINGLE POLE	0.000	2.102	1	6-795 ACSR		478,209	478,209					
26	(0988;01) BLUE LAKE	PARKERS LAKE	345.0	345.0	TOWER	0.137	12.557		6-795 ACSR								
27	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	K-FRAME	20.881	1.202	1	6-795 ACSR		7,142,220	7,142,220					
28	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	SINGLE POLE	0.000	5.108		6-795 ACSR								
29	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.075	2.256		6-795 ACSR								
30	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.148	2.335		6-954 ACSR								
31	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	K-FRAME	22.073	0.000	1	6-795 ACSR	661,692	10,267,733	10,929,425					

32	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	SINGLE POLE	5.108	0.000		6-795 ACSR								
33	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	2.329	0.000		6-795 ACSR								
34	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.121	2.357		6-954 ACSR								
35	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	H-FRAME	16.914	0.000	1	6-954 ACSR	17,816	14,641,383	14,659,199					
36	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	3.362	0.000		6-954 ACSR								
37	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	0.299	0.942		6-954 ACSR								
38	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	6.138	5.467		6-954 ACSR								
39	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	H-FRAME	8.244	0.000	1	6-954 ACSR	506,296	19,341,268	19,847,564					
40	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	7.360	0.000		6-954 ACSR								
41	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	18.982	0.000		6-954 ACSR								
42	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	8.891	0.000		6-954 ACSR								
43	(0984;01) COON CREEK	TERMINAL	345.0	345.0	SINGLE POLE	0.000	4.550	1	6-795 ACSR	160,760	3,812,917	3,973,677					
44	(0984;01) COON CREEK	TERMINAL	345.0	345.0	TOWER	0.126	9.028		6-795 ACSR								
45	(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					
46	(0982;01) CRANDALL	LAKEFIELD GENERATING	345.0	345.0	K-FRAME	2.205	0.000	1	6-795 ACSR	612,272	14,264,454	14,876,726					
47	(0982;01) CRANDALL	WILMARTH	345.0	345.0	H-FRAME	4.300	0.000	1	6-795 ACSR								
48	(0982;01) CRANDALL	WILMARTH	345.0	345.0	K-FRAME	25.203	0.000		6-795 ACSR								
49	(0982;01) CRANDALL	WILMARTH	345.0	345.0	SINGLE POLE	1.656	21.241		6-556.5 ACSR/T2								
50	(0982;01) HELENA	SCOTT CO.	345.0	345.0	3 POLE	1.421	0.000	1	6-397.5 ZTACSR	95,480	22,324,335	22,419,815					
51	(0982;01) HELENA	SCOTT CO.	345.0	345.0	H-FRAME	15.198	0.529		6-397.5 ZTACSR								
52	(0982;01) HELENA	SHEAS LAKE	345.0	345.0	K-FRAME	7.454	0.000	1	6-795 ACSR								
53	(0982;01) LAKEFIELD JCT (IPW)	LAKEFIELD GENERATING	345.0	345.0	K-FRAME	18.391	0.294	1	6-795 ACSR	214,005	7,464,429	7,678,434					

54	(0982;01) SHEAS LAKE	WILMARTH	345.0	345.0	K-FRAME	22.121	0.000	1	6-795 ACSR	271,747	4,686,721	4,958,468				
55	(0982;01) SHEAS LAKE	WILMARTH	345.0	345.0	SINGLE POLE	0.196	0.000		6-795 ACSR							
56	(0982;01) SHEAS LAKE	WILMARTH	345.0	345.0	TOWER	1.115	0.000		6-795 ACSR							
57	(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				
58	(0981-MN;01) ALLEN S KING	EAU CLAIRE	345.0	345.0	TOWER	1.532	15.170		6-795 ACSR							
59	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.0	345.0	SINGLE POLE	31.623	0.376	1	6-954 ACSR	4,408,021	27,990,330	32,398,351				
60	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.0	345.0	TOWER	0.000	5.594		6-795 ACSR							
61	(0980;01) COON CREEK	KOHLMAN LAKE	345.0	345.0	SINGLE POLE	4.550	2.816	1	6-795 ACSR	1,384,573	2,657,526	4,042,099				
62	(0980;01) COON CREEK	KOHLMAN LAKE	345.0	345.0	TOWER	7.340	5.235		6-795 ACSR							
63	(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				
64	(0979;01) BYRON (SMMPA)	NORTH ROCHESTER	345.0	345.0	K-FRAME	13.517	0.000	1	6-795 ACSR	78,135	9,581,530	9,659,665				
65	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	345.0	345.0	H-FRAME	1.120	0.000	1	6-795 ACSR							
66	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	345.0	345.0	K-FRAME	15.177	0.000		6-795 ACSR							
67	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	H-FRAME	1.995	0.000	1	6-795 ACSR	67,126	10,787,569	10,854,695				
68	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	K-FRAME	25.227	0.000		6-795 ACSR							
69	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	TOWER	2.422	0.000		6-954 ACSR							
70	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	H-FRAME	16.905	0.000	1	6-954 ACSR	882,197	19,917,800	20,799,997				
71	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	K-FRAME	3.371	0.000		6-954 ACSR							
72	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	TOWER	5.833	0.000		6-954 ACSR							
73	(0978;01) ELM CREEK	PARKERS LAKE	345.0	345.0	SINGLE POLE	0.586	0.000	1	6-954 ACSR							
74	(0978;01) ELM CREEK	PARKERS LAKE	345.0	345.0	TOWER	10.447	0.000		6-954 ACSR							
75	(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				

76	(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				
77	(0977;01) KOHLMAN LAKE	TERMINAL	345.0	345.0	TOWER	7.376	0.000		6-795 ACSR							
78	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.0	345.0	SINGLE POLE	3.816	0.000	1	6-795 ACSR	977,240	6,465,869	7,443,109				
79	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.0	345.0	TOWER	1.722	0.000		6-795 ACSR							
80	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	2 POLE	0.659	0.000	1	6-954 ACSR							
81	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	K-FRAME	11.874	0.000		6-954 ACSR							
82	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	SINGLE POLE	0.841	0.000		6-795 ACSR							
83	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	TOWER	17.117	0.000		6-795 ACSR							
84	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	TOWER	3.344	0.000		6-954 ACSR							
85	(0976;01) EDEN PRAIRIE	PARKERS LAKE	345.0	345.0	TOWER	9.391	0.094	1	6-795 ACSR	45,639	521,262	566,901				
86	(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				
87	(0976;01) HAMPTON	PRAIRIE ISLAND	345.0	345.0	TOWER	3.564	0.000		6-795 ACSR							
88	(0975;01) ALLEN S KING	RED ROCK	345.0	345.0	K-FRAME	3.544	0.000	1	6-795 ACSR	401,128	2,764,269	3,165,397				
89	(0975;01) ALLEN S KING	RED ROCK	345.0	345.0	TOWER	21.857	0.000		6-795 ACSR							
90	(0974;01) MANKATO ENERGY CENTER	WILMARTH	345.0	345.0	H-FRAME	0.218	0.000	1	6-795 ACSR		888,655	888,655				
91	(0973;01) MONTICELLO SUB	QUARRY	345.0	345.0	SINGLE[d] POLE	30.038	0.000	1	6-954 ACSS/TW	5,368,660	10,969,295	16,337,955				
92	(0972;01) HAWKS NEST LAKE	LYON CO.	345.0	345.0	SINGLE[e] POLE	30.546	0.000	1	6-954 ACSS/TW		666,551	666,551				
93	(0972-SD;01) BROOKINGS CO.	HAWKS NEST LAKE	345.0	345.0	SINGLE[f] POLE	10.193	0.000	1	6-954 ACSS/TW	509,810	20,993,905	21,503,715				
94	(0972-MN;01) BROOKINGS CO.	HAWKS NEST LAKE	345.0	345.0	SINGLE[g] POLE	18.707	0.000	1	6-954 ACSS/TW	7,954,672	57,577,341	65,532,013				
95	(0971;01) BROOKINGS CO.	WHITE (WAPA)	345.0	345.0	SINGLE POLE	0.434	0.000	1	6-795 ACSS							
96	(0970;02) BROOKINGS CO.	WHITE (WAPA)	345.0	345.0	SINGLE POLE	0.378	0.000	1	6-795 ACSS	13,748	2,149,089	2,162,837				
97	(0969;02) BLAZING STAR 1	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	0.080	0.000	1	6-954							

98	(0968;01) BLAZING STAR 1	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	0.079	0.000	1	6-954		7,782	7,782				
99	(0967;01) HUNTLEY (ITC)	WILMARTH	345.0	345.0	SINGLE POLE [h]	52.026	0.000	1	6-556.5 ACSR/T2	2,997,012	48,897,554	51,894,566				
100	(0966;01) BIG STONE SOUTH	DEUEL (OTP)	345.0	345.0	SINGLE POLE [i]	30.879	0.000	1	6-556.5 ACSR/T2							
101	(0966;01) ASTORIA (OTP)	BROOKINGS CO.	345.0	345.0	SINGLE POLE [j]	16.483	0.000	1	6-556.5 ACSR/T2	3,526,999	57,812,368	61,339,367				
102	(0966;01) ASTORIA (OTP)	DEUEL (OTP)	345.0	345.0	SINGLE POLE [k]	24.612	0.000	1	6-556.5 ACSR/T2							
103	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.0	345.0	2 POLE [l]	3.121	0.000	1	6-954 ACSS/TW	5,358,507	59,722,203	65,080,710				
104	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.0	345.0	SINGLE POLE	40.065	0.000		6-954 ACSS/TW							
105	(0964;01) HAMPTON	NORTH ROCHESTER	345.0	345.0	SINGLE POLE [m]	37.851	0.000	1	6-397.5 TACSR/VR2	9,431,341	54,128,384	63,559,725				
106	(0962;01) HAZEL CREEK	LYON CO.	345.0	345.0	SINGLE POLE [n]	24.542	0.000	1	6-954 ACSS/TW	340,384	26,971,692	27,312,076				
107	(0961;01) CHUB LAKE (GRE)	HAMPTON	345.0	345.0	SINGLE POLE [o]	18.101	0.000	1	6-954 ACSS/TW	7,244,068	37,802,537	45,046,605				
108	(0960;01) CHUB LAKE (GRE)	HELENA	345.0	345.0	SINGLE POLE [p]	20.870	0.000	1	6-954 ACSS/TW	8,314,945	36,282,633	44,597,578				
109	(0959;02) CEDAR MTN. (GRE)	HELENA	345.0	345.0	3 POLE [q]	0.000	0.906	1	6-954 ACSS/TW							
110	(0959;02) CEDAR MTN. (GRE)	HELENA	345.0	345.0	SINGLE POLE	0.047	72.109		6-954 ACSS/TW							
111	(0958;01) CEDAR MTN. (GRE)	HELENA	345.0	345.0	3 POLE [r]	0.906	0.000	1	6-954 ACSS/TW	15,584,347	112,135,762	127,720,109				
112	(0958;01) CEDAR MTN. (GRE)	HELENA	345.0	345.0	SINGLE POLE	72.196	0.000		6-954 ACSS/TW							
113	(0957;02) CEDAR MTN. (GRE)	LYON CO.	345.0	345.0	SINGLE POLE [s]	0.000	49.488	1	6-954 ACSS/TW							
114	(0956;01) CEDAR MTN. (GRE)	LYON CO.	345.0	345.0	SINGLE POLE [t]	49.488	0.000	1	6-954 ACSS/TW	5,315,434	65,839,990	71,155,424				
115	(0955-MN;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	2 POLE [u]	2.060	0.000	1	6-954 ACSS/TW	6,637,015	84,241,012	90,878,027				
116	(0955-MN;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	SINGLE POLE	102.332	0.000		6-954 ACSS/TW							
117	(0955-ND;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	SINGLE POLE [v]	34.384	0.000	1	6-954 ACSS/TW	1,513,232	22,705,097	24,218,329				
118	(0954;01) ALEXANDRIA SW. ST.	RIVERVIEW (GRE)	345.0	345.0	SINGLE POLE [w]	45.160	0.000	1	6-954 ACSS/TW	2,327,849	37,137,830	39,465,679				
119	(0954;01) QUARRY	RIVERVIEW (GRE)	345.0	345.0	SINGLE POLE [x]	36.090	0.000	1	6-954 ACSS/TW	1,860,437	29,680,864	31,541,301				

120	(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				
121	(0953;01) LAKEFIELD JCT (IPW)	NOBLES CO.	345.0	345.0	SINGLE POLE	13.270	0.000		6-954 ACSS/TW							
122	(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	70,014,002	73,637,390				
123	(0953-MN;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	32.044	0.000		6-954 ACSS/TW							
124	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	4.432	0.000	1	6-954 ACSS	554,100	12,058,650	12,612,750				
125	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	5.073	0.000		6-954 ACSS/TW							
126	(0963;01) HAZEL CREEK	MINNESOTA VALLEY	230.0	345.0	2 POLE[y]	0.633	0.000	1	6-954 ACSS/TW	355,907	9,176,023	9,531,930				
127	(0963;01) HAZEL CREEK	MINNESOTA VALLEY	230.0	345.0	SINGLE POLE[z]	4.336	0.000		6-954 ACSS/TW							
128	(0929;01) BORDER WIND FARM (RES)	PEACE GARDEN	230.0	230.0	2 POLE	0.042	0.000	1	6-							
129	(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				
130	(0927;01) FOXTAIL	FOXTAIL	230.0	230.0	SINGLE POLE	0.115	0.000	1	3-795 ACSR		48,277	48,277				
131	(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				
132	(0923;01) CASS LAKE (OTP)	WILTON (MPC)	230.0	230.0	SINGLE POLE[aa]	19.318	0.000	1	3-795 ACSS	884,508	9,194,724	10,079,232				
133	(0922;01) BOSWELL (MINNESOTA POWER)	CASS LAKE (OTP)	230.0	230.0	SINGLE POLE[ab]	51.461	0.000	1	3-795 ACSS	1,023,124	23,387,110	24,410,234				
134	(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				
135	(0920;01) PEACE GARDEN	RUGBY (OTP)	230.0	230.0	H-FRAME	54.672	0.000	1	3-954 ACSR		372,625	372,625				
136	(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				
137	(0919;01) PAYNESVILLE TRANS. S	WILLMAR (GRE)	230.0	230.0	SINGLE POLE	27.554	0.000		3-795 ACSR							
138	(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				
139	(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				
140	(0916;01) GRAND FORKS (WAPA)	PRAIRIE	230.0	230.0	SINGLE POLE	0.476	0.000		3-954 ACSR							

141	(0915;01) FARGO (WAPA)	SHEYENNE	230.0	230.0	H-FRAME	4.245	0.000	1	3-795 ACSR	21,223	765,985	787,208				
142	(0912;01) DRAYTON (MINNKOTA)	LETELLIER (MANITOBA HYDRO)	230.0	230.0	H-FRAME	28.660	0.000	1	3-954 ACSR	57,281	3,010,357	3,067,638				
143	(0912;01) DRAYTON (MINNKOTA)	LETELLIER (MANITOBA HYDRO)	230.0	230.0	SINGLE POLE	0.068	0.000		3-954 ACSR							
144	(0911;01) AUDUBON (OTP)	SHEYENNE	230.0	230.0	H-FRAME	1.409	0.000	1	3-795 ACSR	29,249	3,357,210	3,386,459				
145	(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				
146	(0911;01) MAPLE RIVER	SHEYENNE	230.0	230.0	TOWER	0.250	3.530		3-795 ACSR							
147	(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				
148	(0909;01) ERIE JUNCTION (OTP)	HUBBARD (GRE)	230.0	230.0	H-FRAME	26.067	0.000	1	3-795 ACSR							
149	(0909;01) AUDUBON (OTP)	ERIE JUNCTION (OTP)	230.0	230.0	H-FRAME	12.457	0.000	1	3-795 ACSR	39,347	5,609,811	5,649,158				
150	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	H-FRAME	0.922	0.000	1	3-795 ACSR	407,857	8,136,645	8,544,502				
151	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	K-FRAME	52.990	0.000		3-795 ACSR							
152	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	SINGLE POLE	10.985	0.000		3-1272 ACSR							
153	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	TOWER	2.783	0.000		3-1272 ACSR							
154	(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				
155	(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				
156	(0900;01) BLUE LAKE	MCLEOD (MUNI)	230.0	230.0	TOWER	45.150	0.000		3-795 ACSR							
157	(0900;02) GRANITE FALLS (WAPA)	PANTHER (GRE)	230.0	230.0	K-FRAME	0.180	0.000	1	3-795 ACSR	5,902	1,880,562	1,886,464				
158	(0900;02) GRANITE FALLS (WAPA)	PANTHER (GRE)	230.0	230.0	TOWER	32.630	0.000		3-795 ACSR							
159	(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				
160	(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				
161	(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				
162	(5312;01) ADAMS	MOWER CO. WIND FARM	161.0	161.0	SINGLE POLE	7.729	0.000		3-477 ACSR							

163	(5311;01) PLEASANT VALLEY (GRE)	PLEASANT VALLEY WIND FARM	161.0	161.0	SINGLE POLE	4.982	0.000	1	3-954 ACSR							
164	(5310;01) NORTHERN HILLS	NORTH ROCHESTER	161.0	161.0	[ac] SINGLE POLE	15.507	0.000	1	3-795 ACSS	1,314,415	9,559,156	10,873,571				
165	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.0	161.0	[ad] SINGLE POLE	11.408	0.000	1	3-397.5 TACSR/TW	567,003	12,379,705	12,946,708				
166	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.0	161.0	[ae] SINGLE POLE	1.866	14.388		6-954 ACSS/TW							
167	(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				
168	(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				
169	(5305-MN;01) LAWRENCE CREEK	ST CROIX FALLS	161.0	161.0	H-FRAME	0.113	0.000	1	3-795 ACSS	69,923	10,278,048	10,347,971				
170	(5305-MN;01) LAWRENCE CREEK	ST CROIX FALLS	161.0	161.0	SINGLE POLE	1.454	0.000		3-795 ACSS							
171	(5305-MN;01) LAWRENCE CREEK	ST CROIX FALLS	161.0	161.0	UNDERGROUND	0.579	0.000		3-3000 CU							
172	(5301;01) ELK (ITC)	ROCK CO.	161.0	161.0	H-FRAME	5.389	0.000	1	3-477 ACSR	16,110	650,733	666,843				
173	(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				
174	(5301-MN;01) ROCK CO.	SPLIT ROCK	161.0	161.0	SINGLE POLE	0.081	0.000		3-477 ACSR							
175	(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				
176	(5301-SD;01) ROCK CO.	SPLIT ROCK	161.0	161.0	SINGLE POLE	0.867	0.000		3-2312 ACSR							
177	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.0	161.0	H-FRAME	30.153	0.000	1	3-477 ACSR	143,079	1,968,800	2,111,879				
178	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.0	161.0	SINGLE POLE	1.364	0.000		3-565.3 ACSS/TW							
179	SUMMARY OF 115 KV SYSTEM		115.0	115.0	[af] Overhead	1,476.138	157.069			25,649,055	793,315,923	818,964,978				
180	SUMMARY OF 115 KV SYSTEM		115.0	115.0	Underground	13.221	0.000									
181	SUMMARY OF 69 KV SYSTEM		69.0	69.0	Overhead	1,497.872	88.829			7,407,211	569,769,824	577,177,035				
182	SUMMARY OF 69 KV SYSTEM		69.0	69.0	Underground	1.532	0.000									
183	SUMMARY OF 34.5 KV SYSTEM		34.5	34.5	Overhead	61.955	30.628			436,068	29,551,527	29,987,595				
184	SUMMARY OF 34.5 KV SYSTEM		34.5	34.5	Underground	0.590	0.000									

185	Expenses, except depreciation and taxes												785,882	6,305,878	1,426,373	8,518,133
36	TOTAL					5,255.809	662.093	109		154,025,543	2,862,189,073	3,016,214,616	785,882	6,305,878	1,426,373	8,518,133

FOOTNOTE DATA

(a) Concept: SupportingStructureOfTransmissionLineType

NSM ((5653;01) LYON CO.-STEEP BANK LAKE) : Xcel Energy owns 62.2394%(25.122 miles) of 40.363 miles of this circuit: remaining 37.7606%(15.241 miles) is owned by other members of a joint venture partnership

(b) Concept: SupportingStructureOfTransmissionLineType

NSM ((5653-SD;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 62.2394%(6.343 miles) of 10.192 miles of this circuit: remaining 37.7606%(3.849 miles) is owned by other members of a joint venture partnership

(c) Concept: SupportingStructureOfTransmissionLineType

NSM ((5653-MN;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 62.2394%(5.516 miles) of 8.862 miles of this circuit: remaining 37.7606%(3.346 miles) is owned by other members of a joint venture partnership

(d) Concept: SupportingStructureOfTransmissionLineType

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

(e) Concept: SupportingStructureOfTransmissionLineType

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

(f) Concept: SupportingStructureOfTransmissionLineType

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

(g) Concept: SupportingStructureOfTransmissionLineType

NSM ((0972-MN;01) BROOKINGS CO.-HAWKS NEST LAKE) : Xcel Energy owns 67.7971%(12.683 miles) of 18.707 miles of this circuit: remaining 32.2029%(6.024 miles) is owned by other members of a joint venture partnership

(h) Concept: SupportingStructureOfTransmissionLineType

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

(i) Concept: SupportingStructureOfTransmissionLineType

NSM ((0966;01) BIG STONE SOUTH-DEUEL (OTP)) : Xcel Energy owns 50%(15.44 miles) of 30.879 miles of this circuit: remaining 50%(15.44 miles) is owned by other members of a joint venture partnership

(j) Concept: SupportingStructureOfTransmissionLineType

NSM ((0966;01) ASTORIA (OTP)-BROOKINGS CO.) : Xcel Energy owns 50%(8.242 miles) of 16.483 miles of this circuit: remaining 50%(8.242 miles) is owned by other members of a joint venture partnership

(k) Concept: SupportingStructureOfTransmissionLineType

NSM ((0966;01) ASTORIA (OTP)-DEUEL (OTP)) : Xcel Energy owns 50%(12.306 miles) of 24.612 miles of this circuit: remaining 50%(12.306 miles) is owned by other members of a joint venture partnership

(l) Concept: SupportingStructureOfTransmissionLineType

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

(m) Concept: SupportingStructureOfTransmissionLineType

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

(n) Concept: SupportingStructureOfTransmissionLineType

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

(o) Concept: SupportingStructureOfTransmissionLineType

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

(p) Concept: SupportingStructureOfTransmissionLineType

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

(q) Concept: SupportingStructureOfTransmissionLineType
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
(r) Concept: SupportingStructureOfTransmissionLineType
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
(s) Concept: SupportingStructureOfTransmissionLineType
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
(t) Concept: SupportingStructureOfTransmissionLineType
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
(u) Concept: SupportingStructureOfTransmissionLineType
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: SupportingStructureOfTransmissionLineType
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: SupportingStructureOfTransmissionLineType
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: SupportingStructureOfTransmissionLineType
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: SupportingStructureOfTransmissionLineType
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: SupportingStructureOfTransmissionLineType
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
(aa) Concept: SupportingStructureOfTransmissionLineType
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
(ab) Concept: SupportingStructureOfTransmissionLineType
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
(ac) Concept: SupportingStructureOfTransmissionLineType
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
(ad) Concept: SupportingStructureOfTransmissionLineType
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: SupportingStructureOfTransmissionLineType
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
(af) Concept: SupportingStructureOfTransmissionLineType
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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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 competed 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	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	(5653-MN;01) BROOKINGS CO.	STEEP BANK LAKE	8.799	SINGLE POLE	4	2	2	6-397.5	ZTACSR-VR2	26/7	345.0			5,104,878		5,104,878	
2	(5653-SD;01) BROOKINGS CO.	STEEP BANK LAKE	10.192	SINGLE POLE	3	2	2	6-397.5	ZTACSR-VR2	26/7	345.0						
3	(5653;01) LYON CO.	STEEP BANK LAKE	40.300	SINGLE POLE	5	2	2	6-397.5	ZTACSR-VR2	26/7	345.0						
4	(5651;01) SHERBURNE CO.	SHERCO SOLAR WEST	3.247	SINGLE POLE	6	1	2	3-556.5	ACSR	26/7	345.0		8,220,562	3,077,227		11,297,789	
5	(5558;01) CEDAR MTN. (GRE)	FRANKLIN	2.38	SINGLE POLE	8	1	1	3-795	ACSS/TW	26/7	115.0		(19,362)	359,202		339,840	
6	(0811;01) RIVERSIDE	WEST RIVER ROAD	0.84	SINGLE POLE	10	2	2	3-477	ACSS	30/7	115.0		266,960	96,214		363,174	
7	(5521;02) RIVERSIDE	WEST RIVER ROAD	0.85	SINGLE POLE	10	2	2	3-477	ACSS	30/7	115.0			103,178		103,178	
8	(0735,0790;02) CROW RIVER (GRE)	VICTOR (GRE)	0.00	3WAY NONSWITCH	22	1	1	3-477	ACSR	26/7	69.0		322,985			322,985	
9	(0752;01) GROVE LAKE SW. ST.	PAYNESVILLE TRANS. S	0.15	SINGLE POLE	18	1	1	3-477	ACSR	26/7	69.0		116,622	107,464		224,086	
10	(0776;01) HATTON (MINNKOTA)	LERFALD (MINNKOTA)	0.09	3WAY NONSWITCH	28	1	1	3-477	ACSR	26/7	69.0		624,245	215,613		839,858	
11	(0776;01) HATTON (MINNKOTA)	LERFALD (MINNKOTA)	0.01	SINGLE POLE	28	1	1	3-477	ACSR	26/7	69.0						
12	(0724;01) MINNESOTA VALLEY	TROY SW. ST.	0.04	HORIZ POST	19	1	1	3-2/0	ACSR	6/1	69.0		304,094	211,320		515,414	
13	(0726;01) MOON LAKE (GRE)	TRACY SW	0.05	SINGLE POLE	18	1	1	3-477	ACSR	26/7	69.0		6,675,542	4,937,576		11,613,118	
14	(0714;01) MTN. LAKE (ALLIANT)	WATONWAN	0.02	SINGLE POLE	20	1	1	3-4/0	ACSR	6/1	69.0		20,463	70,335		90,798	

44	TOTAL		67		199	19	20						16,532,111	14,283,007		30,815,118	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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 (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: 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	TURTLE RIVER-TR01	Distribution	Unattended	69.00	12.50		5.00	1					
493	TWIN LAKES-TR01	Distribution	Unattended	115.00	13.80		70.00	1					
494	TWIN LAKES-TR02	Distribution	Unattended	115.00	13.80		70.00	1					
495	TWIN LAKES-TR03	Distribution	Unattended	115.00	13.80		70.00	1					
496	UPPER LEVEE-TR01	Distribution	Unattended	115.00	13.80		70.00	1					
497	UPPER LEVEE-TR02	Distribution	Unattended	115.00	13.80		70.00	1					
498	UPPER LEVEE-TR03	Distribution	Unattended	115.00	13.80		70.00	1					
499	VERMILLION RIVER-TR03	Distribution	Unattended	115.00	13.80		28.00	1					
500	VESELI-TR01	Distribution	Unattended	69.00	12.50		8.00	1					
501	VIKING-TR01	Distribution	Unattended	115.00	13.80		72.50	1					
502	VILLARD-TR01	Distribution	Unattended	69.00	12.50		3.00	1					
503	WABASHA-TR01	Distribution	Unattended	69.00	13.80		10.50	1					

504	WABASHA-TR02	Distribution	Unattended	69.00	2.40		20.00	1				
505	WACONIA-TR01	Distribution	Unattended	69.00	13.80		22.00	1				
506	WAKEFIELD-TR02	Distribution	Unattended	115.00	34.50	14.00	10.00	1				
507	WAKEFIELD-TR02ABC	Distribution	Unattended	34.50	13.80		2.00	3				
508	WAKEFIELD-TR06	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
509	WASECA-TR02	Distribution	Unattended	69.00	23.00		14.00	1				
510	WASECA-TR03	Distribution	Unattended	69.00	23.00		28.00	1				
511	WASECA-TR04	Distribution	Unattended	69.00	23.00		28.00	1				
512	WATAB RIVER-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
513	WATERTOWN-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
514	WATERVILLE-TR01	Distribution	Unattended	69.00	23.00		14.00	1				
515	WATERVILLE-TR02	Distribution	Unattended	69.00	4.16		1.50	1				
516	WATERVILLE-TR03	Distribution	Unattended	69.00	12.50		3.50	1				
517	WATKINS-TR01	Distribution	Unattended	69.00	4.16		3.50	1				
518	WAVERLY-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
519	WELLS CREEK-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
520	WESCOTT PROPANE PLANT-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
521	WEST BYRON-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
522	WEST COON RAPIDS-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
523	WEST COON RAPIDS-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
524	WEST COON RAPIDS-TR03	Distribution	Unattended	34.50	13.80		28.00	1				
525	WEST FARIBAULT-TR01	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
526	WEST FARIBAULT-TR02	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
527	WEST FARIBAULT-TR03	Distribution	Unattended	69.00	13.80		22.00	1				

528	WEST FARIBAULT-TR07	Distribution	Unattended	69.00	13.80		7.00	1				
529	WEST HASTINGS-TR01	Distribution	Unattended	115.00	12.50		28.00	1				
530	WEST HASTINGS-TR05	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
531	WEST NEW ULM-TR05	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
532	WEST RIVER ROAD-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
533	WEST RIVER ROAD-TR02	Distribution	Unattended	115.00	13.80		72.50	1				
534	WEST RIVER ROAD-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
535	WEST SIOUX FALLS-TR05	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
536	WEST SIOUX FALLS-TR07	Distribution	Unattended	115.00	13.80		70.00	1				
537	WEST SIOUX FALLS-TR08	Distribution	Unattended	115.00	13.80		70.00	1				
538	WEST WACONIA-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
539	WEST WACONIA-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
540	WESTERN-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
541	WESTERN-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
542	WESTGATE-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
543	WESTGATE-TR02	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
544	WESTGATE-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
545	WESTGATE-TR04	Distribution	Unattended	115.00	13.80		70.00	1				
546	WESTGATE-TR05	Distribution	Unattended	115.00	34.50		70.00	1				
547	WESTGATE-TR06	Distribution	Unattended	115.00	34.50		70.00	1				
548	WESTPORT-TR01X AB,Y CB	Distribution	Unattended	69.00	7.20		0.40	2				
549	WILMARTH-TR06	Transmission	Unattended	115.00	69.00	14.00	70.00	1				

550	WILMARTH-TR07	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
551	WILMARTH-TR08	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
552	WILMARTH-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
553	WILMARTH-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
554	WINONA-TR01	Distribution	Unattended	69.00	13.80		22.00	1				
555	WINONA-TR02	Distribution	Unattended	69.00	13.80		22.00	1				
556	WINONA-TR03	Distribution	Unattended	69.00	13.80		25.00	1				
557	WINSTED-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
558	WINTHROP-TR01	Distribution	Unattended	69.00	4.16		6.25	1				
559	WOBEGON TRAIL-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
560	WOODBURY-TR01	Distribution	Unattended	115.00	34.50		47.00	1				
561	WOODBURY-TR02	Distribution	Unattended	115.00	34.50		46.70	1				
562	WYOMING-TR01	Distribution	Unattended	115.00	12.50		28.00	1				
563	WYOMING-TR02	Distribution	Unattended	115.00	12.50		28.00	1				
564	YANKEE-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
565	YANKEE-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
566	YELLOW MEDICINE-TR01	Distribution	Unattended	69.00	23.00		14.00	1				
567	YOUNG AMERICA-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
568	YOUNG AMERICA-TR02	Distribution	Unattended	69.00	13.80		10.50	1				
569	ZUMBRO FALLS-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
570	ZUMBROTA-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
571	Total						44703	617	44			
572	Count TTL Transformer Banks							569				
573	Count TTL Transformers In Service							617				

574	TTL MVA In Service							44698				
575	Count TTL Subtations with Transformers							306				
576	Count TTL Substations without Transformer							48				
577	Count TTL Substations							354				
578	Count TTL Spares							44				
579	Spare Transformers											
580	Alexandria-B67606			36	2		0		1			
581	Canistota Junc-2741803			23	13		5		1			
582	Chanarambie-T040N00142701			118	34		120		1			
583	Clarks Grove-8975520			69	8		2		1			
584	Emery sub-B67608			36	2		0		1			
585	Falls Sub-P660522			69	14		28		1			
586	Hazel Creek sub-10008553_C001			345	230	14	336		1			
587	Hugo Trg Ctr-242601941			118	14		14		1			
588	Inver Hills sub-10075845-001			345	115	35	672		1			
589	MGRV-TP80279701			345	165	14	336		1			
590	MGRV-8779073			345	118	35	448		1			
591	MGRV-WT02255			345	118	35	672		1			
592	MGRV-WT-03820			230	118	14	336		1			
593	MGRV-TP80240801			161	118	14	187		1			
594	MGRV-WT02258			118	71	14	112		1			
595	MGRV-13623/2			118			102		1			
596	MGRV-N2261			118	71	14	50		1			
597	MGRV-E5074			118	71	14	70		1			
598	MGRV-E4976			118	36		70		1			

599	MGRV-E4990			118	25		90		1			
600	MGRV-WTO4771			118	14		70		1			
601	MGRV-WTO4921			118	14		70		1			
602	MGRV-50939-1			118	14		47		1			
603	MGRV-N2219			118	34		70		1			
604	MGRV-91F0693			71	36		17		1			
605	MGRV-J9E1054			69	35		5		1			
606	MGRV-282210982			70	24		14		1			
607	MGRV-GT-3547			71	14		14		1			
608	MGRV-C184245			69	14		10		1			
609	MGRV-H881493			69	14		8		1			
610	MGRV-C0301051			69	14		7		1			
611	MGRV-1174820415			71	14		7		1			
612	MGRV-249834			69	14		4		1			
613	MGRV-249866			69	14		4		1			
614	MGRV-G852083B			69	12		4		1			
615	MGRV-9F1025			69	14		25		1			
616	MGRV-236578			69	13		4		1			
617	MGRV-6993529			69	4		10		1			
618	MGRV-47011MA014-D221A			69	14		14		1			
619	MGRV-4089204			14	4		5		1			
620	MGRV-N2264			69	13		7		1			
621	Portal Pipeline (Minot)-4088687			14	2		5		1			
622	Prairie Island-C0665551			345	20		866		1			
623	Red River-D590633			115	24		47		1			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/04/2025	Year/Period of Report End of: 2024/ Q4

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	Northern States Power Co. (a Wisconsin corporation)	see note	[(a)]216,192,093
3	Repayments from Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	414,000,000
4	Services provided by Xcel Energy Services Inc.	Xcel Energy Services Inc.	see note	[(b)]709,935,267
5	Contribution of Capital	Xcel Energy Inc.	211	714,772,952
6	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	271,000,000
7	Solar farm materials, financing charges, storage fees	Capital Services LLC	107	30,970,215
8	Company labor, benefits, and related payments	Northern States Power Co. (a Wisconsin corporation)	see note	[(c)]449,627
9	Vehicle and equipment use	Public Service Co of Colorado	see note	[(d)]384,343
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Interchange agreement	Northern States Power Co. (a Wisconsin corporation)	see note	[(e)]459,901,291
22	Gas dispatch and SCADA system agreement	Northern States Power Co. (a Wisconsin corporation)	495	506,883
23	Vehicle and equipment use	Northern States Power Co. (a Wisconsin corporation)	see note	[(f)]7,867,781
24	Company labor, benefits, and related payments	Northern States Power Co. (a Wisconsin corporation)	see note	[(g)]20,588,571
25	Vehicle and equipment use	Public Service Co. of Colorado	see note	[(h)]315,625
26	Repayments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	271,000,000
27	Investments in Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	390,000,000
28	Dividends on Common Stock	Xcel Energy Inc.	216	494,281,150

29	Company labor, benefits, and related payments	Public Service Co. of Colorado	see note	[(j)]330,996
30	Allocation of overhead	Northern States Power Co. (a Wisconsin corporation)	922	289,659
42				

FOOTNOTE DATA

(a) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

557	$	65,035,618
565		151,156,475
	$	216,192,093

(b) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Service Function Group	Updated FERC Group	Total
Accounting, Financial Reporting & Taxes	107-CWIP	30,064,672
	130-176-Current and Accrued Assets	89,636
	181-190-Deferred Debits	3,847,019
	252-283-Deferred Credits	156,826
	408-409-Taxes	9,767,341
	416-Costs and Expenses of Jobbing and Contracting	2
	417-421-Other Income	(3,525,167)
	426.1-426.5-Other Income Deductions	(712,064)
	427-432-Interest Charges	37,377
	500-514-Steam Power Generation	899,889
	517-532-Nuclear Power Generation	403,145
	535-545-Hydraulic Power Generation	2,627
	546-557-Other Power Generation	1,715,603
	560-573-Transmission Expenses	1,439,777
	575.1-575.8-Regional Market Expenses	45,736
	580-598-Distribution Expenses	817,963
	725-742-Gas Raw Materials	100
	800-813-Other Gas Supply Expenses	60,257
	814-837-Underground Storage Expenses	7,897
	840-843-Other Storage Expense	88,443

	844-847-Liquified Natural Gas Terminaling Expenses	2,639
	850-870-Transmission Expenses	212,126
	871-893-Distribution Expenses	138,293
	901-905-Customer Accounts Expenses	1,430,215
	908-910-Customer Service and Informational Expenses	88,510
	911-916-Sales Expense	124,664
	920-935-Administrative and General Expense	62,726,437
Accounting, Financial Reporting & Taxes Total		109,929,963
Aviation Services	426.1-426.5-Other Income Deductions	285
	920-935-Administrative and General Expense	1,953,977
Aviation Services Total		1,954,262
Business Systems	107-CWIP	150,069,203
	130-176-Current and Accrued Assets	1,639
	181-190-Deferred Debits	(116,317)
	252-283-Deferred Credits	72
	408-409-Taxes	357
	417-421-Other Income	374
	426.1-426.5-Other Income Deductions	19,488
	500-514-Steam Power Generation	108,572
	517-532-Nuclear Power Generation	2,224,793
	535-545-Hydraulic Power Generation	472
	546-557-Other Power Generation	575,250
	560-573-Transmission Expenses	7,073,949
	575.1-575.8-Regional Market Expenses	1
	580-598-Distribution Expenses	3,575,457
	725-742-Gas Raw Materials	15
	800-813-Other Gas Supply Expenses	99,687
	840-843-Other Storage Expense	84
	844-847-Liquified Natural Gas Terminaling Expenses	322
	850-870-Transmission Expenses	34,346
	871-893-Distribution Expenses	471,017
	901-905-Customer Accounts Expenses	14,896,218
	908-910-Customer Service and Informational Expenses	95
	911-916-Sales Expense	17,126
	920-935-Administrative and General Expense	148,243,463
Business Systems Total		327,295,683
Claims Services	920-935-Administrative and General Expense	569,323
Claims Services Total		569,323
Corporate Communications	181-190-Deferred Debits	3,756,817
	252-283-Deferred Credits	1,373
	426.1-426.5-Other Income Deductions	2,711,030
	908-910-Customer Service and Informational Expenses	540,179
	911-916-Sales Expense	417

	920-935-Administrative and General Expense	4,717,694
Corporate Communications Total		11,727,510
Corporate Strategy & Business Development	426.1-426.5-Other Income Deductions	88,670
	920-935-Administrative and General Expense	1,593,956
Corporate Strategy & Business Development Total		1,682,626
Customer Service	107-CWIP	433,976
	181-190-Deferred Debits	1,011,302
	252-283-Deferred Credits	429,996
	417-421-Other Income	15,749
	426.1-426.5-Other Income Deductions	934
	580-598-Distribution Expenses	153
	901-905-Customer Accounts Expenses	17,976,670
	908-910-Customer Service and Informational Expenses	190,845
	911-916-Sales Expense	106,953
	920-935-Administrative and General Expense	1,005
Customer Service Total		20,167,583
Employee Communications	181-190-Deferred Debits	1,014
	911-916-Sales Expense	437
	920-935-Administrative and General Expense	479,001
Employee Communications Total		480,452
Energy Delivery - Engineering/Design	107-CWIP	31,454,407
	130-176-Current and Accrued Assets	176,959
	181-190-Deferred Debits	5,330
	408-409-Taxes	2,002
	426.1-426.5-Other Income Deductions	8,814
	500-514-Steam Power Generation	127,959
	535-545-Hydraulic Power Generation	9,540
	546-557-Other Power Generation	1,261,815
	560-573-Transmission Expenses	6,430,317
	580-598-Distribution Expenses	1,981,855
	725-742-Gas Raw Materials	2,918
	814-837-Underground Storage Expenses	181
	840-843-Other Storage Expense	181
	844-847-Liquified Natural Gas Terminaling Expenses	661
	850-870-Transmission Expenses	1,818,690
	871-893-Distribution Expenses	631,003
	920-935-Administrative and General Expense	1,118,079
Energy Delivery - Engineering/Design Total		45,030,711
Energy Delivery Construction, Operations & Maintenance (COM)	107-CWIP	209,616
	408-409-Taxes	378
	416-Costs and Expenses of Jobbing and Contracting	7,479
	426.1-426.5-Other Income Deductions	22,839
	546-557-Other Power Generation	8,170

	560-573-Transmission Expenses	40,066
	580-598-Distribution Expenses	1,929,212
	814-837-Underground Storage Expenses	200,894
	840-843-Other Storage Expense	1,001,511
	844-847-Liquified Natural Gas Terminaling Expenses	81
	850-870-Transmission Expenses	535,373
	871-893-Distribution Expenses	287,882
	901-905-Customer Accounts Expenses	12,949
	908-910-Customer Service and Informational Expenses	483
	920-935-Administrative and General Expense	660,815
Energy Delivery Construction, Operations & Maintenance (COM) Total		4,917,748
Energy Markets - Fuel Procurement	500-514-Steam Power Generation	890,242
	920-935-Administrative and General Expense	109,570
Energy Markets - Fuel Procurement Total		999,812
Energy Markets Regulated Trading & Marketing	426.1-426.5-Other Income Deductions	3,428
	546-557-Other Power Generation	2,689,018
	560-573-Transmission Expenses	389,348
	575.1-575.8-Regional Market Expenses	310,918
	800-813-Other Gas Supply Expenses	199,310
	920-935-Administrative and General Expense	1,091,704
Energy Markets Regulated Trading & Marketing Total		4,683,726
Energy Supply Business Resources	107-CWIP	880,497
	181-190-Deferred Debits	261,260
	426.1-426.5-Other Income Deductions	5,028
	500-514-Steam Power Generation	3,277,131
	517-532-Nuclear Power Generation	947,761
	535-545-Hydraulic Power Generation	5,990
	546-557-Other Power Generation	4,617,877
	920-935-Administrative and General Expense	34,807
Energy Supply Business Resources Total		10,030,351
Energy Supply Engineering & Environmental	107-CWIP	11,349,833
	181-190-Deferred Debits	351,837
	426.1-426.5-Other Income Deductions	21,613
	500-514-Steam Power Generation	4,552,323
	517-532-Nuclear Power Generation	61,335
	535-545-Hydraulic Power Generation	9,734
	546-557-Other Power Generation	704,184
	560-573-Transmission Expenses	20,926
	580-598-Distribution Expenses	50,553
	850-870-Transmission Expenses	58,914
	871-893-Distribution Expenses	181,630
	920-935-Administrative and General Expense	2,941,427

Energy Supply Engineering & Environmental Total		20,304,309
Executive Management Services	426.1-426.5-Other Income Deductions	251,513
	580-598-Distribution Expenses	2,568
	920-935-Administrative and General Expense	6,525,195
Executive Management Services Total		6,779,276
Facilities & Real Estate	107-CWIP	2,640,986
	130-176-Current and Accrued Assets	5,737
	181-190-Deferred Debits	24,860
	252-283-Deferred Credits	250
	416-Costs and Expenses of Jobbing and Contracting	2
	417-421-Other Income	102,460
	426.1-426.5-Other Income Deductions	41,478
	500-514-Steam Power Generation	2,171,954
	517-532-Nuclear Power Generation	8,028,195
	535-545-Hydraulic Power Generation	23,777
	546-557-Other Power Generation	1,648,023
	560-573-Transmission Expenses	1,735,374
	575.1-575.8-Regional Market Expenses	22,775
	580-598-Distribution Expenses	3,787,419
	725-742-Gas Raw Materials	178
	800-813-Other Gas Supply Expenses	10,194
	814-837-Underground Storage Expenses	4,981
	840-843-Other Storage Expense	75,500
	844-847-Liquified Natural Gas Terminaling Expenses	94,594
	850-870-Transmission Expenses	129,410
	871-893-Distribution Expenses	1,824,118
	901-905-Customer Accounts Expenses	327,488
	908-910-Customer Service and Informational Expenses	34,667
	911-916-Sales Expense	25,524
	920-935-Administrative and General Expense	16,727,241
Facilities & Real Estate Total		39,487,185
Facilities Administrative Services	107-CWIP	85,766
Facilities Administrative Services Total		85,766
Finance & Treasury	181-190-Deferred Debits	2,455,000
	417-421-Other Income	(1,630,303)
	426.1-426.5-Other Income Deductions	334
	427-432-Interest Charges	4,775,571
	517-532-Nuclear Power Generation	204,722
	546-557-Other Power Generation	347,285
	560-573-Transmission Expenses	950
	920-935-Administrative and General Expense	17,119,311
Finance & Treasury Total		23,272,870
Fleet	107-CWIP	1,320,754

	130-176-Current and Accrued Assets	60
	181-190-Deferred Debits	27
	417-421-Other Income	61
	426.1-426.5-Other Income Deductions	1
	500-514-Steam Power Generation	23,882
	517-532-Nuclear Power Generation	6,009
	535-545-Hydraulic Power Generation	4
	546-557-Other Power Generation	5,168
	560-573-Transmission Expenses	16,010
	575.1-575.8-Regional Market Expenses	3
	580-598-Distribution Expenses	119,421
	800-813-Other Gas Supply Expenses	2
	814-837-Underground Storage Expenses	1
	840-843-Other Storage Expense	12
	844-847-Liquified Natural Gas Terminaling Expenses	1,420
	850-870-Transmission Expenses	32,589
	871-893-Distribution Expenses	20,539
	901-905-Customer Accounts Expenses	5,904
	908-910-Customer Service and Informational Expenses	20
	911-916-Sales Expense	9
	920-935-Administrative and General Expense	3,020
Fleet Total		1,554,916
Government Affairs	426.1-426.5-Other Income Deductions	639,232
	920-935-Administrative and General Expense	1,039,671
Government Affairs Total		1,678,903
Human Resources	107-CWIP	379,502
	130-176-Current and Accrued Assets	997
	181-190-Deferred Debits	10,502
	227-230-Other Noncurrent Liabilities	1,313,727
	231-245-Current and Accrued Liabilities	22,602,558
	252-283-Deferred Credits	123
	408-409-Taxes	10
	417-421-Other Income	941
	426.1-426.5-Other Income Deductions	160,831
	500-514-Steam Power Generation	3,818
	517-532-Nuclear Power Generation	858,147
	535-545-Hydraulic Power Generation	36
	546-557-Other Power Generation	1,131,953
	560-573-Transmission Expenses	479,490
	575.1-575.8-Regional Market Expenses	1
	580-598-Distribution Expenses	413,160
	725-742-Gas Raw Materials	9
	800-813-Other Gas Supply Expenses	80
	840-843-Other Storage Expense	88

	844-847-Liquified Natural Gas Terminaling Expenses	296
	850-870-Transmission Expenses	1,512
	871-893-Distribution Expenses	1,261
	901-905-Customer Accounts Expenses	5,986
	908-910-Customer Service and Informational Expenses	275,110
	911-916-Sales Expense	1,572
	920-935-Administrative and General Expense	13,797,474
Human Resources Total		41,439,184
Internal Audit	107-CWIP	25,816
	130-176-Current and Accrued Assets	112
	181-190-Deferred Debits	900
	252-283-Deferred Credits	3
	417-421-Other Income	31
	426.1-426.5-Other Income Deductions	195
	500-514-Steam Power Generation	409
	517-532-Nuclear Power Generation	9,083
	535-545-Hydraulic Power Generation	3
	546-557-Other Power Generation	1,024
	560-573-Transmission Expenses	279
	580-598-Distribution Expenses	1,560
	800-813-Other Gas Supply Expenses	4
	840-843-Other Storage Expense	4
	844-847-Liquified Natural Gas Terminaling Expenses	29
	850-870-Transmission Expenses	270
	871-893-Distribution Expenses	209
	901-905-Customer Accounts Expenses	352
	908-910-Customer Service and Informational Expenses	6
	911-916-Sales Expense	23
	920-935-Administrative and General Expense	1,334,262
Internal Audit Total		1,374,574
Investor Relations	920-935-Administrative and General Expense	683,189
Investor Relations Total		683,189
Legal	107-CWIP	(4,193)
	417-421-Other Income	276,351
	426.1-426.5-Other Income Deductions	1,143
	517-532-Nuclear Power Generation	82,227
	560-573-Transmission Expenses	32,967
	725-742-Gas Raw Materials	128
	920-935-Administrative and General Expense	4,496,712
Legal Total		4,885,335
Marketing & Sales	107-CWIP	30,804
	181-190-Deferred Debits	9,906,094
	252-283-Deferred Credits	330,058
	408-409-Taxes	(354)

	417-421-Other Income	427,388
	426.1-426.5-Other Income Deductions	7,232
	908-910-Customer Service and Informational Expenses	694,805
	911-916-Sales Expense	2,002,252
	920-935-Administrative and General Expense	4,670,038
Marketing & Sales Total		18,068,317
Payment & Reporting	920-935-Administrative and General Expense	431,799
Payment & Reporting Total		431,799
Payroll	920-935-Administrative and General Expense	1,518,330
Payroll Total		1,518,330
Rates & Regulation	181-190-Deferred Debits	264
	426.1-426.5-Other Income Deductions	24,669
	920-935-Administrative and General Expense	1,718,855
Rates & Regulation Total		1,743,788
Receipts Processing	426.1-426.5-Other Income Deductions	62
	901-905-Customer Accounts Expenses	116,789
	911-916-Sales Expense	29,512
	920-935-Administrative and General Expense	384,727
Receipts Processing Total		531,090
Supply Chain	107-CWIP	5,213,728
	130-176-Current and Accrued Assets	25,665
	181-190-Deferred Debits	175,860
	252-283-Deferred Credits	2,234
	416-Costs and Expenses of Jobbing and Contracting	7
	417-421-Other Income	15,928
	426.1-426.5-Other Income Deductions	2,510
	500-514-Steam Power Generation	66,272
	517-532-Nuclear Power Generation	350,792
	535-545-Hydraulic Power Generation	686
	546-557-Other Power Generation	246,973
	560-573-Transmission Expenses	61,796
	575.1-575.8-Regional Market Expenses	13
	580-598-Distribution Expenses	184,079
	725-742-Gas Raw Materials	166
	800-813-Other Gas Supply Expenses	1,547
	814-837-Underground Storage Expenses	3
	840-843-Other Storage Expense	1,692
	844-847-Liquified Natural Gas Terminaling Expenses	5,560
	850-870-Transmission Expenses	13,488
	871-893-Distribution Expenses	20,376
	901-905-Customer Accounts Expenses	115,079
	908-910-Customer Service and Informational Expenses	1,538
	911-916-Sales Expense	9,388
	920-935-Administrative and General Expense	111,306
Supply Chain Total		6,626,686
Grand Total		709,935,267

(c) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

107	$ 277,422
108	22,908
163	11,888
184	16,532
506	350
520	192
531	2,006
532	57
537	4,337
539	2,093
543	19,835
544	19,868
548	434
553	461
562	838
566	466
585	1,568
586	3,939
587	-
588	509
593	46,743
594	8
596	479
597	13
841	488
863	5,609
878	316
879	4,969
880	84
892	4,533
893	472
903	210
	$ 449,627

(d) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

107	$ 137,024
108	2,478
583	65
584	45
586	644
587	270
588	945
593	655
594	2
596	20
856	977
857	522
863	199
865	458
874	122,084
875	18,705
877	4,207
878	9,388
879	19,595
887	10,600
889	2,857
892	43,388
893	9,215
	$ 384,343

(e) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

456	$	392,784,615
456.1		67,116,676
	$	459,901,291

(f) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

107	$ 7,188,022
108	537,194
416	67,993
502	571
512	1,255
539	7,176
562	148
563	249
583	5,975
584	237
588	2,672

593	48,025
594	3,473
596	424
846.2	212
847.3	62
874	1,624
877	117
879	460
887	1,486
892	18
903	388
	$ 7,867,781

(g) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

107	$ 18,246,602
108	1,647,650
184	126,417
501	137,462
502	39,379
506	614
511	9,596
512	161,292
513	45,661
514	308
537	1,955
539	31,519
542	1,614
544	51
549	706
553	651
562	3,042
566	3,635
570	667
583	8,795
584	1,509
585	737
586	2,332
587	59
588	8,705
592	237
593	11,121
594	7,735
844.3	54,133
846.2	9,234
856	43
865	384
874	1,060
878	1,234
879	6,678
880	727
887	11,556
889	1,291
892	898
893	1,282
	$ 20,588,571

(h) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

107	$ 1,838
108	330
416	285,737
544	3,359
586	94
593	170
594	130
596	41
857	76
874	23,467
875	13
879	126
892	244
	$ 315,625

(i) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

107	$ 142,532
108	29,050
184	4,441
417.1	906
512	2,752
542	28,286
544	7,461
549	1,114
552	448
553	7,127
562	29
566	2,068
582	118
583	1,520
584	142
585	366
586	37,158
588	288
593	17,807
594	950
596	1,945
816	55
850	394
851	3,469

853	118
856	1,011
857	264
863	708
871	(2,891)
872	118
874	13,198
875	187
878	710
879	10,308
880	1,219
887	6,165
889	152
892	7,793
893	849
903	661
	$ 330,996