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

3 PU-23-168 Filed 05/01/2023 Pages: 329
FERC Financial Report
Northern States Power Company
Alex Nisbet, Reg. Policy Specialist

Exact Legal Name of Respondent (Company)	Year/Period of Report
Northern States Power Company (Minnesota)	End of: 2022/ Q4

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

GENERAL INFORMATION

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.

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:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

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

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

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

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.

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.

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.

When to Submit

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

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

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

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

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

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)).

GENERAL INSTRUCTIONS

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.

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.

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.

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

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

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

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

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

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

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

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

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

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

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

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

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

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

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

EXCERPTS FROM THE LAW

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

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

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

'Person' means an individual or a corporation;

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

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

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

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

"Sec. 304.

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

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

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

"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: 2022/ Q4
03 Previous Name and Date of Change (If name changed during year) /	
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 414 Nicollet Mall, Minneapolis, MN 55401	
05 Name of Contact Person Brian J. Van Abel	06 Title of Contact Person Executive Vice President, Chief Financial Officer
07 Address of Contact Person (Street, City, State, Zip Code) 414 Nicollet Mall, Minneapolis, MN 55401	

08 Telephone of Contact Person, Including Area Code	09 This Report is An Original / A Resubmission	10 Date of Report (Mo, Da, Yr)
612-330-6747	(1) ☑ An Original (2) ☐ A Resubmission	04/07/2023

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	03 Signature	04 Date Signed (Mo, Da, Yr)
Brian J. Van Abel	Brian J. Van Abel	04/07/2023
02 Title Executive Vice President, Chief Financial Officer		

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	
45	**Sales for Resale**	310	

	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: 04/07/2023	Year/Period of Report End of: 2022/ 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.

Brian J. Van Abel

Executive Vice President and Chief Financial Officer

414 Nicollet Mall Minneapolis, MN 55401

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

State of Incorporation: MN

Date of Incorporation: 2000-03-09

Incorporated Under Special Law: N/A

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

Not applicable.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

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

During the year 2022, 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: 04/07/2023	Year/Period of Report End of: 2022/ 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.

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: 04/07/2023	Year/Period of Report End of: 2022/ 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	Senior Vice President, Chief Nuclear Officer	Peter A. Gardner	515,000	2022-01-01	2022-12-31
2	Chairman, Chief Executive Officer	Robert C. Frenzel	467,575	2022-01-01	2022-12-31
3	President	Christopher B. Clark	350,000	2022-01-01	2022-12-31
4	Executive Vice President, Chief Operations Officer	Timothy J. O'Connor	292,234	2022-01-01	2022-12-31
5	Executive Vice President, Chief Financial Officer	Brian J. Van Abel	272,752	2022-01-01	2022-12-31
6	Executive Vice President, Chief Legal and Compliance Officer	Amanda J. Rome	224,156	2022-01-01	2022-12-31
7	Executive Vice President, Group President, Utilities and Chief Customer Officer	Brett C. Carter	211,058	2022-03-01	2022-12-31
8	Senior Vice President, Chief Human Resources Officer	Patricia Correa	200,943	2022-02-01	2022-12-31
9	Vice President, Treasurer	Paul A. Johnson	130,531	2022-01-01	2022-12-31
10	Vice President, Corporate Secretary and Securities	Amy L. Schneider	112,803	2022-01-01	2022-12-31
11	Vice President, Controller	Melissa Ostrom	93,517	2022-04-01	2022-12-31
12	Assistant Treasurer	Patricia L. Martin	80,535	2022-01-01	2022-12-31
13	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: 04/07/2023	Year/Period of Report End of: 2022/ 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	Christopher B. Clark, President	414 Nicollet Mall, Minneapolis, MN 55401	true	false
2	Robert C. Frenzel, Chairman and Chief Executive Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	true
3	Brian J. Van Abel, Executive Vice President and Chief Financial Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	false
4	Brett C. Carter, 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: 04/07/2023	Year/Period of Report End of: 2022/ 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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	110
5	219	Accum Prov for Depr- Elec Utility Plant (Acct 108)	c	20-26, 28
6	227	Materials and Supplies	a	17
7	227	Materials and Supplies	b, c	5
8	232	Other Regulatory Assets	f	20
9	234	Accumulated Deferred Income Taxes (Acct 190)	c	8
10	266-267	Accum. Deferred Investment Tax Credits (Acct 225)	h	8
11	269	Other Deferred Credits (Acct 253)	d, e	19
12	269	Other Deferred Credits (Acct 253)	a	27
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	19
17	300	Electric Operating Revenues (Acct 400)	b	19
18	310-311	Sales for Resale (Acct 447)	a	45

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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 ratio.

1. Franchise

City State Utility Expiration

New Brighton MN Electric Nov. 24, 2023
New Brighton MN Gas Nov. 24, 2023
Owatonna MN Electric Dec. 31, 2023
Wabasha MN Electric Jan. 3, 2042
Wabasha MN Gas Jan. 3, 2042
Wyoming MN Electric Feb. 1, 2042
Wyoming MN Gas Feb. 1, 2042
Darwin MN Gas June 13, 2042
Tracy MN Electric Sept. 25, 2042
Eagan MN Electric Oct. 3, 2042

2. Acquisitions

None.

3. Purchase or sale of an operating unit or system

NSP-Minnesota acquired the 20 MW Rock Aetna wind facility in southwest Minnesota on December 9th, 2022. This transaction was pursuant to the Commission's Order in Docket No. EC22-109-000 issued Oct. 26, 2022.

4. Important leasholds acquired or given, assigned or surrendered

None.

5. Important extension or reduction of transmission or distribution system None.
6. Obligations incurred as a result of securities or assumptions of liabilities See Note 5 of the Financial Statements on Page 123 for disclosure regarding short-term borrowings, long-term debt and other financing activities.
7. Changes in articles of incorporation or amendments to charter. None.
8. Wage scale changes Union Employees — 2.50 percent increase effective Jan. 1, 2022. Non-Union Employees — Base pay cycle increase of 3.00 percent effective March 16, 2022. Nuclear T-Week Integrated Planner — 2.50 percent increase effective June 15, 2022.
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.
12. Important Changes See Notes to the Financial Statements on Page 123 for all other important changes.
13. Changes in officers, directors, major security holders and voting powers Effective Feb. 1, 2022, Darla Figoli resigned as Executive Vice President, Chief Human Resources Officer. Effective Feb. 1, 2022, Patricia Correa elected as Senior Vice President, Chief Human Resources Officer. Effective Feb. 28, 2022, Jeffrey S. Savage resigned as Senior Vice President, Controller. Effective March 1, 2022, Brett C. Carter elected as Director and Executive Vice President, Chief Customer Officer. Effective April 1, 2022, Melissa Ostrom elected as Vice President, Controller. Effective May 13, 2022, Gioia Gentile resigned as Assistant Secretary.
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: 04/07/2023	Year/Period of Report End of: 2022/ 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	26,203,840,362	24,916,523,060
3	Construction Work in Progress (107)	200	913,814,771	999,457,600
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		27,117,655,133	25,915,980,660
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	10,309,195,961	10,022,602,588
6	Net Utility Plant (Enter Total of line 4 less 5)		16,808,459,172	15,893,378,072
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	130,420,153	101,185,344
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)		555,418,343	564,800,500
10	Spent Nuclear Fuel (120.4)		2,496,920,483	2,415,127,584
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	2,891,602,507	2,773,449,236
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		291,156,472	307,664,192
14	Net Utility Plant (Enter Total of lines 6 and 13)		17,099,615,644	16,201,042,264
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		28,919,931	25,364,609
19	(Less) Accum. Prov. for Depr. and Amort. (122)		12,221,441	10,507,228
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	3,596,598	3,221,595
23	Noncurrent Portion of Allowances	228		

24	Other Investments (124)		47,252,298	51,987,027
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		2,882,407,817	3,256,313,854
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		68,406,863	33,273,400
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,018,362,066	3,359,653,257
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		25,041,543	2,307,189
36	Special Deposits (132-134)		3,313,436	896,518
37	Working Fund (135)		119,200	119,320
38	Temporary Cash Investments (136)		36,439,175	67,937,494
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		481,417,687	419,457,821
41	Other Accounts Receivable (143)		116,734,294	61,959,530
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		46,806,293	46,634,661
43	Notes Receivable from Associated Companies (145)			91,000,000
44	Accounts Receivable from Assoc. Companies (146)		46,325,133	29,308,100
45	Fuel Stock (151)	227	104,511,663	82,320,015
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	199,059,317	180,729,953
49	Merchandise (155)	227	1,311,697	916,230
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		

52	Allowances (158.1 and 158.2)	228	150,000	80,418
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)		77,077,473	43,020,518
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		1,970,403	2,006,122
57	Prepayments (165)		[g]30,657,724	33,440,762
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		1,001,317	298,825
60	Rents Receivable (172)		730,070	779,987
61	Accrued Utility Revenues (173)		373,504,067	320,392,108
62	Miscellaneous Current and Accrued Assets (174)		532,062	6
63	Derivative Instrument Assets (175)		157,586,211	86,121,866
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		68,406,863	33,273,400
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)		1,542,269,316	1,343,184,721
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		65,540,642	61,796,052
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	72,525,232	80,704,420
72	Other Regulatory Assets (182.3)	232	3,853,486,957	3,969,567,477
73	Prelim. Survey and Investigation Charges (Electric) (183)		800,567	2,328,546
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	58,483,787	67,848,576

79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		11,014,692	12,313,348
82	Accumulated Deferred Income Taxes (190)	234	1,446,325,651	1,269,457,808
83	Unrecovered Purchased Gas Costs (191)		126,595,043	239,653,666
84	Total Deferred Debits (lines 69 through 83)		5,634,772,571	5,703,669,893
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		27,295,019,597	26,607,550,135

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: Prepayments

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	4,894,553,504	4,722,336,684
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	2,482,182,450	2,393,935,302
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(2,135,689)	(2,510,681)
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(18,428,482)	(20,389,324)
16	Total Proprietary Capital (lines 2 through 15)		7,835,464,312	7,572,664,510
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	7,050,000,000	6,850,000,000
19	(Less) Reaquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	2,780,475	3,227,041
22	Unamortized Premium on Long-Term Debt (225)			

23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		45,306,088	43,809,951
24	Total Long-Term Debt (lines 18 through 23)		7,007,474,387	6,809,417,090
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		[(a)]255,925,918	[(c)]353,281,568
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)		129,038,000	81,348,000
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		66,804,236	15,246,791
32	Long-Term Portion of Derivative Instrument Liabilities		102,316,974	70,575,328
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		2,727,070,951	2,584,739,876
35	Total Other Noncurrent Liabilities (lines 26 through 34)		3,281,156,079	3,105,191,563
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		207,000,000	
38	Accounts Payable (232)		640,064,264	546,365,625
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		90,598,559	65,846,721
41	Customer Deposits (235)		23,938,425	28,727,174
42	Taxes Accrued (236)	262	249,064,345	243,475,938
43	Interest Accrued (237)		75,426,024	75,941,440
44	Dividends Declared (238)		122,448,025	96,267,850
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		41,202,648	33,625,714
48	Miscellaneous Current and Accrued Liabilities (242)		47,491,796	38,922,958
49	Obligations Under Capital Leases-Current (243)		[(b)]98,255,563	[(d)]89,757,245
50	Derivative Instrument Liabilities (244)		143,953,988	105,655,219

51	(Less) Long-Term Portion of Derivative Instrument Liabilities		102,316,974	70,575,328
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,637,126,663	1,254,010,556
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		13,765,191	12,647,763
57	Accumulated Deferred Investment Tax Credits (255)	266	15,408,376	16,831,534
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	321,326,825	332,575,716
60	Other Regulatory Liabilities (254)	278	4,081,245,120	4,295,669,821
61	Unamortized Gain on Reaquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	20,033,462	22,089,096
63	Accum. Deferred Income Taxes-Other Property (282)		2,708,114,707	2,663,872,468
64	Accum. Deferred Income Taxes-Other (283)		373,904,475	522,580,018
65	Total Deferred Credits (lines 56 through 64)		7,533,798,156	7,866,266,416
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		27,295,019,597	26,607,550,135

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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: 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.
(d) 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: 04/07/2023	Year/Period of Report End of: 2022/ 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	6,499,229,959	5,514,179,641			5,479,199,211	4,887,254,162	1,020,030,748	626,925,479		
3	Operating Expenses											
4	Operation Expenses (401)	320	3,996,290,615	3,307,161,317			3,145,443,270	2,817,568,027	850,847,345	489,593,290		

5	Maintenance Expenses (402)	320	229,910,895	234,099,687			213,489,453	220,074,071	16,421,442	14,025,616		
6	Depreciation Expense (403)	336	877,806,251	800,829,343			825,951,308	751,373,925	51,854,943	49,455,418		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	(11,605,484)	(8,957,041)			(12,014,186)	(9,255,001)	408,702	297,960		
8	Amort. & Depl. of Utility Plant (404-405)	336	87,633,430	73,750,205			80,367,209	67,532,227	7,266,221	6,217,978		
9	Amort. of Utility Plant Acq. Adj. (406)	336	3,093,393	3,004,454			3,093,393	3,004,454				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		8,820,689	8,820,689			8,820,689	8,820,689				
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		[(a)]225,977,190	[(e)]89,328,109			225,971,008	88,928,857	6,182	399,252		
13	(Less) Regulatory Credits (407.4)		[(b)]123,882,735	[(f)]163,256,883			111,622,232	154,398,898	12,260,503	8,857,985		
14	Taxes Other Than Income Taxes (408.1)	262	277,860,873	265,407,698			252,630,725	241,519,923	25,230,148	23,887,775		
15	Income Taxes - Federal (409.1)	262	70,440,227	(3,439,153)			44,659,002	37,126,397	25,781,225	(40,565,550)		
16	Income Taxes - Other (409.1)	262	60,138,572	(18,959,271)			47,312,482	1,520,401	12,826,090	(20,479,672)		
17	Provision for Deferred Income Taxes (410.1)	234, 272	326,568,319	398,218,275			306,637,914	298,092,341	19,930,405	100,125,934		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	569,186,390	421,747,826			524,347,471	388,366,329	44,838,919	33,381,497		
19	Investment Tax Credit Adj. - Net (411.4)	266	(1,423,158)	(1,423,818)			(1,316,336)	(1,316,841)	(106,822)	(106,977)		

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)		1,336,777	1,955,637			1,336,777	1,955,637				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		123,613,992	116,081,662			121,406,228	114,396,497	2,207,764	1,685,165		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		5,580,719,902	4,676,961,810			4,625,145,679	4,094,665,103	955,574,223	582,296,707		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		918,510,057	837,217,831			854,053,532	792,589,059	64,456,525	44,628,772		
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)											
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)											
33	Revenues From Nonutility Operations (417)		44,743,305	38,349,170								
34	(Less) Expenses of Nonutility Operations (417.1)		36,020,019	31,765,888								
35	Nonoperating Rental Income (418)		0									

36	Equity in Earnings of Subsidiary Companies (418.1)	119	374,992	668,967								
37	Interest and Dividend Income (419)		2,067,336	4,864,582								
38	Allowance for Other Funds Used During Construction (419.1)		29,439,419	30,338,000								
39	Miscellaneous Nonoperating Income (421)		6,874,697	2,223,061								
40	Gain on Disposition of Property (421.1)		521,002	625,253								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		48,000,732	45,303,145								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		563,787	102,682								
44	Miscellaneous Amortization (425)		0									
45	Donations (426.1)		5,292,102	2,272,947								
46	Life Insurance (426.2)		[c](157,492)	[g](2,752,422)								
47	Penalties (426.3)		[d](285,314)	1,056,795								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,728,833	1,745,127								
49	Other Deductions (426.5)		4,672,896	13,145,924								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		11,814,812	15,571,053								
51	Taxes Applic. to Other Income and Deductions											

52	Taxes Other Than Income Taxes (408.2)	262	329,570	320,421								
53	Income Taxes-Federal (409.2)	262	7,440,688	(4,502,434)								
54	Income Taxes-Other (409.2)	262	(34,248,575)	18,296,576								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	44,498,184	24,096,703								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	16,047,009	38,680,248								
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)		1,972,858	(468,982)								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		34,213,062	30,201,074								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		278,577,570	262,121,328								
63	Amort. of Debt Disc. and Expense (428)		5,915,149	5,580,190								
64	Amortization of Loss on Reaquired Debt (428.1)		1,298,656	1,495,459								
65	(Less) Amort. of Premium on Debt-Credit (429)		0									
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		0									

67	Interest on Debt to Assoc. Companies (430)		1,427,643	395,456								
68	Other Interest Expense (431)		3,199,797	4,129,994								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		12,464,036	12,526,035								
70	Net Interest Charges (Total of lines 62 thru 69)		277,954,779	261,196,392								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		674,768,340	606,222,513								
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)		674,768,340	606,222,513								

FOOTNOTE DATA

(a) Concept: RegulatoryDebits

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

(b) Concept: RegulatoryCredits

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

(c) Concept: LifeInsurance

Income on Company Owned Life Insurance.

(d) Concept: Penalties

Unnatural balance due to reversal of prior year accrual.

(e) Concept: RegulatoryDebits

	Electric	Gas
Minnesota Renewable Development Fund Rider	$ 34,775,141	$ —
Minnesota Sales True Up	33,935,933	—
Theoretical Depreciation Reserve Surplus	10,039,729	—
Minnesota Revenue Decoupling Mechanism	5,970,928	—
Minnesota Incentive Compensation Refund	2,056,721	—
North Dakota Renewable Energy Rider	660,384	—
South Dakota Infrastructure Rider	625,625	—
Sherco Unit 3 Depreciation Deferral	503,130	—
South Dakota Transmission Cost Recovery Rider	181,314	—
Minnesota LED Streetlighting	166,265	—
North Dakota Transmission Cost Recovery Rider	13,687	—
Minnesota Gas Rate Case Deferral	—	399,252
	$ 88,928,857	$ 399,252

(f) Concept: RegulatoryCredits

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	$ 105,141,496	$ 1,983,125
Minnesota Renewable Energy Standard Rider	41,063,836	—
Minnesota Transmission Cost Recovery Rider	5,829,503	—
Business Incentive and Sustainability Rider Pandemic Discount	1,968,230	—
North Dakota AGIS Deferral	395,833	—
Minnesota Gas Utility Infrastructure Rider	—	6,619,425
Minnesota State Energy Policy Rider	—	255,435
	$ 154,398,898	$ 8,857,985

(g) 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: 04/07/2023	Year/Period of Report End of: 2022/ 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		2,393,857,679	2,209,300,233
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)		674,393,348	605,553,546
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	(586,146,200)	(420,996,100)

36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(586,146,200)	(420,996,100)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,482,104,827	2,393,857,679
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)		2,482,182,450	2,393,935,302
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(2,510,681)	(3,179,648)
50	Equity in Earnings for Year (Credit) (Account 418.1)		374,992	668,967
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1	Rounding			
53	Balance-End of Year (Total lines 49 thru 52)		(2,135,689)	(2,510,681)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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)	674,768,340	606,222,513
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	916,877,302	843,613,753
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Nuclear Fuel	118,153,271	114,109,922
5.2	Amortization of Premium, Discount and Debt Expense	7,213,805	7,075,649
5.3	Amortization of Software and Other	95,664,065	80,959,251
8	Deferred Income Taxes (Net)	(214,166,896)	(38,276,352)
9	Investment Tax Credit Adjustment (Net)	(1,423,158)	(1,423,819)
10	Net (Increase) Decrease in Receivables	(92,888,269)	(56,529,313)
11	Net (Increase) Decrease in Inventory	(84,753,441)	(21,671,090)
12	Net (Increase) Decrease in Allowances Inventory	(69,582)	4,742
13	Net Increase (Decrease) in Payables and Accrued Expenses	59,059,188	71,741,641
14	Net (Increase) Decrease in Other Regulatory Assets	425,795,499	(205,670,395)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(67,305,354)	155,463,307
16	(Less) Allowance for Other Funds Used During Construction	29,439,419	30,338,000

17	(Less) Undistributed Earnings from Subsidiary Companies	374,992	668,967
18	Other (provide details in footnote):		
18.1	Other: Decrease (Increase) in Accrued Utility Revenues	(53,111,959)	(71,426,882)
18.2	Other: Net Realized and Unrealized Hedging and Derivative Transactions	2,542,328	(21,033,294)
18.3	Other: Changes in Other Current Assets and Liabilities	6,502,978	(5,483,622)
18.4	Other: Changes in Noncurrent Liabilities and Deferred Amounts	[(a)]112,801,572	[(d)](303,928,159)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	1,875,845,278	1,122,740,885
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,662,060,183)	(1,676,671,278)
27	Gross Additions to Nuclear Fuel	(101,645,552)	(111,445,051)
28	Gross Additions to Common Utility Plant	(165,973,640)	(112,771,721)
29	Gross Additions to Nonutility Plant	(2,940,048)	
30	(Less) Allowance for Other Funds Used During Construction	(29,439,419)	(30,338,000)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,903,180,004)	(1,870,550,050)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies	(6,000,000)	(1,450,000)
40	Contributions and Advances from Assoc. and Subsidiary Companies	6,000,000	
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		

49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Investments in Utility Money Pool Arrangement	(1,522,000,000)	(821,000,000)
53.2	Repayments from Utility Money Pool Arrangement	1,613,000,000	730,000,000
53.3	Other: Miscellaneous Other Investing Activities	4,734,729	1,938,399
53.4	Other: Purchase of Investments in External Decommissioning Fund	(1,331,531,950)	(757,214,680)
53.5	Other: Proceeds from Sale of Investments in External Decomissioning Fund	1,297,175,998	742,789,242
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,841,801,227)	(1,975,487,089)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	488,844,125	835,505,285
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other: Capital Contributions (to) from Parent	124,130,593	648,404,269
64.2	Other: Borrowings under Utility Money Pool Arrangement	6,000,000	434,000,000
66	Net Increase in Short-Term Debt (c)	207,000,000	
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	825,974,718	1,917,909,554
72	Payments for Retirement of:		
73	Long-term Debt (b)	(300,399,911)	251,904
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other: Repayments under Utility Money Pool Arrangement	(6,000,000)	(434,000,000)

76.2	Other: Miscellaneous Other Financing Activities		
78	Net Decrease in Short-Term Debt (c)		(179,000,000)
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(559,966,025)	(430,677,450)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(40,391,218)	874,484,008
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)	(6,347,167)	21,737,804
88	Cash and Cash Equivalents at Beginning of Period	[b]71,260,521	49,522,717
90	Cash and Cash Equivalents at End of Period	[c]64,913,354	[e]71,260,521

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

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

(b) Concept: CashAndCashEquivalents

Cash (131)	$	2,307,189
Special Deposits (132-134)		896,518
Working Fund (135)		119,320
Temporary Cash Investments (136)		67,937,494
Cash and Cash Equivalents at End of Period	$	71,260,521

(c) Concept: CashAndCashEquivalents

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

(d) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Changes in Noncurrent Liabilities and Deferred Amounts		
Change in pension and employee benefit obligation	$	(81,507,500)
Change in deferred debits		(239,561,955)
Change in deferred credits		18,579,968
Change in noncurrent liabilities		(1,438,672)
	$	(303,928,159)

(e) Concept: CashAndCashEquivalents

Cash (131)	$	2,307,189
Special Deposits (132-134)		896,518
Working Fund (135)		119,320
Temporary Cash Investments (136)		67,937,494
Cash and Cash Equivalents at End of Period	$	71,260,521

NOTES TO FINANCIAL STATEMENTS

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

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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 in the regulated purchase, transportation, distribution and sale of natural gas. NSP-Minnesota is subject to regulation by the Federal Energy Regulatory Commission (FERC) and state utility commissions.

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

Basis of Accounting - The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

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

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	$	378
Current assets		393
Current liabilities		709
Other long-term assets		(4,408)
Long-term debt and other long-term liabilities		(4,346)
Statement of Income:		
Operating revenue	$	185
Operating expenses		283
Other income and deductions		(12)
Net Interest charges		1
Statement of Cash Flows:		
Cash provided by operating activities	$	(5)
Cash used in investing activities		3
Cash provided by financing activities		—

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

Estimates are used for items such as plant depreciable lives or potential disallowances, AROs (asset retirement obligations), 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 information available. 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.

NSP-Minnesota uses 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.

The effects of tax rate changes that are attributable to the utility subsidiaries are generally subject to a normalization method of accounting. Therefore, the revaluation of most of the utility subsidiaries' 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 the related property. The requirement to defer and amortize these credits specifically applies to certain federal ITCs (investment tax credits), 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. Utility rate regulation has resulted in the recognition of regulatory assets and liabilities related to income taxes.

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 related to income taxes are reported within other (expense) income or interest charges in the statements of income.

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 — Property, plant and equipment 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 are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred.

Property, plant and equipment 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 property, plant and equipment 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 4% for 2022, and 3.7% for 2021.

AROs — NSP-Minnesota records AROs as a liability for the fair value of an ARO to be recognized in the period incurred (if it 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 3 years and submitted to the state commissions for approval. Due to other regulatory activity, the next decommissioning study has been deferred one year until 2024.

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

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

See Note 9 for further information.

Revenue from Contracts with Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. NSP-Minnesota recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs systematically throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized.

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

NSP-Minnesota recognizes physical sales to customers (native load and wholesale) on a gross basis in electric revenues and cost of sales. Revenues and charges for short-term physical wholesale sales of excess energy transacted through RTOs (Regional Transmission Organization) 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, commodity derivatives 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 the pension and postretirement plan assets and nuclear decommissioning fund, 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. Any derivative instruments 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 statements 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 CIP (conservation improvement program)/DSM (demand side management) 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 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 on a net basis in electric operating revenues in the statements of income.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2022 up to Feb. 23, 2023, the date NSP-Minnesota's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of this report. These financial statements contain all necessary adjustments and disclosures resulting from these evaluations.

2. Investments Accounted for by the Equity Method

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

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

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

Summarized Financial Information of Unconsolidated Investees

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

(Millions of Dollars)	2022	2021
Current assets	$ 7	$ 2
Other assets	(3)	1
Total assets	$ 4	$ 3
Equity	$ 4	$ 3
Total liabilities and equity	$ 4	$ 3

(Millions of Dollars)	2022	2021
Operating income	$ 1	$ 1
Net income	$ 1	$ 1

3. Joint Ownership of Generation, Transmission and Gas Facilities

Jointly owned assets as of Dec. 31, 2022:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
Electric generation:			
Sherco Unit 3	$ 623	$ 468	59 %
Sherco common facilities	180	115	80
Sherco substation	5	4	59
Electric transmission:			
Grand Meadow	11	3	50
Huntley Wilmarth	49	1	50
CapX2020	818	124	51
Total [(a)]	$ 1,686	$ 715	

(a) Projects additionally include $4 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, 2022	Dec. 31, 2021
Other Regulatory Assets		
Asset retirement recovery	$ 2,665	$ 2,554
Pension and retiree medical obligations	344	311
Theoretical deprecation reserve surplus	229	238
Excess deferred taxes - TCJA [(a)]	113	122
Recoverable deferred taxes on AFUDC recorded in plant	112	114
Renewable resources and environmental initiatives	50	179
Deferred electric commodity costs	49	88
Nuclear refueling outage costs	42	54
Contract valuation adjustments [(b)]	44	48
Purchased power contracts costs	27	32
PPA termination	18	36
Other	160	194
Total other regulatory assets	$ 3,853	$ 3,970

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

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

Components of regulatory liabilities:

(Millions of Dollars)	Dec. 31, 2022	Dec. 31, 2021
Other Regulatory Liabilities		
Plant removal costs	$ 1,949	$ 1,936
Deferred income tax adjustments and TCJA refunds [(a)]	1,183	1,232
Investments	654	934
Contract valuation adjustments [(b)]	56	29
Excess deferred taxes - TCJA	23	30
Deferred electric energy costs	26	14
Investment tax credit deferrals	17	19
United States Department of Energy (DOE) Settlement	—	12
Other	173	90
Total other regulatory liabilities	$ 4,081	$ 4,296

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

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

NSP-Minnesota's regulatory assets not earning a return include the unfunded portion of pension and retiree medical obligations and net AROs (i.e. deferrals for which cash has not been disbursed). In addition, regulatory assets included $369 million and $691 million at Dec. 31, 2022 and 2021, respectively, of past expenditures not earning a return. Amounts are predominantly related to purchased natural gas and electric energy costs (including those related to Winter Storm Uri), sales true-up and revenue decoupling, various renewable resources/environmental initiatives and certain prepaid pension amounts.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

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

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:

	Year Ended Dec. 31	
(Amounts in Millions, Except Interest Rates)	**2022**	**2021**
Borrowing limit	$ 250	$ 250
Amount outstanding at period end	—	—
Average amount outstanding	—	6
Maximum amount outstanding	4	236
Weighted average interest rate, computed on a daily basis	3.87 %	0.07 %
Weighted average interest rate at end of period	N/A	N/A

Commercial Paper — Commercial paper outstanding:

	Year Ended Dec. 31	
(Amounts in Millions, Except Interest Rates)	**2022**	**2021**
Borrowing limit	$ 700	$ 500
Amount outstanding at period end	207	—
Average amount outstanding	21	26
Maximum amount outstanding	290	317
Weighted average interest rate, computed on a daily basis	4.14 %	0.18 %
Weighted average interest rate at end of period	4.64	N/A

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, 2022 and 2021, there were $15 million and $9 million of letters of credit outstanding under the credit facility, respectively. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

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

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

Features of NSP-Minnesota's credit facility:

Debt-to-Total Capitalization Ratio [(a)]		Amount Facility May Be Increased (Millions)	Additional Periods for Which a One-Year Extension May Be Requested [(b)]
2022	**2021**		
48 %	47 %	$ 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, 2022, 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, 2022 (in millions of dollars):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 700	$ 222	$ 478

(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, 2022 and 2021.

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

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

Long-Term Borrowings and Other Financing Instruments

Generally, all property of NSP-Minnesota is subject to the lien of its first mortgage indenture. 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	2022	2021
First mortgage bonds	2.15 %	Aug. 15, 2022	$ —	$ 300
First mortgage bonds	2.60	May 15, 2023	400	400
First mortgage bonds	7.125	July 1, 2025	250	250
First mortgage bonds	6.50	March 1, 2028	150	150
First mortgage bonds [(a)]	2.25	April 1, 2031	425	425
First mortgage bonds	5.25	July 15, 2035	250	250
First mortgage bonds	6.25	June 1, 2036	400	400
First mortgage bonds	6.20	July 1, 2037	350	350
First mortgage bonds	5.35	Nov. 1, 2039	300	300
First mortgage bonds	4.85	Aug. 15, 2040	250	250
First mortgage bonds	3.40	Aug. 15, 2042	500	500
First mortgage bonds	4.125	May 15, 2044	300	300
First mortgage bonds	4.00	Aug. 15, 2045	300	300
First mortgage bonds	3.60	May 15, 2046	350	350
First mortgage bonds	3.60	Sept. 15, 2047	600	600
First mortgage bonds	2.90	March 1, 2050	600	600
First mortgage bonds	2.60	June 1, 2051	700	700
First mortgage bonds [(a)]	3.20	April 1, 2052	425	425
First mortgage bonds [(b)]	4.50	June 1, 2052	500	—
Other long-term debt			3	3
Unamortized discount			(45)	(44)
Unamortized debt issuance cost			(66)	(62)
Current maturities			(400)	(300)
Total long-term debt			$ 6,542	$ 6,447

(a) 2021 financing.
(b) 2022 financing.

Maturities of long-term debt are as follows:

(Millions of Dollars)	
2023	$ 400
2024	—
2025	250
2026	—
2027	—

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, 2021:

Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
Low	High	2022
47.2 %	57.6 %	52.3 %

Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
$ 1,446 million	$ 14,984 million	$ 16,140 million

6. Income Taxes

Federal Tax Loss Carryback Claims — In 2020, Xcel Energy identified certain expenses related to tax years 2009 - 2011 that qualify for an extended carryback claim. As a result, a tax benefit of approximately $13 million was recognized in 2020.

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 2024
2019	October 2023

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. Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2022, NSP-Minnesota's earliest open tax years subject to examination by state taxing authorities under applicable statutes of limitations are as follows:

State	Tax Year(s)	Expiration
Minnesota	2014-2016	September 2024
Minnesota	2018	June 2023

In 2020, Minnesota began an audit of tax years 2015-2018. In 2022, the state of Minnesota issued its audit report without any material adjustments. While not material, the Company is protesting an issue which it expects to resolve in the coming year.

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

Unrecognized tax benefits - permanent vs temporary:

(Millions of Dollars)	Dec. 31, 2022	Dec. 31, 2021
Unrecognized tax benefit — Permanent tax positions	$ 31	$ 23
Unrecognized tax benefit — Temporary tax positions	3	3
Total unrecognized tax benefit	$ 34	$ 26

Changes in unrecognized tax benefits:

(Millions of Dollars)	2022	2021
Balance at Jan. 1	$ 26	$ 24
Additions based on tax positions related to the current year	2	2
Additions for tax positions of prior years	6	—
Balance at Dec. 31	$ 34	$ 26

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

(Millions of Dollars)	Dec. 31, 2022	Dec. 31, 2021
NOL and tax credit carryforwards	$ (13)	$ (13)

As the Internal Revenue Service (IRS) progresses its review of the tax loss carryback claims and as state audits progress, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $22 million in the next 12 months.

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

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2022	2021
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (2)	$ (2)
Interest expense related to unrecognized tax benefits	$ (1)	$ —
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (3)	$ (2)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2022 or 2021.

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)	2022	2021
Federal NOL carryforward	$ 3	$ 77
Federal tax credit carryforwards	916	710
State NOL carryforwards	185	352
State tax credit carryforwards, net of federal detriment	70	80
Valuation allowances for state credit carryforwards, net of federal benefit	(58)	(64)

Federal carryforward periods expire starting 2032 and state carryforward periods expire starting 2025.

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

Effective income tax rate for years ended Dec. 31:

	2022	2021 (c)
Federal statutory rate	21.0 %	21.0 %
State income tax on pretax income, net of federal tax effect	7.0	7.0
Increases (decreases) in tax from:		
Wind production tax credits (a)	(39.6)	(27.8)
Plant regulatory differences (b)	(6.7)	(8.1)
Other tax credits, net NOL & tax credit allowances	(1.3)	(1.3)
Other, net	(0.3)	0.6
Effective income tax rate	(19.9)%	(8.6)%

(a) Wind Production Tax Credits are credited to customers (reduction to revenue) and do not materially impact net income.
(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred taxes are offset by corresponding revenue reductions.
(c) Prior period amounts have been restated to conform with current year presentation.

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

(Millions of Dollars)	2022	2021
Current federal tax (benefit) expense	$ 70	$ (10)
Current state tax (benefit) expense	26	(1)

Current change in unrecognized tax expense	8	2
Deferred federal tax benefit	(237)	(87)
Deferred state tax expense	23	49
Deferred ITCs	(1)	(1)
Other	(1)	—
Total income tax benefit	$ (112)	$ (48)

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

(Millions of Dollars)	2022	2021
Deferred tax expense excluding items below	$ (284)	$ 108
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	70	(145)
Tax benefit allocated to other comprehensive income, and other	—	(1)
Deferred tax benefit	$ (214)	$ (38)

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

(Millions of Dollars)	2022	2021
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 3,080	$ 3,055
Regulatory assets	(202)	(194)
Operating lease assets	98	123
Deferred fuel costs	49	92
Pension expense	68	73
Other	9	14
Total deferred tax liabilities	$ 3,102	$ 3,163
Deferred tax assets:		
Tax credit carryforward	$ 986	$ 790
Differences between book and tax bases of property	338	336
Operating lease liabilities	98	123
Regulatory liabilities	(66)	(128)
Tax credit valuation allowances	(58)	(64)
NOL carryforward	15	44
Other employee benefits	27	32
Deferred investment tax credits	5	5
Rate Refund	28	11
Other	73	74
Total deferred tax assets	$ 1,446	$ 1,223
Net deferred tax liability	$ 1,656	$ 1,940

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, 2022 and 2021 is reflected below.

(Millions of Dollars)	Dec. 31, 2022 Account 182.3	Dec. 31, 2022 Account 254	Dec. 31, 2021 Account 182.3	Dec. 31, 2021 Account 254
Protected				
Plant	$ —	$ 1,061	$ —	$ 1,099
Nonplant	98	—	103	—
Unprotected				
Plant	—	122	—	133
Nonplant	15	23	19	30
Total				
Plant	$ —	$ 1,183	$ —	$ 1,232
Nonplant	$ 113	$ 23	$ 122	$ 30

Excess and deficient ADITs in 2022 were amortized in the Statement of Income as follows:

(Millions of Dollars)	Dec. 31, 2022
Protected	
Plant	$ (30)
Nonplant	4
Unprotected	
Plant	(9)
Nonplant	(2)
Total	
Plant	$ (39)
Nonplant	$ 2

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 escrow and investment targets by asset class for the qualified trust.

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

Unrealized gains for the nuclear decommissioning fund were $1 billion and $1.3 billion as of Dec. 31, 2022 and 2021, respectively, and unrealized losses were $90 million and $70 million as of Dec. 31, 2022 and 2021, respectively.

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

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

	Dec. 31, 2021					
		Fair Value				
(Millions of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**NAV**	**Total**
Nuclear decommissioning fund						
Cash equivalents	$ 64	$ 64	$ —	$ —	$ —	$ 64
Commingled funds	856	—	—	—	1,294	1,294
Debt securities	631	—	666	9	—	675
Equity securities	411	1,222	1	—	—	1,223
Total	$ 1,962	$ 1,286	$ 667	$ 9	$ 1,294	$ 3,256

For the years ended Dec. 31, 2022 and 2021, 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, 2022:

	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	$ 6	$ 204	$ 250	$ 216	$ 676

Rabbi Trusts

NSP-Minnesota has established a rabbi trust to provide partial funding for future distributions of its deferred compensation plan. The fair value of assets held in the rabbi trusts were $12 million and $13 million at Dec. 31, 2022 and 2021, respectively, comprised of cash equivalents and mutual funds (level 1 valuation methods). Amounts are reported in nuclear decommissioning fund and other investments on the balance sheet.

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, 2022, accumulated other comprehensive loss related to interest rate derivatives included $1 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings. As of Dec. 31, 2022, NSP-Minnesota had no unsettled interest rate derivatives.

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

Derivative instruments entered into for trading purposes are presented in the statements 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, 2022 and 2021 for this purpose relate to FTR instruments administered by MISO. These instruments are intended to offset the impacts of transmission system congestion. Higher congestion costs in recent years have led to an increase in the fair value of FTRs. Settlements of FTRs are shared with electric customers through fuel and purchased energy cost-recovery mechanisms.

When NSP-Minnesota enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, the instruments are not typically designated as qualifying hedging transactions. The classification of unrealized losses or gains on these instruments as a regulatory asset or liability, if applicable, is based on approved regulatory recovery mechanisms. As of Dec. 31, 2022, 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, 2022	Dec. 31, 2021
Megawatt hours of electricity	44	57
Million British thermal units of natural gas	88	85

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

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

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

As of Dec. 31, 2022, six of NSP-Minnesota's ten most significant counterparties for these activities, comprising $38 million or 34% of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody's Investor Services or Fitch Ratings.

Three of the ten most significant counterparties, comprising $28 million or 25% 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. One of these significant counterparties, comprising $47 million or 41% of this credit exposure, had credit quality less than investment grade, based on internal analysis. Four of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase and normal sale contracts and therefore not reflected on the balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies. As of Dec. 31, 2022 and 2021, there were $4 million and $3 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, 2022 and 2021, there were approximately $76 million and $48 million of derivative liabilities with such underlying contract provisions, respectively.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2022 and 2021.

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

(Millions of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in: Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2022		
Other derivative instruments		
Electric commodity	$ —	$ (7)
Natural gas commodity	—	—
Total	$ —	$ (7)
Year Ended Dec. 31, 2021		
Other derivative instruments		
Electric commodity	$ —	$ 3
Natural gas commodity	—	(3)
Total	$ —	$ —

(Millions of Dollars)	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2022			
Derivatives designated as cash flow hedges			
Interest rate	$ 1 (a)	$ —	$ —
Total	$ 1	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 17 (b)
Electric commodity	—	1 (c)	—

Natural gas commodity	—	2 (d)	(8) (d)(e)
Total	$ —	$ 3	$ 9
Year Ended Dec. 31, 2021			
Derivatives designated as cash flow hedges			
Interest rate	$ 2 (a)	$ —	$ —
Total	$ 2	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 51 (b)
Electric commodity	—	(3) (c)	—
Natural gas commodity	—	1 (d)	(6) (d)(e)
Total	$ —	$ (2)	$ 45

(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, 2022, and 2021.

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

	Dec. 31, 2022						Dec. 31, 2021					
	Fair Value			Fair Value Total	Netting (a)	Total	Fair Value			Fair Value Total	Netting (a)	Total
(Millions of Dollars)	Level 1	Level 2	Level 3				Level 1	Level 2	Level 3			
Current derivative assets												
Other derivative instruments:												
Commodity trading	$ 15	$ 38	$ 33	$ 86	$ (58)	$ 28	$ 9	$ 40	$ 22	$ 71	$ (53)	$ 18
Electric commodity	—	—	58	58	(2)	56	—	—	30	30	(1)	29
Natural gas commodity	—	5	—	5	—	5	—	6	—	6	—	6
Total current derivative assets	$ 15	$ 43	$ 91	$ 149	$ (60)	$ 89	$ 9	$ 46	$ 52	$ 107	$ (54)	$ 53
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 21	$ 40	$ 66	$ 127	$ (59)	$ 68	$ 6	$ 34	$ 35	$ 75	$ (42)	$ 33
Total noncurrent derivative	$ 21	$ 40	$ 66	$ 127	$ (59)	$ 68	$ 6	$ 34	$ 35	$ 75	$ (42)	$ 33

	Dec. 31, 2022						Dec. 31, 2021					
	Fair Value			Fair Value Total	Netting (a)	Total	Fair Value			Fair Value Total	Netting (a)	Total
(Millions of Dollars)	Level 1	Level 2	Level 3				Level 1	Level 2	Level 3			
Current derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 23	$ 60	$ 6	$ 89	$ (63)	$ 26	$ 13	$ 58	$ 4	$ 75	$ (58)	$ 17
Electric commodity	—	—	2	2	(2)	—	—	—	1	1	(1)	—
Natural gas commodity	—	2	—	2	—	2	—	4	—	4	—	4
Total current derivative liabilities	$ 23	$ 62	$ 8	$ 93	$ (65)	28	$ 13	$ 62	$ 5	$ 80	$ (59)	21
PPAs (b)						14						14
Current derivative instruments						$ 42						$ 35
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 37	$ 55	$ 42	$ 134	$ (60)	$ 74	$ 15	$ 48	$ 26	$ 89	$ (53)	$ 36

Total noncurrent derivative	$ 37	$ 55	$ 42	$ 134	$ (60)	74	$ 15	$ 48	$ 26	$ 89	$ (53)	36
PPAs (b)						28						35
Noncurrent derivative instruments						$ 102						$ 71

(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, 2022 and 2021, derivative assets and liabilities include no obligations to return cash collateral. At Dec. 31, 2022 and 2021, derivative assets and liabilities include rights to reclaim cash collateral of $6 million and $16 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:

	Year Ended Dec. 31	
(Millions of Dollars)	**2022**	**2021**
Balance at Jan. 1	$ 56	$ (11)
Purchases (a)	157	54
Settlements (a)	(195)	(82)
Net transactions recorded during the period:		
Gains (losses) recognized in earnings (b)	91	72
Net gains (losses) recognized as regulatory assets and liabilities (a)	(2)	23
Balance at Dec. 31	$ 107	$ 56

(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:

	2022		2021	
(Millions of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion	$ 7,007	$ 5,995	$ 6,809	$ 7,761

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, 2022 and 2021, 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 4.86, 1.96 and 1.78% in 2022, and 2021, respectively. Some employees may participate under legacy formulas such as the traditional final average pay or pension equity. Xcel Energy's and NSP-Minnesota's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a SERP (supplemental executive retirement plan) 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, 2022 and 2021 were $11 million and $43 million, respectively, of which $2 million and $3 million was attributable to NSP-Minnesota in 2022 and 2021, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $17 million in 2022 and $4 million in 2021, respectively, of which immaterial amounts were attributable to NSP-Minnesota.

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 2022 were below the assumed level of 6.60%.
- Investment returns in 2021 were above the assumed level of 6.60%.
- In 2023, 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, 2022 [(a)]					Dec. 31, 2021 [(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	$ 26	$ —	$ —	$ —	$ 26	$ 31	$ —	$ —	$ —	$ 31
Commingled	201	—	—	201	402	304	—	—	274	578
Debt securities	—	129	1	—	130	—	219	1	—	220
Equity securities	11	—	—	—	11	16	—	—	—	16
Other	—	1	—	—	1	—	1	—	7	8
Total	$ 238	$ 130	$ 1	$ 201	$ 570	$ 351	$ 220	$ 1	$ 281	$ 853

(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, 2022 [(a)]					Dec. 31, 2021 [(a)]				
(Millions of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Measured at NAV**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Measured at NAV**	**Total**
Insurance contracts	$ —	$ 1	$ —	$ —	$ 1	$ —	$ —	$ —	$ —	$ —
Commingled funds	1	—	—	1	2	—	—	—	1	1
Debt securities	—	2	—	—	2	—	2	—	—	2
Total	$ 1	$ 3	$ —	$ 1	$ 5	$ —	$ 2	$ —	$ 1	$ 3

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

No assets were transferred in or out of Level 3 for 2022 or 2021.

Funded Status — Benefit obligations for both pension and postretirement plans decreased from Dec. 31, 2021 to Dec. 31, 2022, due primarily to benefit payments and increases in discount rates used in actuarial valuations. 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)	**2022**	**2021**	**2022**	**2021**
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 877	$ 989	$ 64	$ 73
Service cost	27	30	—	—
Interest cost	25	25	2	2
Plan amendments	1	1	—	—
Actuarial (gain) loss	(139)	(28)	(13)	(5)
Benefit payments	(134)	(140)	(5)	(6)
Obligation at Dec. 31	$ 657	$ 877	$ 48	$ 64
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 853	$ 897	$ 3	$ 2
Actual return on plan assets	(154)	62	—	—
Employer contributions	5	34	7	7
Benefit payments	(134)	(140)	(5)	(6)
Fair value of plan assets at Dec. 31	$ 570	$ 853	$ 5	$ 3
Funded status of plans at Dec. 31	$ (87)	$ (24)	$ (43)	$ (61)
Amounts recognized in the Balance Sheet at Dec. 31:				
Current liabilities	$ —	$ —	$ (1)	$ (3)
Noncurrent liabilities	(87)	(24)	(42)	(58)
Net amounts recognized	$ (87)	$ (24)	$ (43)	$ (61)

	Pension Benefits		Postretirement Benefits	
Significant Assumptions Used to Measure Benefit Obligations:	**2022**	**2021**	**2022**	**2021**
Discount rate for year-end valuation	5.80 %	3.08 %	5.80 %	3.09 %
Expected average long-term increase in compensation level	4.25	3.75	N/A	N/A
Mortality table	PRI-2012	PRI-2012	PRI-2012	PRI-2012
Health care costs trend rate — initial: Pre-65	N/A	N/A	6.50 %	5.30 %
Health care costs trend rate — initial: Post-65	N/A	N/A	5.50 %	4.90 %
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	7	4

The accumulated benefit obligation for the pension plan was $600 million and $811 million as of Dec. 31, 2022 and 2021, 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 statements 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 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
Service cost	$ 27	$ 30	$ —	$ —
Interest cost	25	25	2	2
Expected return on plan assets	(48)	(52)	—	—
Amortization of prior service cost	—	—	(3)	(3)
Amortization of net loss	24	34	1	2
Settlement charge [(a)]	38	35	—	—
Net periodic pension cost	66	72	—	1
Effects of regulation	(32)	(44)	—	—
Net benefit cost recognized for financial reporting	$ 34	$ 28	$ —	$ 1
Significant Assumptions Used to Measure Costs:				
Discount rate	3.08 %	2.71 %	3.09 %	2.65 %
Expected average long-term increase in compensation level	3.75	3.75	—	—
Expected average long-term rate of return on assets	6.60	6.60	4.10	4.10

(a) A settlement charge is required when the amount of lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2022 and 2021, as a result of lump-sum distributions during each plan year, NSP-Minnesota recorded a total pension settlement charge of $38 million and $35 million, respectively, which was not recognized in earnings due to the effects of regulation

(Millions of Dollars)	Pension Benefits 2022	Pension Benefits 2021	Postretirement Benefits 2022	Postretirement Benefits 2021
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 309	$ 307	$ 16	$ 31
Prior service credit	—	—	(1)	(4)
Total	$ 309	$ 307	$ 15	$ 27
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	$ 12	$ 25	$ —	$ —
Noncurrent regulatory assets	297	282	14	25
Deferred income taxes	—	—	—	1
Net-of-tax accumulated other comprehensive income	—	—	1	1
Total	$ 309	$ 307	$ 15	$ 27
Measurement date	Dec 31, 2022	Dec 31, 2021	Dec 31, 2022	Dec 31, 2021

Cash Flows — Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2021 - 2023 to meet minimum funding requirements.

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

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

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

- $12 million expected in 2023, of which $6 million is attributable to NSP-Minnesota.
- $13 million during 2022, of which $7 million, was attributable to NSP-Minnesota.
- $15 million during 2021, of which $8 million was attributable to NSP-Minnesota.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2022	2021	2022	2021
Domestic and international equity securities	33 %	33 %	16 %	15 %
Long-duration fixed income and interest rate swap securities	38	37	—	—
Short-to-intermediate fixed income securities	9	11	71	71
Alternative investments	18	17	12	8
Cash	2	2	1	6
Total	100 %	100 %	100 %	100 %

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

Plan Amendments — In 2022, there were no significant plan amendments made which affected the postretirement benefit obligation.

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

Projected Benefit Payments

NSP-Minnesota's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments [(a)]
2023	$ 84	$ 6
2024	64	5
2025	64	5
2026	61	5
2027	59	4
2028-2032	279	17

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

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 $13 million in 2022 and $12 million in 2021.

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 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 financial statements.

Sherco — In 2018, NSP-Minnesota and Southern Minnesota Municipal Power Agency (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 for repair. NSP-Minnesota notified the MPUC of its proposal to refund settlement proceeds to customers through the fuel clause adjustment.

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 March 2020, NSP-Minnesota's insurers filed a petition seeking additional review by the Minnesota Supreme Court. In April 2020, the Minnesota Supreme Court denied the insurers' petition for further review, ending the litigation.

In January 2021, the Minnesota Office of the Attorney General and Minnesota Department of Commerce recommended that NSP-Minnesota refund approximately $17 million of replacement power costs previously recovered through the fuel clause adjustment. NSP-Minnesota subsequently filed its response, asserting that it acted prudently in connection with the Sherco Unit 3 outage, the MPUC has previously disallowed $22 million of related costs and no additional refund or disallowance is appropriate.

A final decision by the MPUC is expected in mid-2024. A loss related to this matter is deemed remote.

MISO ROE Complaints —

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

The FERC subsequently issued various related orders (including Opinion Nos. 569, 569A and 569B) related to ROE methodology/calculations and timing. NSP-Minnesota has processed refunds to customers for applicable complaint periods based on the ROE in the most recent applicable opinions.

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

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 MGPs (manufactured gas plants); and third-party sites, such as landfills, for which NSP-Minnesota is alleged to have sent wastes to that site.

Historical MGP, Landfill and Disposal Sites

NSP-Minnesota is investigating, remediating or performing post-closure actions at 5 MGP, landfill or other disposal sites across its service territories.

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

Environmental Requirements — Water and Waste

Coal Ash Regulation — NSP-Minnesota's operations are subject to federal and state regulations that impose requirements for handling, storage, treatment and disposal of solid waste. Under the CCR (combustion coal residuals) Rule, utilities are required to complete groundwater sampling around their CCR landfills and surface impoundments. Currently, NSP-Minnesota has three regulated ash units in operation.

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

Federal Clean Water Act Section 316(b) — The Federal Clean Water Act requires the 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 $40 million may be required for NSP-Minnesota to comply with the requirements pending approval of mitigation plans from the Minnesota Pollution Control Agency. NSP-Minnesota anticipates these costs will be recoverable through regulatory mechanisms.

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 $2.9 billion and $3.3 billion for 2022 and 2021, respectively.

NSP-Minnesota's AROs were as follows:

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

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

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

	2021				
(Millions of Dollars)	Jan. 1, 2021	Amounts Incurred (a)	Accretion	Cash Flow Revisions (b)	Dec. 31, 2021
Electric					
Nuclear	$ 1,957	$ —	$ 99	$ —	$ 2,056
Wind	270	101	13	—	384
Steam and other production	67	6	2	(2)	73
Distribution	16	—	—	—	16
Natural gas					
Transmission and distribution	39	—	2	14	55
Common					
Common	1	—	—	—	1
Total liability	$ 2,350	$ 107	$ 116	$ 12	$ 2,585

(a) Amounts incurred relate to the wind farms placed in service in 2021 (Blazing Star 2, Mower and Freeborn) and removal of a utility scale battery asset.
(b) In 2021, AROs were revised for changes in timing and estimates of cash flows. Changes in gas transmission and distribution AROs were primarily related to changes in labor rates coupled with increased gas line mileage and number of services.

Indeterminate AROs — Outside of the recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of NSP-Minnesota's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2022. 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 $13.7 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has $450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.2 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 $138 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 $20 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 NEIL (Nuclear Energy Insurance Ltd.) and EMANI (European Mutual Associate for Nuclear Insurance). The coverage limits are $2.8 billion for each of NSP-Minnesota's 2 nuclear plant sites. NEIL also provides business interruption insurance coverage up to $350 million, 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 $12 million for business interruption insurance and $32 million for property damage insurance if losses exceed accumulated reserve funds.

Nuclear Fuel Disposal — NSP-Minnesota is responsible for temporarily storing spent nuclear fuel from its nuclear plants. The DOE 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 (Prairie Island) 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. The PI dry-cask storage facility currently stores 50 of the 64 authorized casks. 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. A certificate of need for additional storage at the Monticello site has been filed with the MPUC, to support possible life extension to 2040. NSP-Minnesota expects a decision by year-end 2023.

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

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

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 2020 nuclear decommissioning filing was approved by the MPUC and became effective in 2022.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. NSP-Minnesota had $2.9 billion and $3.3 billion of assets held in external decommissioning trusts at Dec. 31, 2022, and 2021, respectively.

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. In accordance with FERC requirements as provided in Docket No. AI19-1-000, starting in 2019, the present value of future operating lease payments are recognized in Account 227 and Account 243. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets in Account 101.1.

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 3.8%).

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 minimum 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, 2022	Dec. 31, 2021
PPAs	$ 556	$ 556
Other	78	74
Gross operating lease ROU assets	634	630
Accumulated amortization	(310)	(222)
Net operating lease ROU assets	$ 324	$ 408

Components of lease expense:

(Millions of Dollars)	2022	2021
Operating leases		
PPA capacity payments	$ 98	$ 96
Other operating leases [(a)]	9	8
Total operating lease expense [(b)]	$ 107	$ 104

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

(b) PPA capacity payments are included in electric fuel and purchased power on the statements of income. Expense for other operating leases is included in operating expenses and electric fuel and purchased power.

Commitments under operating leases as of Dec. 31, 2022 in Accounts 227 and 243:

(Millions of Dollars)	PPA [(a)] [(b)] Operating Leases	Other Operating Leases	Total Operating Leases
2023	$ 98	$ 12	$ 110
2024	100	7	107
2025	79	8	87
2026	40	7	47
2027	—	7	7
Thereafter	—	24	24
Total minimum obligation	317	65	382
Interest component of obligation	(19)	(9)	(28)

Present value of minimum obligation	$ 298	$ 56	$ 354
Less current portion			(98)
Noncurrent operating lease liabilities			$ 256
Weighted-average remaining lease term in years			7.6

(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 2026.

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 capacity payments. Certain PPAs, accounted for as executory contracts with various expiration dates through 2033, contain minimum energy purchase commitments. Total energy payments on those contracts were $182 million and $149 million in 2022 and 2021, respectively.

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

Capacity and energy payments are contingent on the Independent power producing entities (IPPs) 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, 2021, 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)]
2022	$ 61	$ 50
2023	63	45
2024	26	51
2025	9	48
2026	7	55
Thereafter	3	28
Total [(b)]	$ 169	$ 277

(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 2023 and 2037. NSP-Minnesota is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases for these contracts as of Dec. 31, 2022:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2023	$ 227	$ 144	$ 130	$ 158
2024	110	112	1	148
2025	17	158	1	138
2026	1	37	—	143
2027	1	155	—	98
Thereafter	—	194	—	116
Total [(a)]	$ 356	$ 800	$ 132	$ 801

(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:

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

(a) Included in interest charges.

	2021			
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges		Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (19)		$ (3)	$ (22)
Losses reclassified from net accumulated other comprehensive loss:				
Interest rate derivatives, net of tax of $—	2	(a)	—	2
Net current period other comprehensive income	2		—	2
Accumulated other comprehensive loss at Dec. 31	$ (17)		$ (3)	$ (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, PSCo and 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)	2022	2021
Operating revenues:		
Electric	$ 514	$ 501
Gas	—	1
Operating expenses:		
Purchased power	70	67
Transmission expense	132	121
Other operating expenses — paid to Xcel Energy Services Inc.	673	615

Accounts receivable and payable with affiliates at Dec. 31:

	2022		2021	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	$ 4	$ —	$ 13	$ —
PSCo	—	2	16	—

SPS	—	3	—	2
Other subsidiaries of Xcel Energy Inc.	42	86	—	64
	$ 46	$ 91	$ 29	$ 66

12. Supplementary Cash Flow Data

	Year Ended Dec. 31	
(Millions of Dollars)	2022	2021
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (271)	$ (248)
Cash (paid) received for income taxes, net	(100)	11
Supplemental disclosure of non-cash investing transactions:		
Accrued property, plant and equipment additions	$ 208	$ 242
Inventory transfers to property, plant and equipment	10	8
Operating lease right-of-use assets	1	4
Allowances for funds used during construction	29	30

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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			(3,709,135)	(18,682,956)		(21,649,216)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				222,356	762,254		984,610		
3	Preceding Quarter/Year to Date Changes in Fair Value				275,443	(161)		275,282		
4	Total (lines 2 and 3)				497,799	762,093		1,259,892	606,222,513	607,482,405
5	Balance of Account 219 at End of Preceding Quarter/Year	742,875			(3,211,336)	(17,920,863)		(20,389,324)		
6	Balance of Account 219 at Beginning of Current Year	742,875			(3,211,336)	(17,920,863)		(20,389,324)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				8,425	570,322		578,747		
8	Current Quarter/Year to Date Changes in Fair Value				1,189,680	192,415		1,382,095		
9	Total (lines 7 and 8)				1,198,105	762,737		1,960,842	674,768,340	676,729,182
10	Balance of Account 219 at End of Current Quarter/Year	742,875			(2,013,231)	(17,158,126)		(18,428,482)		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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)	22,050,816,895	19,225,662,054	1,839,293,246				985,861,595
4	Property Under Capital Leases	[(a)]324,347,085	281,131,487					43,215,598
5	Plant Purchased or Sold							
6	Completed Construction not Classified	3,750,893,000	3,346,381,738	263,249,442				141,261,820
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	26,126,056,980	22,853,175,279	2,102,542,688				1,170,339,013
9	Leased to Others							
10	Held for Future Use	256,129	256,129					
11	Construction Work in Progress	913,814,771	745,031,465	32,824,110				135,959,196
12	Acquisition Adjustments	77,527,253	77,527,253					
13	Total Utility Plant (8 thru 12)	27,117,655,133	23,675,990,126	2,135,366,798				1,306,298,209
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	10,309,195,961	9,043,707,035	745,738,964				519,749,962
15	Net Utility Plant (13 less 14)	16,808,459,172	14,632,283,091	1,389,627,834				786,548,247
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	9,620,588,205	8,749,310,738	737,624,090				133,653,377

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	682,282,517	[(b)] 288,071,058	8,114,874				386,096,585
22	Total in Service (18 thru 21)	10,302,870,722	9,037,381,796	745,738,964				519,749,962
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	6,325,239	[(c)] 6,325,239					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	10,309,195,961	9,043,707,035	745,738,964				519,749,962

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		324,347,085
Total	$	324,347,085

(b) Concept: AmortizationOfOtherUtilityPlantUtilityPlantInService

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

Intangible Plant	$	146,530,189
Nuclear Production Plant		130,764,829
Other Production		7,876,852
Hydraulic Production Plant-Conventional		2,899,188
Total Amort of Other Utility Plant - Electric	$	288,071,058

(c) Concept: AmortizationOfPlantAcquisitionAdjustment

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

Other Production	$	6,264,721
Transmission		60,518
Total Amort of Plant Acquisition Adj - Electric	$	6,325,239

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication	5,898,683	13,504,207		[(b)]12,161,912	7,240,978
3	Nuclear Materials	83,144,477	81,696,838		[(c)]51,308,609	113,532,706
4	Allowance for Funds Used during Construction	12,170,985	6,237,353		[(d)]8,867,406	9,540,932
5	(Other Overhead Construction Costs, provide details in footnote)	(28,801)	207,153		[(e)]72,815	[(h)]105,537
6	SUBTOTAL (Total 2 thru 5)	101,185,344	101,645,551		72,410,742	130,420,153
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)		[(a)]72,395,204		[(f)]72,395,204	
9	In Reactor (120.3)	564,800,500	72,410,742		[(g)]81,792,899	[(i)]555,418,343
10	SUBTOTAL (Total 8 & 9)	564,800,500	144,805,946		154,188,103	555,418,343
11	Spent Nuclear Fuel (120.4)	2,415,127,584	81,792,899			[(j)]2,496,920,483
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,773,449,236		(118,153,271)		2,891,602,507
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	307,664,192				291,156,472
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)					

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

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: OtherOverheadConstructionCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabrication
Consists of Administrative and General Costs
(i) 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
(j) 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: 04/07/2023	Year/Period of Report End of: 2022/ 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	252,070,433	8,712,723				260,783,156
4	(303) Miscellaneous Intangible Plant	182,955,565	21,580,057				204,535,622
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	435,025,998	30,292,780				[(g)]465,318,778
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	10,126,948	(13,880)				10,113,068
9	(311) Structures and Improvements	294,072,194	1,676,802				295,748,996
10	(312) Boiler Plant Equipment	1,512,613,576	11,191,748	1,298,961			1,522,506,363
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	321,920,550	7,698,377				329,618,927

13	(315) Accessory Electric Equipment	187,544,852	154,588				187,699,440
14	(316) Misc. Power Plant Equipment	53,859,252	796,352				54,655,604
15	(317) Asset Retirement Costs for Steam Production	20,240,869					20,240,869
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,400,378,241	21,503,987	1,298,961			2,420,583,267
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	1,757,711					1,757,711
19	(321) Structures and Improvements	605,483,532	4,978,292	1,599,185			608,862,639
20	(322) Reactor Plant Equipment	1,947,653,915	43,265,526	273,321			1,990,646,120
21	(323) Turbogenerator Units	621,347,974	24,144,548	2,304,084			643,188,438
22	(324) Accessory Electric Equipment	539,004,348	5,570,667	20,259			544,554,756
23	(325) Misc. Power Plant Equipment	207,394,912	3,130,855	16,126			210,509,641
24	(326) Asset Retirement Costs for Nuclear Production	(222,547,594)					(222,547,594)
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	3,700,094,798	81,089,888	4,212,975			3,776,971,711
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	1,693,076					1,693,076
28	(331) Structures and Improvements	1,467,522	10,867				1,478,389
29	(332) Reservoirs, Dams, and Waterways	11,086,237	71,174				11,157,411
30	(333) Water Wheels, Turbines, and Generators	10,156,576					10,156,576
31	(334) Accessory Electric Equipment	3,279,239	16,683				3,295,922
32	(335) Misc. Power Plant Equipment	60,825	65,223				126,048
33	(336) Roads, Railroads, and Bridges	152,075	34				152,109
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	27,895,550	163,981				28,059,531
36	D. Other Production Plant						
37	(340) Land and Land Rights	33,599,148	30,166	4,569			33,624,745

38	(341) Structures and Improvements	483,962,208	37,130,324				521,092,532
39	(342) Fuel Holders, Products, and Accessories	27,936,516	491,503				28,428,019
40	(343) Prime Movers	143,662,950	160,772				143,823,722
41	(344) Generators	3,890,118,684	647,917,204	462,685,762			4,075,350,126
42	(345) Accessory Electric Equipment	328,768,622	15,909,678	279,258			344,399,042
43	(346) Misc. Power Plant Equipment	58,952,942	3,575,935				62,528,877
44	(347) Asset Retirement Costs for Other Production	345,108,656	16,412,586				361,521,242
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)	5,316,238,628	721,628,168	462,969,589			5,574,897,207
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	11,444,607,217	824,386,024	468,481,525			[d] 11,800,511,716
47	3. Transmission Plant						
48	(350) Land and Land Rights	168,648,524	983,023				169,631,547
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	154,713,001	3,787,774	653,495		(13,971)	157,833,309
50	(353) Station Equipment	1,453,096,962	49,940,394	9,307,829		134,439	1,493,863,966
51	(354) Towers and Fixtures	126,526,816	1,121,915	1,957			127,646,774
52	(355) Poles and Fixtures	1,546,910,333	43,702,420	2,226,273			1,588,386,480
53	(356) Overhead Conductors and Devices	672,055,787	30,063,014	841,149			701,277,652
54	(357) Underground Conduit	32,181,582					32,181,582
55	(358) Underground Conductors and Devices	35,447,885	(14,357)				35,433,528
56	(359) Roads and Trails		334,471				334,471
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] 4,189,754,319	129,918,654	13,030,703		120,468	[e] 4,306,762,738
59	4. Distribution Plant						

60	(360) Land and Land Rights	19,768,123	24,910	479			19,792,554
61	(361) Structures and Improvements	63,080,071	942,851	249,396		13,971	63,787,497
62	(362) Station Equipment	732,939,308	37,383,072	4,708,471		(134,439)	765,479,470
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	571,993,196	80,340,085	1,797,340			650,535,941
65	(365) Overhead Conductors and Devices	587,830,254	70,196,917	2,905,315			655,121,856
66	(366) Underground Conduit	359,696,434	38,229,735	270,687			397,655,482
67	(367) Underground Conductors and Devices	1,354,765,357	78,740,628	3,424,060			1,430,081,925
68	(368) Line Transformers	504,623,149	28,193,741	3,727,788			529,089,102
69	(369) Services	385,950,714	36,238,828	403,308			421,786,234
70	(370) Meters	99,829,746	34,629,626	16,276,575			118,182,797
71	(371) Installations on Customer Premises	128,517	4,633,039				4,761,556
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	85,502,721	8,684,588	524,907			93,662,402
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]4,778,338,628	418,238,020	34,288,326		(120,468)	[f]5,162,167,854
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	5,440,229	14,300,525				19,740,754
87	(390) Structures and Improvements	76,227,724	6,680,393	254,849			82,653,268
88	(391) Office Furniture and Equipment	92,729,736	13,659,743	3,142,767			103,246,712
89	(392) Transportation Equipment	192,576,245	34,817,381				227,393,626
90	(393) Stores Equipment	1,624,278	42,457				1,666,735
91	(394) Tools, Shop and Garage Equipment	116,662,435	19,124,743	302,172			135,485,006
92	(395) Laboratory Equipment	2,864,646	372,233	245,259			2,991,620
93	(396) Power Operated Equipment	53,687,458	5,085,028				58,772,486
94	(397) Communication Equipment	184,849,607	20,634,491	1,819,101		(235,012)	203,429,985
95	(398) Miscellaneous Equipment	1,902,514					1,902,514
96	SUBTOTAL (Enter Total of lines 86 thru 95)	728,564,872	114,716,994	5,764,148		(235,012)	837,282,706
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)	728,564,872	114,716,994	5,764,148		(235,012)	[(g)]837,282,706
100	TOTAL (Accounts 101 and 106)	21,576,291,034	1,517,552,472	521,564,702		(235,012)	22,572,043,792
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)	21,576,291,034	1,517,552,472	521,564,702		(235,012)	22,572,043,792

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	22,469,018	11,223	(2,411)	—	—	22,477,830
Account 353 - Station Equipment	122,029,705	9,469,591	(74,263)	—	—	131,425,033
Account 354 - Towers & Fixtures	4,916,560	—	—	—	—	4,916,560
Account 355 - Poles & Fixtures	18,793,038	(85,456)	—	—	—	18,707,582
Account 356 - Overhead Conductors & Devices	13,832,985	(17,214)	—	—	—	13,815,771

(b) Concept: DistributionPlant

Distribution Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 361 - Structures & Improvements	$ 838,281	$ —	$ —	$ —	$ —	$ 838,281
Account 362 - Station Equipment	4,224,183	507	—	—	—	4,224,690

(c) Concept: IntangiblePlant

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

(d) Concept: ProductionPlant

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

(e) Concept: TransmissionPlant

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

(f) Concept: DistributionPlant

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

(g) Concept: GeneralPlant

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	General Comm Eq-EMS - Osseo Sub-Dist-MN	11/30/2022	12/31/2023	256,129
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
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32				
33				
34				
35				
36				
37				

38				
39				
40				
41				
42				
43				
44				
45				
46				
47	TOTAL			256,129

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 of these plant balances included in the formula rate.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	NRW Northern Wind Farms	140,878,909
2	GDM Grand Meadow Repower	103,270,147
3	SHC Solar Generating Plant #1	27,735,956
4	PI TN-40 Casks (48-64)	22,824,665
5	DEMS Ph4 HW MN-10756	18,016,219
6	0980 -Str 2 -27A (Phase 2)	13,382,013
7	PI 121-128 Intake Travelling Screen	12,419,307
8	ITC-Operation Work Management SW MN	12,111,605
9	ITC-Nuclear CAP IA Ph2 SW MN	11,213,746
10	MT 2nd License Renewal	10,289,481
11	Elm Creek TR10	10,274,015
12	0726 Pipestone-Rock Ck-Wdstk rebuil	7,946,654
13	PI 122 Cooling Tower Rebuild	7,568,407
14	AGIS Meter Data Mgmt (MDM) SW MN	7,253,525
15	BLL0 - Black Start Conversion	6,996,959
16	ANS2 CT Maj OH Rep Vanes&Blades-104	6,602,982
17	SHC Solar Generating Plant #2	6,518,926
18	NSM0703 FRM NOF Rebuild	5,848,362
19	NSM0754 Becker - Linn Street Rebuil	5,396,276
20	SUB MN Feeder Load Monitoring	4,964,730
21	Lincoln Co 30MVAR Cap Bank Sub	4,630,444

22	HBC8 - U8 CT Ovhl Major Outage - 10		4,471,264
23	AMI-Meter-Data-Lake-BS-SW-NSPM		4,247,032
24	NSM0790 Montrose- Delano Rebuild		4,185,680
25	CSC Redevelopment ? Phase 1		4,073,516
26	Arlington-Replace Bkrs 4S191,4S192,		3,811,114
27	COMM MN Fiber Buildout		3,770,449
28	MT 2022 Maintenance Blanket		3,733,630
29	ITC-DI Services Platform SW 200117		3,656,658
30	ELR MN Sub Feeder Breakers		3,641,034
31	Rebuild Downtown St. Paul Manholes		3,491,694
32	RLK 115 kV Bus Expansion		3,473,407
33	ITC-Purch DEMS HW MN		3,460,089
34	SUB Reinforce Hyland Lake HYL TR2		3,399,168
35	MN EV Public - Infrastructure		3,387,725
36	PI U2 Baffle Bolt Replacement		3,060,547
37	NSM0779 - Canisota Juntion - Salem,		2,927,493
38	ITC ISO Intrfc & Stlmt Rpl SW MN-20		2,856,935
39	Reinforce HYL feeder exits		2,795,977
40	0761 LAK ZUM Rebuild		2,660,203
41	MN-Dist Fleet NewUnit Prchse El Ops		2,527,908
42	BDS2 HP Turbine Blades Rpl		2,427,498
43	SE Region Reliability Initiative		2,417,195
44	Belle Plaine SC New		2,402,635
45	SUB Reinforce Kasson KAN TR1		2,386,060
46	ITC-SAS BookRunner Upgra SW 200134		2,292,506
47	Riverside Relaying-ELP,FST,MST		2,267,385
48	MINNESOTA MAJOR STORM RECOVERY		2,265,744
49	SUB Install Great Plains Area Sub		2,245,497

50	NSM5400 ALB-PAT-WAK Refurb		2,186,188
51	MT #12 EDG Voltage Regulator		2,161,731
52	ITC-VOIP Ref Prairie Island NP MN		2,130,096
53	NSM0703 FRM KLK Rebuild		2,121,679
54	Edina Parking-Yard Pavement Rplc		2,108,598
55	BDS2C-Replace U2 Turbine L-0 Blades		2,101,294
56	PI U2 RV Lower Radial Clevis Bolts		2,039,092
57	NSPM S&E 115kV Line		2,017,946
58	LINE Install Great Plains Area Sub		1,964,070
59	ADMS Data - NSPM		1,960,031
60	MT Rplc Turbine Stop Vlvs		1,941,563
61	SHC3C U3 Landfill Cell 4 2019		1,929,468
62	RIV0C -- Replace Water Treamen		1,898,185
63	ITC-Purch-Cap MT Secur Comp HW MN		1,820,605
64	PVW Pleasant Valley Repower		1,748,824
65	LINE Convert North Broadway NBY 4kV		1,736,964
66	LINE Convert Larimore LAR 4kV		1,731,970
67	MT - WRGM Replacement		1,682,428
68	Relocate STP Tunnel Feeders		1,663,217
69	Reserve TR 115/13.8 kV 50 MVA		1,644,899
70	LINE C Install Chemolite CHE065 Fee		1,644,207
71	Reserve TR 115/13.8 kV 50 MVA #2		1,588,895
72	PI NI Drawer Replacement		1,499,673
73	SW Lic Rnwl-App Del-101630-MN-E		1,499,326
74	0723 Cosmos - Panther rebuild		1,493,913
75	YLM211 and YLM212 Rebuild OH lines		1,468,056
76	MN - Feeder Cable Replacement		1,450,340
77	PI Equipment Sensors (A/I)		1,447,203

78	COMM MN Feeder Load Monitoring	1,436,922
79	NSM0992 CNC SHC REPL STRS PH2	1,427,812
80	Replace FLS064 8th-10th S Phillips	1,426,946
81	PI MT Reactor Head Tensioners	1,425,273
82	Purch Synchrophasor Net HW MN	1,415,767
83	SW Lic Rnwl-Infra-102025-MN-E	1,399,784
84	HBC0C Warming Line to Intake	1,385,619
85	0723 Panther - Bird Island	1,374,729
86	AMI-SW-License-BS-NSPM-NEW	1,355,309
87	MT Rplc Bleach House Tank/Pump	1,350,876
88	MT Equipment Sensors	1,347,959
89	NSM0735 CAR YAM Refurb	1,343,146
90	MN Install Viper Reclosers CSG	1,308,814
91	MT CRD Rebuild and Rplc (RFO31)	1,274,164
92	SD Reloc B 115kV, Line	1,263,907
93	Relocate Lone Oak LOK062 Feeder	1,252,610
94	ITC-MT Security SW MN	1,221,031
95	Inver Grove-Replace 4P8,4P9	1,184,025
96	NSM0790 Victor - 4N185 Rebuild	1,134,122
97	PI GE APM PMCR (PKMJ)	1,104,154
98	NSM0734 West Gate Excelsor Line	1,075,104
99	PI Spare CL Pump	1,061,723
100	MT #11 EDG Voltage Regulator	1,032,460
101	MT Rplc Div 2 FSW Pipe	1,028,313
102	Riverside Relaying - MOL,TWL	1,027,877
103	PI U2 EDG Governor Change	1,015,958
104	MN - Pole Replacement Blanket	1,003,275
105	NSM0984 CNC SHC REPL STRS PH2	1,000,656

106	Douglas Dr OH-UG Conversion	(1,349,027)
107	J545/J905 BRI Interc DIR -SUB	(2,123,261)
108	NSPM Reloc B 115kV, Line	(3,477,610)
109	Minor Projects	132,143,196
110	[(a)] (footnote to page 106)	
43	Total	745,031,465

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: ConstructionWorkInProgressProjectDescription

Construction Work in Progress (Account 107). The Form 1 reports the total Company construction work in progress (CWIP) balances at the end of the year. The Company uses a 13-month average calculation for the specific CWIP project balances included in the formula. The Company can only include CWIP in the formula related to the following specific projects, the balances of which could be a component of the amounts reported on page 216: the three projects in Group 1 of the CapX2020 Project - Twin Cities-Brookings County, Twin Cities-Fargo, and Twin Cities-LaCrosse.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	8,610,857,018	8,610,857,018		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	753,792,424	753,792,424		
4	(403.1) Depreciation Expense for Asset Retirement Costs	(12,014,186)	(12,014,186)		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	15,936,510	15,936,510		
7	Other Clearing Accounts	157,573	157,573		
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)	757,872,321	757,872,321		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(521,564,699)	(521,564,699)		
13	Cost of Removal	(31,359,796)	(31,359,796)		
14	Salvage (Credit)	11,443,607	11,443,607		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(541,480,888)	(541,480,888)		

16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	(77,937,713)	[(a)](77,937,713)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	[(b)]8,749,310,738	8,749,310,738		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	1,856,284,772	[(c)]1,856,284,772		
21	Nuclear Production	2,392,635,109	[(d)]2,392,635,109		
22	Hydraulic Production-Conventional	17,911,645	[(e)]17,911,645		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,120,302,960	[(f)]1,120,302,960		
25	Transmission	1,101,304,734	[(g),(h)]1,101,304,734		
26	Distribution	1,880,626,988	[(i),(j)]1,880,626,988		
27	Regional Transmission and Market Operation				
28	General	380,244,530	[(k)]380,244,530		
29	TOTAL (Enter Total of lines 20 thru 28)	[(l)]8,749,310,738	8,749,310,738		

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToAccumulatedDepreciation

Net change in RWIP	$	(77,717,974)
Net Transfers and Adjustments		(1,526)
(Gain)/Loss		(214,711)
Common Expense Allocation		(3,502)
Total	$	(77,937,713)

(b) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

	"Non-Legal" ARO Balances	
Steam Production	$	157,952,894
Nuclear Production		(70,070,524)
Hydraulic Production-Conventional		3,221,080
Other Production		103,212,270
Transmission		163,131,612
Distribution		236,637,825
General		(1,286,949)
Total	**$**	**592,798,208**

(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

Transmission Serving Production	$	46,138,298
Transmission Serving Production RWIP	$	208,260

(h) 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.

(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	$	2,784,298

(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

		"Non-Legal" ARO Balances
Steam Production	$	157,952,894
Nuclear Production		(70,070,524)
Hydraulic Production-Conventional		3,221,080
Other Production		103,212,270
Transmission		163,131,612
Distribution		236,637,825
General		(1,286,949)
Total	**$**	**592,798,208**

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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.			1,641,006	375,467	(11)	2,016,484	
2	UNITED POWER & LAND CO. - Capital Stock			4,020,000			4,020,000	
3	UNITED POWER & LAND CO. - Paid-In-Capital			749,577		[(a)](11)	749,588	
4	UNITED POWER & LAND CO. - Unappropriated Undistributed Subsidiary Earnings			(3,128,571)	375,467		(2,753,104)	
5	NSP NUCLEAR CO.			1,580,589	(475)		1,580,114	
6	NSP NUCLEAR CO. - Capital Contribution			962,698			962,698	
7	NSP NUCLEAR CO. - Unappropriated Undistributed Subsidiary Earnings			617,891	(475)		617,416	
42	Total Cost of Account 123.1 $ 5,732,286.00		Total	3,221,595	374,992	(11)	3,596,598	

FOOTNOTE DATA

(a) 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: 04/07/2023	Year/Period of Report End of: 2022/ 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)	82,320,015	104,511,663	Electric
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)]34,820,007	[(b)]41,398,564	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	146,323,646	157,660,437	Electric
8	Transmission Plant (Estimated)	868,918	759,981	Electric
9	Distribution Plant (Estimated)	3,045,262	4,582,660	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[(c)](4,327,880)	[(d)](5,342,325)	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	180,729,953	199,059,317	
13	Merchandise (Account 155)	916,230	1,311,697	
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)] note re: page 106 formula rates			0
20	TOTAL Materials and Supplies	263,966,198	304,882,677	

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction

		Electric		Gas
Production	$	16,353,102	$	—
Transmission		5,972,716		—
Distribution		11,074,653		1,419,536
Total	$	33,400,471	$	1,419,536

(b) Concept: PlantMaterialsAndOperatingSuppliesConstruction

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

(c) Concept: PlantMaterialsAndOperatingSuppliesOther

Includes a credit of $2,746,302 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of $1,581,578 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.

(d) Concept: PlantMaterialsAndOperatingSuppliesOther

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

(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: 04/07/2023	Year/Period of Report End of: 2022/ 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		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	1,137,387		93,200		93,016		69,262		1,800,812		3,193,677	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)									69,262		69,262	
5	Returned by EPA	[a]3,362										3,362	
6													
7													
8	Purchases/Transfers:												
9	Allow transfer to SMMPA(CSAPR)	(2,601)										(2,601)	
10	Transfer to SMMPA (ARP)	(4,056)										(4,056)	
11													
12													
13													
14													

15	Total	(6,657)										(6,657)	
16													
17	Relinquished During Year:												
18	Charges to Account 509	(9,221)										(9,221)	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Beginning Balance Adj.	(321)										(321)	
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	1,124,550		93,200		93,016		69,262		1,870,074		3,250,102	
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		40,693		44,397	
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		39,767		42,545	

41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)	926	36							926	9	1,852	45
45	Gains		36								9		45
46	Losses												

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AllowancesReturnedByEnvironmentalProtectionAgencyNumber
Estimate. Amount to be finalized by EPA in first half of 2023.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	68,082		16,659		16,253						100,994	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA	[(a)]2,206										2,206	
6													
7													
8	Purchase/Transfer												
9	Transfer to SMMPA	(1,480)										(1,480)	
10													
11													
12													
13													
14													

15	Total	(1,480)										(1,480)	
16													
17	Relinquished During Year:												
18	Charges to Account 509	(8,348)										(8,348)	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Beginning Balance Adj.	(216)										(216)	
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	60,244		16,659		16,253						93,156	
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: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AllowancesReturnedByEnvironmentalProtectionAgencyNumber
Estimate. Amount to be finalized by EPA in first half of 2023.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	[(a)] Prairie Island Extended Power Uprate Project MN Docket E-002/CN-08-509	[(c)] 78,884,915		[(d)] Various	3,501,289	45,680,141
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	26,845,091
49	TOTAL	126,929,210			8,179,188	72,525,232

(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.

NSP-Minnesota requested recovery of approximately $4 million of deferred costs with a return in its South Dakota electric rate case filed June 30, 2022 (Docket No. EL22-017). NSP-Minnesota proposed recovery over a 11.3 year period beginning Jan. 1, 2023. NSP-Minnesota expects a decision from the South Dakota Public Utilities Commission in mid-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	$	3,852,547
Account No. 426.5 - accretion		(351,258)
	$	3,501,289

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	East River System Impact Study Agreement-600101757358	5,000	561.6,408.1,925,926	10,000	561.6, 242
3	Chaska System Impact Study NSP-694-600101758358	22,672	561.6,408.1,925,926	7,672	561.6
4	NSP-674 GRE North Mankato-600101762358			10,000	242
5	NSP-707 Chaska WCK Sub Fac Study-600101762859	116,943	561.6,408.1,925,926	55,000	561.6
6	Sauk Centre NSP-672 SISA-600101759450	3,842	561.6,408.1,925,926	5,000	561.6, 242
7	NSP-673 GRE Kimball-600101760361	3,954	561.6,408.1,925,926	10,081	561.6, 242
8	NSP-709 GRE Eidswold SISA-600101761866	5,799	561.6,408.1,925,926	10,059	561.6, 242
9	Sauk Centre Facilities Study Agmt-600101762359			55,000	242
10	OTP Lake Preston Interconnection Req-600101768858			10,000	242
20	Total	158,210		172,812	
21	**Generation Studies**				
22	J545/J905 Buffalo Ridge Sub Interc-600101737362	75	561.7,408.1,925,926		
23	J1106 Wind Interc on line #0957-600101744859			66,656	561.7, 242
24	J1445 Mayhew Lake Sub Solar-600101746865	3,442	561.7,408.1,925,926	38,068	561.7, 242
25	J1446 Lake Pulaski Sub Solar-600101746866	8,215	561.7,408.1,925,926	61,577	561.7, 242
26	J1395 CapX Hawks Nest L-LYN 345KV In Sub-600101746871	7,582	561.7,408.1,925,926	78,754	561.7, 242
27	J898 NU-Adam 345/161 kV TR9 Rplcmt-600101747859	7,253	561.7,408.1,925,926	35,833	561.7, 242

28	J946 NU - Sheyenne 115 kV Ln Rbld-600101747860	3,851	561.7,408.1,925,926		
29	J901 NU - Helena Chub Lk 345 kV Ln Rbld-600101747861	3,174	561.7,408.1,925,926		
30	J1468 West Hastings 115 KV Sub battery-600101746868	3,740	561.7,408.1,925,926	75,839	561.7, 242
31	J1315 CapX Lyon Cty-CMT 345KV In Sub-600101746870	2,992	561.7,408.1,925,926	5,013	561.7, 242
32	J1312 Grant Sub solar-600101746863	1,496	561.7,408.1,925,926	2,301	561.7, 242
33	J1349 Crandall Sub Hybrid-600101746864	3,680	561.7,408.1,925,926	39,380	561.7, 242
34	G621 Chanarambie Sub FaS Restudy-600101755858	148	561.7,408.1,925,926	37,462	561.7, 242
35	G057/Viking Chanarambie Sub FaS-600101755859	1,104	561.7,408.1,925,926	17,103	561.7, 242
36	J1572 Huntley BlueEarth Facilities Study-600101756875	50,391	561.7,408.1,925,926		
37	J1620 Pipestone Split Rock Short Circuit-600101756896	6,520	561.7,408.1,925,926		
38	J1572 Huntley Blue Earth Short Circuit-600101756890	6,411	561.7,408.1,925,926		
39	J1588 Bison 345kV Short Circuit-600101756893	6,152	561.7,408.1,925,926		
40	J1498 Chanarambie Subs Short Circuit-600101756888	6,460	561.7,408.1,925,926		
41	J1588 Bison 345kV Facilities Study-600101756878	66,539	561.7,408.1,925,926		
42	J1620 Pipestone Facilities Study-600101756881	68,281	561.7,408.1,925,926		
43	J1498 Chanarambie Facilities Study-600101756873	85,831	561.7,408.1,925,926		
44	J1494 Chisago 115kV Short Circuit-600101756886	5,566	561.7,408.1,925,926		
45	J1826 Cannon Falls Short Circuit-600101756900	8,259	561.7,408.1,925,926		
46	J1495 North Rochester Short Circuit-600101756887	4,240	561.7,408.1,925,926		
47	J1494 Chisago 115kV Facilities Study-600101756871	81,007	561.7,408.1,925,926		
48	J1495 North Rochester Facilities Study-600101756872	60,423	561.7,408.1,925,926		
49	J1581 Nobles County Facilities Study-600101756876	106,613	561.7,408.1,925,926		
50	J1605 Sherburne 345kV Facilities Study-600101756879	59,081	561.7,408.1,925,926		
51	J1826 Cannon Falls Facilities Study-600101756885	18,510	561.7,408.1,925,926		
52	J1581 Nobles County Short Circuit-600101756891	5,821	561.7,408.1,925,926		
53	J1605 Sherburne 345kV Short Circuit-600101756894	909	561.7,408.1,925,926		
54	Flint Hill Sub Solar FaS-600101759861	4,362	561.7,408.1,925,926	35,000	561.7, 242
55	J1040 Bison Capbank NU FaS-600101759487	74,408	561.7,408.1,925,926	46,908	561.7

39	Total	772,537		539,894	
40	Grand Total	930,747		[(a)]712,706	

FOOTNOTE DATA

(a) Concept: StudyCostsReimbursements

NSP-Minnesota has changed its presentation of information on page 231 from a life-to-date view to current year information beginning with reporting year 2022. This change results in reimbursements presented in column D to reflect current year funds received, and does not include prior year deposits applied to current year charges.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Asset Retirement Recovery	2,553,478,679	112,001,681			2,665,480,360
2	Benefit Cost Recovery Deficit	311,201,373	66,843,229	184	34,391,545	343,653,057
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	33,123,179		557	4,913,144	28,210,035
4	Costs to Relocate Facilities Underground - MN Docket E-002/M-99-799 - MN Docket E-002/M-04-1663 - Generally amortized over 36 months	1,841,844	90,742	142	769,414	1,163,172
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	53,737,453	[(a)]27,113,271	[(b)] Various	38,362,370	42,488,354
6	Deferred Tax Collected in Rates in Excess of Current Tax Accrual Levels	165,462	709,689			875,151
7	Derivatives & Hedging - Retail Electric & Gas	4,066,466		244	1,782,442	2,284,024
8	Laurentian Biomass PPA Termination - MN Electric E-002/GR-17-551 - ND Docket PU-17-322 - SD Docket EL 18-027	36,166,668		557	18,083,335	18,083,333
9	Mankato/Cannon Falls Lease Normalization	32,300,737	1,518,792	101.1	7,170,311	26,649,218
10	Minnesota Business Incentive and Sustainability Rider - MN Docket E-002/M-20-436 - MN Docket E-002/GR-21-630 - Amortized through 2024	2,632,920		407.3	890,516	1,742,404

11	Minnesota Deferred Electric Commodity Costs - MN Docket E-002/AA-20-417 - MN Docket E-002/AA-21-295 - MN Docket E-002/GR-21-630 - Generally amortized over 12 month period beginning September of following year	85,149,510	948,619,883	[(c)] Various	984,937,783	48,831,610
12	Minnesota Electric Vehicle Tariff - MN Docket E-002/M-15-111 - MN Docket E-002/M-17-817 - MN Docket E-002/M-18-643 - MN Docket E-002/M-19-186 - MN Docket E-002/M-20-711 - MN Docket E-002/GR-21-630 - Amortized through 2024	2,642,005		912	622,897	2,019,108
13	Minnesota Gas Utility Infrastructure Cost Rider - MN Docket E-002/GR-22-578	32,754,208	32,581,805	407.4	22,937,769	42,398,244
14	Minnesota LED Streetlighting - MN Docket E-002/GR-15-826 - MN Docket E-002/GR-21-630 - Amortized through 2024	368,358		407.3	145,011	223,347
15	Minnesota Renewable Development Fund Rider - MN Docket E-002/M-22-522	28,392,939	35,410,084	407.3	28,352,169	35,450,854
16	Minnesota Renewable Energy Standard - MN Docket E-002/M-20-815 - MN Docket E-002/M-21-794- MN Docket E-002/M-22-528	141,212,566	64,750,455	407.3	191,300,977	14,662,044
17	Minnesota Sales True-Up - 2020 - MN Docket E-002/GR-19-688 - Amortized over 1 year (04/2021-03/2022)	25,154,607		407.3	25,154,607	
18	Minnesota Sales True-Up - 2021 - MN Docket E-002/GR-20-743 - Amortization began 04/2022 over 12-21 months based on customer class	64,112,588		407.3	10,659,153	53,453,435
19	Net of Tax AFUDC in Plant Adjustments	113,557,509		282	1,090,933	112,466,576
20	Nonplant Excess ADIT	122,394,756	1,753	283	9,794,105	[(f)] 112,602,404
21	North Dakota AGIS Deferral - ND Docket PU-20-441	689,892	836,977			1,526,869
22	North Dakota Deferred Electric Commodity Costs - ND Docket PU-22-012	2,896,137	79,943,968	557	82,840,105	
23	North Dakota Environmental Cleanup - ND Docket PU-17-894 - Amortized through 2026	4,571,437		735	359,396	4,212,041
24	North Dakota Transmission Cost Recovery Rider - ND Docket PU-22-402	274,956	1,130,680	407.3	1,405,636	
25	Power Contract Valuation Adjustment - Generally amortized over term of related contract	48,301,369		244	6,209,481	42,091,888
26	Renewable*Connect Classic-MN Docket E-002/GR-22-161	9,133,579	4,314,629	[(d)] Various	13,448,208	

27	Renewable*Connect Government - MN DocketE-002/GR-22-161	320,956	365,014	(e) Various	685,970	
28	Sherco 3 Depreciation Deferral - MN Docket E-002/GR-15-826 - Amortized over 21 years (01/2014-12/2035)	6,540,685		407.3	503,130	6,037,555
29	South Dakota Electric Conservation and Energy Management Program Costs - SD Docket EL 22-010 - Generally amortized over 12 month period following the expenditure	112,580	1,027,714	908	1,140,294	
30	South Dakota Property Tax Collected in the Fuel Clause Adjusment - SD Docket EL 14-058 - SD Docket EL 22-017	278,091	1,959,705	408.1	2,237,796	
31	South Dakota Ratemaking Differences - SD Docket F-3382 - SD Docket F-3422 - Amortized over plant lives	3,369,250	349,000	405	558,000	3,160,250
32	Theoretical Depreciation Reserve Surplus - MN Docket E-002/GR-17-147 - Amortized over plant lives	237,714,474		407.3	9,087,814	228,626,660
33	Transmission Formula Rates	10,910,244	9,481,100	565	5,296,380	15,094,964
44	TOTAL	3,969,567,477	1,389,050,171		1,505,130,691	3,853,486,957

FOOTNOTE DATA

(a) Concept: IncreaseDecreaseInOtherRegulatoryAssets

Accounts charged:		
517	$	762,419
519		594,931
520		3,909,225
523		188,679
524		478,268
528		291,386
530		2,917,888
531		2,361,270
532		15,609,205
Total	$	27,113,271

(b) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:		
517	$	2,016,148
519		637,180
520		5,195,569
523		360,184
524		1,414,316
528		704,040
530		14,428,700
531		2,563,223
532		11,043,010
Total	$	38,362,370

(c) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:		
142	$	28,926,190
557		956,011,593
Total	$	984,937,783

(d) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:		
142	$	2,871,378
456		10,576,830
Total	$	13,448,208

(e) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:		
142	$	269,121
456		416,849
Total	$	685,970

(f) Concept: OtherRegulatoryAssets

	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Total
Electric	$ 78,003,761	$ 30,292,380	$ 108,296,141
Gas	3,101,724	1,204,539	4,306,263
Total	$ 81,105,485	$ 31,496,919	$ 112,602,404

*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 12/31/2021	Amortization 2022	Excess Balance 12/31/2022
Bad Debts	$ 511,760	$ (511,760)	$ —
Deferred Rent	273,252	(273,252)	—
Deferred Revenues	57,966	(57,966)	—
Economic Development Securities - Write-Off	9,558	(9,558)	—
Employee Incentive Plans	398,284	(398,284)	—
Environmental Remediation	4,459	(4,459)	—
Federal Net Operating Loss	79,698,926	(4,194,680)	75,504,246
Fuel Tax Credit - Income Addback	452	(452)	—
Inventory Reserve	99,012	(99,012)	—
Litigation Reserve	10,762	(10,762)	—
Medical Deductions - Self Insured	46,562	(46,562)	—
North Dakota Investment Tax Credit	(3,038,044)	3,038,044	—
North Dakota Investment Tax Credit - Valuation Allowance	3,038,044	(3,038,044)	—
Performance Recognition Awards	1,094	(1,094)	—
Post Employment Benefits - Long Term Disability	1,406,853	(127,896)	1,278,957
Post Employment Benefits - Retiree Medical	4,512,128	(410,193)	4,101,935
Purchased Power Capacity	5,158	(5,158)	—
Rate Refund	598,272	(598,272)	—
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	366,197	(366,197)	—
Regulatory Asset/Liability - Transmission Cost Recovery Rider	191,216	(191,216)	—
Regulatory Asset/Liability - Prairie Island Extended Power Uprate Cancellation	102,104	(102,104)	—
Sale of Emission Allowances	2,041	(2,041)	—
South Dakota Infrastructure Rider	26,222	(26,222)	—
Section 174 - Section 59(e) Adjustment	1,383,286	(1,383,286)	—
Severance Accrual	6,083	(6,083)	—
Solar Rewards Program	676,468	(676,468)	—
State Research and Experimental Credit	(203,574)	203,574	—
State Research Credit - Valuation Allowance	39,060	(39,060)	—
Vacation	454,048	(454,048)	—
VEBA	127,212	(127,212)	—
Workers Compensation	2,366	(2,366)	—
Total Electric	$ 90,807,227	$ (9,922,089)	$ 80,885,138

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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: Credits Account Charged (d)	CREDITS: Credits Amount (e)	Balance at End of Year (f)
1	Conservation and Energy Management Program Costs Minnesota Electric (Docket E-002/M-22-158)	24,097,828	21,329,838	182.3	24,097,828	21,329,838
2	Conservation and Energy Management Program Costs Minnesota Gas Incentive (Docket G-002/M-22-160)	4,798,143	3,631,460	182.3	4,798,142	3,631,461
3	Federal and State Income Taxes Interest Receivable	5,597,109	384,263	171	2,479,176	3,502,196
4	Federal and State Income Tax Receivable	396,690		236	396,472	218
5	IPP Power Contract Billing Adjustments	798,082	3	174	798,085	
6	JOA & Rate Payer Share MTM	21,071,121		557	3,145,907	17,925,214
7	Notes Receivable - 3rd Party	2,743,351	116,532	143	511,329	2,348,554
8	Prepaids - Facility Fees	937,771	1,392,969	431	417,420	1,913,320
9	Minnesota Electric Retail Rate Case Expenses (Docket E-002/GR-21-630) - Amortized through 2024	612,407	1,304,998	928	1,562,100	355,305
10	Minnesota Gas Retail Rate Case Expenses (Docket G-002/GR-21-678) - Amortized through 2024	306,260	852,580	928	1,158,840	
11	North Dakota Electric Retail Rate Case (Docket PU-20-441) - Amortized through 2024	790,800		928	408,497	382,303
12	North Dakota Gas Retail Rate Case Expenses (Docket PU-21-381) - Amortized through 2024	416,898	274,831	928	217,600	474,129
13	South Dakota Electric Retail Rate Case Expenses (Docket EL 22-017)	113,169	508,080			621,249

14	Loan Receivable - 3rd Party	5,168,947	1,539,324	143	708,271	6,000,000
47	Miscellaneous Work in Progress					
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	67,848,576				58,483,787

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	227,384,879	[(a)]233,768,343
3	Electric - Non-Plant	967,920,958	1,170,275,469
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,195,305,837	[(b)]1,404,043,812
9	Gas		
10		32,370,045	[(c)]29,626,876
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	32,370,045	29,626,876
17.1	Other (Specify)	41,781,926	[(d)]12,654,963
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,269,457,808	1,446,325,651

Notes

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Decommissioning	$ —	$ —
Electric Distribution Plant	134,908,217	143,295,665
Electric General Plant	461,788	766,298
Electric Intangible Plant	2,934,406	2,584,392
Electric Nuclear Fuel	29,352,046	29,624,347
Electric Nuclear Production Plant	49,521,279	44,552,368
Electric Production Plant	50,587,382	48,588,131
Electric Transmission Plant	46,449,218	47,398,890
Electric Transmission-Production Plant	2,187,661	2,358,090
Common (Allocation to Electric)	818,921	1,315,305
Regulatory Differences - Effect of Rate Changes	(96,482,375)	(92,722,451)
Regulatory Differences - Investment Tax Credit Gross-Up	6,646,336	6,007,308
Total Electric Plant Related Only	$ 227,384,879	$ 233,768,343

(b) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Electric:		
Avoided Tax Interest	$133,799,625	$129,459,225
Bad Debts	12,162,564	12,171,409
Customer Advances	2,504,403	2,114,072
Deferred Connection Fees	132,080,516	142,145,685
Deferred Rent	2,482,814	2,265,235
Deferred Revenue	544,405	712,408
Economic Development Securities - Write-Off	103,628	103,323
Electric Vehicle Credit	6,912	—
Employee Incentive Plans	3,589,458	3,965,595
Employee Retention	3,160	6,382
Employee Stock Ownership Program Dividends	6,504,761	6,487,006
End of Life Nuclear Fuel Amortization	29,352,046	29,592,532
Environmental Remediation	1,638,646	3,018,528
Excess Nonplant Accumulated Deferred Income Taxes	7,868,974	6,103,491
Federal Net Operating Loss	15,014,069	518,557
Fuel Tax Credit - Income Addback	12,882	6,351
Interest Income/Expense on Disputed Tax	—	215,070
Inventory Reserve	652,061	650,765
Investment Tax Credit	2,071,062	786,145
Litigation Reserve	84,762	—
Medical Deductions - Self Insured	570,405	980,485
Minnesota Net Operating Loss	—	13,552,065
Monticello Extended Power Uprate Writedown	12,979,567	10,684,966
New Hire Retention Credit	51,388	—
North Dakota Investment Tax Credit	71,044,542	63,614,482
North Dakota Investment Tax Credit - Valuation Allowance	(63,267,486)	(57,717,609)
North Dakota Investment Tax Credit - Federal Gross-Up	2,468,865	2,182,546
North Dakota Net Operating Loss	—	1,962
North Dakota Production Tax Credit - Levelization	1,568,199	3,613,269
Operating Lease Liabilities	113,770,244	90,360,911
Payroll Tax Deferral	2,265,208	—
Performance Recognition Awards	112,475	111,732
Post Employment Benefits - Retiree Medical	8,636,859	7,043,941
Post Employment Benefits - Long Term Disability	3,003,275	2,495,807
Public Utility Conservation Investment Programs	—	4,660,514
Rate Refund	11,074,002	27,068,355
Regulatory Asset/Liability - Miscellaneous	1,906,917	9,492,250
Regulatory Asset/Liability - Renewable Energy Standard Rider	—	1,405,560
Regulatory Asset/Liability - Transmission Cost Recovery Rider	6,512,912	5,571,675
Regulatory Asset/Liability - Windsource	—	1,333,789
Regulatory Difference - Effect of Rate Changes	(96,482,375)	(92,722,451)
Regulatory Difference - Investment Tax Credit Gross-Up	6,646,336	6,007,308
Research and Experimentation Credit	49,467,526	51,595,874
Section 174 - Section 59(e) Adjustment	37,015,541	30,637,090
Severance Accrual	23,396	23,220
Solar Rewards Program	1,929,164	3,481,127
South Dakota Infrastructure Tracker	721,804	604,781
State Research Credit	8,492,229	5,751,754
State Research Credit - Valuation Allowance	(235,508)	—
State Tax Deduction Cash vs. Accrual	623,819	2,987,469

Texas Gross Margin Tax	500	—
Vacation Accrual	5,320,422	5,403,369
Wind Production Tax Credit	658,446,267	863,289,576
Workers Compensation	162,596	206,216
Total Electric	$ 1,195,305,837	$ 1,404,043,812

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

Amortization of Excess ADIT (Electric only) included in 410.1 is $3,652,382 for 2021 and $3,546,522 for 2022.

	2021 ARAM	2022 ARAM
Unprotected ARAM:		
Decommissioning	$ —	$ —
Electric Distribution Plant	1,403,133	1,379,735
Electric General Plant	33,819	33,695
Electric Intangible Plant	140,742	147,305
Electric Nuclear Fuel	—	—
Electric Production Plant	1,710,753	1,633,675
Electric Transmission Plant	350,353	337,641
Electric Transmission-Production Plant	4,723	4,843
Common (Allocation to Electric)	8,859	9,628
Total Electric	$ 3,652,382	$ 3,546,522

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

Common (Unallocated)	$ 9,705	$ 10,613

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

	12/31/2022	12/31/2022	12/31/2022
Excess (Electric only)	Excess	Gross up	Total Regulatory
Flow Through	$ 424,342	$ 164,792	$ 589,134
Other Basis Differences (Unprotected)	(67,210,655)	(26,100,930)	$ (93,311,585)
	$ (66,786,313)	$ (25,936,138)	$ (92,722,451)

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

Non-utility			
Other Basis Differences (Unprotected)	$ (8)	$ (3)	$ (11)
	$ (8)	$ (3)	$ (11)
Common (allocated)			
Other Basis Differences (Unprotected)	$ (484,032)	$ (187,971)	$ (672,003)
	$ (484,032)	$ (187,971)	$ (672,003)
Common (unallocated)			
Other Basis Differences (Unprotected)	$ (276,549)	$ (107,396)	$ (383,945)
	$ (276,549)	$ (107,396)	$ (383,945)

(c) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Gas:		
Avoided Tax Interest	$ 3,543,827	$ 4,066,181
Bad Debts	910,064	921,153
Deferred Connection Fees	12,354,273	11,426,851
Deferred Rent	209,244	195,907
Economic Development Securities - Write-Off	7,754	7,820
Electric Vehicle Credit	588	—
Employee Incentive Plans	322,182	379,396
Employee Retention	1,163	611
Employee Stock Ownership Program Dividends	2,548,291	2,556,097
Environmental Remediation	147,056	64,894
Excess Nonplant Accumulated Deferred Income Taxes	445,839	382,276
Federal Net Operating Loss	1,123,428	27,292
Fuel Tax Credit - Income Addback	1,096	549
Interest Income/Expense on Disputed Tax	—	16,277
Inventory Reserve	54,704	56,281
Litigation Reserve	6,342	—
Lower of Cost or Market on Gas Inventories	313,178	22,585
Medical Deduction - Self Insured	51,198	93,805
Minnesota Net Operating Loss	—	713,267
New Hire Retention Credit	4,612	—
North Dakota Net Operating Loss	—	103
Operating Lease Liabilities	9,543,614	7,814,785
Payroll Tax Deferral	169,494	—
Performance Recognition Awards	10,096	10,690
Post Employment Benefits - Retiree Medical	775,226	673,907
Post Employment Benefits - Long Term Disability	269,568	238,779
Public Utility Conservation Investment Programs	—	3,852
Rate Refund	—	486,870
Regulatory Asset/Liability - Miscellaneous	593,887	294,805
Regulatory Difference - Effect of Rate Changes	(5,327,162)	(5,169,981)
Regulatory Difference - Investment Tax Credit Gross-Up	342,229	299,725
Research and Experimentation Credit	247,500	573,037
Section 174 - Section 59(e) Adjustment	3,148,892	2,649,622
Severance Accrual	2,100	2,222
State Research Credit	49,059	85,416
State Tax Deduction Cash vs. Accrual	8,559	195,123
Vacation Accrual	477,550	516,950
Workers Compensation	14,594	19,729
Total Gas	$ 32,370,045	$ 29,626,876

(d) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Other:		
Avoided Tax Interest	$ 78	$ 84
Contributions Carryover	406,079	—
Deferred Compensation Plan Reserve	4,431,231	3,793,520
Low Income Housing Credit	331	85
Minnesota Alternative Minimum Tax Credit	158,238	155,177
Minnesota Net Operating Loss	26,927,340	43,495
North Dakota Net Operating Loss	151,441	2,651
Nonqualified Pension Plans	241,588	220,402
Other Comprehensive Income	7,951,338	7,172,778
Partnership Passthrough	364,244	363,193
Performance Share Plan	971,740	727,339
Regulatory Difference - Effect of Rate Changes	(15)	(15)
State Tax Deduction Cash vs. Accrual	178,293	176,254
Total Other	$ 41,781,926	$ 12,654,963

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										

5	Total									

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2023-04-07	Year/Period of Report End of: 2022/ 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	4,722,336,684
15.1	Increases (Decreases) due to contribution of capital by parent	172,216,820
16	Ending Balance Amount	4,894,553,504
17	**Historical Data - Other Paid in Capital**	

18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	4,894,553,504

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	[a] 2.15% Aug 15, 2022 First Mortgage Bonds		300,000,000		3,088,686		456,000	08/13/2012	08/15/2022	08/13/2012	08/15/2022		2,490,417
3	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
4	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
5	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
6	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] 24,455,460
7	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
8	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	[d] 16,156,992
9	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
10	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	[e] 18,496,479
11	2.60% May 15, 2023 First Mortgage Bonds		400,000,000		4,524,626		732,000	05/20/2013	05/15/2023	05/20/2013	05/15/2023	400,000,000	10,400,000
12	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

13	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
14	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
15	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
16	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
17	2.60% Jun 1, 2051 First Mortgage Bonds		700,000,000		9,787,023		13,174,000	06/15/2020	06/01/2051	06/15/2020	06/01/2051	700,000,000	18,200,000
18	2.25% Apr 1, 2031 First Mortgage Bonds		425,000,000		5,105,108		1,776,500	03/30/2021	04/01/2031	03/30/2021	04/01/2031	425,000,000	9,562,500
19	3.20% Apr 1, 2052 First Mortgage Bond		425,000,000		6,061,358		1,576,750	03/30/2021	04/01/2052	03/30/2021	04/01/2052	425,000,000	13,600,000
20	[b] 4.50% Jun 1, 2052 First Mortgage Bond		500,000,000		7,499,025		3,605,000	05/09/2022	06/01/2052	05/09/2022	06/01/2052	500,000,000	14,500,000
21	Subtotal		7,350,000,000		95,777,195		59,806,751					7,050,000,000	278,349,348
22	Reacquired Bonds (Account 222)												
23													
24													
25													
26	Subtotal												
27	Advances from Associated Companies (Account 223)												
28													
29													
30													
31	Subtotal												
32	Other Long Term Debt (Account 224)												
33	Right of Way Debt											[f] 2,780,475	228,222
34	Interest on Debt to Associated Companies												[g] 1,427,643
35	Subtotal											2,780,475	1,655,865
33	TOTAL		7,350,000,000									7,052,780,475	280,005,213

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription

NSPMN 2.15% $300MM FMB Retired May 20,2022

(b) Concept: ClassAndSeriesOfObligationCouponRateDescription

Minnesota Public Utilities Commission Docket no. E, G-002/S-21-704. Order dated January 26, 2022.

In May 2022, NSPMN issued $500,000,000 of 4.50 percent First Mortgage Bonds, due June 1, 2052. NSPMN used the net proceeds to finance or refinance, existing and future Eligible Green Expenditures.

(c) Concept: InterestExpenseBonds

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

(d) Concept: InterestExpenseBonds

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

(e) Concept: InterestExpenseBonds

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

(f) Concept: OtherLongTermDebt

	Balance Dec. 31, 2021	Additions	Reductions	Balance Dec. 31, 2022
Right of Way Debt	$3,227,041	$85,598	$(532,164)	$2,780,475

(g) Concept: InterestExpenseOtherLongTermDebt

Xcel Energy Service Inc	$	1,427,007
Money Pool		636
	$	1,427,643

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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)	674,768,340
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		[(a)]53,533,000
9	Deductions Recorded on Books Not Deducted for Return	
10		[(b)]1,807,556,224
14	Income Recorded on Books Not Included in Return	
15		[(c)](126,265,068)
19	Deductions on Return Not Charged Against Book Income	
20		[(d)](1,771,490,487)
21	Equity in Earnings of Subsidiary Companies	(374,992)
22	Total Income Tax Expense	(111,819,142)
27	Federal Tax Net Income	525,907,875
28	Show Computation of Tax:	
29	Federal Income Tax at 21 percent	110,440,654
30	Other	(32,559,739)
31	Total Federal Income Tax Payable	[(e)]77,880,915

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: TaxableIncomeNotReportedOnBooks

TAXABLE INCOME NOT REPORTED ON BOOKS:		
Contributions in Aid of Construction	$	53,533,000
	$	53,533,000

(b) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

DEDUCTIONS RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:		
Avoided Cost Interest	$	25,717,374
Bad Debts		171,632
Book Amortization - Acquisition Adjustments		14,976
Book Amortization - Computer Software		81,940,537
Book Amortization - Other		18,138,786
Book Depreciation		852,034,555
Book Income - Wisconsin/South Dakota Allowance for Funds During Construction		51,000
Book Unamortized Cost of Reacquired Debt		1,298,656
Capitalization of Software Expense - Books		73,476
Clearing Account Book Expense		23,380,408
Deferred Fuel Costs		152,272,660
Deferred Revenue		604,795
Electric Vehicle Charging Tariff		622,897
Employee Incentive Plans		1,579,274
Employee Retention		9,579
Employee Stock Ownership Plan Dividends		1,455,674
Environmental Remediation		4,653,100
Executive Officer Nondeductible Compensation		645,880
Gain/(Loss) on Dispositions (Book)		235,000
Interest Expense - Capital Leases		295,803
Interest Income/Expense on Disputed Tax		1,823,665
Inventory Reserve		6,429
Lobbying Expenses		1,734,000
Mark to Market Adjustment		3,866,306
Medical Deduction - Self Insured		350,276
Meals & Entertainment		1,000,000
Nuclear Decommissioning		34,355,950
Nuclear Fuel Expense		117,938,541
Operating Lease Assets		88,915,191
Pension Expense		20,445,282
Performance Recognition Awards		407
Prairie Island Extended Power Uprate Writedown Amortization		3,852,547
Prepaid Insurance		9,691,681
Public Utility Conservation Investments Programs Adjustment		45,448,464
Rate Case/Restructuring Expense		406,547
Rate Refund		59,005,876
Rate Surcharge		59,845,766
Regulatory Asset - Nuclear Refueling Outage Costs		11,249,099
Regulatory Asset - Property Tax		278,091
Regulatory Asset/Liability Cancellation		4,326,641
Regulatory Asset - Miscellaneous		26,067,762
Regulatory Asset/Liability - Renewable Energy Standard Rider		134,642,405
Regulatory Asset/Liability - Windsource		10,163,729
Regulatory Reserve - Environmental		359,396
Renewable Energy Standard/Credit		80,418
Solar Rewards Program		5,563,124
Suite and Entertainment Tickets		285,000
Vacation Accrual		481,909
Workers Compensation		175,660
	$	1,807,556,224

(c) Concept: IncomeRecordedOnBooksNotIncludedInReturn

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:		
Allowance for Funds During Construction - Equity (Non-Conservation Improvement Program)	$	(35,937,080)
Deferred Revenue - Investment Tax Credit Grant		(68,945)
Insurance Fund Income (Cash Value)		(1,065,707)
Operating Lease Liabilities		(88,922,911)
Penalties		(270,425)
	$	(126,265,068)

(d) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:		
Allowance for Funds During Construction - Debt (Non-Conservation Improvement Program)	$	(14,074,227)
Contributions Carryover		(631,247)
Deferred Compensation Plan Reserve		(2,245,816)
Deferred Rent		(804,866)
External Qualified Nuclear Decommissioning Fund		(34,355,950)
Gain/(Loss) on Dispositions (Tax)		(258,110)
Internally Developed Software		(438,000)
Litigation Reserve		(325,000)
Luverne Batteries		(668,658)
Net Operating Loss		(105,898,409)
Nonqualified Pension Plan		(73,886)
Payroll Tax Deferral		(8,860,624)
Pension and Benefit Capitalized		(3,628,549)
Performance Share Plan		(866,280)
Post Employment Benefits - Long Term Disability		(1,899,155)
Post Employment Benefits - Retiree Medical		(5,984,684)
Prepaid Advertising		(330,389)
Regulatory Asset - Gas Safety Deferrals		(9,575,285)
Regulatory Asset/Liability - Transmission Attach O		(103,242)
Regulatory Asset/Liability - Transmission Cost Recovery Rider		(3,314,947)
Repair Expenditures		(60,100,000)
Section 174		(4,700,000)
Section 174 - Section 59(e) Adjustment		(36,475,026)
State Tax Deduction		(12,159,989)
South Dakota Infrastructure Tracker		(412,817)
Tax Amortization - Monticello Rerate		(6,295,644)
Tax Amortization - Computer Software		(71,433,055)
Tax Depreciation		(1,257,264,295)
Tax Expense - Spent Fuel Isolation Devices		(20,766,916)
Tax Removal Cost Over Book		(107,545,421)
	$	(1,771,490,487)

(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 2022. The other members of the affiliated group and the federal income tax provision of each are:

Xcel Energy Inc.	(83,690,118)
NSP Nuclear Corporation	(2,456)
United Power and Land Company	116,281
Northern States Power Company (Wisconsin) and Subsidiaries	29,277,701
Public Service Company of Colorado and Subsidiaries	40,477,971
Southwestern Public Service Company	(64,284,979)
Nicollet Holdings Company, LLC and Subsidiaries	517,287
Nicollet Project Holdings LLC and Subsidiaries	(1,129,535)
Xcel Energy Communications Group Inc. and Subsidiaries	(18,727)
Xcel Energy Markets Holdings Inc. and Subsidiaries	(304,101)
Xcel Energy International Inc.	249
Xcel Energy Nuclear Services, Inc.	(16,237)
Xcel Energy Retail Holdings Inc. and Subsidiaries	7,718
Xcel Energy Transmission Holding Company, LLC and Subsidiaries	(65,476)
Xcel Energy Ventures Inc. and Subsidiaries	(373,430)
Xcel Energy Venture Holdings, Inc. and Subsidiaries	1,373,038
Xcel Energy Wholesale Group Inc. and Subsidiaries	84,248
Xcel Energy WYCO Inc.	4,749,250
WestGas Interstate, Inc.	13,263
Xcel Energy Services Inc.	4,825,139

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: 04/07/2023	Year/Period of Report End of: 2022/ 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			5,648,154		70,406,669	87,778,232	[d]11,723,409			37,298,691			[l]33,107,978
2	Income Tax Adjustment	Federal Tax					7,474,246		[e](7,474,246)			7,360,311			[m]113,935
3	FICA	Federal Tax		2021	10,398,552			10,398,552							
4	FICA	Federal Tax		2022			35,485,534	32,476,170		3,009,364		26,668,834			[n]8,816,700
5	Unemployment	Federal Tax		2021	5,472			5,472							
6	Unemployment	Federal Tax		2022			189,268	181,986		7,282		151,041			[o]38,227
7	**Subtotal Federal Tax**				16,052,178		113,555,717	130,840,412	4,249,163	3,016,646		71,478,877			42,076,840
8	Income	State Tax	Minnesota		541,567		25,882,862	12,332,140	[f](2,006,514)	12,085,775		47,344,225			[p](21,461,363)
9	Income Tax Adjustment	State Tax	Minnesota				(261,294)		[g]261,294			(269,994)			[q]8,700
10	Unemployment	State Tax	Minnesota	2021	143,484			143,484							
11	Unemployment	State Tax	Minnesota	2022			3,371,705	3,371,705				1,920,221			[r]1,451,484
12	Property Tax	State Tax	Minnesota	2021	213,551,061		(4,647,927)	208,903,134				(4,223,404)			[s](424,523)
13	Property Tax	State Tax	Minnesota	2022			218,160,000			218,160,000		197,766,000			[t]20,394,000
14	Property Tax MN Settlement	State Tax	Minnesota	2022			17,329,512		(17,329,512)			17,329,512			
15	Income	State Tax	North Dakota		4,445		(612)	(186,887)	[h](6,002)	184,718		(85,379)			[u]84,767
16	Income Tax Adjustment	State Tax	North Dakota				144		[i](144)						[v]144
17	Unemployment	State Tax	North Dakota	2021	1,300			1,300							

18	Unemployment	State Tax	North Dakota	2022			25,811	25,004		807		13,061			(w)12,750
19	Property Tax	State Tax	North Dakota	2021	6,906,000		82,757	6,988,757				57,079			(x)25,678
20	Property Tax	State Tax	North Dakota	2022			7,290,000	25,518		7,264,482		5,961,600			(y)1,328,400
21	Unemployment	State Tax	South Dakota	2021	133			133							
22	Unemployment	State Tax	South Dakota	2022			23,636	23,544		92		11,961			(z)11,675
23	Property Tax	State Tax	South Dakota	2021	4,890,000		(151,105)	4,738,895				(151,105)			
24	Property Tax	State Tax	South Dakota	2022			6,378,000			6,378,000		6,378,000			
25	(a) Personal Property FCA	State Tax	South Dakota	2022			540,040	540,040				540,040			
26	Personal Property	State Tax	Kansas	2022			1,034,672	1,034,672							(aa)1,034,672
27	Income	State Tax	Wisconsin	2022			(46,386)	(94,032)	(j)(47,646)			(46,015)			(ab)(371)
28	Unemployment	State Tax	Wisconsin	2022	(476)		5,703	5,227				2,886			(ac)2,817
29	Income	State Tax	Texas		220		315,283	108,768	(k)24,531	231,266		369,645			(ad)(54,362)
30	Unemployment	State Tax	Georgia	2022			15	8		7		8			(ae)7
31	Unemployment	State Tax	Colorado	2022			20			20		10			(af)10
32	**Subtotal State Tax**				226,037,734		275,332,836	237,961,410	(19,103,993)	244,305,167		272,918,351			2,414,485
33	Denver Occ'l Privilege	Other Taxes		2022								12,346			(ag)(12,346)
34	Miscellaneous Income	Other Taxes		2022											
35	(b) Property Tax on Rail Car	Other Taxes		2021	4,800		(1,332)	3,468							(ah)(1,332)
36	(c) Property Tax on Rail Car	Other Taxes		2022			4,800			4,800					(ai)4,800
37	Other	Other Taxes		2022			205,701	205,701				192,635			(aj)13,066
38	Use	Other Taxes		2022	1,381,226		16,047,054	15,690,548		1,737,732					(ak)16,047,054
39	**Subtotal Other Tax**				1,386,026		16,256,223	15,899,717		1,742,532		204,981			16,051,242
40	TOTAL				243,475,938		405,144,776	384,701,539	(14,854,830)	249,064,345		344,602,209			60,542,567

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfTaxesAccruedPrepaidAndCharged

South Dakota Personal Property Tax collected through the Fuel Clause Adjustment. See page 232.

(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)	$	(246,285)
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (211)		340,876
Federal income tax benefit (accrual and cash) in other accounts receivable (143)		1,885,686
Federal income tax receivable on carryback claim (143)		9,743,133
Rounding		(1)
Total	$	11,723,409

(e) Concept: TaxAdjustments

Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (186)	$	43,977
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)		(8,741,607)
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)		1,223,384
Total	$	(7,474,246)

(f) Concept: TaxAdjustments

Annual allocation of unitary benefit/detriment for Minnesota income taxes accrued as additional paid in capital (211)	$	(1,602,603)
State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)		(387,970)
State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)		(15,941)
Total	$	(2,006,514)

(g) Concept: TaxAdjustments

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (186)	$	18,068
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)		778,923
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)		(535,697)
Total	$	261,294

(h) Concept: TaxAdjustments

Annual allocation of unitary benefit/detriment for North Dakota income taxes accrued as additional paid in capital (211)	$	2,499
State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)		(8,502)
Rounding		1
Total	$	(6,002)

(i) Concept: TaxAdjustments

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (186)	$	414
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)		(1,451)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)		893
Total	$	(144)

(j) Concept: TaxAdjustments

Annual allocation of unitary benefit/detriment for Wisconsin income tax accrued as additional paid in capital (211)	$	(47,646)

(k) Concept: TaxAdjustments

Annual allocation of unitary benefit/detriment for Texas income taxes accrued as additional paid in capital (211)	$	24,531
Total	$	24,531

(l) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	25,667,290
Other income and deductions (Account No. 409.2)		7,440,688
Total	$	33,107,978

(m) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	113,935
Total	$	113,935

(n) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	2,709,305
Other income and deductions (Account No. 408.2)		250,549
Other		5,856,846
Total	$	8,816,700

(o) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	15,351
Other income and deductions (Account No. 408.2)		1,497
Other		21,379
Total	$	38,227

(p) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	12,564,912
Other income and deductions (Account No. 409.2)		(34,026,275)
Total	$	(21,461,363)

(q) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	16,100
Other income and deductions (Account No. 409.2)		(7,400)
Total	$	8,700

(r) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	194,688
Other income and deductions (Account No. 408.2)		12,578
Other		1,244,218
Total	$	1,451,484

(s) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	(423,101)
Other income and deductions (Account No. 408.2)		(1,422)
Total	$	(424,523)

(t) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	20,328,000
Other income and deductions (Account No. 408.2)		66,000
Total	$	20,394,000

(u) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	271,970
Other income and deductions (Account No. 409.2)		(187,203)
Total	$	84,767

(v) Concept: TaxesIncurredOther

Other income and deductions (Account No. 409.2)	$	144

(w) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	1,324
Other income and deductions (Account No. 408.2)		66
Other		11,360
Total	$	12,750

(x) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	25,678

(y) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	1,328,400

(z) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	1,211
Other income and deductions (Account No. 408.2)		61
Other		10,403
Total	$	11,675

(aa) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	1,034,672

(ab) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	2
Other income and deductions (Account No. 408.2)		(373)
Total	$	(371)

(ac) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	291
Other income and deductions (Account No. 408.2)		15
Other		2,511
Total	$	2,817

(ad) Concept: TaxesIncurredOther

Gas (Account No. 409.1)	$	(26,894)
Other income and deductions (Account No. 409.2)		(27,468)
Total	$	(54,362)

(ae) Concept: TaxesIncurredOther

Other	$	7

(af) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	1
Other		9
Total	$	10

(ag) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	1,262
Other income and deductions (Account No. 408.2)		226
Other		(13,834)
Total	$	(12,346)

(ah) Concept: TaxesIncurredOther

Other	$	(1,332)

(ai) Concept: TaxesIncurredOther

Other	$	4,800

(aj) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	13,066

(ak) Concept: TaxesIncurredOther

Gas (Account No. 408.1)	$	—
Other	$	16,047,054
Total	$	16,047,054

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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%	38,224			411.4	4,718		33,506	56 Years	
4	7%									
5	10%	14,658,301			411.4	1,207,451		13,450,850	52 Years	
6	30%	1,187,206			411.4	97,312		1,089,894	21 Years	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	15,883,731				1,309,481		[(a)] 14,574,250		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
11	Gas Utility									
12	4%	1,362			411.4	63		1,299	70 Years	
13	10%	870,870			411.4	106,293		764,577	50 Years	
14	TOTAL Gas Utility	872,232				106,356		765,876		
15	Common Utility									
16	4%	2,163			411.4	756		1,407	50 Years	
17	10%	73,408			411.4	6,565		66,843	50 Years	
18	TOTAL Common Utility	75,571				7,321		[(b)] 68,250		

47	OTHER TOTAL									
48	GRAND TOTAL	16,831,534				1,423,158		15,408,376		

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 - 91.95%	$	63,909
Gas - 8.05%		4,341
	$	68,250

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	231,095	232	203,023		28,072
2	Customer Prepayments	90,000	107	533,890	638,890	195,000
3	Deferred Compensation - Employees	11,251,752	131	2,705,847	1,367,105	9,913,010
4	Deferred Compensation - Employees (Wealth Op)	4,556,009	232	952,932	45,857	3,648,934
5	401 Nicollet Lease Credit	7,073,702	101	757,896		6,315,806
6	Deferred Revenue	1,942,085	(b) Various	1,089,430	1,694,225	2,546,880
7	Deferred Revenue-ITC Grant - Amortized over plant lives	901,371	405	68,945		832,426
8	Environmental & Regulatory Reserves	2,229,125	242	2,050,204	2,231,659	2,410,580
9	Executive PSP - Long Term	1,063,542	232	1,063,564	502,071	502,049
10	FERC Hydro Assessments	13,753	242	45,846	32,093	
11	Laurentian Biomass PPA Termination	18,083,335	182.3	18,083,335		
12	Long-Term Income Tax & Interest Payable	12,788,215	236	398,481	85,845	12,475,579
13	Unfunded Nonqualified Pension Benefit Costs	2,324,097	232	694,083	156,083	1,786,097
14	Nuclear Waste Strategy Coalition	55,714	232	26,863	10,000	38,851
15	Postemployment Benefit-Injury Compensation	11,675,378	(c) Various	1,899,155		9,776,223
16	Pre-Funded AFUDC: Metro Emissions Reduction Rider	47,874,126	405	2,236,181		45,637,945
17	Pre-Funded AFUDC: Mercury Emission Reduction Rider	272,735	405	26,942		245,793

18	Pre-Funded AFUDC: Minnesota Transmission Cost Recovery Rider	37,803,443	[(d)] Various	1,408,083	648,186	37,043,546
19	Pre-Funded AFUDC: FERC Transmission	37,048,630	405	[(e)] 670,116	[(f)] 0	36,378,514
20	Pre-Funded AFUDC: Renewable Energy Standards Rider	92,545,053	405	4,265,834	12,446,005	100,725,224
21	Pre-Funded AFUDC: South Dakota Transmission Cost Recovery Rider	2,063,367				2,063,367
22	Pre-Funded AFUDC: North Dakota Transmission Cost Recovery Rider	1,608,469				1,608,469
23	Coal Car Residual Value Deficit	3,657,379	151	75,320		3,582,059
24	Renewable Development Fund Obligations	34,428,034	232	27,336,675	35,500,000	42,591,359
25	Security Deposits	1,500				1,500
26	Shared Network Upgrade	993,807	565	14,265		979,542
27	[(a)] **Footnote from page 106b					
47	TOTAL	332,575,716		66,606,910	55,358,019	321,326,825

(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	$	496,747
456		592,683
Total	$	1,089,430

(c) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:		
131	$	1,192,046
232		707,109
Total	$	1,899,155

(d) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:		
405	$	26,942
419.1		98,906
432		41,561
Total	$	167,409

(e) Concept: DecreaseInOtherDeferredCredits

The amount reported for Pre-funded AFUDC-FERC Transmission is a jurisdictional amount. For purposes of calculating the Midcontinent ISO Formula Rate under Attachment O of the Northern States Power Companies FERC Tariff, a total company unjurisdictionalized amortization expense (405) amount is $1,011,056.

(f) Concept: IncreaseInOtherDeferredCredits

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

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	22,089,096	(2,055,634)								[(a)] 20,033,462
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	22,089,096	(2,055,634)								[(b)] 20,033,462
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)	22,089,096	(2,055,634)								20,033,462
18	Classification of TOTAL										
19	Federal Income Tax	17,206,572	(1,592,321)								15,614,251
20	State Income Tax	4,882,524	(463,313)								4,419,211
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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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 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)	ADJUSTMENTS Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	2,510,026,292	95,054,276				182.3, 254	110,227,605	182.3, 254	51,268,711	[(a)] 2,546,121,674
3	Gas	153,881,315	4,411,887				182.3, 254	140,616	182.3, 254	3,568,014	161,720,600
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	2,663,907,607	99,466,163					110,368,221		54,836,725	2,707,842,274
6	Other (Non-Operating)	(35,139)			307,572						272,433
9	TOTAL Account 282 (Total of Lines 5 thru 8)	2,663,872,468	99,466,163		307,572			110,368,221		54,836,725	2,708,114,707
10	Classification of TOTAL										
11	Federal Income Tax	1,806,761,240	51,500,467		210,618			70,859,422		54,387,332	1,842,000,235
12	State Income Tax	857,111,228	47,965,696		96,953			39,508,799		449,393	866,114,471
13	Local Income Tax										

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

	Dec. 31, 2021	410.1 & Adjustments	Dec. 31, 2022
Decommissioning Nonqualified	$ —	$ —	$ —
Electric Distribution Plant	809,464,250	(3,470,839)	805,993,411

Electric General Plant	79,870,709	1,110,229	80,980,938
Electric Intangible Plant	7,149,663	(1,030,548)	6,119,115
Electric Nuclear Fuel	19,049,335	(1,511,647)	17,537,688
Electric Nuclear Production Plant	536,825,275	(33,724,999)	503,100,276
Electric Production Plant	888,208,830	105,493,372	993,702,202
Electric Transmission Plant	890,594,894	20,620,397	911,215,291
Electric Transmission-Production Plant	19,293,349	5,629,665	24,923,014
Common (Allocation to Electric)	34,539,530	1,938,645	36,478,175
Regulatory Differences - Prior Flow Thru / Rate Change	(1,243,060,221)	50,635,386	(1,192,424,835)
Regulatory Differences - AFUDC Equity	107,861,396	(1,755,287)	106,106,109
Decommissioning Qualified	360,229,282	(107,838,992)	252,390,290
Total Electric Plant Related Only	$ 2,510,026,292	$ 36,095,382	$ 2,546,121,674

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 $45,942,238 for 2021 and $41,156,507 for 2022.

	2021 ARAM	2022 ARAM
Protected ARAM:		
Decommissioning	$ —	$ —
Electric Distribution Plant	4,099,198	4,664,039
Electric General Plant	2,669,382	2,794,314
Electric Intangible Plant	69,909	76,419
Electric Nuclear Fuel	2,246,548	339,415
Electric Production Plant	18,816,459	17,191,693
Electric Transmission Plant	1,443,703	1,394,250
Electric Transmission-Production Plant	48,046	84,889
Common (Allocation to Electric)	3,540,197	2,918,976
Total Protected ARAM	32,933,442	29,463,995
Unprotected ARAM:		
Decommissioning	—	—
Electric Distribution Plant	3,016,103	2,740,444
Electric General Plant	140,041	100,395
Electric Intangible Plant	323,958	327,641
Electric Nuclear Fuel	119,742	45,565
Electric Production Plant	7,584,083	6,903,403
Electric Transmission Plant	1,501,240	1,276,051
Electric Transmission-Production Plant	4,844	9,032
Common (Allocation to Electric)	318,652	289,458
Total Unprotected ARAM	13,008,663	11,691,989
Non Utility	133	523
Total Electric	$ 45,942,238	$ 41,156,507

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

Common (Unallocated)	$ 3,839,647	$ 3,536,551

The Flowback of permanent items included above in 410.1 is $8,762,526 for 2021 and $8,893,860 for 2022 for Electric only.

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

	Dec. 31, 2022	Dec. 31, 2022	Dec. 31, 2022
Excess (Electric only)	Excess	Gross up	Total Regulatory
Flow Through	$ (4,082,190)	$ (1,585,298)	$ (5,667,488)
Method Life (Protected)	(710,949,555)	(276,093,791)	(987,043,346)
Other Basis Differences (Unprotected)	(143,850,400)	(55,863,601)	(199,714,001)
	$ (858,882,145)	$ (333,542,690)	$ (1,192,424,835)

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	$ 99,328	$ 38,573	137,901
Method Life (Protected)	1,565	608	2,173
Other Basis Differences (Unprotected)	—	—	—
	$ 100,893	$ 39,181	$ 140,074
Common (allocated)			
Flow Through	$ 19,427	$ 7,544	$ 26,971
Method Life (Protected)	(7,830,159)	(3,040,804)	(10,870,963)
Other Basis Differences (Unprotected)	(449,479)	(174,553)	(624,032)
	$ (8,260,211)	$ (3,207,813)	$ (11,468,024)
Common (unallocated)			
Flow Through	$ 25,756	$ 10,002	$ 35,758
Method Life (Protected)	(10,381,179)	(4,031,480)	(14,412,659)
Other Basis Differences (Unprotected)	(595,916)	(231,421)	(827,337)
	$ (10,951,339)	$ (4,252,899)	$ (15,204,238)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	48,900,991	(2,573,476)				182.3	85,145	182.3	68	46,242,438 [(a)]
4	Electric - Non-Plant	369,886,424	32,544,336	136,586,828			182.3	9,296,616	182.3	1,684	256,549,000
5											0
9	TOTAL Electric (Total of lines 3 thru 8)	418,787,415	29,970,860	136,586,828				9,381,761		1,752	302,791,438 [(b)]
10	Gas										
11	Gas	103,436,331	6,108,214	38,063,861			182.3	497,489	182.3	69	70,983,264
17	TOTAL Gas (Total of lines 11 thru 16)	103,436,331	6,108,214	38,063,861				497,489		69	70,983,264
18	TOTAL Other	356,272			(226,499)						129,773
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	522,580,018	36,079,074	174,650,689	(226,499)			9,879,250		1,821	373,904,475
20	Classification of TOTAL										
21	Federal Income Tax	360,182,805	25,399,073	118,428,480	(154,548)			8,890,469		124	258,108,505
22	State Income Tax	162,397,213	10,680,001	56,222,209	(71,951)			988,781		1,697	115,795,970
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	$ 145,312	$ (4,476)	$ 140,836
Electric General Plant	627,014	(66,271)	560,743
Electric Intangible Plant	3,506,389	547,377	4,053,766
Electric Nuclear Production Plant	2,424,704	(383,465)	2,041,239
Electric Production Plant	—	—	—
Electric Transmission Plant	(433,279)	159,707	(273,572)
Common (Allocation to Electric)	41,318,507	(2,826,349)	38,492,158
Regulatory Differences - AFUDC Equity	1,312,344	(85,076)	1,227,268
Total Electric Plant Related Only	$ 48,900,991	$ (2,658,553)	$ 46,242,438

(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.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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 Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Deferred Tax Collected in Rates in Excess of Current Tax Accrual Levels	1,231,657,178	282	48,686,557		1,182,970,621
2	Department of Energy Settlement Payment - MN Docket E-002/M-21-062	12,128,236	142	12,122,845	1,208	6,599
3	Derivatives and Hedging - Retail Electric & Gas	29,337,858			26,655,726	55,993,584
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	10,834,958	[(a)] Various	16,677,099	17,445,887	11,603,746
5	Gas Low Income Discount Program - MN Docket G-002/GR-06-1429	3,163,326	[(b)] Various	2,238,735	3,095,074	4,019,665
6	South Dakota Inver Hills Gain Sharing - SD Docket EL 22-017				235,000	235,000
7	ITC Gross-Up to Pre-Tax Rate Levels	6,988,565	190	681,532		6,307,033
8	Minnesota Deferred Property Tax - 2020 - MN Docket E-002/M-19-688	12,542,556	142	12,790,802	248,246	
9	Minnesota Deferred Property Tax - 2021 - MN Docket E-002/GR-20-743	7,492,534			3,857,594	11,350,128
10	Minnesota Deferred Property Tax - 2022 - MN Docket E-002/GR-21-630				13,956,266	13,956,266
11	Minnesota Electric Decoupling - 2022- MN Docket E-002/GR-21-630				21,505,674	21,505,674
12	Minnesota Electric Conservation and Energy Management Program Costs - MN Docket G-002/M-22-158 - Generally amortized over 12 month period following the expenditure	353,912	232	10,484,129	48,096,553	37,966,336

13	Minnesota Gas Conservation and Energy Management Program Costs - MN Docket G-002/M-22-160 - Generally amortized over 12 month period following the expenditure	347,478	232	7,652,597	10,950,350	3,645,231
14	Minnesota Gas Rate Case Deferral - MN Docket G-002/GR-09-1153 - MN Docket G-002/GR-21-678 - Amortized through 2024	3,183,270	928	1,030,646	91,230	2,243,854
15	Minnesota Gas State Energy Policy Rider - MN Docket G-002/M-21-151	62,569			6,183	68,752
16	Minnesota Incentive Compensation Refund- MN Docket E-002/M-22-254	3,733,807	407.3	2,139,795	1,715,138	3,309,150
17	Minnesota Service Quality Program - MN Docket E,G-002/CI-02-2034 - MN Docket E,G-002/M-12-383	1,700,210	456	1,749,479	799,271	750,002
18	Minnesota Transmission Cost Recovery Rider - MN Docket E-002/GR-21-814	3,534,941	407.3	84,645,628	85,258,592	4,147,905
19	Nonplant Excess ADIT	29,661,862	190	6,475,480	425	[g]23,186,807
20	North Dakota Deferred Electric Commodity Costs - ND Docket PU-22-012				4,110,448	4,110,448
21	North Dakota Earnings Sharing - ND Docket PU-20-441 - ND Docket PU-21-160	7,740,150	142	25,584	5,992,914	13,707,480
22	North Dakota ITC	11,756,499	410.1	1,363,427		10,393,072
23	North Dakota Production Tax Credit Levelization - ND Docket PU-20-426 - ND Docket PU-20-441	10,133,407			8,379,749	18,513,156
24	North Dakota Renewable Energy Rider - ND Docket PU-22-368	1,461,672	407.4	287,866		1,173,806
25	North Dakota Retail Asset and Non-Asset Margin Sharing - ND Docket PU-10-657	6,170,486	557	10,207,752	11,608,607	7,571,341
26	North Dakota Transmission Cost Recovery Rider - ND Docket PU-22-402				563,879	563,879
27	Power Purchase Agreement	798,081	174	266,028	3	532,056
28	Pre-ARO Decommissioning	1,935,952,366			13,446,664	1,949,399,030
29	Renewable*Connect Classic - MN Docket E-002/GR-22-161		[c] Various	2,862,104	3,888,082	1,025,978
30	Renewable*Connect Government - MN Docket E-002/GR-22-161		555	179,750	279,031	99,281
31	Residential Payment Plan Credit Program - MN Docket E-002/M-20-760	5,296,687	142	3,540,198		1,756,489

32	South Dakota Deferred Electric Commodity Costs - SD Docket EL 14-058 - SD Docket EL 22-017	2,923,378	557	73,136,070	78,339,059	8,126,367
33	South Dakota Electric Conservation and Energy Management Program Costs - SD Docket EL 22-010 - Generally amortized over 12 month period following the expenditure				24,974	24,974
34	South Dakota Infrastructure - SD Docket EL 22-026	2,574,928	407.4	412,817		2,162,111
35	South Dakota Production Tax Credit Sharing - SD Docket EL 14-058 - SD Docket EL 22-017	2,664,792	557	15,373,446	16,109,572	3,400,918
36	South Dakota Property Tax Collected in the Fuel Clause Adjustment - SD Docket EL 14-058 - SD Docket EL 22-017				261,949	261,949
37	South Dakota Retail Asset and Non-Asset Margin Sharing - SD Docket EL 14-058 - SD Docket EL 22-017	2,274,206	557	10,480,137	10,676,592	2,470,661
38	South Dakota Transmission Cost Recovery Rider - SD Docket EL 22-022	1,044,368	407.4	665,842		378,526
39	Transmission Formula Rates	10,398,654	456	6,140,806	10,222,283	14,480,131
40	Unrealized Gains on Decommissioning Trust	933,697,743	128	279,513,709		654,184,034
41	Windsource - MN Docket E-002/M-01-1479 - MN Docket E-002/GR-13-868	4,059,144	(d) Various	18,440,694	18,024,630	3,643,080
41	TOTAL	4,295,669,821		630,271,554	415,846,853	4,081,245,120

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Accounts charged:		
142	$	16,133,756
232		543,343
Total	$	16,677,099

(b) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

142	$	2,143,896
232		94,839
Total	$	2,238,735

(c) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Accounts charged:		
555	$	2,829,793
912		32,311
Total	$	2,862,104

(d) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Accounts charged:		
142	$	29
555		18,153,325
921		287,340
Total	$	18,440,694

(e) Concept: OtherRegulatoryLiabilities

	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Total
Electric	$ 15,716,667	$ 6,103,491	$ 21,820,158
Gas	984,373	382,276	1,366,649
Total	$ 16,701,040	$ 6,485,767	$ 23,186,807

*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 12/31/2021	Amortization 2022	Excess Balance 12/31/2022
Book Unamortized Cost of Reaquired Debt	$ 476,138	$ (476,138)	$ —
Deferred Fuel Costs	116,134	(116,134)	—
Electric Vehicle Charging Tariff	4,634	(4,634)	—
Employee Retention	2,629	(2,629)	—
Interest Income/Expense on Disputed Tax	46,718	(46,718)	—
Low Income Discount Program	4,124	(4,124)	—
Mark to Market Adjustment	262,718	(262,718)	—
Nuclear Refueling	1,757,146	(1,757,146)	—
Partnership Passthrough	31,788	(31,788)	—
Pension Expense	16,621,118	(1,511,011)	15,110,107
Prepaid Insurance	507,996	(507,996)	—
Property Tax - LT Total	416,720	(416,720)	—
Public Utility Conservation Investment Programs	1,623,566	(1,623,566)	—
Rate Case / Restructuring Expense	93,157	(93,157)	—
Rate Surcharge	1,285,601	(1,285,601)	—
Renewable Energy Standard/Credit	720	(720)	—
Transmission Attachment O	42,098	(42,098)	—
State Tax Deduction Cash vs Accrual	105,319	(105,319)	—
Windsource	6,163	(6,163)	—
Total Electric	$ 23,404,487	$ (8,294,380)	$ 15,110,107

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

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	1,629,315,036	1,486,050,261	10,721,559	10,846,862	1,368,821	1,353,504
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	1,864,063,304	1,607,362,856	14,505,025	14,170,236	161,184	160,691
5	Large (or Ind.) (See Instr. 4)	[(a)]809,170,472	[(f)]709,762,530	7,972,062	7,921,431	540	549
6	(444) Public Street and Highway Lighting	30,373,968	25,208,248	113,345	113,332	6,560	6,386
7	(445) Other Sales to Public Authorities	11,165,510	9,982,991	79,606	80,587	1,602	1,616
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales	574,363	403,692	4,685	3,359		
10	TOTAL Sales to Ultimate Consumers	4,344,662,653	3,838,770,578	33,396,282	33,135,807	1,538,707	1,522,746
11	(447) Sales for Resale	369,903,563	291,393,346	16,157,437	15,696,940		
12	TOTAL Sales of Electricity	4,714,566,216	4,130,163,924	49,553,719	48,832,747	1,538,707	1,522,746
13	(Less) (449.1) Provision for Rate Refunds	51,100,032	[(g)](1,720,403)				

14	TOTAL Revenues Before Prov. for Refunds	4,663,466,184	4,131,884,327	49,553,719	48,832,747	1,538,707	1,522,746
15	Other Operating Revenues						
16	(450) Forfeited Discounts	5,589,366	606,228				
17	(451) Miscellaneous Service Revenues	[(b)]2,593,982	[(h)]2,456,276				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	[(c)]5,594,594	5,630,823				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[(d)]466,480,169	[(i)]443,892,912				
22	(456.1) Revenues from Transmission of Electricity of Others	[(e)]335,474,916	[(j)]302,783,596				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	815,733,027	755,369,835				
27	TOTAL Electric Operating Revenues	5,479,199,211	4,887,254,162				

Line12, column (b) includes $ 28,165,050 of unbilled revenues.
Line12, column (d) includes 41,231 MWH relating to unbilled revenues

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FOOTNOTE DATA

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

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

(b) Concept: MiscellaneousServiceRevenues

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

(c) Concept: RentFromElectricProperty

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

(d) Concept: OtherElectricRevenue

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

Fixed Production Expense	$	236,163,196
Variable Production Expense		216,631,126
Total Interchange Agreement	$	452,794,322

Also includes the following items:

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

*Represents reclass between FERC 440-448 and FERC 456

(e) Concept: RevenuesFromTransmissionOfElectricityOfOthers

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

(f) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

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

(g) Concept: ProvisionForRateRefunds

Credit balance due to accrual reversal.

(h) Concept: MiscellaneousServiceRevenues

Connection charges	$	2,138,326
NSF Check Fees		289,875
Other, less than $250,000 each		28,075
	$	2,456,276

(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	$	241,617,825
Variable Production Expense		197,336,757
Total Interchange Agreement	$	438,954,582

Also includes the following items:

Windsource Program	$	11,534,411
Fees charged to burn Refuse Derived Fuel		7,565,926
Renewable*Connect		7,513,399
Conservation Improvement Program incentive, net of accruals and recoveries		6,603,510
Distribution Facility Fixed Charges		720,877
Purchased Power Reimbursement		680,943
Manitoba Hydro Energy Service Agreement		470,732
Solar Gardens-Subscribed		419,500
Energy Services		324,652
Facilities Agreement		324,527
Transmission Owner's Interconnection Facilities (TOIF) Billings		269,850
Work on Customers' Equipment		220,847
Change in net over-recovered electric commodity costs		71,488
Solar Energy Standard Exclusion		(822,045)
Service Quality Plans		(1,908,399)
Low Income Funding Pursuant to Docket CI-17-895		(2,000,000)
North Dakota Earnings Test		(7,740,150)
Net distribution of commodity trading margins under Joint Operating Agreement		(19,763,726)
Other less than $250,000 each		451,988
	$	443,892,912

(j) Concept: RevenuesFromTransmissionOfElectricityOfOthers

Includes $62,383,262 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: 04/07/2023	Year/Period of Report End of: 2022/ 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)
1	Residential Sales					
2	Minnesota					
3	A00 Water Heating	130	18,418	37	3,514	0.1417
4	A01 Residential	5,048,752	791,426,921	777,744	6,492	0.1568
5	A02 Residential Time of Day	5,407	744,032	473	11,431	0.1376
6	A03 Residential Underground	3,878,606	596,585,375	407,790	9,511	0.1538
7	A04 Residential TOD Underground	6,525	907,468	452	14,436	0.1391
8	A05 Energy Control	39,177	3,605,109	3,130	12,517	0.0920
9	A06 Limited Off Peak	2,720	279,853	362	7,514	0.1029
10	A07 Auto Protective Lighting	5,236	1,259,106			0.2405
11	A08 Residential Electric Vehicle	5,033	572,418			0.1137
12	A72 Resid TOU Pilot-Overhead	31,520	5,001,571	5,621	5,608	0.1587
13	A74 Resid TOU Pilot-Underground	31,945	5,018,885	3,513	9,093	0.1571
14	A80 Resid EV Pilot Bundled	2,960	408,881			0.1381
15	A81 Resid EV Pilot Pre-Pay	1,447	380,739			0.2631
16	A82 Resid EV Pilot Bundled Subs	558	62,246			0.1116
17	A83 Resid EV Pilot Pre-Pay Subs	99	8,420			0.0851

18	Unbilled-MN-Residential Sales	35,368	12,739,974			0.3602
19	North Dakota					
20	D01 Residential	615,429	78,508,525	68,843	8,940	0.1276
21	D02 Residential Time of Day	874	95,445	30	29,133	0.1092
22	D03 Residential Underground	171,271	20,749,469	12,853	13,325	0.1211
23	D04 Residential TOD Underground	127	14,126	8	15,875	0.1112
24	D05 Energy Control	3,539	320,853	290	12,203	0.0907
25	D10 Limited Off Peak	726	60,692	97	7,485	0.0836
26	D11 Auto Protective Lighting	311	62,774			0.2018
27	Unbilled-ND-Residential Sales	3,745	706,708			0.1887
28	South Dakota					
29	E01 Residential	354,072	47,384,486	46,359	7,638	0.1338
30	E02 Residential Time of Day	106	12,599	9	11,778	0.1189
31	E03 Residential Underground	467,574	61,422,787	40,996	11,405	0.1314
32	E04 Residential Time of Day	150	18,677	10	15,000	0.1245
33	E06 Residential Heat Pump	1,747	170,869	100	17,470	0.0978
34	E10 Energy Control	1,268	108,604	103	12,311	0.0856
35	E11 Limited Off Peak	8	598	1	8,000	0.0748
36	E12 Auto Protective Lighting	322	63,375			0.1968
37	Unbilled-SD-Residential Sales	4,807	595,033			0.1238
41	TOTAL Billed Residential Sales	10,677,639	1,615,273,321	1,368,821	7,801	0.1513
42	TOTAL Unbilled Rev. (See Instr. 6)	43,920	14,041,715			0.3197
43	TOTAL	10,721,559	1,629,315,036	1,368,821	7,833	0.1520

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
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41	TOTAL Billed Small or Commercial					
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)					
43	TOTAL Small or Commercial	14,505,025	1,864,063,304	161,184		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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)
1						
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3						
4						
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41	TOTAL Billed Large (or Ind.) Sales					
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)					
43	TOTAL Large (or Ind.)	7,972,062	[a]809,170,472	540		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Minnesota					
2	A05 Energy Control	2,031	211,331	111	18,297	0.1041
3	A06 Limited Off Peak	1,525	206,767	79	19,304	0.1356
4	A07 Auto Protective Lighting	22,519	4,047,578			0.1797
5	A09 Small General Service	25	15,075	100	250	0.6030
6	A10 Small General Service	734,641	117,133,623	76,202	9,641	0.1594
7	A11 Water Heating	202	29,930	73	2,767	0.1482
8	A12 Small General TOD Service	39,487	5,796,192	3,010	13,119	0.1468
9	A13 Direct Current	6	9,213	1	6,000	1.5355
10	A14 General Service	7,700,039	1,038,178,464	42,667	180,468	0.1348
11	A15 General TOD Service	7,642,161	818,217,634	4,972	1,537,040	0.1071
12	A16 Small General kWh metered	16,110	2,628,923	3,120	5,163	0.1632
13	A18 Small General TOD Service	26,919	4,135,039	4,225	6,371	0.1536
14	A22 Small General TOD Low Wattage	1,022	155,475	63	16,222	0.1521
15	A23 Peak Control Tiered	1,028,299	131,369,159	1,306	787,365	0.1278
16	A24 Peak Control Time of Day	2,220,548	223,490,613	319	6,960,966	0.1006
17	A27 Tier 1 Energy Control	247,703	18,287,007	9	27,522,556	0.0738

18	A29 Hiawatha Light Rail	34,300	4,204,561	30	1,143,333	0.1226
19	A62 Firm Real Time Pricing	23,198	2,539,859	3	7,732,667	0.1095
20	A87 - EV Fleet Pilot Service	786	196,709			0.2503
21	Unbilled-MN-Commercial Sales	(2,261)	13,144,822			(5.8137)
22	North Dakota					
23	D05 Energy Control	1,398	124,908	52	26,885	0.0893
24	D10 Limited Off Peak	550	65,725	34	16,176	0.1195
25	D11 Auto Protective Lighting	2,539	381,898	0		0.1504
26	D12 Small General Service	96,135	12,286,901	8,118	11,842	0.1278
27	D14 Small General TOD Service	2,536	302,680	194	13,072	0.1194
28	D16 General Service	672,965	79,252,124	3,901	172,511	0.1178
29	D17 General TOD Service	197,141	19,568,613	201	980,801	0.0993
30	D18 Small General TOD Service	548	73,539	99	5,535	0.1342
31	D19 Small General kWh metered	946	138,604	208	4,548	0.1465
32	D20 Peak Control	30,171	3,377,201	48	628,563	0.1119
33	D21 Peak Control Time of Day	130,841	11,864,634	15	8,722,733	0.0907
34	D22 Tier 1 Energy Control	221,640	19,530,781	64	3,463,125	0.0881
35	D34 Sm General TOD Low Wattage	55	5,792	5	11,000	0.1053
36	Unbilled-ND-Commercial Sales	(754)	492,321			(0.6529)
37	South Dakota					
38	E10 Energy Control	106	9,098	11	9,636	0.0858
39	E11 Limited Off Peak	361	35,949	9	40,111	0.0996
40	E12 Auto Protective Lighting	2,127	359,923	0		0.1692
41	E13 Small General Service	83,158	10,474,111	7,699	10,801	0.1260
42	E14 Small General TOD Service	2,414	306,076	372	6,489	0.1268
43	E15 General Service	678,731	74,170,272	4,043	167,878	0.1093
44	E16 General TOD Service	475,958	42,934,987	251	1,896,247	0.0902
45	E18 Small General TOD Service	5	739	6	833	0.1478

46	E20 Peak Control	56,479	6,398,469	78	724,090	0.1133
47	E21 Peak Control Time of Day	62,695	5,352,040	14	4,478,214	0.0854
48	E22 Energy Control	18,302	1,587,830	12	1,525,167	0.0868
49	Unbilled-SD-Commercial Sales	780	140,587			0.1802
41	TOTAL Billed Commercial and Industrial Sales	22,479,322	[(a)]2,659,456,046	161,724	138,998	0.1183
42	TOTAL Unbilled Rev. (See Instr. 6)	(2,235)	13,777,730			(6.1645)
43	TOTAL	22,477,087	2,673,233,776	161,724	138,984	0.1189

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: CommercialAndIndustrialSalesBilled

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

A00	$	4,462
A01		171,104,668
A02		158,953
A03		132,859,844
A04		207,482
A05		1,344,667
A06		137,116
A07		746,592
A08		166,954
A09		879
A10		25,130,287
A11		7,072
A12		1,362,791
A13		206
A14		263,321,687
A15		247,819,568
A16		559,959
A17		—
A18		944,687
A21		—
A22		34,946
A23		34,784,500
A24		71,694,797
A27		7,896,641
A29		1,133,971
A30		840,086
A32		621,295
A34		911,934
A37		24,414
A40		188,679
A41		1,976,796
A62		761,452
A72		1,019,237
A74		1,077,670
A80		105,249
A81		50,156
A82		334
A83		31
A87		26,204
Minnesota jurisdiction		969,026,266

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:	
D01	$ 20,623,257
D02	29,289
D03	5,735,396
D04	4,249
D05	166,650
D10	43,201
D11	74,098
D12	3,231,616
D14	85,299
D16	22,424,121
D17	6,407,878
D18	18,301
D19	31,606
D20	1,005,901
D21	4,217,533
D22	7,230,297
D30	20,151
D31	256,001
D32	596
D33	67,715
D34	1,818
D40	26,192
D41	446,763
North Dakota jurisdiction	$ 72,147,928
Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:	
E01	$9,004,865
E02	2,639
E03	11,852,731
E04	3,810
E06	43,951
E10	34,370
E11	9,334
E12	45,866
E13	2,094,766
E14	60,144
E15	16,834,548
E16	11,389,749
E18	166
E20	1,388,144
E21	1,505,423
E22	443,786
E30	15,019
E31	55,186
E32	106,080
E33	12,983
South Dakota jurisdiction	$54,903,560
Total Company	$1,096,077,754

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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.
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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	A30 Street Lighting Company Owned	31,393	21,127,162	2,138	14,683	0.6730
3	A32 Street Lighting Customer Owned	23,099	2,115,140	418	55,261	0.0916
4	A34 Street Lighting Metered	34,721	3,185,952	3,215	10,800	0.0918
5	A37 Street Lighting St Paul	907	159,742	1	907,000	0.1761
6	Unbilled-MN-Street Lighting Sales	96	365,760			3.8100
7	North Dakota					
8	D30 Street Lighting Company Owned	776	541,328	61	12,721	0.6976
9	D31 Street Lighting Customer Owned	9,854	965,347	33	298,606	0.0980
10	D32 Street Lighting Ornamental	23	2,091	2	11,500	0.0909
11	D33 Street Lighting Metered	2,619	220,833	152	17,230	0.0843
12	Unbilled-ND-Street Lighting Sales	(32)	14,619			(0.4568)
13	South Dakota					
14	E30 Street Lighting Company Owned	801	789,686	121	6,620	0.9859
15	E31 Street Lighting Customer Owned	2,935	305,463	16	183,438	0.1041
16	E32 Street Lighting Metered	5,691	546,151	313	18,182	0.0960
17	E33 Street Lighting Ornamental	694	66,461	90	7,711	0.0958

18	Unbilled-SD-Street Lighting Sales	(232)	(31,767)			0.1369
41	TOTAL Billed Public Street and Highway Lighting	113,513	30,025,356	6,560	17,304	0.2645
42	TOTAL Unbilled Rev. (See Instr. 6)	(168)	348,612			(2.0751)
43	TOTAL	113,345	30,373,968	6,560	17,278	0.2680

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	A40 Small Municipal Pumping	5,606	890,131	877	6,392	0.1588
3	A41 Municipal Pumping	59,996	8,439,540	571	105,072	0.1407
4	A42 Fire Siren		39,284			
5	Unbilled-MN-Other Sales	(388)	(22,591)			0.0582
6	North Dakota					
7	D40 Small Municipal Pumping	803	102,186	64	12,547	0.1273
8	D41 Municipal Pumping	13,487	1,693,251	90	149,856	0.1255
9	D42 Fire Siren		1,161			
10	Unbilled-ND-Other Sales	102	19,584			0.1920
11	South Dakota					
12	E40 Fire Siren		2,964			
41	TOTAL Billed Other Sales to Public Authorities	79,892	11,168,517	1,602	49,870	0.1398
42	TOTAL Unbilled Rev. (See Instr. 6)	(286)	(3,007)			0.0105
43	TOTAL	79,606	11,165,510	1,602	49,692	0.1403

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	Interdepartmental					
2	Interdepartmental Sales	4,685	574,363			0.1226
41	TOTAL Billed Interdepartmental Sales	4,685	574,363			0.1226
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	4,685	574,363			0.1226

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	(Footnote for Instruction 5)					
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		51,100,032			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	33,355,051	4,316,497,603	1,538,707	21,677	0.1294
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	41,231	28,165,050			0.6831
43	TOTAL - All Accounts	33,396,282	4,344,662,653	1,538,707	21,677	0.1301

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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.

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

			(c)								
1	NSP- Wisconsin	RQ									[b]0
2	Citigroup Energy, Inc.	OS	V6				80,000			5,042,020	[c]5,042,020
3	Citigroup Energy, Inc.	SF	V6				92,800		4,756,317		[d]4,756,317
4	City of Ada, MN	OS	V6				0	48,600			48,600
5	City of Ada, MN	SF	V6				6,268		563,616		563,616
6	City of Ada, MN	AD	V6				0			13,421	[e]13,421
7	City of Kasota, MN	OS	V6				0	24,300			24,300
8	City of Kasota, MN	SF	V6				4,172		249,369		249,369
9	City of Kasota, MN	AD	V6				73			5,646	[f]5,646
10	Dairyland Power Co	AD	V6				0	350,000			[g]350,000
11	Dairyland Power Co	OS	V6				0	687,500			687,500
12	Dahlberg Light and Power Co	OS	V6				10,471	397,160	165,085		562,245
13	Dahlberg Light and Power Co	SF	V6				100,732		6,369,557		6,369,557
14	Dahlberg Light and Power Co	AD	V6				0			66,176	[h]66,176
15	Direct Energy Marketing	SF	V6				2,160		123,957		[i]123,957
16	Direct Energy Marketing	OS	V6				26,158			1,547,192	[j]1,547,192
17	East Texas Electric Cooperative, Inc.	SF	V6				131,400		2,587,266		[k]2,587,266
18	EDF Trading North America, LLC	OS	V6				254,000			20,487,993	[l]20,487,993
19	EDF Trading North America, LLC	SF	V6				23,000		1,866,406		[m]1,866,406
20	Great River Energy	OS	V6				0	(750,000)		1,800,000	[n]1,050,000
21	Great River Energy	SF	V6				42,800		1,305,740		[o]1,305,740
22	J. Aron & Company LLC	SF	V6				8,400		831,617		[p]831,617
23	J. Aron & Company LLC	OS	V6				93,600			9,179,665	[q]9,179,665
24	ICE NGX Canada Inc	OS	V6				108,400			11,623,207	[r]11,623,207
25	ICE NGX Canada Inc	SF	V6				68,800		6,948,800		[s]6,948,800

26	Midcontinent Independent System Operator	OS	V6				13,633,959	90,281,846	134,638,433	7,821,393	[t] 232,741,672
27	Midcontinent Independent System Operator	AD	V6				76,864			575,454	[u] 575,454
28	Morgan Stanley Capital Group, Inc.	OS	V6				65,600			3,289,727	[v] 3,289,727
29	Morgan Stanley Capital Group, Inc.	SF	V6				132,000		3,432,000		[w] 3,432,000
30	NextEra Energy Power Marketing, LLC	OS	V6				219,200			20,555,036	[x] 20,555,036
31	NextEra Energy Power Marketing, LLC	SF	V6				450,400		11,701,289		[y] 11,701,289
32	NRG Power Marketing LLC	OS	V6				16,032			1,100,835	[z] 1,100,835
33	NRG Power Marketing LLC	SF	V6				1,488		103,370		[aa] 103,370
34	North Central Power Company, Inc.	OS	V6				0	116,757		(14,346)	102,411
35	North Central Power Company, Inc.	SF	V6				0		204		204
36	North Central Power Company, Inc.	AD	V6				0			553	[ab] 553
37	Northwestern Wisconsin Electric Company	OS	V6				0	549,752			549,752
38	Northwestern Wisconsin Electric Company	SF	V6				0		912		912
39	Northwestern Wisconsin Electric Company	AD	V6				0			1,706	[ac] 1,706
40	Ohio Power Company	AD	V6				260			12,092	[ad] 12,092
41	Shelleneno	OS	V6				70,400			3,039,680	[ae] 3,039,680
42	Shelleneno	SF	V6				438,000		11,639,850		[af] 11,639,850
43	Taygete Energy Project, LLC	OS	V6				0			(733,590)	[ag] (733,590)
44	Taygete Energy Project, LLC	AD	V6				0			5,500,000	[ah] 5,500,000
45	[a] Footnote for 106b										

15	Subtotal - RQ						6,427,474					
16	Subtotal-Non-RQ						16,157,437	91,705,915	187,283,788	90,913,860	369,903,563
17	Total						16,157,437	91,705,915	187,283,788	90,913,860	369,903,563

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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 6,427,474 Mwh in column G, $382,894,799 in column I, and $382,894,799 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
Demand - Resource Adequacy Auction, Other - Ancillary Services
(u) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(v) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(w) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(x) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(y) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(z) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(aa) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(ab) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(ac) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(ad) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(ae) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(af) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(ag) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(ah) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	3,408,576	3,340,408
5	(501) Fuel	284,472,170	232,681,698
6	(502) Steam Expenses	17,520,606	17,515,825
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	4,671,087	4,307,877
10	(506) Miscellaneous Steam Power Expenses	14,399,952	13,819,285
11	(507) Rents	1,415,102	1,468,987
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	325,887,493	273,134,080
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,285,539	1,542,150
16	(511) Maintenance of Structures	3,902,411	4,343,962
17	(512) Maintenance of Boiler Plant	17,112,746	19,972,701
18	(513) Maintenance of Electric Plant	3,473,602	7,600,877
19	(514) Maintenance of Miscellaneous Steam Plant	7,060,544	7,380,213
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	32,834,842	40,839,903
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	358,722,335	313,973,983

22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	38,834,193	39,028,000
25	(518) Fuel	118,153,272	114,109,922
26	(519) Coolants and Water	8,267,994	8,366,224
27	(520) Steam Expenses	50,586,702	48,946,966
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,924,434	2,483,948
31	(524) Miscellaneous Nuclear Power Expenses	121,481,633	125,082,191
32	(525) Rents	5,313,358	5,360,174
33	TOTAL Operation (Enter Total of lines 24 thru 32)	345,561,586	343,377,425
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	7,614,287	7,690,102
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment	29,836,448	32,883,569
38	(531) Maintenance of Electric Plant	11,972,440	12,513,587
39	(532) Maintenance of Miscellaneous Nuclear Plant	25,024,623	24,961,813
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	74,447,798	78,049,071
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	420,009,384	421,426,496
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	71,095	88,626
45	(536) Water for Power	35,532	59,158
46	(537) Hydraulic Expenses	1,198	
47	(538) Electric Expenses	309,165	328,332
48	(539) Miscellaneous Hydraulic Power Generation Expenses	138,570	93,789

49	(540) Rents	23,067	34,834
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	578,627	604,739
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	240	882
54	(542) Maintenance of Structures	48,860	45,690
55	(543) Maintenance of Reservoirs, Dams, and Waterways	189,740	66,760
56	(544) Maintenance of Electric Plant	39,868	180,673
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,328	4,031
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	280,036	298,036
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	858,663	902,775
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	4,498,558	4,162,274
63	(547) Fuel	240,473,124	222,898,257
64	(548) Generation Expenses	8,061,409	6,709,961
64.1	(548.1) Operation of Energy Storage Equipment		668,658
65	(549) Miscellaneous Other Power Generation Expenses	23,515,092	13,207,667
66	(550) Rents	16,293,981	13,356,428
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	292,842,164	261,003,245
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,719,645	1,828,452
70	(552) Maintenance of Structures	6,860,460	6,916,872
71	(553) Maintenance of Generating and Electric Plant	10,748,762	10,741,953
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	13,371,788	11,789,212
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	32,700,655	31,276,489
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	325,542,819	292,279,734

75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,062,214,692	936,152,706
76.1	(555.1) Power Purchased for Storage Operations	0	
77	(556) System Control and Load Dispatching	1,203,960	1,214,953
78	(557) Other Expenses	[(a)]143,268,025	[(e)]80,110,978
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	1,206,686,677	1,017,478,637
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	2,311,819,878	2,046,061,625
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	9,486,961	9,056,290
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	4,068,232	5,058,224
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	8,133,121	8,456,229
89	(561.5) Reliability, Planning and Standards Development	1,968	9,061
90	(561.6) Transmission Service Studies	25,542	[(f)](21,770)
91	(561.7) Generation Interconnection Studies	482,946	507,498
92	(561.8) Reliability, Planning and Standards Development Services	3,141,620	3,194,344
93	(562) Station Expenses	5,068,723	5,528,565
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	599,788	697,406
95	(564) Underground Lines Expenses	15,379	13,395
96	(565) Transmission of Electricity by Others	[(b)]368,862,290	[(g)]348,602,482
97	(566) Miscellaneous Transmission Expenses	8,638,072	8,803,522
98	(567) Rents	1,234,581	1,194,543
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	409,759,223	391,099,789
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	2,356,030	3,437,754
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	9,103,900	5,961,980
109	(572) Maintenance of Underground Lines	1,992	42,829
110	(573) Maintenance of Miscellaneous Transmission Plant		51,022
111	TOTAL Maintenance (Total of Lines 101 thru 110)	11,461,922	9,493,585
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	[(c)]421,221,145	400,593,374
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	187,179	184,986
116	(575.2) Day-Ahead and Real-Time Market Facilitation	223,648	153,516
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		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	10,276,196	10,318,466
122	(575.8) Rents	14,182	10,183
123	Total Operation (Lines 115 thru 122)	10,701,205	10,667,151
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)	10,701,205	10,667,151
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	16,333,026	13,890,964
135	(581) Load Dispatching	1,145,333	918,297
136	(582) Station Expenses	3,025,752	3,113,343
137	(583) Overhead Line Expenses	4,933,639	2,633,788
138	(584) Underground Line Expenses	7,386,712	9,426,088
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	742,321	605,065
140	(586) Meter Expenses	[d](1,145,078)	542,356
141	(587) Customer Installations Expenses	1,347,236	1,783,791
142	(588) Miscellaneous Expenses	16,968,169	20,336,023
143	(589) Rents	2,901,539	2,639,657
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	53,638,649	55,889,372
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	83,913	16,230
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	1,716,010	2,309,146
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	51,441,608	47,889,439
150	(594) Maintenance of Underground Lines	5,239,674	7,055,503
151	(595) Maintenance of Line Transformers		6,426
152	(596) Maintenance of Street Lighting and Signal Systems	1,507,407	1,540,440

153	(597) Maintenance of Meters	314,597	284,499
154	(598) Maintenance of Miscellaneous Distribution Plant	540,792	252,217
155	TOTAL Maintenance (Total of Lines 146 thru 154)	60,844,001	59,353,900
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	114,482,650	115,243,272
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	129,775	127,217
160	(902) Meter Reading Expenses	20,096,455	23,634,718
161	(903) Customer Records and Collection Expenses	24,102,289	23,064,885
162	(904) Uncollectible Accounts	17,081,485	22,002,181
163	(905) Miscellaneous Customer Accounts Expenses	278,844	129,519
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	61,688,848	68,958,520
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	140,847,934	128,982,197
169	(909) Informational and Instructional Expenses	1,033,307	944,211
170	(910) Miscellaneous Customer Service and Informational Expenses	245,827	285,129
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	142,127,068	130,211,537
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	7,633,299	2,866,012
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	58,239	33,090
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	7,691,538	2,899,102
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		

181	(920) Administrative and General Salaries	91,087,571	89,687,743
182	(921) Office Supplies and Expenses	69,989,064	63,562,361
183	(Less) (922) Administrative Expenses Transferred-Credit	64,263,099	60,175,636
184	(923) Outside Services Employed	21,133,076	19,474,893
185	(924) Property Insurance	10,062,689	[(b)](1,497,249)
186	(925) Injuries and Damages	17,752,560	14,306,151
187	(926) Employee Pensions and Benefits	83,039,174	80,397,090
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	9,501,872	8,302,819
190	(929) (Less) Duplicate Charges-Cr.	6,121,912	5,449,179
191	(930.1) General Advertising Expenses	3,884,214	3,376,810
192	(930.2) Miscellaneous General Expenses	4,536,316	4,129,842
193	(931) Rents	47,678,667	46,128,785
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	288,280,192	262,244,430
195	Maintenance		
196	(935) Maintenance of General Plant	920,199	763,087
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	289,200,391	263,007,517
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	3,358,932,723	3,037,642,098

FOOTNOTE DATA

(a) Concept: OtherExpensesOtherPowerSupplyExpenses

Includes $47,067,946 of fixed costs and $22,831,577 of variable costs reimbursed to NSP-Wisconsin for production costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

(b) Concept: TransmissionOfElectricityByOthers

Includes $132,294,095 of fixed costs reimbursed to NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

(c) Concept: TransmissionExpenses

Total Transmission Expense as reported in the Form 1, page 321, line 112 is reduced by amounts related to transactions with an affiliated Company based on the FERC-approved Interchange Agreement.

(d) Concept: MeterExpenses

Credit balance due to meter transfer install O&M credits.

(e) Concept: OtherExpensesOtherPowerSupplyExpenses

Includes $47,082,251 of fixed costs and $20,416,594 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: TransmissionServiceStudies

Credit balance results from Pension, Insurance and Taxes on Company labor billed for performing transmission service studies being recorded to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is recorded to Account No. 561.6.

(g) Concept: TransmissionOfElectricityByOthers

Includes $121,303,129 of fixed costs reimbursed to NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

(h) Concept: PropertyInsurance

Credit balance due to nuclear insurance distribution.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1	ACE Lincoln Heights Wind Holdings, LLC	AD					176					[(a)]5,797		5,797
2	ACE Lincoln Heights Wind Holdings, LLC	LU					22,296					735,778		735,778
3	Adams Wind Generations	LU					57,889					3,849,585		3,849,585
4	AEP Energy Partners, Inc.	LU					1,810					81,364		81,364

5	Agassiz Beach, LLC	LU					4,531					120,210		120,210
6	Aurora Distributed Solar, LLC	LU					178,396					18,972,427		18,972,427
7	Best Power International LLC	AD					(41)					(b)(3,864)		(3,864)
8	Best Power International LLC	LU					1,838					182,964		182,964
9	Big Blue Wind Farm, LLC	AD										(c)696		696
10	Big Blue Wind Farm, LLC	LU					95,564					7,923,062		7,923,062
11	Bisson Windfarm, LLC	AD					86					(d)2,921		2,921
12	Bisson Windfarm, LLC	LU					4,713					160,226		160,226
13	Boeve Windfarm, L.L.C.	AD					(1)					(e)(20)		(20)
14	Boeve Windfarm, L.L.C.	LU					6,017					201,564		201,564
15	Calpine Energy Services, L.P.	OS											(be)934,800	934,800
16	Cannon Falls Energy Center	AD										(f)18,958		18,958
17	Cannon Falls Energy Center	LU		345			171,322				29,747,078	16,440,120		46,187,198
18	Carleton College	AD					23					(g)769		769
19	Carleton College	LU					4,905					161,852		161,852
20	CG Windfarm, LLC	AD					(109)					(h)(3,700)		(3,700)
21	CG Windfarm, LLC	LU					2,587					87,955		87,955
22	Chanarambie Power Partners, L.L.C.	LU					102,661					2,720,508		2,720,508
23	Cisco Wind Energy, L.L.C.	AD										(i)(20)		(20)
24	Cisco Wind Energy, L.L.C.	LU					17,545					577,224		577,224
25	Citigroup Energy, Inc.	OS											(bf)2	2
26	Covanta Hennepin Energy Resource Co LP	AD										(j)167,738		167,738
27	Covanta Hennepin Energy Resource Co LP	LU					199,466					8,834,395		8,834,395
28	Crowned Ridge Wind, LLC	AD					(20,276)					(k)(286,499)		(286,499)
29	Crowned Ridge Wind, LLC	LU					764,656					19,453,624		19,453,624
30	Dairyland Electric Cooperative Incorporated	LU					17,200					212,420		212,420
31	Dakota Range III, LLC	LU					509,007					13,780,462		13,780,462
32	Danielson Wind Farms, LLC	LU					53,994					3,590,594		3,590,594
33	Deuel Harvest Wind Energy LLC	AD					1,584					(l)(158,914)		(158,914)
34	Deuel Harvest Wind Energy LLC	LU					378,141					7,121,489		7,121,489
35	Direct Energy Business Marketing, LLC	LU										3		3

36	Dragonfly Solar, LLC	AD					(2)					[m] (207)		(207)
37	Dragonfly Solar, LLC	LU					1,033					87,779		87,779
38	East Ridge group	AD					(4)					[n] (131)		(131)
39	East Ridge group	LU					24,200					798,613		798,613
40	EDF TRADING NORTH AMERICA LLC	OS											8,420,682[bg]	8,420,682
41	Electric Reliability Council of Texas	AD					(3,423)					(3,845,792)[o]		(3,845,792)
42	Electric Reliability Council of Texas	SF					66,275					9,741,236		9,741,236
43	Elk Creek Solar, LLC	LU					159,626					6,225,410		6,225,410
44	Ewington Energy Systems, LLC	LU					58,543					1,584,615		1,584,615
45	Exelon Generation Company, LLC	OS											2,383,068[bh]	2,383,068
46	Fenton Power Partners I, L.L.C.	AD										[p] 90,101		90,101
47	Fenton Power Partners I, L.L.C.	LU					396,211					37,820,943		37,820,943
48	Fey Windfarm, L.L.C.	LU					5,826					203,898		203,898
49	Garwin McNeilus	AD					(154)					[q] (8,128)		(8,128)
50	Garwin McNeilus	LU					92,934					3,055,510		3,055,510
51	Grant County Windfarm, LLC	LU					63,060					4,288,059		4,288,059
52	Great American West Wind, LLC	AD					11					[r] 149		149
53	Great American West Wind, LLC	LU					451,410					6,087,091		6,087,091
54	Hastings Lock & Dam	LU		2			23,144				395,624	330,815		726,439
55	Heartland Divide Wind II, LLC	AD										(5,000,000)[s]		(5,000,000)
56	Heartland Divide Wind II, LLC	LU					579,950					11,614,482		11,614,482
57	Hilltop Power, L.L.C.	LU					4,350					191,407		191,407
58	ICAP Energy LLC	OS											[bi] 2,496	2,496
59	J. Aron & Company LLC	OS											[bj] 2	2
60	JJN Windfarm, LLC	AD					2					[t] 63		63
61	JJN Windfarm, LLC	LU					4,049					136,763		136,763
62	JPMorgan Chase Bank New York	OS											10,126,688[bk]	10,126,688
63	Kas Brothers Windfarm, L.L.C.	LU					4,306					171,136		171,136
64	K-Brink Windfarm, L.L.C.	AD					4					[u] 123		123
65	K-Brink Windfarm, L.L.C.	LU					5,617					188,158		188,158
66	Keller Paving & Landscaping, Inc.	AD					6					[v] 126		126

67	Keller Paving & Landscaping, Inc.	LU					207					5,177		5,177
68	KODA Energy, LLC	AD					(59)					[w](3,158)		(3,158)
69	KODA Energy, LLC	LU					1,241					39,493		39,493
70	Lake Benton Power Partners, L.L.C.	AD										[x]18,028		18,028
71	Lake Benton Power Partners, L.L.C.	LU					247,993					7,300,865		7,300,865
72	LCO Hydro	AD										[y](25)		(25)
73	LCO Hydro	LU										(266,028)		(266,028)
74	Lower Colorado River Authority	OS											[bl] 4,029,026	4,029,026
75	LSP Cottage Grove Incorporated	LU		245			593,646				7,853,494	35,552,542		43,406,036
76	Luminant Energy Company LLC	SF											7,318,224	7,318,224
77	Manitoba Hydro	AD									(1,473,754)			(1,473,754)
78	Manitoba Hydro	LU		350			2,161,379				52,898,027	181,749,483		234,647,510
79	Mankato Energy Center I, L.L.C.	AD					440				117	[z](672,265)		(672,148)
80	Mankato Energy Center I, L.L.C.	LU		375			831,697				39,861,103	97,210,970		137,072,073
81	Mankato Energy Center II, L.L.C.	AD					259					[aa](86,905)		(86,905)
82	Mankato Energy Center II, L.L.C.	LU		345			922,299				28,232,428	7,122,899		35,355,327
83	Marshall Solar	LU					100,660					7,411,792		7,411,792
84	Merrill Lynch Commodities, Inc.	OS											[bm]164,489	164,489
85	Metro Wind LLC	LU					825					21,963		21,963
86	Midcontinent ISO (MISO)	AD					54,199					[ab] (3,211,011)		(3,211,011)
87	Midcontinent ISO (MISO)	SF					5,561,246					[ac] (38,653,930)		(38,653,930)
88	MinnDakota Wind LLC	AD										[ad]3,396		3,396
89	MinnDakota Wind LLC	LU					280,565					21,116,111		21,116,111
90	Miscellaneous	AD											[bn] 1,179,804	1,179,804
91	Miscellaneous	OS											[bo] 1,451,304	1,451,304
92	Moraine Wind, L.L.C.	AD					4,332					[ae]73,719		73,719
93	Moraine Wind, L.L.C.	LU					97,020					2,810,781		2,810,781
94	Morgan Stanley Capital Group Inc.	LU					16,800					1,190,335		1,190,335
95	N A E Lakota Ridge, LLC	AD					(30)					[af](326)		(326)
96	N A E Lakota Ridge, LLC	LU					17,201					189,214		189,214
97	N A E Shaokatan Hills, LLC	AD	NAEMA				(4,123)					[ag](45,196)		(45,196)
98	N A E Shaokatan Hills, LLC	LU					29,656					326,216		326,216

99	NAE Shaokatan, LLC	LU					27,658					747,323		747,323
100	Natural Gas Exchange Inc.	AD											26	26
101	Natural Gas Exchange Inc.	OS											[(bp)] 40,445,320	40,445,320
102	New England ISO	OS											[(bq)]12,628	12,628
103	New York ISO	OS											[(br)](1,146)	(1,146)
104	NextEra Energy Power Marketing, LLC	OS											[(bs)] 12,231,365	12,231,365
105	North Star Solar	AD					(10)					[(ah)](146)		(146)
106	North Star Solar	LU					192,748					13,525,019		13,525,019
107	NSP-M Solar Gardens	AD					(6,038)					[(ai)] 175,919,134		175,919,134
108	NSP-M Solar Gardens	LU					1,409,585					8,111,100		8,111,100
109	Odell Wind Farm, LLC	AD										[(aj)](1)		(1)
110	Odell Wind Farm, LLC	LU					869,721					23,086,676		23,086,676
111	Olsen Wind Farm	AD					1					[(ak)]43		43
112	Olsen Wind Farm	LU					1,373					54,161		54,161
113	Pipestone	AD					(21)					[(al)](681)		(681)
114	Pipestone	LU					19,669					649,073		649,073
115	PJM Interconnection LLC	AD											1,752	1,752
116	PJM Interconnection LLC	OS											[(bt)](22,017)	(22,017)
117	Prairie Rose Wind, LLC	AD										[(am)](37)		(37)
118	Prairie Rose Wind, LLC	LU					741,740					32,516,094		32,516,094
119	Ridgewind Power Partners, LLC	LU					86,666					5,654,288		5,654,288
120	Rock Ridge Power Partners LLC	AD										[(an)]423		423
121	Rock Ridge Power Partners LLC	LU					3,428					75,024		75,024
122	Ruthton Ridge	AD										[(ao)]55		55
123	Ruthton Ridge	LU					40,691					1,094,274		1,094,274
124	SAF Hydroelectric, L.L.C.	LU					30,255					1,659,167		1,659,167
125	Shane's Wind Machine LLC	LU					6,414					211,663		211,663
126	Slayton Solar, LLC	AD					(32)					[(ap)](3,602)		(3,602)
127	Slayton Solar, LLC	LU					2,579					293,983		293,983
128	South Ridge Power Partners, LLC	AD										[(aq)]294		294
129	South Ridge Power Partners, LLC	LU					3,540					78,200		78,200

130	Southwest Power Pool, Inc.	AD					(19)					[ar](1,787)		(1,787)
131	Southwest Power Pool, Inc.	OS					4,710					227,571		227,571
132	St Cloud	LU					50,590					1,818,718		1,818,718
133	St. Olaf College	AD					2					[as]82		82
134	St. Olaf College	LU					9					286		286
135	St. Paul Cogeneration	AD										[at]227,244		227,244
136	St. Paul Cogeneration	LU					167,026					27,523,784		27,523,784
137	Taygete Energy Project, LLC	AD					(1)							
138	Taygete Energy Project, LLC	SF					391,431					9,965,514		9,965,514
139	TG Windfarm, LLC	AD					86					[au]2,921		2,921
140	TG Windfarm, LLC	LU					4,713					160,226		160,226
141	Tholen Transmission-Trust	AD					(84)					[av](2,764)		(2,764)
142	Tholen Transmission-Trust	LU					40,901					1,349,742		1,349,742
143	Tofteland Windfarm, LLC	AD					86					[aw]2,921		2,921
144	Tofteland Windfarm, LLC	LU					4,713					160,226		160,226
145	Uilk Wind Farm, LLC	LU					14,377					1,036,524		1,036,524
146	University of Minnesota	LU					2,828					103,439		103,439
147	Valley View Transmission	AD										[ax](2,897)		(2,897)
148	Valley View Transmission	LU					31,413					1,975,847		1,975,847
149	Velva Windfarm, LLC	LU					31,575					1,041,963		1,041,963
150	Viking Wind Partners	AD										[ay](1,496)		(1,496)
151	Viking Wind Partners	LU					8,166					36,527		36,527
152	Western Area Power Administration	AD	NAEMA, WSPP									[az](96)		(96)
153	Western Area Power Administration	LU					10,830					260,232		260,232
154	Westridge Windfarm, LLC	AD					(109)					[ba](3,700)		(3,700)
155	Westridge Windfarm, LLC	LU					2,587					87,955		87,955
156	Windcurrent Farms, L.L.C.	LU					4,732					165,629		165,629
157	Windvest Power Partners, LLC	AD										[bb]638		638
158	Windvest Power Partners, LLC	LU					3,911					64,047		64,047
159	Winona County Wind LLC	LU					5,199					347,810		347,810
160	Woodstock Hills, L.L.C.	AD										[bc]30		30
161	Woodstock Hills, L.L.C.	LU					42,092					842,094		842,094
162	Woodstock Municipal Wind, LLC	LU					1,715					114,710		114,710

163	Zephyr Wind LLC	AD										[bd](47)		(47)
164	Zephyr Wind LLC	LU					77,821					6,928,595		6,928,595
15	TOTAL						19,761,674	0	0	0	157,514,117	816,022,062	88,678,513	1,062,214,692

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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
Credit balance mainly driven by increased FTR values which were partially offset by higher congestion costs.
(ad) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ae) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(af) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ag) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ah) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(ai) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment

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

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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 ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	East Grand Forks, City of	WAPA	East Grand Forks, City of	OS	483	WAPA	East Grand Forks						[h]55,981	55,981
2	Great River Energy	Various	Various	FNO	[f] Various	Various	Various				50,112,745		[i]126,983	50,239,728
3	Marshall Solar	Marshall Solar	MISO	OS	3514	Lyon County	Lyon County						[j]70,776	70,776
4	MidAmerican Energy Company	Palo Alto	MISO	OS	3721	Palo Alto	Palo Alto						[k]363,398	363,398
5	Midcontinent ISO (MISO)	Various	Various	[e] FNO	MISO OATT	Various	Various				128,961,082	77,296,341 [g]		206,257,423
6	Missouri River Energy Services (MRES)	Various	Various	FNO	304	Various	Various				6,191,960			6,191,960
7	North Star Solar PV LLC	North Star Solar	MISO	OS	2871	Chisago County	Chisago County						[l]337,939	337,939
8	[a] Northern States Power-Minnesota	Blazing Star 2	MISO	OS	3418	Steep Bank Lake	Steep Bank Lake						[m]914,115	914,115
9	Sioux Falls, City of	WAPA	Sioux Falls, City of	OS	484	WAPA	Sioux Falls, City of						[n]206,209	206,209
10	South Dakota State Penitentiary (SDSP)	WAPA	SDSP	OS	385	WAPA	SDSP						[o]14,940	14,940
11	Southern MN Municipal Power Agency	Various	Various	FNO	304	Various	Various				7,555,113			7,555,113

12	Stoneray Power	Stoneray Power Partners	MISO	OS	3513	Chanarambie	Chanarambie						[p]145,716	145,716
13	Tenaska Nobles 2 Holdings LLC	Nobles 2 Wind Farm	MISO	OS	3347	Zephyr	Zephyr						[q]1,483,551	1,483,551
14	University of North Dakota	WAPA	University of North Dakota	OS	440	WAPA	UND						[r]66,584	66,584
15	Walleye Wind, LLC	Walleye Wind	MISO	OS	1495	Rock County	Rock County						[s]528,506	528,506
16	Wisconsin Public Power, Inc. (WPPI)	MP	WPPI	OS	466								[t]40,320	40,320
17	[b]Northern States Power-Wisconsin	[d]Various	Various	OS	437	Various	Various				61,002,657			61,002,657
18	[c]Footnote from page 106b													
35	TOTAL							0	0	0	253,823,557	77,296,341	4,355,018	335,474,916

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

Facilities Charge

(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: 04/07/2023	Year/Period of Report End of: 2022/ 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: MegaWatt Hours Received (c)	TRANSFER OF ENERGY: MegaWatt Hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: 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			1,466,443			1,466,443
3	Dairyland Power	OS					[k]19,744	19,744
4	Great River Energy	FNS			42,437,798			42,437,798
5	ITC Midwest	OS					[l](3,349)	(3,349)
6	McLeod Coop Power	[c]OLF			26,111			26,111
7	Midcontinent ISO (MISO)	[d]LFP			98,166,001	[i]68,706,873	[m]1,000	166,873,874
8	MN Municipal Pwr Agy	FNS			1,360,798			1,360,798
9	Minnkota Power Coop	[e]OLF				20,515	[n]780,000	800,515
10	Missouri Riv Engy Serv	FNS			1,568,228			1,568,228
11	Montana-Dakota Util Co	OS					[o]1,480,072	1,480,072
12	Northwestern Wis Elect	FNS			607,761			607,761

13	[(a)] Northern States Pwr-MN	OS					[(e)] 914,115	914,115
14	Otter Tail Pwr Co	OS					[(g)] 1,517,157	1,517,157
15	Rochester Public Util	FNS			1,900,281			1,900,281
16	Southern MN Muncipl Pwr	FNS			15,384,572			15,384,572
17	Southwest Power Pool	FNS			81,727	464		82,191
18	Stearns Coop Electric	[(f)] OS				2,796	[(r)] 509	3,305
19	Verendrye Electric Coop	[(g)] OLF				126,179		126,179
20	[(b)] Northern States Pwr-WI	[(h)] OLF			132,294,095			132,294,095
	TOTAL		0	0	295,293,815	68,856,827	4,711,648	368,862,290

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

(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

2022 MISO Annual Membership

(n) Concept: OtherChargesTransmissionOfElectricityByOthers

Fixed Transmission Service Charge

(o) Concept: OtherChargesTransmissionOfElectricityByOthers

Interconnection upgrade charge

(p) Concept: OtherChargesTransmissionOfElectricityByOthers

Affiliate - Interconnection upgrade charge

(q) Concept: OtherChargesTransmissionOfElectricityByOthers

Interconnection upgrade charge

(r) Concept: OtherChargesTransmissionOfElectricityByOthers

Fixed Facility Charge

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,922,708
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	SEC Filing Expense	44,171
7	Shareholder Related Expenses	138,683
8	Director Fees and Expenses	1,430,971
9	Other	[(a)](217)
46	TOTAL	4,536,316

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OtherMiscellaneousGeneralExpenses
Credit received from facilities chargeback process

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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)]32,633,390	(19,301)	32,614,089
2	Steam Production Plant	111,299,696	986,992		(1,041,299)	111,245,389
3	Nuclear Production Plant	198,218,042	(28,364,126)			169,853,916
4	Hydraulic Production Plant-Conventional	1,495,103			(67,064)	1,428,039
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	217,039,173	15,120,132	739,978	(5,049,094)	227,850,188
7	Transmission Plant	[(b)]83,167,711	5,255		(1,303,493)	81,869,473
8	Distribution Plant	[(c)]139,806,785	234,059			140,040,844
9	Regional Transmission and Market Operation					
10	General Plant	37,121,865			(549,242)	36,572,623
11	Common Plant-Electric	[(d)]37,802,933	3,502	55,024,402	(1,068)	92,829,770
12	TOTAL	825,951,308	(12,014,186)	88,397,770	(8,030,561)	894,304,331

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	10,120					
14	311	294,911					
15	312	1,517,560					
16	314	325,770					
17	315	187,622					
18	316	54,257					
19	317	20,241					
20	Subtotal Steam Prod	2,410,481					
21	Nuclear Production						
22	320	1,758					
23	321	607,173					
24	322	1,969,150					
25	323	632,268					
26	324	541,780					
27	325	208,952					
28	326	(222,548)					
29	Subtotal Nuclear Prod	3,738,533					
30	Hydro Production						
31	330	1,693					
32	331	1,473					
33	332	11,122					

34	333	10,157					
35	334	3,288					
36	335	93					
37	336	152					
38	337						
39	Subtotal Hydro Prod	27,978					
40	Other Production						
41	340	32,722					
42	341	502,527					
43	342	28,182					
44	343	143,743					
45	344	3,982,734					
46	345	336,584					
47	346	60,741					
48	347	353,315					
49	348	4,129					
50	Subtotal Other Prod	5,444,677					
51	Transmission						
52	350	169,140					
53	352	156,273					
54	353	1,473,480					
55	354	127,087					
56	355	1,567,648					
57	356	686,667					
58	357	32,182					
59	358	35,441					
60	359.1	173					

61	Subtotal Transmission	4,248,091					
62	Distribution						
63	360	19,780					
64	361	63,434					
65	362	749,209					
66	364	611,265					
67	365	621,476					
68	366	378,676					
69	367	1,392,424					
70	368[e]	487,218					
71	368[f]	29,638					
72	369[g]	95,877					
73	369[h]	307,991					
74	370	109,006					
75	371	18,446					
76	373	89,583					
77	374	12,231					
78	Subtotal Distribution	4,986,254					
79	General						
80	389	12,590					
81	390[i]	78,356					
82	390[j]	1,085					
83	391[k]	34,477					
84	391[l]	63,511					
85	392[m]	7,255					

86	[(n)] 392	44,729					
87	[(o)] 392	25,894					
88	[(p)] 392	132,107					
89	393	1,646					
90	394	126,074					
91	395	2,928					
92	396	56,230					
93	[(q)] 397	57,274					
94	[(r)] 397	63,116					
95	[(s)] 397	8,254					
96	[(t)] 397	52,445					
97	[(u)] 397	13,050					
98	398	1,903					
99	Subtotal General	782,924					
100	TOTAL	[(v)] 21,638,938					

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AmortizationOfLimitedTermPlantOrProperty

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

Intangible Plant	$	18,471,761
Nuclear Production Plant		14,054,801
Hydraulic Production Plant - Conventional		106,828
Total	$	32,633,390

(b) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

Transmission Serving Production	$	3,620,663

(c) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

Distribution Serving Production	$	116,219

(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	$	(4,745,033)
Transmission Plant		(4,171,205)
General Plant		(171,576)
Total	$	(9,087,814)

(e) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

368 Line Transformers

(f) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

368 Line Capacitors

(g) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

369 Overhead Services

(h) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

369 Underground Services

(i) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

390 Structures and Improvements

(j) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

390 Structures and Improvements - Leasehold Improvements

(k) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

391 Office Furniture and Equipment

(l) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

391 Network Equipment

(m) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392 Transportation Equipment - Automobiles

(n) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392 Transportation Equipment - Light Trucks

(o) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392 Transportation Equipment - Trailers

(p) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

392 Transportation Equipment - Heavy Trucks

392/396 Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1).

392 Transportation Equipment	$	13,035,657	$	209,985,000
396 Power Operated Equipment		2,900,853		56,230,000
Total	$	15,936,510	$	266,215,000

(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 Following wind farm had a life extension in December 2022 (Order PU-20-425 & PU-21-93)
Nobles Wind farm. Life was extended 10 years until 2045 for all jurisdictions except SD..

The following new wind production assets have been added with a 25 year life: Dakota Range (Jan 2022)

For subaccounts 350-398, the parameters as approved by the Minnesota Jurisdiction are reported. Columns (c), (d), and (f) were approved in Docket No. EG002-D-22-299, with rates off the 2021 MN TD&G Depr Study. Columns (e) and (g) were approved in Docket No. EG002-D-22-299 in the same 2021 study.

(3) P337 Line 23 - 29 (d) - Effective Aug 1, 1981, Nuclear Plant Decommissioning costs are recovered using an external sinking fund calculation.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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 (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	7,567,242		7,567,242		Elec	928	6,684,052				
3	Gas Assessments					Gas	928	883,190				
4	GR-09-1153 2010 Natural Gas Rate Increase - Amortized through 2024	(1,064,667)		(1,064,667)		Gas	928			186	(1,064,667)	
5	GR-21-678 2022 Natural Gas Rate Increase - Amortized through 2024	1,158,840		1,158,840		Gas	928			186	1,158,840	
6	GR-21-630 2022 Electric Rate Increase - Amortized through 2024	1,562,100		1,562,100		Elec	928			186	1,562,100	
7	CI-21-135 & CI-21-610 February 2021 Natural Gas Price Investigation		782,734	782,734		Gas	928	782,734				
8	AA-18-373 Sherco Unit 3		24,879	24,879		Elec	928	24,879				

9	GR-21-63 Audit & Assurance Services	72,000		72,000		Elec	928	72,000				
10	WS-17-410 Freeborn Wind Site Permit		11,396	11,396		Elec	928	11,396				
11	12-1246 Large Electric Plants and High-Voltage Lines		9,229	9,229		Elec	928	9,229				
12	Electric Miscellaneous - Minnesota	2,368	29,381	31,749		Elec	928	8,391				
13	Gas Miscellaneous - Minnesota					Gas	928	23,358				
14	NORTH DAKOTA PUBLIC SERVICE COMMISSION											
15	Gross Receipts Tax Assessment Electric	51,562		51,562		Elec	928	46,624				
16	Gross Receipts Tax Assessment Gas					Gas	928	4,938				
17	PU-21-389 Renewable Energy Rider	(9,839)		(9,839)		Elec	928	(9,839)				
18	PU-22-311 Power Purchase Agreement Costs	10,000		10,000		Elec	928	10,000				
19	PU-22-368 Renewable Energy Rider	10,000		10,000		Elec	928	10,000				
20	PU-22-402 Transmission Cost Recovery Rider	10,000		10,000		Elec	928	10,000				
21	PU-20-433 Heartland Divide PPA ADP		1,014	1,014		Elec	928	1,014				
22	PU-20-441 2021 Electric Rate Increase - Amortized through 2024	359,404		359,404		Elec	928			186	359,404	
23	PU-21-381 2021 Gas Rate Increase - Amortized through 2024	217,600		217,600		Gas	928			186	217,600	
24	PU-22-180 Advanced Metering Infrastructure	10,000		10,000		Elec	928	10,000				
25	PU-22-185 Competitive Response Rider (CRR)	10,050		10,050		Elec	928	10,050				

26	PU-21-386 NG Distribution System - Cass and Richland		1,210	1,210		Elec	928	1,210				
27	PU-22-12 Fuel Cost Adjustment 2022		400	400		Elec	928	400				
28	PU-13-64 200.5 MW Wind Energy Conversion Facility-Stutsman		(12,750)	(12,750)		Elec	928	(12,750)				
29	PU-22-9 Cost of Gas 2022		400	400		Gas	928	400				
30	PU-22-410 Advance Prudence MinnDakota Wind PPGA		101,995	101,995		Elec	928	101,995				
31	Electric Miscellaneous - North Dakota		2,305	2,305		Elec	928	4,055				
32	Gas Miscellaneous - North Dakota					Gas	928	(1,750)				
33	SOUTH DAKOTA PUBLIC UTILITIES COMMISSION											
34	Gross Receipts Tax Assessment	395,912		395,912		Elec	928	395,912				
35	EL21-025 Transmission Cost Recovery Rider	5,559		5,559		Elec	928	5,559				
36	EL21-028 Infrastructure Rider	10,445		10,445		Elec	928	10,445				
37	FEDERAL ENERGY REGULATORY COMMISSION											
38	ER22-80 Coyote Ridge Wind & ER22-93 Tatanka Ridge Wind		66,545	66,545		Elec	928	66,545				
39	EL22-78 MISO Complaint		106,155	106,155		Elec	928	106,155				
40	Miscellaneous		3,923	3,923		Elec	928	3,046				
41						Gas	928	877				
46	TOTAL	10,378,576	1,128,816	11,507,392				9,274,115			2,233,277	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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		3,531,325	[(a)] See Note	3,531,325	
2	B(2)	Edison Electric Institute		932,111	[(b)] See Note	932,111	
3	B(4)	Renewable Development Fund		341,309	[(c)] 253	341,309	

4	B(5)	Total		4,804,745		4,804,745	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Accounts charged:		
524	$	2,329,876
930.2		1,201,449
	$	3,531,325

(b) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Accounts charged:		
426.4	$	126,206
930.2		805,905
	$	932,111

(c) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

The "Renewable Development Fund" is a program authorized by Minnesota Statute 116C3.779. Funding through this statute supports energy production and research and development of alternative sources of electricity. The projects listed below support the research and development of renewable sources of electricity. Also see page 269, Other Deferred Credits (Account 253).

Research Projects		
University of Minnesota	$	241,309
City of Red Wing		100,000
	$	341,309

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	178,420,229		
4	Transmission	17,201,488		
5	Regional Market	394,831		
6	Distribution	30,844,606		
7	Customer Accounts	15,333,320		
8	Customer Service and Informational	1,385,875		
9	Sales	2,457,345		
10	Administrative and General	90,745,537		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	336,783,231		
12	Maintenance			
13	Production	62,619,735		
14	Transmission	2,046,515		
15	Regional Market			
16	Distribution	19,567,283		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	84,233,533		
19	Total Operation and Maintenance			

20	Production (Enter Total of lines 3 and 13)	241,039,964		
21	Transmission (Enter Total of lines 4 and 14)	19,248,003		
22	Regional Market (Enter Total of Lines 5 and 15)	394,831		
23	Distribution (Enter Total of lines 6 and 16)	50,411,889		
24	Customer Accounts (Transcribe from line 7)	15,333,320		
25	Customer Service and Informational (Transcribe from line 8)	1,385,875		
26	Sales (Transcribe from line 9)	2,457,345		
27	Administrative and General (Enter Total of lines 10 and 17)	90,745,537		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	421,016,764	11,539,059	432,555,823
29	Gas			
30	Operation			
31	Production - Manufactured Gas	3,124		
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	152,814		
34	Storage, LNG Terminaling and Processing	1,430,286		
35	Transmission	467,815		
36	Distribution	17,923,732		
37	Customer Accounts	3,814,454		
38	Customer Service and Informational	1,027,170		
39	Sales	784		
40	Administrative and General	6,940,440		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	31,760,619		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	2,423,207		
47	Transmission	106,505		

48	Distribution	6,205,121		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	8,734,833		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	3,124		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	152,814		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	3,853,493		
56	Transmission (Lines 35 and 47)	574,320		
57	Distribution (Lines 36 and 48)	24,128,853		
58	Customer Accounts (Line 37)	3,814,454		
59	Customer Service and Informational (Line 38)	1,027,170		
60	Sales (Line 39)	784		
61	Administrative and General (Lines 40 and 49)	6,940,440		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	40,495,452	1,782,836	42,278,288
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	461,512,216	13,321,895	474,834,111
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	152,549,597	60,740,410	213,290,007
69	Gas Plant	16,608,590	13,082,949	29,691,539
70	Other (provide details in footnote):	[(a)]631,711		631,711
71	TOTAL Construction (Total of lines 68 thru 70)	169,789,898	73,823,359	243,613,257
72	Plant Removal (By Utility Departments)			
73	Electric Plant	15,281,381	5,645,572	20,926,953
74	Gas Plant	499,893	1,216,006	1,715,899

75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	15,781,274	6,861,578	22,642,852
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Regulatory Assets (Acct No. 182.3)	9,629,804	530,192	10,159,996
80	Preliminary Survey and Investigation (Acct No. 183)	(280,403)	(735)	(281,138)
81	Miscellaneous Deferred Debits (Acct No. 186)		42,136	42,136
82	Miscellaneous Deferred Credits (Acct No. 253)	170,644	2,625	173,269
83	Regulatory Liabilities (Acct No. 254)	146,424	8,553	154,977
84	Non-utility (Accts No. 416-417.1)	4,180,447	40,113	4,220,560
85	Miscellaneous Income and Deductions (Accts No. 426.1-426.5)	277,874	5,766	283,640
86	Non-utility CWP and RWP	1,096,376	30,944	1,127,320
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	15,221,166	659,594	15,880,760
96	TOTAL SALARIES AND WAGES	662,304,554	94,666,426	756,970,980

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: 04/07/2023	Year/Period of Report End of: 2022/ 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.

COMMON UTILITY PLANT AND EXPENSES

Instruction 1:

Account		Allocated to Utility Departments Electric	Gas	Cost at Dec. 31, 2022
COMMON UTILITY PLANT IN SERVICE AND COMPLETED NOT CLASSIFIED (ACCOUNTS 101 AND 106)				
301	Organization	90,135	10,473	100,608
303	Computer Software	597,801,459	69,462,141	667,263,600
Total intangible plant		597,891,594	69,472,614	667,364,208
389	Land and land rights	8,264,900	559,973	8,824,873
390	Structures and improvements	218,609,039	14,811,465	233,420,504
391	Office furniture and equipment	176,092,139	11,930,808	188,022,947
392	Transportation equipment	12,585,605	2,696,465	15,282,070
393	Stores equipment	230,542	15,620	246,162
394	Tools/shop/garage equipment	10,538,872	722,777	11,261,649
395	Laboratory equipment	—	—	—
396	Power operated equipment	1,330,837	201,834	1,532,671
397	Communications equipment	553,207	37,481	590,688
398	Miscellaneous equipment	220,658	14,950	235,608
399.1	Asset retirement costs for general plant	320,332	21,703	342,035
Total		1,026,637,725	100,485,690	1,127,123,415
COMMON UTILITY PLANT HELD FOR FUTURE USE (ACCOUNT 105)				
389	Land and Land Rights	—	—	—
COMMON UTILITY PLANT CONSTRUCTION WORK IN PROGRESS (ACCOUNT 107)				
	General Plant	124,943,041	11,016,156	135,959,197

Instruction 2:

		Electric	Gas	Total
COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (ACCOUNT 108 AND 111)				
	General Plant	470,243,446	49,506,516	519,749,962

Common utility plant and accumulated provision for depreciation has been allocated to the various utilities on the basis of customers, employee labor, or direct assignment based on actual use.

	"Non-Legal" ARO Balance
Common General	$ (5,047,164)
Common Intangible	—
Total Common	(5,047,164)

Instruction 3:

Common Utility Plant Expenses

		Electric	Gas	Total
403	Depreciation Expense	37,802,934	2,582,516	40,385,450
403.1	Depreciation Expense - ARC	3,502	238	3,740
404	Amortization of limited term plant	55,024,402	5,862,653	60,887,055
405	Amortization of other plant	(1,068)	(73)	(1,141)
407.4	Amortization of regulatory credits	(23,336)	(1,585)	(24,921)
411.1	Accretion expense	19,834	1,346	21,180
Total		92,826,268	8,445,095	101,271,363

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: 04/07/2023	Year/Period of Report End of: 2022/ 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	MISO				
8	MISO - Net Purchases (Account 555)	16,618,425	39,344,771	80,943,354	108,193,624
9	MISO - Net Sales (Account 447)	(22,385,817)	(15,666,205)	(142,288,574)	(233,317,128)
10	MISO - Transmission Rights (Account 555)	(11,418,010)	(64,582,259)	(120,235,288)	(130,758,299)
11	MISO - Ancillary Services (Account 555)	(1,645,880)	(1,062,740)	(524,002)	493,652
12	MISO - Uplift Charges (Account 555)	(2,590,080)	(3,508,734)	(12,486,089)	(19,793,920)
13	ERCOT				
14	ERCOT - Net Purchases (Account 555)	1,278,572	2,270,173	8,404,200	5,841,685
15	ERCOT - Net Sales (Account 447)				
16	ERCOT - Transmission Rights (Account 555)				
17	ERCOT - Ancillary Services (Account 555)				
18	ERCOT - Uplift Charges (Account 555)	12,264	16,306	41,666	53,760
19	NEISO				

20	NEISO - Net Purchases (Account 555)				
21	NEISO - Net Sales (Account 447)				
22	NEISO - Ancillary Services (Account 555)	1,112	4,983	8,760	12,628
23	NEISO - Uplift Charges (Account 555)				
24	NYISO				
25	NYISO - Net Purchases (Account 555)				
26	NYISO - Transmission Rights (Account 555)				
27	NYISO - Ancillary Services (Account 555)	(1,146)	(1,146)	(1,146)	(1,146)
28	PJM				
29	PJM - Net Purchases (Account 555)	(28,630)	(28,630)	(28,630)	(28,630)
30	PJM - Net Sales (Account 447)				
31	PJM - Transmission Rights (Account 555)				
32	PJM - Ancillary Services (Account 555)	31	278	692	821
33	PJM - Uplift Charges (Account 555)	435	270	404	7,543
34	SPP				
35	SPP - Net Purchases (Account 555)	33,873	70,473	137,128	208,617
36	SPP - Transmission Rights (Account 555)				
37	SPP - Ancillary Services (Account 555)	576	1,380	2,234	3,200
38	SPP - Uplift Charges (Account 555)	2,436	5,557	9,969	13,967
46	TOTAL	(20,121,839)	(43,135,523)	(186,015,322)	(269,069,626)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	8,430,590	[(c)]0	[(d)]0	810,379
2	Reactive Supply and Voltage	[(e)]0	[(f)]0	10,832,493	[(g)]0	[(h)]0	8,956,397
3	Regulation and Frequency Response	[(i)]0	[(j)]0	2,095,361	[(k)]0	[(l)]0	5,917,609
4	Energy Imbalance	0	0		0	0	
5	Operating Reserve - Spinning	[(m)]0	[(n)]0	1,889,386	[(o)]0	[(p)]0	5,060,071
6	Operating Reserve - Supplement	[(q)]0	[(r)]0	345,061	[(s)]0	[(t)]0	133,104
7	Other	[(u)]0	[(v)]0	[(w)]1,379,648	[(x)]0	[(y)]0	[(z)]1,896,426
8	Total (Lines 1 thru 7)			24,972,539			22,773,986

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	$	1,379,648

(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	$	118,242
NSPP Day-Ahead Ramp Capability Amount	$	200,252
NSPP Day-Ahead Short-Term Reserve Amount	$	895,374
NSPP Real-Time Short-Term Reserve Amount	$	682,558
		1,896,426

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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)] 7,572	5	18	[(b)] 6,229	1,666				
2	February	7,279	2	19	6,035	1,567				
3	March	6,742	11	11	5,554	1,440				
4	Total for Quarter 1				17,818	4,673	0			0
5	April	6,557	14	12	5,420	1,382				
6	May	7,991	12	18	6,526	1,677				
7	June	10,808	20	17	9,023	2,127				
8	Total for Quarter 2				20,969	5,186	0			0
9	July	10,486	18	17	8,752	2,056				
10	August	10,282	2	18	8,563	2,047				
11	September	9,525	1	17	7,838	1,974				
12	Total for Quarter 3				25,153	6,077	0			0
13	October	6,608	11	14	5,466	1,365				
14	November	7,063	30	18	5,738	1,574				
15	December	7,649	22	18	6,259	1,676				
16	Total for Quarter 4				17,463	4,615	0			0

17	Total				81,403	20,551	0	0	0	0

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	339
February	339
March	265
April	259
May	222
June	362
July	343
August	347
September	306
October	238
November	264
December	302
Total	3,586

"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	66
February	59
March	52
April	45
May	39
June	64
July	82
August	63
September	84
October	44
November	59
December	64
Total	721

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2023-04-07	Year/Period of Report End of: 2022/ 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)	33,396,282
3	Steam	9,566,089	23	Requirements Sales for Resale (See instruction 4, page 311.)	6,427,474
4	Nuclear	14,658,149	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	16,157,437
5	Hydro-Conventional	58,872	25	Energy Furnished Without Charge	319
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	49,813
7	Other	13,550,867	27	Total Energy Losses	1,564,326
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	37,833,977	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	57,595,651
10	Purchases (other than for Energy Storage)	19,761,674			
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)	57,595,651	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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)]5,383,410	1,808,341	5,352	5	18
30	February	4,699,764	1,465,645	5,194	2	19
31	March	4,541,402	1,278,200	4,799	11	11
32	April	4,352,654	1,190,309	4,629	14	12
33	May	4,112,719	994,209	5,607	12	18
34	June	5,070,601	1,434,760	7,882	20	17
35	July	5,526,884	1,391,985	7,686	18	17
36	August	5,431,619	1,375,285	7,446	2	18
37	September	4,556,557	1,251,753	6,857	1	17
38	October	4,467,782	1,314,208	4,661	11	14
39	November	4,486,485	1,214,876	4,747	17	18
40	December	4,965,774	1,437,866	5,326	22	18
41	Total	57,595,651	16,157,437			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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
5-Jan	1800	6,424	4,618	388	346	1,048	24
2-Feb	1900	6,210	4,485	377	332	993	23
11-Mar	1100	5,763	4,144	347	308	943	21
14-Apr	1200	5,566	4,065	278	286	917	20
12-May	1800	6,732	5,059	248	300	1,103	22
20-Jun	1700	9,244	6,973	393	516	1,339	23
18-Jul	1700	9,009	6,741	423	522	1,300	23
2-Aug	1800	8,768	6,534	362	550	1,299	23
1-Sep	1700	8,089	5,980	388	489	1,210	22
11-Oct	1400	5,597	4,104	253	304	918	18
17-Nov	1800	5,768	4,150	296	301	1,000	21
22-Dec	1800	6,453	4,649	355	322	1,103	24

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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 Mct.
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	405.66	554.29	559.32	644.06	280.50	684.97	1,186.20	585.90	2,084.45	25.00
6	Net Peak Demand on Plant - MW (60 minutes)	514	335	558	315	627	264	657	1,118	508	1,810	14
7	Plant Hours Connected to Load	2,888	910	3,185	551	4,644	439	8,684	8,760	4,111	8,760	8,057
8	Net Continuous Plant Capability (Megawatts)	511	386	526	543	580	348	646	1,092	500	1,879	18
9	When Not Limited by Condenser Water	511	386	526	543	580	348	646	1,092	500	1,879	18
10	When Limited by Condenser Water	511	327	494	447	530	252	617	1,040	454	1,879	18
11	Average Number of Employees	73	8	23	5	24	6	335	430	28	154	27
12	Net Generation, Exclusive of Plant Use - kWh	1,160,196,000	113,260,821	742,426,000	88,093,000	1,813,734,000	16,799,000	5,546,946,000	9,111,203,000	1,452,630,000	8,179,312,620	95,806,000
13	Cost of Plant: Land and Land Rights	1,335,100	1,155,577	952,692	141,878	523,582	351,801	778,651	969,282	450,133	7,502,735	499,773
14	Structures and Improvements	39,752,446	8,242,481	57,326,846	1,703,454	71,180,573	1,617,415	258,640,323	350,222,317	53,106,052	231,091,966	12,047,597
15	Equipment Costs	671,066,944	139,423,842	298,322,531	107,265,123	339,000,407	59,572,149	1,334,396,523	2,054,502,436	283,542,316	1,296,976,755	58,479,030

16	Asset Retirement Costs	4,604,709	712,520	64,419	170,055	20,138	26,851	68,805,022	(291,352,616)	55,000	11,627,501	1,935,846
17	Total cost (total 13 thru 20)	716,759,198	149,534,421	356,666,487	109,280,511	410,724,699	61,568,216	1,662,620,519	2,114,341,418	337,153,501	1,547,198,957	72,962,246
18	Cost per KW of Installed Capacity (line 17/5) Including	1,197.7928	368.6201	643.4655	195.3810	637.7119	219.4945	2,427.2895	1,782.4493	575.4455	742.2576	2,918.4898
19	Production Expenses: Oper, Supv, & Engr	811,834	127,717	229,241	33,153	279,978	33,579	16,444,379	22,389,814	313,180	1,993,777	370,303
20	Fuel	38,170,656	10,949,811	47,859,694	9,746,711	95,522,963	2,605,006	41,889,307	76,263,965	88,382,899	225,509,903	3,355,009
21	Coolants and Water (Nuclear Plants Only)							3,710,314	4,557,680			
22	Steam Expenses	4,944,669						21,688,315	28,898,387		8,886,244	2,081,955
23	Steam From Other Sources											
24	Steam Transferred (Cr)											
25	Electric Expenses	754,530	84,081	2,576,591	238,140	1,723,058	162,031	181,704	2,742,730	2,022,147	3,897,314	19,150
26	Misc Steam (or Nuclear) Power Expenses	3,179,297	601,079	1,032,571	112,560	872,064	115,088	52,228,440	69,253,193	901,809	8,945,513	1,263,029
27	Rents	326,705	27,027	102,837	13,751	60,637	14,068	2,107,730	3,205,628	74,269	842,424	114,237
28	Allowances											
29	Maintenance Supervision and Engineering	412,308	38,131	158,748	23,665	215,391	22,422	4,188,940	3,425,348	104,783	682,124	7,527
30	Maintenance of Structures	953,637	498,281	1,378,278	154,401	1,097,476	393,035			1,292,762	2,248,262	200,517
31	Maintenance of Boiler (or reactor) Plant	3,297,230						11,834,972	18,001,475		11,266,603	1,144,199
32	Maintenance of Electric Plant	640,658	1,041,816	3,660,069	635,212	1,018,208	498,923	4,243,742	7,728,698	1,750,553	1,517,042	266,130
33	Maintenance of Misc Steam (or Nuclear) Plant	1,822,751	7,124	89,765	23,060	164,043	23,280	9,228,735	15,795,888	205,048	3,922,578	524,842
34	Total Production Expenses	55,314,275	13,375,067	57,087,794	10,980,653	100,953,818	3,867,432	167,746,578	252,262,807	95,047,450	269,711,784	9,346,898
35	Expenses per Net kWh	0.0477	0.1181	0.0769	0.1246	0.0557	0.2302	0.0302	0.0277	0.0654	0.0330	0.0976

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	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	Nuclear	Nuclear	Gas	Oil	Coal	Oil	Gas	RDF	Wood
37	Fuel Unit	T	Mcf	bbl	Mcf	bbl	Mcf	Mcf	bbl	Mcf	Mcf	g	g	Mcf	bbl	T	bbl	Mcf	T	T
38	Quantity (Units) of Fuel Burned	689,823	121,368	507	1,333,638	2,039	6,037,222	1,036,983	4,078	12,970,734	292,306	478,385	848,586	10,953,558	2	4,418,736	22,719	46,504	150,403	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	(e) 8,801	801	15,570	1,028	179,941	1,077	976	135,060	1,015	1,098	122,441	113,060	1,000	15,570	(f) (g) 10,028	172,826	1,033	7,180	0

40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	44.561	9.670	73.850	8.068	92.851	7.918	9.006	100.046	7.364	8.255			8.069	69.241	47.321	167.166	8.787	2.635	
41	Average Cost of Fuel per Unit Burned	54.677	9.670	73.850	8.068	92.851	7.918	9.006	100.046	7.364	8.255			8.069	69.241	49.793	167.166	8.787	22.115	
42	Average Cost of Fuel Burned per Million BTU	[(b)]3.106	12.077	112.928	7.850	12.286	7.355	9.230	17.637	7.255	7.516	0.726	0.797	8.071	4.213	[(i)]2.483	23.030	8.507	1.540	
43	Average Cost of Fuel Burned per kWh Net Gen		0.050			0.100	0.080		0.100	0.060	0.160	0.010	0.010		0.057		0.030	0.040		
44	Average BTU per kWh Net Generation		15,222.80			12,838.66	11,435.66		10,167.66	7,940.41	19,972.70	10,243.68	10,674.87		7,116.91		10,235.17	22,658.63		

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 4.0 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 4.95 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.

(e) Concept: FuelBurnedAverageHeatContent

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

(f) Concept: FuelBurnedAverageHeatContent

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

(g) Concept: FuelBurnedAverageHeatContent

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

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

(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: 04/07/2023	Year/Period of Report End of: 2022/ 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)		13.89
6	Net Peak Demand on Plant-Megawatts (60 minutes)		12
7	Plant Hours Connect to Load		8,056
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		58,872,000
13	**Cost of Plant**		
14	Land and Land Rights		1,548,707
15	Structures and Improvements		1,440,465
16	Reservoirs, Dams, and Waterways		8,961,134
17	Equipment Costs		13,578,546

18	Roads, Railroads, and Bridges		152,109
19	Asset Retirement Costs		
20	Total cost (total 13 thru 20)		25,680,962
21	Cost per KW of Installed Capacity (line 20 / 5)		1,848.881
22	**Production Expenses**		
23	Operation Supervision and Engineering		71,095
24	Water for Power		35,532
25	Hydraulic Expenses		1,198
26	Electric Expenses		309,165
27	Misc Hydraulic Power Generation Expenses		138,570
28	Rents		23,067
29	Maintenance Supervision and Engineering		240
30	Maintenance of Structures		48,860
31	Maintenance of Reservoirs, Dams, and Waterways		189,740
32	Maintenance of Electric Plant		39,868
33	Maintenance of Misc Hydraulic Plant		1,328
34	Total Production Expenses (total 23 thru 33)		858,663
35	Expenses per net kWh		0.0146

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	24	130,774,000	79,736,399	3,466,800	2,983,037	615,324	3,921,948	RDF, Gas	1.23	
3	WIND TURBINES												
4	Rock Aetna Wind	2022	21.62	20	6,366,719	36,018,860	1,665,997	22,849		8,816			Wind
5	Blazing Star Wind 1	2020	218.00	205	911,198,701	350,483,594	1,607,723	5,178,635		489,348			Wind
6	Lake Benton Wind	2019	100.20	101	454,189,506	182,525,285	1,821,610	1,361,841		984,720			Wind
7	Ben Fowke Wind Energy Center	2008	100.50	96	251,992,370	226,360,426	2,252,343	1,341,179		1,204,425			Wind
8	Nobles Wind	2010	212.80	197	415,411,252	307,242,847	1,443,810	3,183,117		1,429,676			Wind
9	Borders Wind	2015	150.00	146	661,573,491	284,691,252	1,897,942	1,758,637		1,059,250			Wind
10	Pleasant Valley Wind	2015	200.00	194	863,323,495	370,363,825	1,851,819	3,054,791		1,893,684			Wind
11	Courtenay Wind	2016	200.00	193	810,572,176	308,635,392	1,543,177	3,228,909		1,870,239			Wind
12	Foxtail Wind	2019	163.60	150	551,856,178	248,849,021	1,521,082	1,473,874		1,097,794			Wind

13	Blazing Star Wind 2	2020	218.00	200	908,542,120	384,917,320	1,765,676	4,050,074		1,960,289			Wind
14	Community Wind North	2020	26.40	26	120,673,035	36,340,045	1,376,517	569,183		295,795			Wind
15	Crowned Ridge	2020	200.60	198	879,836,487	345,117,588	1,720,427	2,080,680		2,024,823			Wind
16	Jeffers	2020	44.00	44	208,415,304	52,457,887	1,192,225	906,089		586,829			Wind
17	Mower County	2020	98.90	91	350,969,231	225,762,753	2,282,738	2,166,556		493,692			Wind
18	Freeborn	2021	218.00	199	785,760,566	360,997,479	1,655,952	5,614,255		769,516			Wind
19	Dakota Range 1 & 2	2022	304.00	295	1,140,674,787	418,948,504	1,378,120	4,627,718		2,037,283			Wind
20	Northern Wind CV	2023	100.24	82	[(a)]2,568,964								Wind

FOOTNOTE DATA

(a) Concept: NetGenerationExcludingPlantUse
Test energy prior to commercial operation

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	(5703;01) CHISAGO CO.	FORBES	500.0	500.0	TOWER	61.450	0.000	1	9-1192 ACSR	2,237,403	16,180,329	18,417,732				
2	(5702;01) FORBES	RIE	500.0	500.0	TOWER	203.628	0.000	1	9-1192.5 ACSR	1,723,645	88,004,435	89,728,080				
3	(5650;01) DAKOTA RANGE WIND	TWIN BROOKS SW. ST.	345.0	345.0	SINGLE POLE	0.091	0.000	1	6-795 ACSR							
4	(0998;01) SIOUX CITY (WAPA)	SPLIT ROCK	345.0	345.0	SINGLE POLE	0.000	4.427	1	6-954 ACSS		670,200	670,200				
5	(0998;01) SIOUX CITY (WAPA)	SPLIT ROCK	345.0	345.0	SINGLE POLE	0.000	0.629		6-954 ACSS/TW							
6	(0997;01) SPLIT ROCK	WHITE (WAPA)	345.0	345.0	SINGLE POLE	4.912	0.240	1	6-954 ACSS/TW	139,860	8,455,822	8,595,682				
7	(0996;01) DICKINSON SW STA (GRE)	PARKERS LAKE	345.0	345.0	TOWER	0.133	9.593	1	6-954 ACSR		576,160	576,160				
8	(0994;01) ALLEN S KING	CHISAGO CO.	345.0	345.0	SINGLE POLE	0.000	31.547	1	6-954 ACSR		1,648,291	1,648,291				
9	(0994;01) ALLEN S KING	CHISAGO CO.	345.0	345.0	TOWER	0.000	6.660		6-795 ACSR							
10	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	H-FRAME	2.308	0.000	1	6-954 ACSR	472,775	7,210,872	7,683,647				

11	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	14.614	0.639	1	6-954 ACSR							
12	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	0.117	14.649	1	6-954 ACSR							
13	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	0.058	11.056	1	6-954 ACSR							
14	(0991;01) MONTICELLO SUB	SHERBURNE CO.	345.0	345.0	TOWER	0.072	5.753	1	6-954 ACSR		196,978	196,978				
15	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	K-FRAME	0.787	0.000	1	6-795 ACSR	80,238	1,436,429	1,516,667				
16	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	SINGLE POLE	0.000	0.841		6-795 ACSR							
17	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	TOWER	3.541	17.150		6-795 ACSR							
18	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	H-FRAME	0.532	0.000	1	6-795 ACSR	272,767	1,672,480	1,945,247				
19	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	K-FRAME	1.997	0.000		6-795 ACSR							
20	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	TOWER	6.022	0.000		6-795 ACSR							
21	(0988;01) BLUE LAKE	PARKERS LAKE	345.0	345.0	SINGLE POLE	0.000	2.102	1	6-795 ACSR		478,209	478,209				
22	(0988;01) BLUE LAKE	PARKERS LAKE	345.0	345.0	TOWER	0.078	12.616		6-795 ACSR							
23	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	K-FRAME	20.910	1.175	1	6-795 ACSR		4,692,966	4,692,966				
24	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	SINGLE POLE	0.000	5.108		6-795 ACSR							
25	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.000	2.331		6-795 ACSR							
26	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.148	2.335		6-954 ACSR							
27	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	K-FRAME	22.073	0.000	1	6-795 ACSR	661,692	8,097,684	8,759,376				
28	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	SINGLE POLE	5.108	0.000		6-795 ACSR							
29	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	2.329	0.000		6-795 ACSR							
30	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.121	2.357		6-954 ACSR							
31	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	H-FRAME	16.261	1.126	1	6-954 ACSR	17,816	14,641,383	14,659,199				
32	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	3.362	0.000		6-954 ACSR							

33	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	0.384	0.406		6-954 ACSR							
34	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	5.810	5.795		6-954 ACSR							
35	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	19.765	0.000	1	6-954 ACSR	506,296	10,174,263	10,680,559				
36	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	14.822	0.000		6-954 ACSR							
37	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	8.891	0.000		6-954 ACSR							
38	(0984;01) COON CREEK	TERMINAL	345.0	345.0	SINGLE POLE	0.000	4.613	1	6-795 ACSR	160,760	3,812,919	3,973,679				
39	(0984;01) COON CREEK	TERMINAL	345.0	345.0	TOWER	0.077	9.014		6-795 ACSR							
40	(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				
41	(0982;01) CRANDALL	LAKEFIELD GENERATING	345.0	345.0	K-FRAME	2.205	0.000	1	6-795 ACSR	24,675	406,619	431,294				
42	(0982;01) CRANDALL	WILMARTH	345.0	345.0	H-FRAME	4.319	0.000	1	6-795 ACSR	587,597	13,544,411	14,132,008				
43	(0982;01) CRANDALL	WILMARTH	345.0	345.0	K-FRAME	25.203	0.000	1	6-795 ACSR							
44	(0982;01) CRANDALL	WILMARTH	345.0	345.0	SINGLE POLE	1.443	21.434	1	6-556.5 ACSR-T2							
45	(0982;01) HELENA	SCOTT CO.	345.0	345.0	3 POLE	1.421	0.000	1	6-397.5 ZTACSR		20,713,968	20,713,968				
46	(0982;01) HELENA	SCOTT CO.	345.0	345.0	H-FRAME	15.728	0.000		6-397.5 ZTACSR							
47	(0982;01) HELENA	SHEAS LAKE	345.0	345.0	K-FRAME	7.454	0.000	1	6-795 ACSR	95,480	1,602,336	1,697,816				
48	(0982;01) LAKEFIELD JCT (IPW)	LAKEFIELD GENERATING	345.0	345.0	K-FRAME	18.685	0.000	1	6-795 ACSR	214,005	7,464,608	7,678,613				
49	(0982;01) SHEAS LAKE	WILMARTH	345.0	345.0	K-FRAME	22.317	0.000	1	6-795 ACSR	271,747	4,686,721	4,958,468				
50	(0982;01) SHEAS LAKE	WILMARTH	345.0	345.0	TOWER	1.115	0.000		6-795 ACSR							
51	(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				
52	(0981-MN;01) ALLEN S KING	EAU CLAIRE	345.0	345.0	TOWER	2.008	15.222		6-795 ACSR							
53	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.0	345.0	SINGLE POLE	31.453	0.545	1	6-954 ACSR	4,408,021	10,856,196	15,264,217				
54	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.0	345.0	TOWER	0.000	5.594		6-795 ACSR							

55	(0980;01) COON CREEK	KOHLMAN LAKE	345.0	345.0	SINGLE POLE	4.613	2.816	1	6-795 ACSR	1,384,573	2,657,526	4,042,099				
56	(0980;01) COON CREEK	KOHLMAN LAKE	345.0	345.0	TOWER	6.892	5.620		6-795 ACSR							
57	(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				
58	(0979;01) BYRON (SMMPA)	NORTH ROCHESTER	345.0	345.0	K-FRAME	13.517	0.000	1	6-795 ACSR	35,037	4,307,001	4,342,038				
59	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	345.0	345.0	H-FRAME	1.120	0.000	1	6-795 ACSR	43,098	5,272,671	5,315,769				
60	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	345.0	345.0	K-FRAME	15.177	0.000		6-795 ACSR							
61	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	K-FRAME	27.222	0.000	1	6-795 ACSR	67,126	8,541,478	8,608,604				
62	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	TOWER	2.422	0.000		6-954 ACSR							
63	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	H-FRAME	16.905	0.000	1	6-954 ACSR	868,700	16,113,725	16,982,425				
64	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	K-FRAME	3.371	0.000		6-954 ACSR							
65	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	TOWER	5.833	0.000		6-954 ACSR							
66	(0978;01) ELM CREEK	PARKERS LAKE	345.0	345.0	SINGLE POLE	0.586	0.000	1	6-954 ACSR	13,498	914,131	927,629				
67	(0978;01) ELM CREEK	PARKERS LAKE	345.0	345.0	TOWER	10.447	0.000		6-954 ACSR							
68	(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				
69	(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				
70	(0977;01) KOHLMAN LAKE	TERMINAL	345.0	345.0	TOWER	7.376	0.000		6-795 ACSR							
71	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.0	345.0	SINGLE POLE	3.816	0.000	1	6-795 ACSR	104,148	593,836	697,984				
72	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.0	345.0	TOWER	1.722	0.000		6-795 ACSR							
73	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	2 POLE	0.659	0.000	1	6-954 ACSR	873,092	4,579,023	5,452,115				
74	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	K-FRAME	8.890	0.000		6-954 ACSR							
75	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	SINGLE POLE	0.792	0.000		6-795 ACSR							
76	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	TOWER	17.122	0.000		6-795 ACSR							

77	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	TOWER	6.372	0.000		6-954 ACSR							
78	(0976;01) EDEN PRAIRIE	PARKERS LAKE	345.0	345.0	TOWER	9.486	0.000	1	6-795 ACSR	45,639	521,262	566,901				
79	(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				
80	(0976;01) HAMPTON	PRAIRIE ISLAND	345.0	345.0	TOWER	3.564	0.000		6-795 ACSR							
81	(0975;01) ALLEN S KING	RED ROCK	345.0	345.0	K-FRAME	3.544	0.000	1	6-795 ACSR	401,128	2,690,176	3,091,304				
82	(0975;01) ALLEN S KING	RED ROCK	345.0	345.0	TOWER	21.857	0.000		6-795 ACSR							
83	(0974;01) MANKATO ENERGY CENTER	WILMARTH	345.0	345.0	H-FRAME	0.218	0.000	1	6-795 ACSR		888,655	888,655				
84	(0973;01) MONTICELLO SUB	QUARRY	345.0	345.0	SINGLE POLE	[(a)]30.038	[(ae)]0.000	1	6-954 ACSS/TW	5,368,656	10,969,295	16,337,951				
85	(0972-MN;01) BROOKINGS CO.	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	[(b)]8.862	[(af)]0.000	1	6-954 ACSS/TW	7,954,672	57,171,639	65,126,311				
86	(0972-SD;01) BROOKINGS CO.	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	[(c)]10.192	[(ag)]0.000	1	6-954 ACSS/TW	509,810	20,993,906	21,503,716				
87	(0972;01) HAWKS NEST LAKE	LYON CO.	345.0	345.0	SINGLE POLE	[(d)]30.547	[(ah)]0.000	1	6-954 ACSS/TW		135,628	135,628				
88	(0972;01) HAWKS NEST LAKE	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	[(e)]9.958	[(ai)]0.000	1	6-954 ACSS/TW		530,922	530,922				
89	(0971;01) BROOKINGS CO.	WHITE (WAPA)	345.0	345.0	SINGLE POLE	0.434	0.000	1	6-795 ACSS	13,748	933,240	946,988				
90	(0970;02) BROOKINGS CO.	WHITE (WAPA)	345.0	345.0	SINGLE POLE	0.378	0.000	1	6-795 ACSS		1,215,849	1,215,849				
91	(0969;02) BLAZING STAR 1	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	0.080	0.000	1	6-954		7,782	7,782				
92	(0968;01) BLAZING STAR 1	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	0.079	0.000	1	6-954							
93	(0967;01) HUNTLEY (ITC)	WILMARTH	345.0	345.0	SINGLE POLE	[(f)]52.026	[(aj)]0.000	1	6-556.5 ACSR-T2	2,997,012	48,903,175	51,900,187				
94	(0966;01) BROOKINGS CO.	BIG STONE SOUTH	345.0	345.0	SINGLE POLE	[(g)]71.980	[(ak)]0.000	1	6-556.5 ACSR/T2	3,526,999	57,810,786	61,337,785				
95	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.0	345.0	2 POLE	[(h)]3.121	[(al)]0.000	1	6-954 ACSS/TW	5,358,507	59,722,203	65,080,710				
96	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.0	345.0	SINGLE POLE	[(i)]40.065	[(am)]0.000		6-954 ACSS/TW							
97	(0964;01) HAMPTON	NORTH ROCHESTER	345.0	345.0	SINGLE POLE	[(j)]37.851	[(an)]0.000	1	6-397.5 TACSR/VR2	9,430,408	54,553,588	63,983,996				
98	(0962;01) HAZEL CREEK	LYON CO.	345.0	345.0	SINGLE POLE	[(k)]24.543	[(ao)]0.000	1	6-954 ACSS/TW	340,384	26,971,692	27,312,076				

99	(0961;01) CHUB LAKE (GRE)	HAMPTON	345.0	345.0	SINGLE POLE	[l]18.101	[ap]0.000	1	6-954 ACSS/TW	7,244,068	37,681,201	44,925,269				
100	(0960;01) CHUB LAKE (GRE)	HELENA	345.0	345.0	SINGLE POLE	[m]20.870	[aq]0.000	1	6-954 ACSS/TW	8,314,945	36,282,633	44,597,578				
101	(0959;02) CEDAR MTN. (GRE)	HELENA	345.0	345.0	3 POLE	[n]0.000	[ar]0.906	1	6-954 ACSS/TW							
102	(0959;02) CEDAR MTN. (GRE)	HELENA	345.0	345.0	SINGLE POLE	[o]0.000	[as]72.157		6-954 ACSS/TW							
103	(0958;01) CEDAR MTN. (GRE)	HELENA	345.0	345.0	3 POLE	[p]0.906	[at]0.000	1	6-954 ACSS/TW	15,584,347	112,135,762	127,720,109				
104	(0958;01) CEDAR MTN. (GRE)	HELENA	345.0	345.0	SINGLE POLE	[q]72.196	[au]0.000		6-954 ACSS/TW							
105	(0957;02) CEDAR MTN. (GRE)	LYON CO.	345.0	345.0	SINGLE POLE	[r]0.000	[av]49.488	1	6-954 ACSS/TW							
106	(0956;01) CEDAR MTN. (GRE)	LYON CO.	345.0	345.0	SINGLE POLE	[s]49.488	[aw]0.000	1	6-954 ACSS/TW	5,315,434	65,839,990	71,155,424				
107	(0955-MN;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	2 POLE	[t]3.355	[ax]0.000	1	6-954 ACSS/TW	6,637,015	84,241,012	90,878,027				
108	(0955-MN;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	SINGLE POLE	[u]101.037	[ay]0.000		6-954 ACSS/TW							
109	(0955-ND;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	SINGLE POLE	[v]34.384	[az]0.000	1	6-954 ACSS/TW	1,513,232	22,705,097	24,218,329				
110	(0954;01) ALEXANDRIA SW. ST.	RIVERVIEW (GRE)	345.0	345.0	SINGLE POLE	[w]45.160	[ba]0.000	1	6-954 ACSS/TW	2,327,849	37,137,830	39,465,679				
111	(0954;01) QUARRY	RIVERVIEW (GRE)	345.0	345.0	SINGLE POLE	[x]36.090	[bb]0.000	1	6-954 ACSS/TW	1,860,437	29,680,864	31,541,301				
112	(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	57,400,334	60,916,002				
113	(0953;01) LAKEFIELD JCT (IPW)	NOBLES CO.	345.0	345.0	SINGLE POLE	13.270	0.000		6-954 ACSS/TW							
114	(0953-MN;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	10.689	0.000	1	6-397.5 ZTACSR	3,623,388	65,053,709	68,677,097				
115	(0953-MN;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	32.044	0.000		6-954 ACSS/TW							
116	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	4.427	0.000	1	6-954 ACSR	554,100	4,451,932	5,006,032				
117	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	5.073	0.000		6-954 ACSS/TW							
118	(0963;01) HAZEL CREEK	MINNESOTA VALLEY	230.0	345.0	2 POLE	0.633	0.000	1	6-954 ACSS/TW	355,907	9,176,023	9,531,930				
119	(0963;01) HAZEL CREEK	MINNESOTA VALLEY	230.0	345.0	SINGLE POLE	[y]4.336	[bc]0.000		6-954 ACSS/TW							
120	(0929;01) BORDER WIND FARM (RES)	PEACE GARDEN	230.0	230.0	2 POLE	0.042	0.000	1	6-		98,889	98,889				

121	(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				
122	(0927;01) FOXTAIL	FOXTAIL	230.0	230.0	SINGLE POLE	0.115	0.000	1	3-795 ACSR		48,277	48,277				
123	(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				
124	(0923;01) CASS LAKE (OTP)	WILTON (MPC)	230.0	230.0	SINGLE POLE	[z]19.318	[bd]0.000	1	3-795 ACSS	884,508	9,194,724	10,079,232				
125	(0922;01) BOSWELL (MINNESOTA POWER)	CASS LAKE (OTP)	230.0	230.0	SINGLE POLE	[aa]51.461	[be]0.000	1	3-795 ACSS	1,023,124	23,387,110	24,410,234				
126	(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				
127	(0920;01) PEACE GARDEN	RUGBY (OTP)	230.0	230.0	H-FRAME	54.672	0.000	1	3-954 ACSR		312,055	312,055				
128	(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				
129	(0919;01) PAYNESVILLE TRANS. S	WILLMAR (GRE)	230.0	230.0	SINGLE POLE	27.554	0.000		3-795 ACSR							
130	(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				
131	(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				
132	(0916;01) GRAND FORKS (WAPA)	PRAIRIE	230.0	230.0	SINGLE POLE	0.476	0.000		3-954 ACSR							
133	(0915;01) FARGO (WAPA)	SHEYENNE	230.0	230.0	H-FRAME	4.094	0.152	1	3-795 ACSR	21,223	818,189	839,412				
134	(0912;01) DRAYTON (MINNKOTA)	LETELLIER (MANITOBA HYDRO)	230.0	230.0	3 POLE	0.068	0.000	1	3-954 ACSR	57,281	3,010,357	3,067,638				
135	(0912;01) DRAYTON (MINNKOTA)	LETELLIER (MANITOBA HYDRO)	230.0	230.0	H-FRAME	28.660	0.000		3-954 ACSR							
136	(0911;01) AUDUBON (OTP)	SHEYENNE	230.0	230.0	H-FRAME	1.409	0.000	1	3-795 ACSR	10,733	237,425	248,158				
137	(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				
138	(0911;01) MAPLE RIVER	SHEYENNE	230.0	230.0	TOWER	0.047	3.734		3-795 ACSR							
139	(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				
140	(0909;01) AUDUBON (OTP)	HUBBARD (GRE)	230.0	230.0	H-FRAME	38.557	0.000	1	3-795 ACSR	57,863	7,828,503	7,886,366				
141	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	H-FRAME	0.922	0.000	1	3-795 ACSR	407,857	7,873,513	8,281,370				

142	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	K-FRAME	52.990	0.000		3-795 ACSR							
143	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	SINGLE POLE	10.887	0.098		3-1272 ACSR							
144	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	TOWER	2.783	0.000		3-1272 ACSR							
145	(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				
146	(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				
147	(0900;01) BLUE LAKE	MCLEOD (MUNI)	230.0	230.0	TOWER	45.151	0.000	1	3-795 ACSR							
148	(0900;02) GRANITE FALLS (WAPA)	PANTHER (GRE)	230.0	230.0	TOWER	32.809	0.000	1	3-795 ACSR	5,902	1,849,869	1,855,771				
149	(0900;01) MCLEOD (MUNI)	PANTHER (GRE)	230.0	230.0	TOWER	28.490	0.000	1	3-795 ACSR	59,673	1,511,161	1,570,834				
150	(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				
151	(5312;01) ADAMS	MOWER CO. WIND FARM	161.0	161.0	2 POLE	0.203	0.000	1	3-477 ACSR		1,024,202	1,024,202				
152	(5312;01) ADAMS	MOWER CO. WIND FARM	161.0	161.0	SINGLE POLE	7.729	0.000		3-477 ACSR							
153	(5311;01) PLEASANT VALLEY (GRE)	PLEASANT VALLEY WIND FARM	161.0	161.0	SINGLE POLE	4.982	0.000	1	3-954 ACSR		2,268,717	2,268,717				
154	(5310;01) NORTHERN HILLS	NORTH ROCHESTER	161.0	161.0	SINGLE POLE	[ab]15.507	[bf]0.000	1	3-795 ACSS	1,314,415	9,559,156	10,873,571				
155	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.0	161.0	SINGLE POLE	[ac]11.408	[bg]0.000	1	3-397.5 TACSR/TW	567,003	12,379,705	12,946,708				
156	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.0	161.0	SINGLE POLE	[ad]1.145	[bh]15.108		6-954 ACSS/TW							
157	(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				
158	(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				
159	(5305-MN;01) LAWRENCE CREEK	ST CROIX FALLS	161.0	161.0	SINGLE POLE	1.567	0.000	1	3-795 ACSS	52,746	10,282,174	10,334,920				
160	(5305-MN;01) LAWRENCE CREEK	ST CROIX FALLS	161.0	161.0	UNDERGROUND	0.579	0.000		3-3000 CU							
161	(5301;01) ELK (ALLIANT)	ROCK CO.	161.0	161.0	H-FRAME	5.253	0.135	1	3-477 ACSR	16,110	646,377	662,487				
162	(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				
163	(5301-MN;01) ROCK CO.	SPLIT ROCK	161.0	161.0	SINGLE POLE	0.081	0.000		3-477 ACSR							

164	(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				
165	(5301-SD;01) ROCK CO.	SPLIT ROCK	161.0	161.0	SINGLE POLE	0.867	0.000		3-2312 ACSR							
166	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.0	161.0	H-FRAME	29.952	0.154	1	3-477 ACSR	143,079	1,967,358	2,110,437				
167	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.0	161.0	SINGLE POLE	0.000	1.410		3-565.3 ACSS/TW							
168	SUMMARY OF 115 KV SYSTEM		115.0	115.0	Overhead	1,480.693	151.834			23,676,854	743,298,806	766,975,660				
169	SUMMARY OF 115 KV SYSTEM		115.0	115.0	Underground	13.221	0.000									
170	SUMMARY OF 69 KV SYSTEM		69.0	69.0	Overhead	1,489.083	98.289			6,569,119	347,904,744	354,473,863				
171	SUMMARY OF 69 KV SYSTEM		69.0	69.0	Underground	1.532	0.000									
172	SUMMARY OF 34.5 KV SYSTEM		34.5	34.5	Overhead	60.119	32.471			436,068	29,463,324	29,899,392				
173	SUMMARY OF 34.5 KV SYSTEM		34.5	34.5	Underground	0.590	0.000									
174	Expenses, except depreciation and taxes												615,167	9,105,892	1,234,581	10,955,640
36	TOTAL					5,227	629	109		151,273,294	2,486,853,302	2,638,126,596	615,167	9,105,892	1,234,581	10,955,640

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: LengthForStandAloneTransmissionLines

NSM ((0973;01) MONTICELLO SUB-QUARRY) : Xcel Energy owns 36.1%(10.84 miles) of 30.04 miles of this circuit: remaining 63.9%(19.19 miles) is owned by other members of a joint venture partnership

(b) Concept: LengthForStandAloneTransmissionLines

NSM ((0972-MN;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.01 miles) of 8.86 miles of this circuit: remaining 32.2%(2.85 miles) is owned by other members of a joint venture partnership

(c) Concept: LengthForStandAloneTransmissionLines

NSM ((0972-SD;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.91 miles) of 10.19 miles of this circuit: remaining 32.2%(3.28 miles) is owned by other members of a joint venture partnership

(d) Concept: LengthForStandAloneTransmissionLines

NSM ((0972;01) HAWKS NEST LAKE-LYON CO.) : Xcel Energy owns 67.8%(20.71 miles) of 30.55 miles of this circuit: remaining 32.2%(9.84 miles) is owned by other members of a joint venture partnership

(e) Concept: LengthForStandAloneTransmissionLines

NSM ((0972;01) HAWKS NEST LAKE-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.75 miles) of 9.96 miles of this circuit: remaining 32.2%(3.21 miles) is owned by other members of a joint venture partnership

(f) Concept: LengthForStandAloneTransmissionLines

NSM ((0967;01) HUNTLEY (ITC)-WILMARTH) : Xcel Energy owns 50.0%(26.01 miles) of 52.03 miles of this circuit: remaining 50.0%(26.01 miles) is owned by other operating companies

(g) Concept: LengthForStandAloneTransmissionLines

NSM ((0966;01) BROOKINGS CO.-BIG STONE SOUTH) : Xcel Energy owns 50.0%(35.99 miles) of 71.98 miles of this circuit: remaining 50.0%(35.99 miles) is owned by other members of a joint venture partnership

(h) Concept: LengthForStandAloneTransmissionLines

NSM ((0965-MN;01) BRIGGS ROAD-NORTH ROCHESTER) : Xcel Energy owns 64.0%(27.64 miles) of 43.19 miles of this circuit: remaining 36.0%(15.55 miles) is owned by other members of a joint venture partnership

(i) Concept: LengthForStandAloneTransmissionLines

NSM ((0965-MN;01) BRIGGS ROAD-NORTH ROCHESTER) : Xcel Energy owns 64.0%(27.64 miles) of 43.19 miles of this circuit: remaining 36.0%(15.55 miles) is owned by other members of a joint venture partnership

(j) Concept: LengthForStandAloneTransmissionLines

NSM ((0964;01) HAMPTON-NORTH ROCHESTER) : Xcel Energy owns 64.0%(24.22 miles) of 37.85 miles of this circuit: remaining 36.0%(13.63 miles) is owned by other members of a joint venture partnership

(k) Concept: LengthForStandAloneTransmissionLines

NSM ((0962;01) HAZEL CREEK-LYON CO.) : Xcel Energy owns 67.8%(16.64 miles) of 24.54 miles of this circuit: remaining 32.2%(7.9 miles) is owned by other members of a joint venture partnership

(l) Concept: LengthForStandAloneTransmissionLines

NSM ((0961;01) CHUB LAKE (GRE)-HAMPTON) : Xcel Energy owns 67.8%(12.27 miles) of 18.1 miles of this circuit: remaining 32.2%(5.83 miles) is owned by other members of a joint venture partnership

(m) Concept: LengthForStandAloneTransmissionLines

NSM ((0960;01) CHUB LAKE (GRE)-HELENA) : Xcel Energy owns 67.8%(14.15 miles) of 20.87 miles of this circuit: remaining 32.2%(6.72 miles) is owned by other members of a joint venture partnership

(n) Concept: LengthForStandAloneTransmissionLines

NSM ((0959;02) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.53 miles) of 73.06 miles of this circuit: remaining 32.2%(23.53 miles) is owned by other members of a joint venture partnership

(o) Concept: LengthForStandAloneTransmissionLines

NSM ((0959;02) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.53 miles) of 73.06 miles of this circuit: remaining 32.2%(23.53 miles) is owned by other members of a joint venture partnership

(p) Concept: LengthForStandAloneTransmissionLines

NSM ((0958;01) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.56 miles) of 73.1 miles of this circuit: remaining 32.2%(23.54 miles) is owned by other members of a joint venture partnership

(q) Concept: LengthForStandAloneTransmissionLines
NSM ((0958;01) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.56 miles) of 73.1 miles of this circuit: remaining 32.2%(23.54 miles) is owned by other members of a joint venture partnership
(r) Concept: LengthForStandAloneTransmissionLines
NSM ((0957;02) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8%(33.55 miles) of 49.49 miles of this circuit: remaining 32.2%(15.94 miles) is owned by other members of a joint venture partnership
(s) Concept: LengthForStandAloneTransmissionLines
NSM ((0956;01) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8%(33.55 miles) of 49.49 miles of this circuit: remaining 32.2%(15.94 miles) is owned by other members of a joint venture partnership
(t) Concept: LengthForStandAloneTransmissionLines
NSM ((0955-MN;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(37.69 miles) of 104.39 miles of this circuit: remaining 63.9%(66.71 miles) is owned by other members of a joint venture partnership
(u) Concept: LengthForStandAloneTransmissionLines
NSM ((0955-MN;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(37.69 miles) of 104.39 miles of this circuit: remaining 63.9%(66.71 miles) is owned by other members of a joint venture partnership
(v) Concept: LengthForStandAloneTransmissionLines
NSM ((0955-ND;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(12.41 miles) of 34.38 miles of this circuit: remaining 63.9%(21.97 miles) is owned by other members of a joint venture partnership
(w) Concept: LengthForStandAloneTransmissionLines
NSM ((0954;01) ALEXANDRIA SW. ST.-RIVERVIEW (GRE)) : Xcel Energy owns 36.1%(16.3 miles) of 45.16 miles of this circuit: remaining 63.9%(28.86 miles) is owned by other members of a joint venture partnership
(x) Concept: LengthForStandAloneTransmissionLines
NSM ((0954;01) QUARRY-RIVERVIEW (GRE)) : Xcel Energy owns 36.1%(13.03 miles) of 36.09 miles of this circuit: remaining 63.9%(23.06 miles) is owned by other members of a joint venture partnership
(y) Concept: LengthForStandAloneTransmissionLines
NSM ((0963;01) HAZEL CREEK-MINNESOTA VALLEY) : Xcel Energy owns 67.8%(3.37 miles) of 4.97 miles of this circuit: remaining 32.2%(1.6 miles) is owned by other members of a joint venture partnership
(z) Concept: LengthForStandAloneTransmissionLines
NSM ((0923;01) CASS LAKE (OTP)-WILTON (MPC)) : Xcel Energy owns 26.2%(5.06 miles) of 19.32 miles of this circuit: remaining 73.8%(14.26 miles) is owned by other members of a joint venture partnership
(aa) Concept: LengthForStandAloneTransmissionLines
NSM ((0922;01) BOSWELL (MINNESOTA POWER)-CASS LAKE (OTP)) : Xcel Energy owns 26.2%(13.48 miles) of 51.46 miles of this circuit: remaining 73.8%(37.98 miles) is owned by other members of a joint venture partnership
(ab) Concept: LengthForStandAloneTransmissionLines
NSM ((5310;01) NORTHERN HILLS-NORTH ROCHESTER) : Xcel Energy owns 64.0%(9.92 miles) of 15.51 miles of this circuit: remaining 36.0%(5.58 miles) is owned by other members of a joint venture partnership
(ac) Concept: LengthForStandAloneTransmissionLines
NSM ((5309;01) CHESTER (RPU)-NORTH ROCHESTER) : Xcel Energy owns 64.0%(17.7 miles) of 27.66 miles of this circuit: remaining 36.0%(9.96 miles) is owned by other members of a joint venture partnership
(ad) Concept: LengthForStandAloneTransmissionLines
NSM ((5309;01) CHESTER (RPU)-NORTH ROCHESTER) : Xcel Energy owns 64.0%(17.7 miles) of 27.66 miles of this circuit: remaining 36.0%(9.96 miles) is owned by other members of a joint venture partnership
(ae) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0973;01) MONTICELLO SUB-QUARRY) : Xcel Energy owns 36.1%(10.84 miles) of 30.04 miles of this circuit: remaining 63.9%(19.19 miles) is owned by other members of a joint venture partnership
(af) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0972-MN;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.01 miles) of 8.86 miles of this circuit: remaining 32.2%(2.85 miles) is owned by other members of a joint venture partnership
(ag) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0972-SD;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.91 miles) of 10.19 miles of this circuit: remaining 32.2%(3.28 miles) is owned by other members of a joint venture partnership
(ah) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0972;01) HAWKS NEST LAKE-LYON CO.) : Xcel Energy owns 67.8%(20.71 miles) of 30.55 miles of this circuit: remaining 32.2%(9.84 miles) is owned by other members of a joint venture partnership
(ai) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0972;01) HAWKS NEST LAKE-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.75 miles) of 9.96 miles of this circuit: remaining 32.2%(3.21 miles) is owned by other members of a joint venture partnership

(aj) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0967;01) HUNTLEY (ITC)-WILMARTH) : Xcel Energy owns 50.0%(26.01 miles) of 52.03 miles of this circuit: remaining 50.0%(26.01 miles) is owned by other operating companies
(ak) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0966;01) BROOKINGS CO.-BIG STONE SOUTH) : Xcel Energy owns 50.0%(35.99 miles) of 71.98 miles of this circuit: remaining 50.0%(35.99 miles) is owned by other members of a joint venture partnership
(al) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0965-MN;01) BRIGGS ROAD-NORTH ROCHESTER) : Xcel Energy owns 64.0%(27.64 miles) of 43.19 miles of this circuit: remaining 36.0%(15.55 miles) is owned by other members of a joint venture partnership
(am) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0965-MN;01) BRIGGS ROAD-NORTH ROCHESTER) : Xcel Energy owns 64.0%(27.64 miles) of 43.19 miles of this circuit: remaining 36.0%(15.55 miles) is owned by other members of a joint venture partnership
(an) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((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
(ao) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0962;01) HAZEL CREEK-LYON CO.) : Xcel Energy owns 67.8%(16.64 miles) of 24.54 miles of this circuit: remaining 32.2%(7.9 miles) is owned by other members of a joint venture partnership
(ap) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0961;01) CHUB LAKE (GRE)-HAMPTON) : Xcel Energy owns 67.8%(12.27 miles) of 18.1 miles of this circuit: remaining 32.2%(5.83 miles) is owned by other members of a joint venture partnership
(aq) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0960;01) CHUB LAKE (GRE)-HELENA) : Xcel Energy owns 67.8%(14.15 miles) of 20.87 miles of this circuit: remaining 32.2%(6.72 miles) is owned by other members of a joint venture partnership
(ar) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0959;02) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.53 miles) of 73.06 miles of this circuit: remaining 32.2%(23.53 miles) is owned by other members of a joint venture partnership
(as) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0959;02) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.53 miles) of 73.06 miles of this circuit: remaining 32.2%(23.53 miles) is owned by other members of a joint venture partnership
(at) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((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
(au) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0958;01) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.56 miles) of 73.1 miles of this circuit: remaining 32.2%(23.54 miles) is owned by other members of a joint venture partnership
(av) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((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
(aw) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0956;01) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8%(33.55 miles) of 49.49 miles of this circuit: remaining 32.2%(15.94 miles) is owned by other members of a joint venture partnership
(ax) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0955-MN;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(37.69 miles) of 104.39 miles of this circuit: remaining 63.9%(66.71 miles) is owned by other members of a joint venture partnership
(ay) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0955-MN;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(37.69 miles) of 104.39 miles of this circuit: remaining 63.9%(66.71 miles) is owned by other members of a joint venture partnership
(az) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0955-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
(ba) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0954;01) ALEXANDRIA SW. ST.-RIVERVIEW (GRE)) : Xcel Energy owns 36.1%(16.3 miles) of 45.16 miles of this circuit: remaining 63.9%(28.86 miles) is owned by other members of a joint venture partnership
(bb) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0954;01) QUARRY-RIVERVIEW (GRE)) : Xcel Energy owns 36.1%(13.03 miles) of 36.09 miles of this circuit: remaining 63.9%(23.06 miles) is owned by other members of a joint venture partnership

(bc) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0963;01) HAZEL CREEK-MINNESOTA VALLEY) : Xcel Energy owns 67.8%(3.37 miles) of 4.97 miles of this circuit: remaining 32.2%(1.6 miles) is owned by other members of a joint venture partnership
(bd) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0923;01) CASS LAKE (OTP)-WILTON (MPC)) : Xcel Energy owns 26.2%(5.06 miles) of 19.32 miles of this circuit: remaining 73.8%(14.26 miles) is owned by other members of a joint venture partnership
(be) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((0922;01) BOSWELL (MINNESOTA POWER)-CASS LAKE (OTP)) : Xcel Energy owns 26.2%(13.48 miles) of 51.46 miles of this circuit: remaining 73.8%(37.98 miles) is owned by other members of a joint venture partnership
(bf) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((5310;01) NORTHERN HILLS-NORTH ROCHESTER) : Xcel Energy owns 64.0%(9.92 miles) of 15.51 miles of this circuit: remaining 36.0%(5.58 miles) is owned by other members of a joint venture partnership
(bg) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((5309;01) CHESTER (RPU)-NORTH ROCHESTER) : Xcel Energy owns 64.0%(17.7 miles) of 27.66 miles of this circuit: remaining 36.0%(9.96 miles) is owned by other members of a joint venture partnership
(bh) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures
NSM ((5309;01) CHESTER (RPU)-NORTH ROCHESTER) : Xcel Energy owns 64.0%(17.7 miles) of 27.66 miles of this circuit: remaining 36.0%(9.96 miles) is owned by other members of a joint venture partnership

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	(0712;01) CANNON FALLS TRANS	ZUMBROTA	0.371	SINGLE POLE	13	1	1	3-4/0	ACSR/VR2	6/1	69.0		683,783	283,140		966,923	
2	(0521,0522;01) BUFFALO RIDGE	CHB341	0.193	2 POLE	28	1	1	3-477	ACSR/T2	18/1	34.5		32,738	147,342		180,080	
3	(0520;01) BUFFALO RIDGE	ECHO	0.193	2 POLE	26	1	1	3-477	ACSR/T2	18/1	34.5		648,293	241,416		889,709	
4	(5650;01) DAKOTA RANGE WIND	TWIN BROOKS SW. ST.	0.091	SINGLE POLE	22	1	1	6-795	ACSR	26/7	345.0						
44	TOTAL		1		89	4	4						1,364,814	671,898		2,036,712	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/07/2023	Year/Period of Report End of: 2022/ 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	GREEN ISLE-TR01	Distribution	Unattended	69.00	4.16		2.00	1				
207	GREENFIELD-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
208	HADLEY-TR01	Distribution	Unattended	69.00	13.80		2.80	1				
209	HASSAN-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
210	HASSAN-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
211	HASTINGS-TR01	Distribution	Unattended	69.00	12.50		28.00	1				
212	HASTINGS-TR02	Distribution	Unattended	69.00	12.50		28.00	1				

213	HATFIELD-TR01ABC	Distribution	Unattended	23.00	12.50		2.00	3				
214	HATTON-TR01	Distribution	Unattended	69.00	4.16		2.00	1				
215	HAZEL CREEK-TR09	Transmission	Unattended	345.00	230.00	14.00	336.00	1				
216	HECTOR-TR01	Distribution	Unattended	69.00	4.16		3.00	1				
217	HENDERSON-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
218	HIAWATHA WEST-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
219	HIGH BRIDGE-TR04	Distribution	Unattended	115.00	13.80		46.70	1				
220	HOLLYDALE-TR01	Distribution	Unattended	69.00	13.80		25.00	1				
221	HOLLYDALE-TR02	Distribution	Unattended	34.50	13.80		28.00	1				
222	HOWARD LAKE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
223	HUGO-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
224	HUGO-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
225	HYLAND LAKE-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
226	HYLAND LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
227	INDIANA-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
228	INDIANA-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
229	INVER GROVE-TR01	Transmission	Unattended	115.00	69.00	14.00	63.00	1				
230	INVER GROVE-TR02	Transmission	Unattended	115.00	69.00	14.00	63.00	1				
231	INVER HILLS-PLTSDU	Distribution	Unattended	34.50	13.80		1.00	1				
232	INVER HILLS-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
233	JAMAICA-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
234	JORDAN-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
235	KASSON-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
236	KASSON-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
237	KEGAN LAKE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
238	KENYON-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
239	KIMBALL-TR01	Distribution	Unattended	69.00	12.50		7.00	1				

240	KOCH REFINERY-TR11	Distribution	Unattended	115.00	13.80		46.70	1				
241	KOCH REFINERY-TR12	Distribution	Unattended	115.00	13.80		46.70	1				
242	KOCH REFINERY-TR13	Distribution	Unattended	115.00	13.80		46.70	1				
243	KOCH REFINERY-TR14	Distribution	Unattended	115.00	13.80		46.70	1				
244	KOCH REFINERY-TR15	Distribution	Unattended	115.00	13.80		46.70	1				
245	KOCH REFINERY-TR16	Distribution	Unattended	115.00	13.80		46.70	1				
246	KOHLMAN LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
247	KOHLMAN LAKE-TR02	Distribution	Unattended	115.00	13.80		50.00	1				
248	KOHLMAN LAKE-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
249	KOHLMAN LAKE-TR10	Transmission	Unattended	345.00	115.00	14.00	450.00	1				
250	LA CRESCENT-TR01	Distribution	Unattended	69.00	13.80		16.00	1				
251	LAFAYETTE-TR01	Distribution	Unattended	69.00	4.16		1.00	1				
252	LAKE BAVARIA-TR01	Distribution	Unattended	115.00	34.50		73.50	1				
253	LAKE EMILY-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
254	LAKE LILLIAN-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
255	LAKE PULASKI-TR03	Distribution	Unattended	115.00	34.50		28.00	1				
256	LAKE PULASKI-TR05	Transmission	Unattended	115.00	69.00	35.00	46.70	1				
257	LAKE PULASKI-TR06	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
258	LAKE YANKTON-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
259	LAKE YANKTON-TR02	Transmission	Unattended	115.00	69.00	14.00	15.00	1				
260	LAKE YANKTON-TR03	Distribution	Unattended	69.00	13.80		10.50	1				
261	LARIMORE-TR01	Distribution	Unattended	69.00	4.16		4.00	1				

262	LAWRENCE CREEK-TR01	Distribution	Unattended	115.00	34.50		28.00	1				
263	LAWRENCE CREEK-TR04	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
264	LAWRENCE CREEK-TR05	Transmission	Unattended	161.00	115.00	14.00	336.00	1				
265	LAWRENCE-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
266	LAWRENCE-TR07	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
267	LAWRENCE-TR08	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
268	LENNOX-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
269	LESTER PRAIRIE-TR01	Distribution	Unattended	69.00	13.80		9.00	1				
270	LEXINGTON-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
271	LEXINGTON-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
272	LEXINGTON-TR03	Distribution	Unattended	115.00	34.50		70.00	1				
273	LEXINGTON-TR04	Distribution	Unattended	34.50	13.80		46.70	1				
274	LINCOLN COUNTY-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
275	LINCOLN COUNTY-TR07	Distribution	Unattended	115.00	13.80		50.00	1				
276	LINCOLN COUNTY-TR08	Distribution	Unattended	115.00	13.80		50.00	1				
277	LINDE-TR01	Distribution	Unattended	115.00	13.80		50.00	1				
278	LINDSTROM-TR01	Distribution	Unattended	115.00	12.50		28.70	1				
279	LINDSTROM-TR02	Distribution	Unattended	115.00	12.50		28.70	1				
280	LINN STREET-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
281	LINN STREET-TR02	Distribution	Unattended	69.00	12.50		10.50	1				
282	LONE OAK-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
283	LONE OAK-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
284	LONG LAKE-TR01	Distribution	Unattended	115.00	13.80		12.00	1				
285	LONG LAKE-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
286	LOUISE-TR01	Distribution	Unattended	115.00	13.80		51.50	1				

287	LOWRY-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
288	LYON COUNTY-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
289	LYON COUNTY-TR09	Transmission	Unattended	345.00	115.00	35.00	270.00	1				
290	M E INTERNATIONAL-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
291	M E INTERNATIONAL-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
292	MAIN STREET-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
293	MAIN STREET-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
294	MAPLE LAKE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
295	MAPLE RIVER-TR05	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
296	MAPLE RIVER-TR06	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
297	MAPLETON-TR01	Distribution	Unattended	69.00	13.80		6.00	1				
298	MARION-TR01	Distribution	Unattended	23.00	4.16		4.00	1				
299	MAYHEW LAKE-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
300	MAYNARD TRANSMISSION-TR01	Transmission	Unattended	115.00	69.00		46.70	1				
301	MAYNARD-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
302	MAYVILLE-TR01	Distribution	Unattended	69.00	4.16		6.00	1				
303	MAYVILLE-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
304	MAZEPPA-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
305	MEDFORD JUNCTION-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
306	MEDICINE LAKE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
307	MEDICINE LAKE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
308	MEDICINE LAKE-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
309	MEIRE GROVE-TR01	Distribution	Unattended	69.00	12.50		2.00	1				
310	MERIDEN-TR01	Distribution	Unattended	69.00	12.50		3.00	1				

311	MERRIAM PARK-TR01	Distribution	Unattended	115.00	13.80		63.00	1				
312	MERRIAM PARK-TR02	Distribution	Unattended	115.00	13.80		72.00	1				
313	MERRIAM PARK-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
314	MIDTOWN-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
315	MINNEHAHA-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
316	MINNEHAHA-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
317	MINNESOTA LAKE-TR01	Distribution	Unattended	69.00	4.16		2.00	1				
318	MINNESOTA PIPELINE-TR01	Distribution	Unattended	115.00	4.16		8.00	1				
319	MINNESOTA VALLEY-TR02	Distribution	Unattended	69.00	23.00		14.00	1				
320	MINNESOTA VALLEY-TR05	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
321	MINNESOTA VALLEY-TR06	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
322	MINNESOTA VALLEY-TR11	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
323	MINNESOTA VALLEY-TR12	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
324	MONTEVIDEO-TR01	Distribution	Unattended	69.00	4.16		6.00	1				
325	MONTEVIDEO-TR02	Distribution	Unattended	69.00	12.50		5.00	1				
326	MONTICELLO-TR06	Transmission	Unattended	345.00	230.00	14.00	336.00	1				
327	MONTICELLO-TR10	Transmission	Unattended	345.00	115.00	14.00	345.00	1				
328	MONTROSE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
329	MOORE LAKE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
330	MOORE LAKE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
331	MOORE LAKE-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
332	MORGAN-TR01	Distribution	Unattended	69.00	23.00		14.00	1				
333	MORRISTOWN-TR01	Distribution	Unattended	69.00	12.50		5.00	1				

334	MOUND-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
335	MOUND-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
336	NERSTRAND-TR01XY	Distribution	Unattended	69.00	12.50		3.00	2				
337	NINE MILE CREEK-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
338	NINE MILE CREEK-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
339	NOBLES COUNTY-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
340	NOBLES COUNTY-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
341	NOBLES COUNTY-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
342	NOBLES COUNTY-TR10	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
343	NORDIC-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
344	NORDIC-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
345	NORTH BROADWAY-TR01	Distribution	Unattended	23.00	4.16		5.00	1				
346	NORTH BROADWAY-TR02	Distribution	Unattended	23.00	4.16		5.00	1				
347	NORTH ROCHESTER-TR09	Transmission	Unattended	345.00	161.00	35.00	672.00	1				
348	NORTHFIELD-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
349	NORTHFIELD-TR02	Distribution	Unattended	69.00	13.80		17.00	1				
350	OAK PARK-TR01	Distribution	Unattended	115.00	23.00	14.00	28.00	1				
351	OAK PARK-TR07	Distribution	Unattended	115.00	13.80		46.70	1				
352	OAK PARK-TR08	Distribution	Unattended	115.00	13.80		46.70	1				
353	OAKDALE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
354	OAKDALE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
355	ORONO-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
356	OSSEO-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
357	OSSEO-TR02	Distribution	Unattended	115.00	13.80		70.00	1				

358	PARKERS LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
359	PARKERS LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
360	PARKERS LAKE-TR03	Distribution	Unattended	115.00	13.80		50.00	1				
361	PARKERS LAKE-TR09ABC	Transmission	Unattended	345.00	115.00	14.00	450.00	3				
362	PARKERS LAKE-TR10ABC	Transmission	Unattended	345.00	115.00	14.00	450.00	3				
363	PAYNESVILLE XMSN-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
364	PAYNESVILLE XMSN-TR02	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
365	PAYNESVILLE XMSN-TR04	Distribution	Unattended	115.00	34.50		28.00	1				
366	PAYNESVILLE XMSN-TR09	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
367	PINE BEND-TR03	Distribution	Unattended	69.00	13.80		14.00	1				
368	PINE ISLAND-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
369	PINE ISLAND-TR02	Distribution	Unattended	69.00	12.50		7.00	1				
370	PIPESTONE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
371	PIPESTONE-TR02	Distribution	Unattended	69.00	4.16		9.00	1				
372	PIPESTONE-TR03	Distribution	Unattended	69.00	25.00		6.00	1				
373	PIPESTONE-TR05	Transmission	Unattended	115.00	69.00	3.00	25.00	1				
374	PIPESTONE-TR06	Transmission	Unattended	115.00	69.00	14.00	25.00	1				
375	PLATO-TR01	Distribution	Unattended	115.00	12.50		15.00	1				
376	PRAIRIE ISLAND-TR10	Transmission	Unattended	345.00	161.00	14.00	224.00	1				
377	PRAIRIE-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
378	PRAIRIE-TR03	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
379	PRAIRIE-TR05	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
380	PRAIRIE-TR07	Transmission	Unattended	230.00	115.00	14.00	336.00	1				

381	PRAIRIE-TR08	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
382	PRIOR-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
383	QUARRY-TR09	Transmission	Unattended	345.00	115.00	35.00	448.00	1				
384	RAMSEY-TR01	Distribution	Unattended	115.00	13.80		50.00	1				
385	RAMSEY-TR02	Distribution	Unattended	115.00	13.80		50.00	1				
386	RAPIDAN-TR01	Distribution	Unattended	69.00	13.80		3.00	1				
387	RED RIVER-TR01	Distribution	Unattended	115.00	23.00	14.00	91.00	1				
388	RED RIVER-TR02	Distribution	Unattended	115.00	23.00	14.00	91.00	1				
389	RED RIVER-TR03	Distribution	Unattended	115.00	23.00	5.00	91.00	1				
390	RED ROCK-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
391	RED ROCK-TR02	Distribution	Unattended	115.00	13.80		20.00	1				
392	RED ROCK-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
393	RED ROCK-TR05	Transmission	Unattended	345.00	230.00	14.00	336.00	1				
394	RED ROCK-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
395	RED ROCK-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
396	RED WING-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
397	RED WING-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
398	RENVILLE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
399	REYNOLDS-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
400	RICH SPRING-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
401	RICH VALLEY-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
402	RICHMOND-TR01	Distribution	Unattended	69.00	13.80		5.00	1				
403	RIVERSIDE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
404	RIVERSIDE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
405	RIVERWOOD-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
406	RIVERWOOD-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
407	ROCK RIVER-TR01	Distribution	Unattended	69.00	23.00		8.00	1				
408	ROGERS LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				

409	ROGERS LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
410	ROSE PLACE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
411	ROSE PLACE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
412	ROSEMOUNT-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
413	SACRED HEART-TR01	Distribution	Unattended	69.00	13.80	4.00	5.00	1				
414	SALEM-TR01ABC	Distribution	Unattended	69.00	34.50	3.00	4.00	3				
415	SALEM-TR02	Distribution	Unattended	69.00	13.80		7.00	1				
416	SALIDA CROSSING-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
417	SALIDA CROSSING-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
418	SARTELL-TR01	Distribution	Unattended	34.50	12.50	2.00	7.00	1				
419	SAUK RIVER-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
420	SAUK RIVER-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
421	SAVAGE-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
422	SAVAGE-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
423	SCANDIA-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
424	SCOTT COUNTY-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
425	SCOTT COUNTY-TR02	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
426	SCOTT COUNTY-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
427	SCOTT COUNTY-TR10	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
428	SEDAN-TR01 AB	Distribution	Unattended	69.00	7.20		0.30	1				
429	SHEAS LAKE-TR05	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
430	SHEAS LAKE-TR09	Transmission	Unattended	345.00	115.00	35.00	336.00	1				
431	SHEPARD-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
432	SHEPARD-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
433	SHERBURNE COUNTY-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				

434	SHEYENNE-TR05	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
435	SHEYENNE-TR06	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
436	SIBLEY PARK-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
437	SIBLEY PARK-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
438	SLAYTON WEST-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
439	SOURIS-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
440	SOURIS-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
441	SOURIS-TR03	Distribution	Unattended	115.00	13.80		52.50	1				
442	SOUTH BEND-TR05	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
443	SOUTH BEND-TR06	Transmission	Unattended	161.00	115.00	14.00	187.00	1				
444	SOUTH HAVEN-TR01	Distribution	Unattended	69.00	34.50		1.00	1				
445	SOUTH RENNER-TR01	Distribution	Unattended	115.00	34.50		73.50	1				
446	SOUTH RIDGE-TR01	Distribution	Unattended	69.00	23.00		5.00	1				
447	SOUTH SIOUX FALLS-TR01	Distribution	Unattended	69.00	4.16		6.70	1				
448	SOUTH SIOUX FALLS-TR02	Distribution	Unattended	69.00	4.16		6.00	1				
449	SOUTH SIOUX FALLS-TR03	Distribution	Unattended	69.00	13.80		28.00	1				
450	SOUTH SIOUX FALLS-TR04	Distribution	Unattended	69.00	13.80		28.00	1				
451	SOUTHTOWN-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
452	SOUTHTOWN-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
453	SOUTHTOWN-TR03	Distribution	Unattended	115.00	13.80		62.50	1				
454	SOUTH-TR01ABC	Distribution	Unattended	69.00	2.40		1.00	3				
455	SPLIT ROCK-TR06	Transmission	Unattended	161.00	115.00	35.00	187.00	1				
456	SPLIT ROCK-TR07	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
457	SPLIT ROCK-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
458	SPLIT ROCK-TR11	Transmission	Unattended	345.00	115.00	14.00	448.00	1				

459	ST CLOUD-TR01	Distribution	Unattended	115.00	34.50		42.00	1				
460	ST CLOUD-TR02	Distribution	Unattended	115.00	34.50		42.00	1				
461	ST JAMES MUNICIPAL-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
462	ST JOHNS-TR01	Distribution	Unattended	69.00	4.16		4.00	1				
463	ST JOSEPH-TR01	Distribution	Unattended	69.00	4.16		7.00	1				
464	ST LOUIS PARK-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
465	ST LOUIS PARK-TR04	Distribution	Unattended	115.00	13.80		70.00	1				
466	ST LOUIS PARK-TR05	Distribution	Unattended	115.00	13.80		70.00	1				
467	ST LOUIS PARK-TR06	Distribution	Unattended	115.00	13.80		70.00	1				
468	ST. PAUL WATER-TR01	Distribution	Unattended	13.80	4.16		5.00	1				
469	STEWART-TR01	Distribution	Unattended	69.00	12.50		6.00	1				
470	STOCKYARDS-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
471	STOCKYARDS-TR02	Distribution	Unattended	118.00	13.80		46.70	1				
472	SUMMIT AVENUE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
473	SUMMIT AVENUE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
474	SWAN LAKE-TR01	Distribution	Unattended	115.00	12.50		10.50	1				
475	TANNERS LAKE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
476	TANNERS LAKE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
477	TANNERS LAKE-TR23A1B1C1	Distribution	Unattended	13.80	12.50		10.00	3				
478	TANNERS LAKE-TR23A2B2C2	Distribution	Unattended	13.80	12.50		10.00	3				
479	TANNERS LAKE-TR32A1B1C1	Distribution	Unattended	13.80	12.50		10.00	3				
480	TANNERS LAKE-TR32A2B2C2	Distribution	Unattended	13.80	12.50		10.00	3				

481	TANNERS LAKE-TR34A1B1C1	Distribution	Unattended	13.80	12.50		10.00	3				
482	TANNERS LAKE-TR34A2B2C2	Distribution	Unattended	13.80	12.50		10.00	3				
483	TERMINAL-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
484	TERMINAL-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
485	TERMINAL-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
486	TERMINAL-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
487	TERMINAL-TR10	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
488	THOMPSON-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
489	TRACY SWITCHING-TR01	Distribution	Unattended	69.00	13.80		5.00	1				
490	TRACY-TR01	Distribution	Unattended	69.00	4.16	2.00	5.00	1				
491	TWIN LAKES-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
492	TWIN LAKES-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
493	TWIN LAKES-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
494	UPPER LEVEE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
495	UPPER LEVEE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
496	UPPER LEVEE-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
497	VERMILLION RIVER-TR03	Distribution	Unattended	115.00	13.80		28.00	1				
498	VESELI-TR01	Distribution	Unattended	69.00	12.50		8.00	1				
499	VIKING-TR01	Distribution	Unattended	115.00	13.80		72.50	1				
500	VILLARD-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
501	WABASHA-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
502	WABASHA-TR02	Distribution	Unattended	69.00	2.40		20.00	1				
503	WACONIA-TR01	Distribution	Unattended	69.00	13.80		22.00	1				
504	WAKEFIELD-TR02	Distribution	Unattended	115.00	34.50	14.00	10.00	1				
505	WAKEFIELD-TR02ABC	Distribution	Unattended	34.50	13.80		2.00	3				
506	WAKEFIELD-TR06	Transmission	Unattended	115.00	69.00	14.00	70.00	1				

507	WASECA-TR02	Distribution	Unattended	69.00	23.00		14.00	1				
508	WASECA-TR03	Distribution	Unattended	69.00	23.00		28.00	1				
509	WASECA-TR04	Distribution	Unattended	69.00	23.00		28.00	1				
510	WATAB RIVER-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
511	WATERTOWN-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
512	WATERVILLE-TR01	Distribution	Unattended	69.00	23.00		14.00	1				
513	WATERVILLE-TR02	Distribution	Unattended	69.00	4.16		1.50	1				
514	WATERVILLE-TR03	Distribution	Unattended	69.00	12.50		3.50	1				
515	WATKINS-TR01	Distribution	Unattended	69.00	4.16		3.50	1				
516	WAVERLY-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
517	WELLS CREEK-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
518	WESCOTT PROPANE PLANT-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
519	WEST BYRON-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
520	WEST COON RAPIDS-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
521	WEST COON RAPIDS-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
522	WEST COON RAPIDS-TR03	Distribution	Unattended	34.50	13.80		28.00	1				
523	WEST FARIBAULT-TR01	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
524	WEST FARIBAULT-TR02	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
525	WEST FARIBAULT-TR03	Distribution	Unattended	69.00	13.80		22.00	1				
526	WEST FARIBAULT-TR07	Distribution	Unattended	69.00	13.80		7.00	1				
527	WEST HASTINGS-TR01	Distribution	Unattended	115.00	12.50		28.00	1				
528	WEST HASTINGS-TR05	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
529	WEST NEW ULM-TR05	Transmission	Unattended	115.00	69.00	14.00	112.00	1				

530	WEST RIVER ROAD-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
531	WEST RIVER ROAD-TR02	Distribution	Unattended	115.00	13.80		72.50	1				
532	WEST RIVER ROAD-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
533	WEST SIOUX FALLS-TR05	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
534	WEST SIOUX FALLS-TR07	Distribution	Unattended	115.00	13.80		70.00	1				
535	WEST SIOUX FALLS-TR08	Distribution	Unattended	115.00	13.80		70.00	1				
536	WEST WACONIA-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
537	WEST WACONIA-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
538	WESTERN-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
539	WESTERN-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
540	WESTGATE-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
541	WESTGATE-TR02	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
542	WESTGATE-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
543	WESTGATE-TR04	Distribution	Unattended	115.00	13.80		70.00	1				
544	WESTGATE-TR05	Distribution	Unattended	115.00	34.50		70.00	1				
545	WESTGATE-TR06	Distribution	Unattended	115.00	34.50		70.00	1				
546	WESTPORT-TR01X AB,Y CB	Distribution	Unattended	69.00	7.20		0.40	2				
547	WILMARTH-TR06	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
548	WILMARTH-TR07	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
549	WILMARTH-TR08	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
550	WILMARTH-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
551	WILMARTH-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
552	WINONA-TR01	Distribution	Unattended	69.00	13.80		22.00	1				
553	WINONA-TR02	Distribution	Unattended	69.00	13.80		22.00	1				

554	WINONA-TR03	Distribution	Unattended	69.00	13.80		25.00	1				
555	WINSTED-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
556	WINTHROP-TR01	Distribution	Unattended	69.00	4.16		6.25	1				
557	WOBEGON TRAIL-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
558	WOODBURY-TR01	Distribution	Unattended	115.00	34.50		47.00	1				
559	WOODBURY-TR02	Distribution	Unattended	115.00	34.50		46.70	1				
560	WYOMING-TR01	Distribution	Unattended	115.00	12.50		28.00	1				
561	WYOMING-TR02	Distribution	Unattended	115.00	12.50		28.00	1				
562	YANKEE-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
563	YANKEE-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
564	YELLOW MEDICINE-TR01	Distribution	Unattended	69.00	23.00		14.00	1				
565	YOUNG AMERICA-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
566	YOUNG AMERICA-TR02	Distribution	Unattended	69.00	13.80		10.50	1				
567	ZUMBRO FALLS-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
568	ZUMBROTA-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
569	573	Distribution	Unattended	69.00	23.00		44819.00	617				
570	Count TTL Transformer Banks							573				
571	Count TTL Transformers In Service							617				
572	TTL MVA In Service							44819				
573	Count TTL Subtations with Transformers							306				
574	Count TTL Substations without Transformer							48				
575	Count TTL Substations							354				
576	Count TTL Spares							44				
577	Spare Transformers											

578	Alexandria-B67606			36	2		0		1			
579	Canistota Junc-2741803			23	13		5		1			
580	Chanarambie-T040N00142701			118	34		120		1			
581	Clarks Grove-8975520			69	8		2		1			
582	Emery sub-B67608			36	2		0		1			
583	Falls Sub-P660522			69	14		28		1			
584	Hazel Creek sub-10008553_C001			345	230	14	336		1			
585	Hugo Trg Ctr-242601941			118	14		14		1			
586	Inver Hills sub-10075845-001			345	115	35	672		1			
587	MGRV-TP80279701			345	165	14	336		1			
588	MGRV-8779073			345	118	35	448		1			
589	MGRV-WT02255			345	118	35	672		1			
590	MGRV-WT-03820			230	118	14	336		1			
591	MGRV-TP80240801			161	118	14	187		1			
592	MGRV-WT02258			118	71	14	112		1			
593	MGRV-13623/2			118			102		1			
594	MGRV-N2261			118	71	14	50		1			
595	MGRV-E5074			118	71	14	70		1			
596	MGRV-E4976			118	36		70		1			
597	MGRV-E4990			118	25		90		1			
598	MGRV-WTO4771			118	14		70		1			
599	MGRV-WTO4921			118	14		70		1			
600	MGRV-50939-1			118	14		47		1			
601	MGRV-N2219			118	34		70		1			
602	MGRV-91F0693			71	36		17		1			
603	MGRV-J9E1054			69	35		5		1			

604	MGRV-282210982			70	24		14		1			
605	MGRV-GT-3547			71	14		14		1			
606	MGRV-C184245			69	14		10		1			
607	MGRV-H881493			69	14		8		1			
608	MGRV-C0301051			69	14		7		1			
609	MGRV-1174820415			71	14		7		1			
610	MGRV-249834			69	14		4		1			
611	MGRV-249866			69	14		4		1			
612	MGRV-G852083B			69	12		4		1			
613	MGRV-9F1025			69	14		25		1			
614	MGRV-236578			69	13		4		1			
615	MGRV-6993529			69	4		10		1			
616	MGRV-47011MA014-D221A			69	14		14		1			
617	MGRV-4089204			14	4		5		1			
618	MGRV-N2264			69	13		7		1			
619	Portal Pipeline (Minot)-4088687			14	2		5		1			
620	Prairie Island-C0665551			345	20		866		1			
621	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: 04/07/2023	Year/Period of Report End of: 2022/ 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	NSP-Wisconsin	see note	[(a)]202,193,618
3	Receipts from Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	1,522,000,000
4	Services provided by Xcel Energy Services Inc.	Xcel Energy Services Inc.	see note	[(b)]672,640,531
5	Contribution of Capital	Xcel Energy Inc.	211	124,130,593
6	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	6,000,000
7	Wind farm materials, financing charges, storage fees	Capital Services LLC	E107	18,959,312
8	Company labor, benefits, and related payments	NSP-Wisconsin	see note	[(c)]264,541
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Interchange agreement	NSP-Wisconsin	see note	[(d)]513,796,979
22	Gas dispatch and SCADA system agreement	NSP-Wisconsin	G495	465,516
23	Vehicle and equipment use	NSP-Wisconsin	see note	[(e)]8,357,509
24	Company labor, benefits, and related payments	NSP-Wisconsin	see note	[(f)]23,657,268
25	Company labor, benefits, and related payments	Public Service Co. of Colorado	see note	[(g)]364,258
26	Repayments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	6,000,000
27	Investments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	1,613,000,000
28	Dividends on Common Stock	Xcel Energy Inc.	216	559,966,025
42				

FOOTNOTE DATA

(a) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

E557	$	69,899,523
E565		132,294,095
		202,193,618

(b) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Service Function Group	Updated FERC Group	Total
Accounting, Financial Reporting & Taxes	107-CWIP	$ 124,711
	408-409-Taxes	598
	417-421-Other Income	2,538,265
	426.1-426.5-Other Income Deductions	218,447
	427-432-Interest Charges	46,488
	500-514-Steam Power Generation	18,661
	517-532-Nuclear Power Generation	(66)
	535-545-Hydraulic Power Generation	74
	546-557-Other Power Generation	145,778
	560-573-Transmission Expenses	(1,511)
	580-598-Distribution Expenses	17,268
	725-742-Gas Raw Materials	377
	800-813-Other Gas Supply Expenses	20,486
	850-870-Transmission Expenses	576
	871-893-Distribution Expenses	6,237
	901-905-Customer Accounts Expenses	2,586
	920-935-Administrative and General Expense	21,017,128
Accounting, Financial Reporting & Taxes Total		24,156,103
Aviation Services	426.1-426.5-Other Income Deductions	281

	920-935-Administrative and General Expense	2,185,072
Aviation Services Total		2,185,353
Business Systems	107-CWIP	152,057,781
	130-176-Current and Accrued Assets	652
	181-190-Deferred Debits	77,489
	252-283-Deferred Credits	235
	408-409-Taxes	212
	417-421-Other Income	(13,429)
	426.1-426.5-Other Income Deductions	44,014
	500-514-Steam Power Generation	385,503
	517-532-Nuclear Power Generation	3,529,380
	535-545-Hydraulic Power Generation	1,765
	546-557-Other Power Generation	706,348
	560-573-Transmission Expenses	5,314,722
	575.1-575.8-Regional Market Expenses	1
	580-598-Distribution Expenses	4,135,734
	725-742-Gas Raw Materials	38
	800-813-Other Gas Supply Expenses	74,121
	814-837-Underground Storage Expenses	-
	840-843-Other Storage Expense	113
	844-847-Liquified Natural Gas Terminaling Expenses	286
	850-870-Transmission Expenses	62,518
	871-893-Distribution Expenses	979,767
	901-905-Customer Accounts Expenses	9,760,334
	908-910-Customer Service and Informational Expenses	104
	911-916-Sales Expense	46,295
	920-935-Administrative and General Expense	136,881,899
Business Systems Total		314,045,882
Claims Services	920-935-Administrative and General Expense	559,914
Claims Services Total		559,914
Corporate Communications	181-190-Deferred Debits	3,252,084
	252-283-Deferred Credits	67
	408-409-Taxes	7
	417-421-Other Income	58
	426.1-426.5-Other Income Deductions	3,115,045
	580-598-Distribution Expenses	5,664
	908-910-Customer Service and Informational Expenses	256,767
	911-916-Sales Expense	23
	920-935-Administrative and General Expense	3,118,789
Corporate Communications Total		9,748,504
Corporate Strategy & Business Development	181-190-Deferred Debits	5,606
	426.1-426.5-Other Income Deductions	67,826
	911-916-Sales Expense	76,093
	920-935-Administrative and General Expense	1,577,633

Corporate Strategy & Business Development Total		1,727,158
Customer Service	107-CWIP	58,393
	181-190-Deferred Debits	738,555
	252-283-Deferred Credits	129,613
	417-421-Other Income	48,289
	426.1-426.5-Other Income Deductions	2,163
	901-905-Customer Accounts Expenses	14,760,510
	908-910-Customer Service and Informational Expenses	441,881
	911-916-Sales Expense	70,812
	920-935-Administrative and General Expense	59,988
Customer Service Total		16,310,204
Employee Communications	426.1-426.5-Other Income Deductions	82
	920-935-Administrative and General Expense	649,383
Employee Communications Total		649,465
Energy Delivery - Engineering/Design	107-CWIP	28,528,909
	130-176-Current and Accrued Assets	127,166
	181-190-Deferred Debits	19,231
	408-409-Taxes	19
	426.1-426.5-Other Income Deductions	19,520
	500-514-Steam Power Generation	357,851
	535-545-Hydraulic Power Generation	15,140
	546-557-Other Power Generation	232,564
	560-573-Transmission Expenses	8,528,622
	580-598-Distribution Expenses	3,452,503
	725-742-Gas Raw Materials	642
	840-843-Other Storage Expense	242,216
	850-870-Transmission Expenses	1,703,277
	871-893-Distribution Expenses	698,457
	920-935-Administrative and General Expense	662,991
Energy Delivery - Engineering/Design Total		44,589,108
Energy Delivery Construction, Operations & Maintenance (COM)	107-CWIP	42,477
	426.1-426.5-Other Income Deductions	9,243
	560-573-Transmission Expenses	15,836
	580-598-Distribution Expenses	2,672,606
	814-837-Underground Storage Expenses	97,665
	840-843-Other Storage Expense	1,113,032
	850-870-Transmission Expenses	549,799
	871-893-Distribution Expenses	343,603
	920-935-Administrative and General Expense	705,123
Energy Delivery Construction, Operations & Maintenance (COM) Total		5,549,384
Energy Markets - Fuel Procurement	426.1-426.5-Other Income Deductions	25
	500-514-Steam Power Generation	758,619
	920-935-Administrative and General Expense	122,694
Energy Markets - Fuel Procurement Total		881,338

Energy Markets Regulated Trading & Marketing	426.1-426.5-Other Income Deductions	2,409
	546-557-Other Power Generation	3,864,962
	560-573-Transmission Expenses	445,753
	575.1-575.8-Regional Market Expenses	349,793
	800-813-Other Gas Supply Expenses	159,900
	920-935-Administrative and General Expense	1,167,962
Energy Markets Regulated Trading & Marketing Total		5,990,779
Energy Supply Business Resources	107-CWIP	1,108,508
	181-190-Deferred Debits	(53,579)
	426.1-426.5-Other Income Deductions	3,788
	500-514-Steam Power Generation	4,458,370
	517-532-Nuclear Power Generation	420,314
	535-545-Hydraulic Power Generation	43,895
	546-557-Other Power Generation	5,703,788
	920-935-Administrative and General Expense	98,699
Energy Supply Business Resources Total		11,783,783
Energy Supply Engineering & Environmental	107-CWIP	8,707,073
	181-190-Deferred Debits	(673,575)
	408-409-Taxes	126
	417-421-Other Income	80,004
	426.1-426.5-Other Income Deductions	38,105
	500-514-Steam Power Generation	4,362,054
	517-532-Nuclear Power Generation	79,773
	535-545-Hydraulic Power Generation	6,361
	546-557-Other Power Generation	1,498,155
	560-573-Transmission Expenses	33,332
	580-598-Distribution Expenses	14,930
	871-893-Distribution Expenses	292,832
	920-935-Administrative and General Expense	824,628
Energy Supply Engineering & Environmental Total		15,263,798
Executive Management Services	426.1-426.5-Other Income Deductions	186,236
	580-598-Distribution Expenses	4,020
	850-870-Transmission Expenses	202,210
	871-893-Distribution Expenses	1,797
	920-935-Administrative and General Expense	5,990,658
Executive Management Services Total		6,384,921
Facilities & Real Estate	107-CWIP	1,780,218
	130-176-Current and Accrued Assets	4,155
	181-190-Deferred Debits	18,397
	252-283-Deferred Credits	361
	417-421-Other Income	234,381
	426.1-426.5-Other Income Deductions	25,205
	500-514-Steam Power Generation	1,899,743
	517-532-Nuclear Power Generation	6,929,083

	535-545-Hydraulic Power Generation	20,794
	546-557-Other Power Generation	1,281,661
	560-573-Transmission Expenses	1,574,942
	575.1-575.8-Regional Market Expenses	18,950
	580-598-Distribution Expenses	3,254,183
	725-742-Gas Raw Materials	323
	800-813-Other Gas Supply Expenses	7,802
	814-837-Underground Storage Expenses	2,860
	840-843-Other Storage Expense	56,802
	844-847-Liquified Natural Gas Terminaling Expenses	88,233
	850-870-Transmission Expenses	90,077
	871-893-Distribution Expenses	1,579,538
	901-905-Customer Accounts Expenses	367,842
	908-910-Customer Service and Informational Expenses	32,480
	911-916-Sales Expense	30,838
	920-935-Administrative and General Expense	14,614,721
Facilities & Real Estate Total		33,913,589
Facilities Administrative Services	107-CWIP	76,065
Facilities Administrative Services Total		76,065
Finance & Treasury	107-CWIP	24,035,085
	130-176-Current and Accrued Assets	62,980
	181-190-Deferred Debits	3,205,583
	252-283-Deferred Credits	135,381
	408-409-Taxes	10,115,121
	417-421-Other Income	63,293
	426.1-426.5-Other Income Deductions	63,447
	427-432-Interest Charges	1,427,643
	500-514-Steam Power Generation	1,164,679
	517-532-Nuclear Power Generation	692,508
	535-545-Hydraulic Power Generation	5,948
	546-557-Other Power Generation	1,708,392
	560-573-Transmission Expenses	1,101,870
	575.1-575.8-Regional Market Expenses	45,290
	580-598-Distribution Expenses	762,734
	725-742-Gas Raw Materials	624
	800-813-Other Gas Supply Expenses	17,782
	814-837-Underground Storage Expenses	10,680
	840-843-Other Storage Expense	106,782
	844-847-Liquified Natural Gas Terminaling Expenses	4,960
	850-870-Transmission Expenses	237,338
	871-893-Distribution Expenses	202,368
	901-905-Customer Accounts Expenses	1,849,369
	908-910-Customer Service and Informational Expenses	64,435
	911-916-Sales Expense	252,960

	920-935-Administrative and General Expense	53,523,110
Finance & Treasury Total		100,860,362
Fleet	107-CWIP	136,436
	130-176-Current and Accrued Assets	-
	181-190-Deferred Debits	-
	252-283-Deferred Credits	-
	417-421-Other Income	1
	426.1-426.5-Other Income Deductions	-
	500-514-Steam Power Generation	70
	517-532-Nuclear Power Generation	17
	535-545-Hydraulic Power Generation	-
	546-557-Other Power Generation	12
	560-573-Transmission Expenses	53
	575.1-575.8-Regional Market Expenses	-
	580-598-Distribution Expenses	685
	725-742-Gas Raw Materials	-
	800-813-Other Gas Supply Expenses	-
	814-837-Underground Storage Expenses	-
	840-843-Other Storage Expense	-
	844-847-Liquified Natural Gas Terminaling Expenses	6
	850-870-Transmission Expenses	167
	871-893-Distribution Expenses	83
	901-905-Customer Accounts Expenses	9
	908-910-Customer Service and Informational Expenses	-
	911-916-Sales Expense	-
	920-935-Administrative and General Expense	17
Fleet Total		137,556
Government Affairs	426.1-426.5-Other Income Deductions	703,118
	920-935-Administrative and General Expense	1,008,662
Government Affairs Total		1,711,780
Human Resources	107-CWIP	211,377
	130-176-Current and Accrued Assets	302
	181-190-Deferred Debits	4,538
	227-230-Other Noncurrent Liabilities	1,403,000
	231-245-Current and Accrued Liabilities	20,640,268
	252-283-Deferred Credits	58
	408-409-Taxes	(64,458)
	417-421-Other Income	1,501
	426.1-426.5-Other Income Deductions	111,372
	500-514-Steam Power Generation	6,700
	517-532-Nuclear Power Generation	419,826
	535-545-Hydraulic Power Generation	9
	546-557-Other Power Generation	5,711
	560-573-Transmission Expenses	1,431

	575.1-575.8-Regional Market Expenses	-
	580-598-Distribution Expenses	17,316
	725-742-Gas Raw Materials	15
	800-813-Other Gas Supply Expenses	14
	814-837-Underground Storage Expenses	-
	840-843-Other Storage Expense	56
	844-847-Liquified Natural Gas Terminaling Expenses	170
	850-870-Transmission Expenses	1,656
	871-893-Distribution Expenses	568
	901-905-Customer Accounts Expenses	2,477
	908-910-Customer Service and Informational Expenses	201,947
	911-916-Sales Expense	23,997
	920-935-Administrative and General Expense	11,544,720
Human Resources Total		34,534,571
Internal Audit	426.1-426.5-Other Income Deductions	646
	920-935-Administrative and General Expense	1,008,260
Internal Audit Total		1,008,906
Investor Relations	920-935-Administrative and General Expense	692,042
Investor Relations Total		692,042
Legal	107-CWIP	51,893
	181-190-Deferred Debits	(33,244)
	408-409-Taxes	561
	426.1-426.5-Other Income Deductions	49,789
	517-532-Nuclear Power Generation	135,722
	560-573-Transmission Expenses	27,238
	725-742-Gas Raw Materials	1,759
	920-935-Administrative and General Expense	5,252,730
Legal Total		5,486,448
Marketing & Sales	181-190-Deferred Debits	7,405,338
	252-283-Deferred Credits	200,035
	408-409-Taxes	88
	417-421-Other Income	2,955,889
	426.1-426.5-Other Income Deductions	45,446
	908-910-Customer Service and Informational Expenses	359,342
	911-916-Sales Expense	3,555,025
	920-935-Administrative and General Expense	5,715,834
Marketing & Sales Total		20,236,997
Payment & Reporting	426.1-426.5-Other Income Deductions	84
	920-935-Administrative and General Expense	416,495
Payment & Reporting Total		416,579
Payroll	920-935-Administrative and General Expense	731,650
Payroll Total		731,650
Rates & Regulation	181-190-Deferred Debits	15,060
	426.1-426.5-Other Income Deductions	1,049

	920-935-Administrative and General Expense	1,674,248
Rates & Regulation Total		1,690,357
Receipts Processing	426.1-426.5-Other Income Deductions	1,409
	901-905-Customer Accounts Expenses	344,625
	920-935-Administrative and General Expense	363,616
Receipts Processing Total		709,650
Supply Chain	107-CWIP	8,013,847
	130-176-Current and Accrued Assets	25,159
	181-190-Deferred Debits	179,657
	252-283-Deferred Credits	3,217
	408-409-Taxes	-
	417-421-Other Income	5,750
	426.1-426.5-Other Income Deductions	15,776
	500-514-Steam Power Generation	167,369
	517-532-Nuclear Power Generation	482,837
	535-545-Hydraulic Power Generation	1,056
	546-557-Other Power Generation	383,849
	560-573-Transmission Expenses	139,730
	575.1-575.8-Regional Market Expenses	21
	580-598-Distribution Expenses	857,206
	725-742-Gas Raw Materials	925
	800-813-Other Gas Supply Expenses	1,105
	814-837-Underground Storage Expenses	4
	840-843-Other Storage Expense	4,401
	844-847-Liquified Natural Gas Terminaling Expenses	18,514
	850-870-Transmission Expenses	146,110
	871-893-Distribution Expenses	105,878
	901-905-Customer Accounts Expenses	174,349
	908-910-Customer Service and Informational Expenses	2,794
	911-916-Sales Expense	17,883
	920-935-Administrative and General Expense	(139,152)
Supply Chain Total		10,608,285
Grand Total		$ 672,640,531

(c) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

107	$ 148,571
108	15,475
506	(82)
510	3,517
538	451
542	4,649
543	3,128
544	15,923
552	5,895
553	108
560	167
571	1,006
580	65
582	377
586	1,846
587	647
588	1,681
593	19,553
594	-
846	39,118
874	327
878	507
879	1,186
880	-
889	117
892	309
	$ 264,541

(d) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

E456	$	452,794,322
E456.1		61,002,657
		513,796,979

(e) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

107	$	7,597,920
108		583,028
502		340
511		47
537		525
539		400
544		324
548		61
571		1,001
583		44,115
584		253
588		3,862
593		123,016
594		1,689
596		621
887		92
921		215
	$	8,357,509

(f) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

107	$	21,428,991
108		1,450,027
163		2,501
184		88,271
501		30,784
502		94,217
505		2,136
506		350
511		1,189
512		91,392
513		7,616
535		5,441
537		675
538		744
539		375
542		6,751
543		1,268
544		44,510
548		129
551		420
552		4,945
553		2,193
560		606
561		35,745
562		505
566		1,185
570		464
571		18,420
580		912
582		1,108
583		3,917
584		6,539
585		427
586		5,671
587		529
588		35,823
592		2,032
593		227,852
594		11,389
844		9,143
846		652
847		840
870		105
874		3,336
877		1,797
878		602
880		20,750
887		782
889		559
892		147
903		273
921		233
	$	23,657,268

(g) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

107	$	268,406
108		3,777
417		626
502		696
512		853
513		249
539		1,047
542		4,538
544		341
552		189
553		494
560		8
562		2,670
566		30
570		798
582		1,180
583		1,188
584		506
585		409
586		7,908
587		2,178
593		4,265
594		25
596		1,351
598		450
850		56
856		553
866		3,262
870		98
874		2,872
875		112
878		1,254
879		16,425
880		293
887		2,638
892		29,654
893		2,775
903		84
	$	364,258