

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-22-183 Filed 05/02/2022 Pages: 345
2021 FERC Financial Report - FERC Form No. 1 - electronic only
Northern States Power Company
Dave Sederquist
- 3 PU-22-182 Filed 05/02/2022 Pages: 345
2021 FERC Financial Report - FERC Form No. 1 - electronic only
Northern States Power Company
Dave Sederquist

Exact Legal Name of Respondent (Company) Northern States Power Company (Minnesota)	Year/Period of Report End of: 2021/ Q4
--	---

FERC FORM NO. 1 (REV. 02-04)

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.)

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

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.

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

"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 filed..."

GENERAL PENALTIES

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent Northern States Power Company (Minnesota)		02 Year/ Period of Report End of: 2021/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 414 Nicollet Mall, Minneapolis, MN 55401		
05 Name of Contact Person Brian J. Van Abel		06 Title of Contact Person Executive Vice President, Chief Financial Officer
07 Address of Contact Person (Street, City, State, Zip Code) 414 Nicollet Mall, Minneapolis, MN 55401		
08 Telephone of Contact Person, Including Area Code 612-330-6747	09 This Report is An Original / A Resubmission (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 04/14/2022

Annual Corporate Officer Certification

The undersigned officer certifies that:

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

01 Name Brian J. Van Abel	03 Signature Brian J. Van Abel	04 Date Signed (Mo, Da, Yr) 04/14/2022
02 Title Executive Vice President, Chief Financial Officer		

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	N/A

18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	N/A
25	Unrecovered Plant and Regulatory Study Costs	230b	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	N/A
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	

46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
64	Hydroelectric Generating Plant Statistics	406	
65	Pumped Storage Generating Plant Statistics	408	N/A
66	Generating Plant Statistics Pages	410	
0	Energy Storage Operations (Large Plants)	414	N/A
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	
69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports (check appropriate box)		

	Stockholders' Reports Check appropriate box: <input checked="" type="checkbox"/> Two copies will be submitted <input type="checkbox"/> No annual report to stockholders is prepared		
--	---	--	--

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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 2021, 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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
CONTROL OVER RESPONDENT			
1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.			
Northern States Power Co. (a Minnesota corporation) is a first tier subsidiary of Xcel Energy Inc.			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	NSP Nuclear Corp	Nuclear generation support	100	
2	Private Fuel Storage, LLC	Nuclear waste storage	32.8	
3	United Power and Land Co.	Real estate holdings	100	
4	Crowned Ridge Interconnection Co.	Transmission system interconnection	50	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	490,000	2021-01-01	2021-12-31
2	President	Christopher B. Clark	355,000	2021-01-01	2021-12-31
3	Chairman, Chief Executive Officer	Ben Fowke	332,427	2021-01-01	2021-08-18
4	Executive Vice President, Chief Financial Officer	Brian J. Van Abel	253,278	2021-01-01	2021-12-31
5	Executive Vice President, General Counsel	Amanda J. Rome	228,785	2021-01-01	2021-12-31
6	Executive Vice President, Chief Human Resources Officer	Darla Figoli	216,509	2021-01-01	2021-12-31
7	Chairman, Chief Executive Officer	Robert C. Frenzel	184,683	2021-08-18	2021-12-31
8	Executive Vice President, Chief Operating Officer	Robert C. Frenzel	178,254	2021-01-01	2021-08-17
9	Executive Vice President, Chief Generation Officer	Timothy J. O'Connor	140,304	2021-01-01	2021-08-17
10	Senior Vice President, Controller	Jeffrey S. Savage	132,484	2021-01-01	2021-12-31
11	Executive Vice President, Chief Operations Officer	Timothy J. O'Connor	117,466	2021-08-18	2021-12-31
12	Vice President, Treasurer	Paul A. Johnson	112,910	2021-06-28	2021-12-31
13	Vice President, Corporate Secretary	Amy L. Schneider	96,976	2021-03-16	2021-12-31
14	Assistant Treasurer	Patricia L. Martin	74,181	2021-01-01	2021-12-31
15	Vice President, Treasurer	Sarah W. Soong	59,431	2021-01-01	2021-07-02
16	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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	^(a) Ben Fowke, Chairman and Chief Executive Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	true
3	^(b) Robert C. Frenzel, Chairman and Chief Executive Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	true
4	Brian J. Van Abel, Executive Vice President and Chief Financial Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	false
5	Robert C. Frenzel, Executive Vice President and Chief Operating Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	false

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: NameAndTitleOfDirector

Ben Fowke retired as Chairman and Chief Executive Officer effective Aug. 18, 2021.

(b) Concept: NameAndTitleOfDirector

Robert C. Frenzel was elected Chairman and Chief Executive Officer effective Aug. 18, 2021

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> 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		ER18-2322-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 20, 2018, Accession No. 20181220-3030

	FERC Electric Tariff updated effective 01-01-2019 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)	
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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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

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)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	66
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	25
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	14
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	17
17	300	Electric Operating Revenues (Acct 400)	b	19
18	310-311	Sales for Resale (Acct 447)	a	52

19	320-323	Electric Operation and Maintenance Expenses	b	112
20	328	Transmission of Electricity for Others	a	15
21	356	Common Utility Plant and Expenses	n/a	n/a

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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.

City State Utility Expiration

Frontier ND Gas Jan. 10, 2041
Holland MN Electric March 8, 2041
Atwater MN Electric April 4, 2041
Dakota MN Electric June 13, 2041
Elba MN Electric April 11, 2041
Florence MN Electric July 11, 2041
Ruthton MN Electric April 4, 2041
Shakopee MN Electric Aug. 3, 2041
Woodbury MN Electric Aug. 10, 2041
Woodbury MN Gas Aug. 10, 2041
Woodstock MN Electric Aug. 18, 2041
Iona MN Electric Oct. 4, 2041
Otsego MN Electric Oct. 24, 2041
Chandler MN Electric Nov. 7, 2041
Fargo ND Electric Nov. 14, 2041

None.

Pursuant to the Commission's Order in Docket No. EC19-89-000 approved on July 17, 2019, NSP-Minnesota purchased Community North Wind and Jeffers Wind Facilities on Dec. 31, 2020 with a total gross capacity of 70.4 MW. Community North Wind is a Wind Farm located in Lincoln County in southwestern Minnesota. Jeffers Wind is a Wind Farm located in Cottonwood County in southwestern Minnesota. Final accounting entries were approved by the Commission on July 22, 2021 in Docket No. AC21-135-000.

Pursuant to the Commission's Order in Docket No. EC20-69-000, approved on Aug. 20, 2020, NSP-Minnesota acquired ESI Energy, LLC membership interests in FPL Energy Mower County, LLC (Mower) on March 23, 2021 with a total operating capacity of 98.9 megawatts (MW). Mower is a wind farm located in Mower County in southeastern Minnesota. Final accounting entries were approved by the Commission on Oct. 14, 2021 in Docket No. AC21-162-000.

None.
None.
See Note 5 of the Financial Statements on Page 123 for disclosure regarding short-term borrowings, long-term debt and other financing activities.
None.
Union Employees — 2.60 percent increase effective Jan. 1, 2021. Non-Union Employees — Base pay cycle increase of 3.00 percent effective March 16, 2021.
See Note 9 of the Financial Statements on Page 123 for disclosures regarding material legal proceedings.
None.
None.
Effective Jan. 8, 2021, Wendy B. Mahling resigned as Vice President, Corporate Secretary. Effective March 16, 2021, Amy L. Schneider elected as Vice President, Corporate Secretary. Effective June 28, 2021, Paul A. Johnson elected as Vice President, Treasurer. Effective July 2, 2021, Sarah W. Soong resigned as Vice President, Treasurer. Effective Aug. 18, 2021, Ben Fowke retired as Chairman and Chief Executive Officer. Effective Aug. 18, 2021, Robert C. Frenzel elected as Chairman and Chief Executive Officer. Effective Aug. 18, 2021, Timothy J. O'Connor elected as Executive Vice President, Chief Operations Officer.
Not applicable as proprietary capital ratio is greater than 30 percent.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	24,916,523,060	23,041,860,697
3	Construction Work in Progress (107)	200	999,457,600	1,171,453,675
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		25,915,980,660	24,213,314,372
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	10,022,602,588	9,318,564,314
6	Net Utility Plant (Enter Total of line 4 less 5)		15,893,378,072	14,894,750,058
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	101,185,344	135,797,133
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)		564,800,500	559,743,218
10	Spent Nuclear Fuel (120.4)		2,415,127,584	2,274,128,026
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	2,773,449,236	2,659,339,314
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		307,664,192	310,329,063
14	Net Utility Plant (Enter Total of lines 6 and 13)		16,201,042,264	15,205,079,121
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		25,364,609	19,233,675
19	(Less) Accum. Prov. for Depr. and Amort. (122)		10,507,228	9,965,131
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	3,221,595	2,552,605
23	Noncurrent Portion of Allowances	228		

24	Other Investments (124)		51,987,027	53,925,426
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		3,256,313,854	2,776,449,233
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		33,273,400	4,624,047
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,359,653,257	2,846,819,855
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		2,307,189	3,871,985
36	Special Deposits (132-134)		896,518	3,814,203
37	Working Fund (135)		119,320	119,320
38	Temporary Cash Investments (136)		67,937,494	41,717,209
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		419,457,821	361,540,331
41	Other Accounts Receivable (143)		61,959,530	63,984,346
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		46,634,661	33,808,878
43	Notes Receivable from Associated Companies (145)		91,000,000	
44	Accounts Receivable from Assoc. Companies (146)		29,308,100	42,536,458
45	Fuel Stock (151)	227	82,320,015	92,325,796
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	180,729,953	177,806,924
49	Merchandise (155)	227	916,230	284,535
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		

52	Allowances (158.1 and 158.2)	228	80,418	85,160
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)		43,020,518	22,208,411
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		2,006,122	2,726,625
57	Prepayments (165)		33,440,762	27,113,708
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		298,825	1,006,454
60	Rents Receivable (172)		779,987	702,954
61	Accrued Utility Revenues (173)		320,392,108	248,965,226
62	Miscellaneous Current and Accrued Assets (174)		6	6
63	Derivative Instrument Assets (175)		86,121,866	21,593,499
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		33,273,400	4,624,047
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)		1,343,184,721	1,073,970,225
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		61,796,052	54,241,490
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	80,704,420	88,805,434
72	Other Regulatory Assets (182.3)	232	3,969,567,477	3,890,950,092
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,328,546	2,489,728
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	67,848,576	48,224,868

79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		12,313,348	13,808,807
82	Accumulated Deferred Income Taxes (190)	234	1,269,457,808	1,088,842,369
83	Unrecovered Purchased Gas Costs (191)		239,653,666	19,554,237
84	Total Deferred Debits (lines 69 through 83)		5,703,669,893	5,206,917,025
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		26,607,550,135	24,332,786,226

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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.

FERC FORM No. 1 (REV. 12-03)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	4,722,336,684	4,105,547,671
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	2,393,935,302	2,209,377,856
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(2,510,681)	(3,179,648)
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(20,389,324)	(21,649,216)
16	Total Proprietary Capital (lines 2 through 15)		7,572,664,510	6,769,389,192
17	LONG-TERM DEBT			
18	Bonds (221)	256	6,850,000,000	6,000,000,000
19	(Less) Reaquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	3,227,041	514,916
22	Unamortized Premium on Long-Term Debt (225)			

23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		43,809,951	42,449,988
24	Total Long-Term Debt (lines 18 through 23)		6,809,417,090	5,958,064,928
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		¹⁹ 353,281,568	¹⁹ 443,250,687
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)		81,348,000	158,653,000
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		15,246,791	16,685,463
32	Long-Term Portion of Derivative Instrument Liabilities		70,575,328	71,067,750
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		2,584,739,876	2,350,074,360
35	Total Other Noncurrent Liabilities (lines 26 through 34)		3,105,191,563	3,039,731,260
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)			179,000,000
38	Accounts Payable (232)		546,365,625	460,243,854
39	Notes Payable to Associated Companies (233)			1,450,000
40	Accounts Payable to Associated Companies (234)		65,846,721	67,342,144
41	Customer Deposits (235)		28,727,174	29,129,353
42	Taxes Accrued (236)	262	243,475,938	250,323,838
43	Interest Accrued (237)		75,941,440	70,112,005
44	Dividends Declared (238)		96,267,850	105,949,200
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		33,625,714	34,272,110
48	Miscellaneous Current and Accrued Liabilities (242)		38,922,958	44,500,668
49	Obligations Under Capital Leases-Current (243)		¹⁹ 89,757,245	¹⁹ 84,619,026
50	Derivative Instrument Liabilities (244)		105,655,219	92,984,158

51	(Less) Long-Term Portion of Derivative Instrument Liabilities		70,575,328	71,067,750
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)		1,254,010,556	1,348,858,606
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		12,647,763	9,445,865
57	Accumulated Deferred Investment Tax Credits (255)	266	16,831,534	18,255,352
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	332,575,716	318,879,456
60	Other Regulatory Liabilities (254)	278	4,295,669,821	3,949,612,148
61	Unamortized Gain on Reaquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	22,089,096	24,566,414
63	Accum. Deferred Income Taxes-Other Property (282)		2,663,872,468	2,429,790,261
64	Accum. Deferred Income Taxes-Other (283)		522,580,018	466,192,744
65	Total Deferred Credits (lines 56 through 64)		7,866,266,416	7,216,742,240
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		26,607,550,135	24,332,786,226

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	5,514,179,641	4,950,901,260			4,887,254,162	4,449,179,237	626,925,479	501,722,023		
3	Operating Expenses											
4	Operation Expenses (401)	320	3,307,161,317	2,953,812,326			2,817,568,027	2,589,607,310	489,593,290	364,205,016		

	(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)		1,955,637	557,582			1,955,637	557,582				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		116,081,662	115,980,410			114,396,497	114,395,866	1,685,165	1,584,544		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,676,961,810	4,147,499,869			4,094,665,103	3,689,348,870	582,296,707	458,150,999		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		837,217,831	803,401,391			792,589,059	759,830,367	44,628,772	43,571,024		
28	Other Income and Deductions											
29	Other Income											
30	Nonutility 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)		38,349,170	36,475,152								
34	(Less) Expenses of Nonutility Operations (417.1)		31,765,888	29,621,881								
35	Nonoperating Rental Income (418)		0									
36		119	668,967	(102,065)								

	Equity in Earnings of Subsidiary Companies (418.1)											
37	Interest and Dividend Income (419)		4,864,582	2,923,697								
38	Allowance for Other Funds Used During Construction (419.1)		30,338,000	25,425,203								
39	Miscellaneous Nonoperating Income (421)		2,223,061	2,204,628								
40	Gain on Disposition of Property (421.1)		625,253	163,543								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		45,303,145	37,468,277								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		102,682	83,099								
44	Miscellaneous Amortization (425)		0									
45	Donations (426.1)		2,272,947	2,974,131								
46	Life Insurance (426.2)		(2,752,422)	(2,546,823)								
47	Penalties (426.3)		1,056,795	116,701								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,745,127	1,651,175								
49	Other Deductions (426.5)		13,145,924	6,943,859								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		15,571,053	9,222,142								
51	Taxes Applic. to Other Income and Deductions											
52		262	320,421	230,674								

	Taxes Other Than Income Taxes (408.2)											
53	Income Taxes- Federal (409.2)	262	(4,502,434)	(5,458,665)								
54	Income Taxes-Other (409.2)	262	18,296,576	970,239								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	24,096,703	23,812,443								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	38,680,248	18,374,779								
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)		(468,982)	1,179,912								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		30,201,074	27,066,223								
61	Interest Charges											
62	Interest on Long- Term Debt (427)		262,121,328	240,208,222								
63	Amort. of Debt Disc. and Expense (428)		5,580,190	5,006,710								
64	Amortization of Loss on Reaquired Debt (428.1)		1,495,459	1,695,869								
65	(Less) Amort. of Premium on Debt- Credit (429)		0									
66	(Less) Amortization of Gain on Reaquired Debt- Credit (429.1)		0									
67			395,456	829,871								

	Interest on Debt to Assoc. Companies (430)											
68	Other Interest Expense (431)		4,129,994	3,269,166								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		12,526,035	11,100,540								
70	Net Interest Charges (Total of lines 62 thru 69)		261,196,392	239,909,298								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		606,222,513	590,558,316								
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)		606,222,513	590,558,316								

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: RegulatoryDebits

	Electric	Gas
Minnesota Renewable Development Fund	\$ 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 AIP Refund	2,056,721	—
North Dakota Renewable Energy Rider	660,384	—
South Dakota Infrastructure	625,625	—
Sherco Unit 3 Depreciation Deferral	503,130	—
South Dakota Transmission Cost Recovery	181,314	—
LED Streetlighting	166,265	—
North Dakota Transmission Cost Recovery	13,687	—
Minnesota Gas Rate Case Deferral	—	399,252
	<u>\$ 88,928,857</u>	<u>\$ 399,252</u>

(b) Concept: RegulatoryCredits

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

(c) Concept: LifeInsurance

Income on Company Owned Life Insurance.

(d) Concept: RegulatoryDebits

	Electric	Gas
Minnesota Renewable Development Fund	\$ 35,230,487	\$ —
Minnesota Revenue Decoupling Mechanism	18,537,602	—
Theoretical Depreciation Reserve Surplus	10,039,728	—
North Dakota Renewable Energy Rider	4,583,859	—
Minnesota Transmission Cost Recovery	2,765,458	—
Minnesota AIP Refund	1,806,224	—
South Dakota Infrastructure	738,306	—
Sherco Unit 3 Depreciation Deferral	503,130	—
LED Streetlighting	11,097	—
Minnesota Gas Utility Infrastructure	—	2,875,332
	<u>\$ 74,215,891</u>	<u>\$ 2,875,332</u>

(e) Concept: RegulatoryCredits

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	\$ 108,182,173	\$ 1,864,518
Minnesota Sales True Up	77,620,939	—
Minnesota Renewable Energy Standard	58,474,169	—
Business Incentive and Sustainability Rider Pandemic Discount	664,690	—
South Dakota Transmission Cost Recovery	516,236	—
North Dakota Transmission Cost Recovery	296,380	—
Minnesota State Energy Policy	—	89,379
	<u>\$ 245,754,587</u>	<u>\$ 1,953,897</u>

(f) Concept: LifeInsurance

Income on Company Owned Life Insurance.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

STATEMENT OF RETAINED EARNINGS

- Do not report Lines 49-53 on the quarterly report.
- Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
- 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).
- State the purpose and amount for each reservation or appropriation of retained earnings.
- 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.
- Show dividends for each class and series of capital stock.
- Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
- 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.
- 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		2,209,300,233	2,039,401,766
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1				
4.2				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Cumulative Effect Adjustment - Accounting Standards Update (ASU) No. 2016-13			/a/782,918
10.2	Rounding			(4)
15	TOTAL Debits to Retained Earnings (Acct. 439)			782,914
16	Balance Transferred from Income (Account 433 less Account 418.1)		605,553,546	590,660,381
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)		(420,996,100)	(419,979,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(420,996,100)	(419,979,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,393,857,679	2,209,300,233
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)		2,393,935,302	2,209,377,856
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(3,179,648)	(3,077,581)
50	Equity in Earnings for Year (Credit) (Account 418.1)		668,967	(102,065)
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1	Rounding			(2)
53	Balance-End of Year (Total lines 49 thru 52)		(2,510,681)	(3,179,648)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AdjustmentsToRetainedEarningsDebit

On May 7, 2020 the FERC issued guidance in Docket No. AI20-2-000 approving use of Account 439, Adjustments to Retained Earnings, to record the cumulative adjustment to beginning retained earnings for the implementation of Accounting Standards Update (ASU) No. 2016-13, Financial Instruments - Credit Losses (ASC Topic 326). See Note 1 to the Financial Statements for additional information.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	606,222,513	590,558,316
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	843,613,753	747,517,612
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Nuclear Fuel	114,109,922	123,483,842
5.2	Amortization of Premium, Discount and Debt Expense	7,075,649	6,702,580
5.3	Amortization of Software and Other	80,959,251	75,838,068
8	Deferred Income Taxes (Net)	(38,276,352)	(63,284,533)
9	Investment Tax Credit Adjustment (Net)	(1,423,819)	(1,423,819)
10	Net (Increase) Decrease in Receivables	(56,529,313)	(26,836,104)
11	Net (Increase) Decrease in Inventory	(21,671,090)	(14,750,140)
12	Net (Increase) Decrease in Allowances Inventory	4,742	653,000
13	Net Increase (Decrease) in Payables and Accrued Expenses	71,741,641	25,658,228
14	Net (Increase) Decrease in Other Regulatory Assets	(205,670,395)	(188,501,946)
15	Net Increase (Decrease) in Other Regulatory Liabilities	155,463,307	108,151,902
16	(Less) Allowance for Other Funds Used During Construction	30,338,000	25,425,203

17	(Less) Undistributed Earnings from Subsidiary Companies	668,967	(102,067)
18	Other (provide details in footnote):		
18.1	Other: (Increase) Decrease in Accrued Utility Revenues	(71,426,882)	644,002
18.2	Other: Net Realized and Unrealized Hedging and Derivative Transactions	(21,033,294)	(3,857,314)
18.3	Other: Changes in Other Current Assets and Liabilities	(5,483,622)	(25,764,564)
18.4	Other: Changes in Noncurrent Liabilities and Deferred Amounts	(303,928,159)	(136,214,710)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	1,122,740,885	1,193,251,284
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,676,671,278)	(1,766,701,091)
27	Gross Additions to Nuclear Fuel	(111,445,051)	(59,942,179)
28	Gross Additions to Common Utility Plant	(112,771,721)	(103,568,706)
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	(30,338,000)	(25,425,203)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,870,550,050)	(1,904,786,773)
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	(1,450,000)	
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		

49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Investments in Utility Money Pool Arrangement	(821,000,000)	(718,000,000)
53.2	Repayments from Utility Money Pool Arrangement	730,000,000	718,000,000
53.3	Other: Miscellaneous Other Investing Activities	1,938,399	1,666,719
53.4	Other: Purchase of Investments in External Decommissioning Fund	(757,214,680)	(1,397,959,932)
53.5	Other: Proceeds from Sale of Investments in External Decommissioning Fund	742,789,242	1,377,591,184
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,975,487,089)	(1,923,488,802)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	835,505,285	677,001,475
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other: Capital Contributions by Parent	648,404,269	526,789,286
64.2	Other: Borrowings under Utility Money Pool Arrangement	434,000,000	136,000,000
66	Net Increase in Short-Term Debt (c)		149,000,000
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,917,909,554	1,488,790,761
72	Payments for Retirement of:		
73	Long-term Debt (b)	251,904	(300,003,151)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other: Repayments under Utility Money Pool Arrangement	(434,000,000)	(136,000,000)

76.2	Other: Miscellaneous Other Financing Activities		3,380,768
78	Net Decrease in Short-Term Debt (c)	(179,000,000)	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(430,677,450)	(408,348,325)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	874,484,008	647,820,053
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)	21,737,804	(82,417,465)
88	Cash and Cash Equivalents at Beginning of Period	(b)49,522,717	131,940,182
90	Cash and Cash Equivalents at End of Period	(e)71,260,521	(e)49,522,717

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) 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)
	\$	<u>(303,928,159)</u>

(b) Concept: CashAndCashEquivalents

Cash (131)	\$	3,871,985
Special Deposits (132-134)		3,814,203
Working Fund (135)		119,320
Temporary Cash Investments (136)		41,717,209
Cash and Cash Equivalents at End of Period	\$	<u>49,522,717</u>

(c) 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	\$	<u>71,260,521</u>

(d) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Changes in Noncurrent Liabilities and Deferred Amounts

Change in pension and employee benefit obligation	\$	(41,166,500)
Change in deferred debits		(20,560,248)
Change in deferred credits		(67,357,197)
Change in noncurrent liabilities		(7,130,765)
	\$	<u>(136,214,710)</u>

(e) Concept: CashAndCashEquivalents

Cash (131)	\$	3,871,985
Special Deposits (132-134)		3,814,203
Working Fund (135)		119,320
Temporary Cash Investments (136)		41,717,209
Cash and Cash Equivalents at End of Period	\$	<u>49,522,717</u>

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

NOTES TO FINANCIAL STATEMENTS

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

NOTES TO FINANCIAL STATEMENTS (Continued)

1. Use this space to paste the disclosure required by instruction 1 of Page 122.

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:

NSP-Minnesota, these financial statements and items have not been audited (2020) and were audited by the same predecessor auditor.

(Millions of Dollars)

Balance Sheet:		
Net utility plant	\$	229
Current assets		533
Current liabilities		473
Other long-term assets		(4,560)
Long-term debt and other long-term liabilities		(4,272)
Statement of Income:		
Operating revenue	\$	242
Operating expenses		297
Other income and deductions		4
Net Interest charges		(3)
Statement of Cash Flows:		
Cash provided by operating activities	\$	(1)
Cash used in investing activities		6
Cash provided by financing activities		1

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

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

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

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. 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 from its balance sheet. 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. NSP-Minnesota defers income taxes 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 NSP-Minnesota's tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most of its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, which would be refundable to utility customers over the remaining life of the related assets. NSP-Minnesota anticipates that a tax rate increase would 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 it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal investment tax credits (ITCs) related to public utility property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes. 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.

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

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

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. 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. Planned maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property.

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

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

NSP-Minnesota records depreciation expense 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 recovered in rates as authorized by the appropriate regulatory entities. The amount of removal costs is based on current factors used in existing depreciation rates. Accumulated removal costs are reflected in the balance sheet as a regulatory liability. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.7% for 2021 and 3.7% for 2020.

AROs — NSP-Minnesota accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement 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 depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount 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 performed at least every three years and submitted to the state commissions for approval.

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 deferred debits on the balance sheet.

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 liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that 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 proceeds. 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.

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.

NSP-Minnesota does not recognize a separate financing component of its collections from customers as contract terms are short-term in nature. NSP-Minnesota presents its revenues net of any excise or sales taxes or fees.

NSP-Minnesota participates in Midcontinent Independent System Operator, Inc. (MISO). NSP-Minnesota recognizes sales to both customer demand of retail and wholesale customers that a utility has an obligation to serve under statute or long-term contract (native load) and other end use customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through Regional Transmission Organizations (RTOs) are recorded based upon our evaluation each hour as to whether we are a net seller or a net buyer based upon the total volumes. The real time and day-ahead market are each evaluated separately. If NSP-Minnesota is a net seller the transaction is recorded on a gross basis in electric revenues and cost of sales. If NSP-Minnesota is a net buyer, the transaction is recorded on a net basis in cost of sales.

Revenues and charges for energy transacted through MISO are recorded based upon our evaluation each hour as to whether we are a net seller or a net buyer based upon the total volumes. The real time and day-ahead market are each evaluated separately. If NSP-Minnesota is a net seller the transaction is recorded on a gross basis in electric revenues and cost of sales. If NSP-Minnesota is a net buyer the transaction is 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 average cost.

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. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted net asset values (NAVs).

For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish 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, NSP-Minnesota may use quoted prices for similar contracts or internally prepared valuation models 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 estimate fair value for each security.

See Notes 7 and 8 for further information.

Derivative Instruments — NSP-Minnesota uses derivative instruments in connection with its interest rate, utility commodity price and commodity trading activities, 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 and interest rate hedging transactions are recorded as a component of interest expense.

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 a derivative exists and/or whether an instrument may be exempted from derivative accounting if designated as a normal purchase or normal sale.

Commodity Trading Operations — Pursuant to the joint operating agreement (JOA) approved by the FERC, some of the commodity trading margins from NSP-Minnesota are apportioned to Public Service Company of Colorado (PSCo) and Southwestern Public Service Company (SPS). 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. AFUDC 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 for establishing utility rates.

Alternative Revenue — Certain rate rider mechanisms (including decoupling/sales true up and conservation improvement programs (CIP)/demand side management (DSM) programs) qualify as alternative revenue programs. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate or from other instances where 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 equal to the revenue requirement, which may include incentives and return on rate base items.

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

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

Emission Allowances — Emission allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emission allowances and 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. 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 shown on a net basis in electric operating revenues in the statements of income.

Credit Losses — In 2016, the FASB issued Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326), which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards.

NSP-Minnesota implemented the guidance using a modified-retrospective approach, recognizing an immaterial cumulative effect charge (after tax) to retained earnings on Jan 1, 2020. The Jan. 1, 2020 adoption of ASC Topic 326 did not have a significant impact on NSP-Minnesota's financial statements.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2021 up to Feb. 23, 2022, 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)	2021		2020	
Current assets	\$	2	\$	2
Other assets		1		1
Total assets	\$	3	\$	3
Equity	\$	3	\$	3
Total liabilities and equity	\$	3	\$	3
(Millions of Dollars)	2021		2020	
Operating income	\$	1	\$	—
Net income	\$	1	\$	—

3. Joint Ownership of Generation, Transmission and Gas Facilities

Jointly owned assets as of Dec. 31, 2021:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation ^(a)	Percent Owned
Electric generation:			
Sherco Unit 3	\$ 620	\$ 451	59 %
Sherco common facilities	178	108	80
Sherco substation	5	4	59
Electric transmission:			
Grand Meadow	11	3	50
Huntley Wilmarth	48	1	50
CapX2020 ^(b)	952	127	51
Total ^(c)	\$ 1,814	\$ 694	

^(a) ARO is not included.

^(b) Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort (CAPX2020).

^(c) Projects additionally include \$7 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, 2021	Dec. 31, 2020
Other Regulatory Assets		
Asset retirement recovery	\$ 2,554	\$ 2,446
Pension and retiree medical obligations	311	378
Theoretical depreciation reserve surplus	238	248

Renewable resources and environmental initiatives		179		137
Excess deferred taxes - TCJA ^(a)		122		132
Recoverable deferred taxes on AFUDC recorded in plant		114		113
Deferred electric commodity costs		88		7
Contract valuation adjustments ^(b)		48		64
Purchased power agreement (PPA) termination		36		54
Nuclear refueling outage costs		54		38
Purchased power contracts costs		32		36
Other		194		238
Total other regulatory assets	\$	3,970	\$	3,891

^(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 PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

Components of regulatory liabilities:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Other Regulatory Liabilities		
Plant removal costs	\$ 1,936	\$ 1,774
Deferred income tax adjustments and TCJA refunds ^(a)	1,232	1,297
Investments	934	704
Excess deferred taxes - TCJA	30	36
Contract valuation adjustments ^(b)	29	12
ITC deferrals	19	18
Deferred natural gas and electric energy/fuel costs	14	8
United States Department of Energy (DOE) Settlement	12	10
Other	90	91
Total other regulatory liabilities	\$ 4,296	\$ 3,950

^(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.

At Dec. 31, 2021 and 2020, NSP-Minnesota's regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations and net AROs. In addition, regulatory assets included \$691 million and \$399 million at Dec. 31, 2021 and 2020, respectively, of past expenditures not earning a return. Amounts are related to funded pension obligations, sales true-up and revenue decoupling, purchased natural gas and electric energy costs (including those related to Winter Storm Uri), various renewable resources and certain environmental initiatives.

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 may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool borrowings:

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31	
	2021	2020
Borrowing limit	\$ 250	\$ 250
Amount outstanding at period end	—	—
Average amount outstanding	6	3
Maximum amount outstanding	236	116
Weighted average interest rate, computed on a daily basis	0.07 %	1.53 %
Weighted average interest rate at end of period	N/A	N/A

Commercial Paper — Commercial paper outstanding:

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31	
	2021	2020
Borrowing limit	\$ 500	\$ 500
Amount outstanding at period end	—	179
Average amount outstanding	26	10
Maximum amount outstanding	317	179
Weighted average interest rate, computed on a daily basis	0.18 %	1.25 %
Weighted average interest rate at end of period	N/A	0.18

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, 2021 and 2020, there were \$9 million and \$10 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:

2021	2020	Amount Facility May Be Increased (Millions)	Additional Periods for Which a One-Year Extension May Be Requested ^(b)
47 %	47 %	\$ 100	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, 2021, 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, 2021 (in millions of dollars):

Credit Facility ^(a)	Drawn ^(b)	Available
\$ 500	\$ 9	\$ 491

(a) This credit facility matures in June 2024.

(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, 2021 and 2020.

Bilateral Credit Agreement — In April 2021, 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, 2021, NSP-Minnesota had \$45 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	2021	2020
First mortgage bonds	2.15 %	Aug. 15, 2022	\$ 300	\$ 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	—
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 ^(b)	2.60	June 1, 2051	700	700
First mortgage bonds ^(a)	3.20	April 1, 2052	425	—
Other long-term debt			3	—
Unamortized discount			(44)	(42)
Unamortized debt issuance cost			(62)	(54)
Current maturities			(300)	—
Total long-term debt			<u>\$ 6,447</u>	<u>\$ 5,904</u>

(a) 2021 financing.

(b) 2020 financing.

Maturities of long-term debt are as follows:

(Millions of Dollars)

2022	\$ 300
2023	400
2024	—
2025	250
2026	—

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	2021
47.2 %	52.9 %
High	Limit on Total Capitalization
57.6 %	\$ 45,000

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	December 2022
2018	September 2022

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, 2021, NSP-Minnesota's earliest open tax year subject to examination by state taxing authorities under applicable statutes of limitations is 2014. In July 2020, Minnesota began an audit of tax years 2015 - 2018. As of Dec. 31, 2021, no material adjustments have been proposed.

Unrecognized 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.

Permanent vs. temporary:

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
Unrecognized tax benefit — Permanent tax positions	\$ 23	\$ 21
Unrecognized tax benefit — Temporary tax positions	3	3
Total unrecognized tax benefit	<u>\$ 26</u>	<u>\$ 24</u>

Changes in unrecognized tax benefits:

(Millions of Dollars)	2021	2020
Balance at Jan. 1	\$ 24	\$ 20
Additions based on tax positions related to the current year	2	2
Additions for tax positions of prior years	—	16
Reductions for tax positions of prior years	—	(14)
Balance at Dec. 31	<u>\$ 26</u>	<u>\$ 24</u>

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

(Millions of Dollars)	Dec. 31, 2021	Dec. 31, 2020
NOL and tax credit carryforwards	\$ (13)	\$ (11)

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 \$14 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)	2021	2020
Payable for interest related to unrecognized tax benefits at Jan. 1	\$ (2)	\$ (2)
Payable for interest related to unrecognized tax benefits at Dec. 31	<u>\$ (2)</u>	<u>\$ (2)</u>

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2021 or 2020.

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)	2021	2020
Federal NOL carryforward	\$ 77	\$ —
Federal tax credit carryforwards	710	548
State NOL carryforwards	352	158
State tax credit carryforwards, net of federal detriment	80	73
Valuation allowances for state credit carryforwards, net of federal benefit	(64)	(59)

Federal carryforward periods expire between 2031 and 2041 and state carryforward periods expire starting 2022.

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:

	2021	2020
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	(27.8)	(19.3)
Plant regulatory differences ^(a)	(8.1)	(7.2)
Other tax credits, net NOL & tax credit allowances	(1.3)	(1.2)
NOL Carryback	—	(2.1)
Other, net	0.6	0.8
Effective income tax rate	<u>(8.6)%</u>	<u>(1.0)%</u>

(a) 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 credits are offset by corresponding revenue reductions.

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

(Millions of Dollars)	2021	2020
Current federal tax (benefit) expense	\$ (10)	\$ 41
Current state tax (benefit) expense	(1)	12
Current change in unrecognized tax expense	2	6
Deferred federal tax benefit	(87)	(101)
Deferred state tax expense	49	38
Deferred ITCs	(1)	(1)
Other	—	(1)
Total income tax benefit	<u>\$ (48)</u>	<u>\$ (6)</u>

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

(Millions of Dollars)	2021	2020
Deferred tax expense excluding items below	\$ 108	\$ 64
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(145)	(127)
Tax benefit allocated to other comprehensive income, net of adoption of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 326, and other	(1)	—
Deferred tax benefit	<u>\$ (38)</u>	<u>\$ (63)</u>

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

(Millions of Dollars)	2021	2020
Deferred tax liabilities:		
Differences between book and tax bases of property	\$ 3,055	\$ 2,846
Regulatory assets	(148)	(158)
Operating lease assets	123	147
Deferred fuel costs	92	7
Pension expense	73	72
Other	14	7
Total deferred tax liabilities	<u>\$ 3,209</u>	<u>\$ 2,921</u>
Deferred tax assets:		
Tax credit carryforward	\$ 790	\$ 621
Differences between book and tax bases of property	336	331
Operating lease liabilities	123	147
Regulatory liabilities	(82)	(80)
Tax credit valuation allowances	(64)	(59)
NOL carryforward	44	12
Other employee benefits	32	38
Deferred investment tax credits	5	5
Other	85	74
Total deferred tax assets	<u>\$ 1,269</u>	<u>\$ 1,089</u>
Net deferred tax liability	<u>\$ 1,940</u>	<u>\$ 1,832</u>

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, 2021 and 2020 is reflected below.

(Millions of Dollars)	Dec. 31, 2021		Dec. 31, 2020	
	Account 182.3	Account 254	Account 182.3	Account 254
Protected				
Plant	\$ —	\$ 1,099	\$ —	\$ 1,150
Nonplant	103	—	108	—
Unprotected				
Plant	—	133	—	147
Nonplant	19	30	24	36
Total				
Plant	\$ —	\$ 1,232	\$ —	\$ 1,297
Nonplant	\$ 122	\$ 30	\$ 132	\$ 36

Excess and deficient ADITs in 2021 were amortized in the Statement of Income as follows:

(Millions of Dollars)	Dec. 31, 2021
Protected	
Plant	\$ (36)
Nonplant	4

Plant		(10)
Nonplant		(2)
Total		
Plant	\$	(46)
Nonplant	\$	2

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- 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 highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted 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 are those valued with models requiring significant management judgment or estimation.

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset value (NAV).

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. The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled fund investments 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' investments may be redeemed with proper notice, however, 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 — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The 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 contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of forward prices and volatilities 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 financial transmission rights (FTRs). FTRs purchased from a Regional Transmission Organization (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 value of an FTR is derived from, and designed to offset, the cost 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 an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of certain inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3.

Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of NSP-Minnesota's FTRs relative to its electric utility operations, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the financial statements of NSP-Minnesota.

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 \$1.3 billion and \$981 million as of Dec. 31, 2021 and 2020, respectively, and unrealized losses were \$7 million and \$5 million as of Dec. 31, 2021 and 2020, respectively.

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

		Dec. 31, 2021				
		Fair Value				Total
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	
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
		Dec. 31, 2020				
		Fair Value				Total
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	
Nuclear decommissioning fund						
Cash equivalents	\$ 40	\$ 40	\$ —	\$ —	\$ —	\$ 40
Commingled funds	787	—	—	—	1,041	1,041
Debt securities	528	—	572	13	—	585
Equity securities	446	1,109	2	—	—	1,111
Total	\$ 1,801	\$ 1,149	\$ 574	\$ 13	\$ 1,041	\$ 2,777

For the years ended Dec. 31, 2021 and 2020, 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, 2021:

(Millions of Dollars)	Final Contractual Maturity					Total
	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years		
Debt securities	\$ 4	\$ 149	\$ 208	\$ 314	\$ 675	

Rabbi Trusts

NSP-Minnesota has established a rabbi trust to provide partial funding for future deferred compensation plan distributions.

Cost and fair value of assets held in rabbi trusts:

(Millions of Dollars)	Dec. 31, 2021				
	Cost	Fair Value			Total
		Level 1	Level 2	Level 3	
Rabbi Trusts ^(a)					
Mutual funds	\$ 10	\$ 13	\$ —	\$ —	\$ 13
Total	\$ 10	\$ 13	\$ —	\$ —	\$ 13

(a) Reported in other investments on the balance sheet.

(Millions of Dollars)	Dec. 31, 2020				
	Cost	Fair Value			Total
		Level 1	Level 2	Level 3	
Rabbi Trusts ^(a)					
Cash equivalents	\$ 1	\$ 1	\$ —	\$ —	\$ 1
Mutual funds	14	16	—	—	16
Total	\$ 15	\$ 17	\$ —	\$ —	\$ 17

(a) Reported in other investments on the balance sheet.

Derivative Instruments 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, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — NSP-Minnesota enters into instruments that effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes, with changes in fair value prior to settlement recorded as other comprehensive income.

As of Dec. 31, 2021, accumulated other comprehensive loss related to settled interest rate derivatives included \$1 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged interest rate transactions impact earnings. As of Dec. 31, 2021, NSP-Minnesota had no unsettled interest rate derivatives.

Wholesale and Commodity Trading Risk — 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 activities governed by this policy.

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, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel, and weather derivatives.

As of Dec. 31, 2021, NSP-Minnesota had no commodity contracts designated as cash flow hedges. NSP-Minnesota may enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, but may not be 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.

NSP-Minnesota enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

Gross notional amounts of commodity forwards, options and FTRs:

(Amounts in Millions) ^{(a)(b)}	Dec. 31, 2021	Dec. 31, 2020
Megawatt hours of electricity		57
Million British thermal units of natural gas		85
		65
		83

(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, 2021, eight of NSP-Minnesota's 10 most significant counterparties for these activities, comprising \$33 million or 63% of this credit exposure, had investment grade credit ratings from Standard & Poor's Global Ratings, Moody's Investor Services or Fitch Ratings. One of the 10 most significant counterparties, comprising \$17 million or 34% of this credit exposure, was not rated by these external agencies, but based on NSP-Minnesota's internal analysis, had credit quality consistent with investment grade. One of these significant counterparties, comprising an immaterial amount or less than 1% of this credit exposure, had credit quality less than investment grade, based on internal analysis. Six of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate and vehicle fuel 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:

(Millions of Dollars)	2021	2020
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	\$ —	\$ (19)
After-tax net realized losses on derivative transactions reclassified into earnings	2	1
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	\$ (17)	\$ (19)

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, 2021			
Other derivative instruments			
Electric commodity	\$	—	\$ 3
Natural gas commodity		—	(3)
Total	\$	—	\$ —
Year Ended Dec. 31, 2020			
Other derivative instruments			
Electric commodity	\$	—	\$ 2
Natural gas commodity		—	(2)
Total	\$	—	\$ —

Pre-Tax (Gains) Losses Reclassified into Income During the Period from:

(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
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)
Total	\$ —	\$ (2)	\$ 45
Year Ended Dec. 31, 2020			
Derivatives designated as cash flow hedges			
Interest rate	\$ 1 ^(a)	\$ —	\$ —
Total	\$ 1	\$ —	\$ —
Other derivative instruments			
Commodity trading	\$ —	\$ —	\$ (5) ^(b)
Electric commodity	—	(3) ^(c)	—
Natural gas commodity	—	2 ^(d)	(4) ^(d)
Total	\$ —	\$ (1)	\$ (9)

- (a) 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.
- (b) Amounts are recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms and reclassified out of income as regulatory assets and liabilities, as appropriate.
- (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.
- (d) Amounts are recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms and reclassified out of income as regulatory assets and liabilities, as appropriate.

NSP-Minnesota had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2021 and 2020.

Credit Related Contingent Features — Contract provisions for derivative instruments that NSP-Minnesota enters into, including those accounted for as normal purchase-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 NSP-Minnesota's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies. As of Dec. 31, 2021 and 2020, there were \$3 million and \$4 million derivative instruments in a liability position 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 the other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2021 and 2020, there were approximately \$48 million and \$14 million of derivative instruments in a liability position with such underlying contract provisions, respectively.

Provisions allow counterparties to seek performance assurance, including cash collateral, in the event that NSP-Minnesota's ability to fulfill its contractual obligations is reasonably expected to be impaired. NSP-Minnesota had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2021 and 2020.

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

(Millions of Dollars)	Dec. 31, 2021						Dec. 31, 2020					
	Fair Value			Fair Value Total	Netting ^(a)	Total	Fair Value			Fair Value Total	Netting ^(a)	Total
	Level 1	Level 2	Level 3				Level 1	Level 2	Level 3			
Current derivative Assets												
Other derivative instruments:												
Commodity trading	\$ 9	\$ 40	\$ 22	\$ 71	\$ (53)	\$ 18	\$ 1	\$ 26	\$ —	\$ 27	\$ (25)	\$ 2
Electric commodity	—	—	30	30	(1)	29	—	—	13	13	(1)	12
Natural gas commodity	—	6	—	6	—	6	—	3	—	3	—	3
Total current derivative assets	<u>\$ 9</u>	<u>\$ 46</u>	<u>\$ 52</u>	<u>\$ 107</u>	<u>\$ (54)</u>	<u>\$ 53</u>	<u>\$ 1</u>	<u>\$ 29</u>	<u>\$ 13</u>	<u>\$ 43</u>	<u>\$ (26)</u>	<u>\$ 17</u>
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	\$ 6	\$ 34	\$ 35	\$ 75	\$ (42)	\$ 33	\$ 7	\$ 39	\$ —	\$ 46	\$ (41)	\$ 5
Total noncurrent derivative assets	<u>\$ 6</u>	<u>\$ 34</u>	<u>\$ 35</u>	<u>\$ 75</u>	<u>\$ (42)</u>	<u>\$ 33</u>	<u>\$ 7</u>	<u>\$ 39</u>	<u>\$ —</u>	<u>\$ 46</u>	<u>\$ (41)</u>	<u>\$ 5</u>

(Millions of Dollars)	Dec. 31, 2021						Dec. 31, 2020					
	Fair Value			Fair Value Total	Netting ^(a)	Total	Fair Value			Fair Value Total	Netting ^(a)	Total
	Level 1	Level 2	Level 3				Level 1	Level 2	Level 3			
Current derivative Liabilities												
Other derivative instruments:												
Commodity trading	\$ 13	\$ 58	\$ 4	\$ 75	\$ (58)	\$ 17	\$ 3	\$ 18	\$ 10	\$ 31	\$ (25)	\$ 6
Electric commodity	—	—	1	1	(1)	—	—	—	1	1	(1)	—
Natural gas commodity	—	4	—	4	—	4	—	2	—	2	—	2
Total current derivative liabilities	\$ 13	\$ 62	\$ 5	\$ 80	\$ (59)	\$ 21	\$ 3	\$ 20	\$ 11	\$ 34	\$ (26)	\$ 8
Power Purchase Agreements ^(b)						14						14
Current derivative instruments						\$ 35						\$ 22
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	\$ 15	\$ 48	\$ 26	\$ 89	\$ (53)	\$ 36	\$ 2	\$ 35	\$ 13	\$ 50	\$ (27)	\$ 23
Total noncurrent derivative liabilities	\$ 15	\$ 48	\$ 26	\$ 89	\$ (53)	\$ 36	\$ 2	\$ 35	\$ 13	\$ 50	\$ (27)	\$ 23
Power Purchase Agreements ^(b)						35						48
Noncurrent derivative instruments						\$ 71						\$ 71

^(a) NSP-Minnesota nets derivative instruments and related collateral on its balance sheets when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2021 and 2020. At Dec. 31, 2021 derivative assets and liabilities include no obligations to return cash collateral. At Dec. 31, 2020 derivative assets and liabilities include \$15 million of obligations to return cash collateral. At Dec. 31, 2021 and 2020, derivative assets and liabilities include the rights to reclaim cash collateral of \$16 million and \$1 million, respectively. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

^(b) During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives for the years ended Dec. 31, 2021 and 2020:

(Millions of Dollars)	Year Ended Dec. 31	
	2021	2020
Balance at Jan. 1	\$ (11)	\$ 5
Purchases	54	28
Settlements	(82)	(49)
Net transactions recorded during the period:		
Gains (losses) recognized in earnings ^(a)	72	(8)
Net gains (losses) recognized as regulatory assets and liabilities	23	13
Balance at Dec. 31	\$ 56	\$ (11)

^(a) Level 3 losses and gains recognized in earnings are subject to offsetting gains and losses of derivative instruments categorized as levels 1 and 2 in the income statement.

NSP-Minnesota recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the years ended Dec. 31, 2021 and 2020.

Fair Value of Long-Term Debt

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

(Millions of Dollars)	2021		2020	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	\$ 6,809	\$ 7,761	\$ 5,958	\$ 7,391

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, 2021 and 2020, 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 1.96 and 1.78 percent in 2021 and 2020, respectively. Some employees may participate under legacy formulas such as the traditional final average pay or pension equity. Xcel Energy's and NSP-Minnesota's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives who participated in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's operating cash flows. Obligations of the SERP and nonqualified plan as of Dec. 31, 2021 and 2020 were \$43 million and \$43 million, respectively, of which \$3 million and \$4 million was attributable to NSP-Minnesota in 2021 and 2020, respectively. In 2021 and 2020, Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of \$4 million and \$6 million, respectively, of which \$1 million was attributable to NSP-Minnesota in 2020 and the cost for 2021 was immaterial.

Xcel Energy, which includes 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 long-term projected return levels. 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 2021 were above the assumed level of 6.60%.
- Investment returns in 2020 were above the assumed level of 7.10%.
- In 2022, NSP-Minnesota's expected investment-return assumption is 6.60%.

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 result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

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

(Millions of Dollars)	Dec. 31, 2021 ^(a)					Dec. 31, 2020 ^(a)				
	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	\$ 31	\$ —	\$ —	\$ —	\$ 31	\$ 52	\$ —	\$ —	\$ —	\$ 52
Commingled funds	304	—	—	274	578	369	—	—	284	653
Debt securities	—	219	1	—	220	—	167	1	—	168
Equity securities	16	—	—	—	16	20	—	—	—	20
Other	—	1	—	7	8	3	1	—	—	4
Total	\$ 351	\$ 220	\$ 1	\$ 281	\$ 853	\$ 444	\$ 168	\$ 1	\$ 284	\$ 897

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

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

(Millions of Dollars)	Dec. 31, 2021 ^(a)					Dec. 31, 2020 ^(a)				
	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Commingled funds	\$ —	\$ —	\$ —	\$ 1	\$ 1	\$ —	\$ —	\$ —	\$ —	\$ —
Debt securities	—	2	—	—	2	—	2	—	—	2
Total	\$ —	\$ 2	\$ —	\$ 1	\$ 3	\$ —	\$ 2	\$ —	\$ —	\$ 2

^(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 2021 or 2020.

Funded Status — Benefit obligations for both pension and postretirement plans decreased from Dec. 31, 2020 to Dec. 31, 2021, 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:

(Millions of Dollars)	Pension Benefits		Postretirement Benefits	
	2021	2020	2021	2020
Change in Benefit Obligation:				
Obligation at Jan. 1	\$ 989	\$ 942	\$ 73	\$ 76
Service cost	30	27	—	—
Interest cost	25	31	2	2
Plan amendments	1	—	—	—
Actuarial (gain) loss	(28)	84	(5)	2
Benefit payments	(140)	(95)	(6)	(7)
Obligation at Dec. 31	\$ 877	\$ 989	\$ 64	\$ 73
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	\$ 897	\$ 815	\$ 2	\$ 3
Actual return on plan assets	62	133	—	—
Employer contributions	34	44	7	6
Benefit payments	(140)	(95)	(6)	(7)
Fair value of plan assets at Dec. 31	\$ 853	\$ 897	\$ 3	\$ 2
Funded status of plans at Dec. 31	\$ (24)	\$ (92)	\$ (61)	\$ (71)
Amounts recognized in the Balance Sheet at Dec. 31:				
Noncurrent liabilities	(24)	(92)	(61)	(71)

Significant Assumptions Used to Measure Benefit Obligations:	Pension Benefits		Postretirement Benefits	
	2021	2020	2021	2020
Discount rate for year-end valuation	3.08 %	2.71 %	3.09 %	2.65 %
Expected average long-term increase in compensation level	3.75 %	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	5.30 %	5.50 %
Health care costs trend rate — initial: Post-65	N/A	N/A	4.90 %	5.00 %
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	4	5

The accumulated benefit obligation for the pension plan was \$811 million and \$912 million as of Dec. 31, 2021 and 2020, 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		Postretirement Benefits	
	2021	2020	2021	2020
Service cost	\$ 30	\$ 27	\$ —	\$ —
Interest cost	25	31	2	2

Expected return on plan assets	(52)	(55)	—	—
Amortization of prior service cost	—	—	(3)	(3)
Amortization of net loss	34	33	2	1
Settlement charge ^(a)	35	—	—	—
Net periodic pension cost	72	36	1	—
Effects of regulation	(44)	(4)	—	—
Net benefit cost recognized for financial reporting	\$ 28	\$ 32	\$ 1	\$ —
Significant Assumptions Used to Measure Costs:				
Discount rate	2.71 %	3.49 %	2.65 %	3.47 %
Expected average long-term increase in compensation level	3.75	3.75	—	—
Expected average long-term rate of return on assets	6.60	7.10	4.10	4.50

^(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 2021, as a result of lump-sum distributions during the 2021 plan year, NSP-Minnesota recorded a total pension settlement charge of \$35 million in 2021, which was not recognized due to the effects of regulation. There were no settlement charges recorded to the qualified pension plans in 2020.

(Millions of Dollars)	Pension Benefits		Postretirement Benefits	
	2021	2020	2021	2020
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	\$ 307	\$ 414	\$ 31	\$ 37
Prior service credit	—	—	(4)	(6)
Total	\$ 307	\$ 414	\$ 27	\$ 31
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Noncurrent deferred debits	\$ 307	\$ 414	\$ 25	\$ 29
Deferred income taxes	—	—	1	1
Net-of-tax accumulated other comprehensive income	—	—	1	1
Total	\$ 307	\$ 414	\$ 27	\$ 31
Measurement date	Dec. 31, 2021		Dec. 31, 2020	

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 2020 - 2022 to meet minimum funding requirements.

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

- \$50 million in January 2022, of which \$5 million is attributable to NSP-Minnesota.
- \$131 million in 2021, of which \$34 million was attributable to NSP-Minnesota.
- \$150 million in 2020, of which \$44 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:

- \$9 million in January 2022, of which \$6 million is attributable to NSP-Minnesota.
- \$15 million in 2021, of which \$8 million was attributable to NSP-Minnesota.
- \$11 million in 2020, of which \$6 million was attributable to NSP-Minnesota.

Target asset allocations:

	Pension Benefits		Postretirement Benefits	
	2021	2020	2021	2020
Domestic and international equity securities	33 %	35 %	15 %	15 %
Long-duration fixed income and interest rate swap securities	37	35	—	—
Short-to-intermediate fixed income securities	11	13	71	72
Alternative investments	17	15	8	9
Cash	2	2	6	4
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 2019, the Pension Protection Act measurement concept was extended beyond 2019 for NSP bargaining terminations and retirements to Dec. 31, 2022.

In 2020, 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	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2022	\$ 118	\$ 6	\$ —	\$ 6
2023	72	6	—	6
2024	68	5	—	5

2025	67	5	—	5
2026	64	5	—	5
2027-2031	292	18	—	18

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 \$12 million in 2021 and 2020.

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.

Minnesota Winter Storm Uri Costs — In its Minnesota jurisdiction, NSP-Minnesota is participating in a contested case regarding the prudence of incremental natural gas costs incurred during Winter Storm Uri. Other parties to the case have recommended significant cost disallowances, and while ultimate resolution of the matter is uncertain, it is reasonably possible that the MPUC could disallow certain deferred costs, resulting in earnings losses. The OAG recommended the MPUC deny recovery of up to \$179 million, the largest recommendation among the intervenor positions.

NSP-Minnesota strongly disagrees with the recommendations of the DOC, OAG and CUB, and believes that it acted prudently and according to MPUC approved procedures for the best interest of its customers and stakeholders. NSP-Minnesota filed rebuttal testimony in January 2022 detailing its position that the disallowances recommended by other parties lack any merit in the prudence review given the pertinent facts regarding NSP-Minnesota's actions before, during and after the storm event. An MPUC decision is expected in the summer of 2022.

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

In March 2019, the MPUC approved NSP-Minnesota's settlement refund proposal. Additionally, the MPUC decided to withhold any decision as to NSP-Minnesota's prudence in connection with the incident at Sherco Unit 3 until after conclusion of an appeal pending between GE and NSP-Minnesota's insurers. In February 2020, the Minnesota Court of Appeals affirmed the district court's judgment in favor of GE. In 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 OAG and the Minnesota Department of Commerce (DOC) recommended that NSP-Minnesota refund approximately \$17 million of replacement power costs previously recovered through the FCA. 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 pending. A loss related to this matter is deemed remote.

Westmoreland Arbitration — In November 2014, insurers of the Westmoreland Coal Company filed an arbitration demand against NSP-Minnesota, Southern Minnesota Municipal Power Agency and Western Fuels Association, seeking recovery of alleged \$36 million of business losses due to a turbine failure at Sherco Unit 3. The Westmoreland insurers claim NSP-Minnesota's invocation of the force majeure clause to stop the supply of coal was improper because the incident was allegedly caused by NSP-Minnesota's failure to conform to industry maintenance standards.

NSP-Minnesota denies the claims asserted by the Westmoreland insurers and believes it properly stopped the supply of coal based upon the force majeure provision. A final hearing has been scheduled for October 2022. The parties are also required to participate in mediation, which has been scheduled for the first quarter of 2022. At this stage of the proceeding, a reasonable estimate of damages or range of damages cannot be determined.

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

In September 2016, the FERC issued an order (Opinion No. 551) granting a 10.32% base ROE effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The D.C. Circuit subsequently vacated and remanded Opinion No. 551.

In November 2019, the FERC issued an order (Opinion No. 569), which set the MISO base ROE at 9.88%, effective Sept. 28, 2016 and for the first complaint period. The FERC also dismissed the second complaint. In December 2019, MISO TOs filed a request for rehearing regarding the new ROE methodology announced in Opinion No. 569. Customers also filed requests for rehearing claiming, among other points, that the FERC erred by dismissing the second complaint without refunds.

In May 2020, the FERC issued an order (Opinion No. 569-A) which granted rehearing in part to Opinion 569 and further refined the FERC's ROE methodology, most significantly to incorporate the risk premium model (in addition to the discounted cash flow and capital asset pricing models), resulting in a new base ROE of 10.02%, effective Sept. 28, 2016 and for the first complaint period. The FERC also affirmed its decision in Opinion No. 569 to dismiss the second complaint.

In November 2020, the FERC issued an order (Opinion No. 569-B) in response to rehearing requests. The FERC corrected certain inputs to its ROE calculation model, did not change the ROE effective Sept. 28, 2016, and for the first MISO complaint period and upheld its decision to deny refunds for the second complaint period. NSP-Minnesota has recognized a liability for its best estimate of final refunds to customers. Each 10 basis point reduction in ROE for the first complaint period, second complaint period and subsequent period relative to amounts accrued would reduce Xcel Energy's net income by \$1 million, \$1 million and \$2 million, respectively.

The MISO TOs and various parties have filed petitions for review of Opinion Nos. 569, 569-A and 569-B at the United States Court of appeals for the District of Columbia (D.C. Circuit). Oral arguments were held in late 2021 and a decision is expected by the end of the third quarter of 2022.

Environmental

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

Site Remediation

Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. NSP-Minnesota may sometimes pay all or a portion of the cost to remediate sites where past activities of NSP-Minnesota's predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former manufactured gas plants (MGPs); and third-party sites, such as landfills, for which NSP-Minnesota is alleged to have sent wastes to that site.

Historical MGP, Landfill and Disposal Sites

NSP-Minnesota is currently investigating, remediating or performing post closure actions at seven historical MGP, landfill or other disposal sites across its service territories, excluding sites that are being addressed under current coal ash regulations (see below).

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 Wastes

Environmental requirements — water and waste

Coal Ash Regulation — NSP-Minnesota’s operations are subject to federal and state regulations that impose requirements for handling, storage, treatment and disposal of solid waste. Under the coal combustion residuals (CCR) final rule (40 CFR 257.50 - 257.107) published by the United States Environmental Protection Agency (EPA) regulating the management, storage and disposal of CCRs as a nonhazardous waste (CCR 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.

In August 2020, the EPA published its final rule to implement closure by April 2021 for all CCR impoundments affected by the August 2018 D.C. Circuit ruling. This final rule required NSP-Minnesota to expedite closure plans for one impoundment.

In October 2020, NSP-Minnesota completed construction and placed in service a new impoundment to replace the clay lined impoundment. With the new ash pond in service, NSP-Minnesota has initiated closure activities for the existing ash pond at an estimated cost of \$4 million. NSP-Minnesota has five years to complete closure activities.

Closure costs for existing impoundments are included in the calculation of the ARO.

Federal Clean Water (CWA) Waters of the U.S. Rule — NSP-Minnesota is monitoring ongoing changes to the definition of Waters of the U.S. under the CWA. Regardless of which definition is applicable in the states in which we operate, NSP-Minnesota does not anticipate that compliance costs will be material.

CWA Effluent Limitations Guidelines (ELG) — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive CCRs. In October 2020, the EPA published a final rule revising the regulations.

The retirement of units affected by the final ELG rule is subject to regulatory approval. The exact total cost of ELG compliance is therefore uncertain but NSP-Minnesota does not anticipate that compliance costs will be material.

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing impingement and entrainment of aquatic species. NSP-Minnesota estimates the likely future cost for complying with impingement and entrainment requirements is approximately \$36 million, to be incurred between 2022 and 2028. NSP-Minnesota believes six plants could be required to make improvements to reduce impingement and entrainment. The exact total cost of the impingement and entrainment improvements is uncertain, but could be up to \$188 million. NSP-Minnesota anticipates these costs will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires sulfur dioxide, nitrogen oxide and particulate matter emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes best available retrofit technology and reasonable further progress. The regional haze first planning period requirements were approved by the EPA and implemented by 2014.

All states are now subject to a second round of regional haze planning/rulemaking, focusing on additional reductions to meet reasonable progress requirements. Any additional impacts to NSP-Minnesota facilities are expected to be minimal.

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

Aggregate fair value of NSP-Minnesota’s legally restricted assets, for funding future nuclear decommissioning, was \$3.3 billion and \$2.8 billion for 2021 and 2020, respectively.

NSP-Minnesota’s AROs were as follows:

(Millions of Dollars)	2021				
	Jan. 1, 2021	Amounts Incurred ^(a)	Accretion	Cash Flow Revisions ^(b)	Dec. 31, 2021 ^(c)
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	<u>\$ 2,350</u>	<u>\$ 107</u>	<u>\$ 116</u>	<u>\$ 12</u>	<u>\$ 2,585</u>

^(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.

^(c) There were no ARO amounts settled in 2021.

(Millions of Dollars)	2020					
	Jan. 1, 2020	Amounts Incurred ^(a)	Amounts Settled ^(b)	Accretion	Cash Flow Revisions ^(c)	Dec. 31, 2020
Electric						
Nuclear	\$ 2,068	\$ —	\$ —	\$ 105	\$ (216)	\$ 1,957
Wind	113	90	—	7	60	270
Steam and other production	47	—	(3)	2	21	67
Distribution	15	—	—	1	—	16
Natural gas						
Transmission and distribution	36	—	—	2	1	39
Common						
Common	1	—	—	—	—	1
Total liability	<u>\$ 2,280</u>	<u>\$ 90</u>	<u>\$ (3)</u>	<u>\$ 117</u>	<u>\$ (134)</u>	<u>\$ 2,350</u>

^(a) Amounts incurred relate to the wind farms placed in service in 2020 (Blazing Star 1, Crowned Ridge, Jeffers and Community Wind North).

^(b) Amounts settled related to closure of certain ash containment facilities.

^(c) In 2020, AROs were revised for changes in timing and estimates of cash flows. Revisions in the nuclear AROs were driven by reductions in spent fuel cooling time requirements in the nuclear triennial filing coupled with decreasing interest rates. Changes in wind AROs were driven by new dismantling studies. Revisions in steam and other production AROs primarily related to changes in cost estimates for remediation of ash containment facilities.

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, 2021. 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 \$13.5 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured \$450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining \$13.0 billion of exposure is funded by the Secondary Financial Protection Program available from assessments by the federal government.

companies. The remaining \$13.0 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 \$21 million per reactor-incident during any one year. Maximum assessments are subject to inflation adjustments.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL) and European Mutual Association for Nuclear Insurance (EMANI). The coverage limits are \$2.8 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage up to \$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 \$11 million for business interruption insurance and \$33 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 Prairie Island (PI) nuclear plants, which consist of storage pools and dry cask facilities. The Monticello dry-cask storage facility currently stores all 30 of the authorized canisters. The PI dry-cask storage facility currently stores 47 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 (CON) for additional storage at the Monticello site has been filed with the MPUC, to support possible life extension. 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 operating license and be completed by 2091. 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.

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.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. The cost study assumes the external decommissioning fund will earn an after-tax return between 5.23% and 6.30%. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Decommissioning costs are quantified in 2014 dollars. Escalation rates are 4.36% for plant removal activities and 3.36% for fuel management and site restoration activities.

NSP-Minnesota had \$3.3 billion of assets held in external decommissioning trusts at Dec. 31, 2021. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation. Xcel Energy believes future decommissioning costs will continue to be recovered in customer rates. The following amounts were prepared on a regulatory basis and not directly recorded in the financial statements as an ARO.

(Millions of Dollars)	Regulatory Basis	
	2021	2020
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	\$ 3,012	\$ 3,012
Effect of escalating costs	1,006	844
Estimated decommissioning cost obligation (in current dollars)	4,018	3,856
Effect of escalating costs to payment date	7,187	7,349
Estimated future decommissioning costs (undiscounted)	11,205	11,205
Effect of discounting obligation (using average risk-free interest rate of 1.96% and 1.64% for 2021 and 2020, respectively)	(4,651)	(4,181)
Discounted decommissioning cost obligation	\$ 6,554	\$ 7,024
Assets held in external decommissioning trust	\$ 3,256	\$ 2,777
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	3,298	4,247

Calculations and data used by the regulator in approving NSP-Minnesota's rates are useful in assessing future cash flows. Regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting.

Reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Millions of Dollars)	2021	2020
Discounted decommissioning cost obligation - regulated basis	\$ 6,554	\$ 7,024
Differences in discount rate and market risk premium	(2,209)	(2,628)
Operating expenses not included for GAAP	(1,584)	(1,734)
ARO differences between 2020 and 2014 cost studies	(705)	(705)
Nuclear production decommissioning ARO - GAAP	\$ 2,056	\$ 1,957

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	2021	2020
Annual decommissioning recorded as depreciation expense: ^(a) ^(b)	22	20

^(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

^(b) Decommissioning expenses in 2021 and 2020 include Minnesota's retail jurisdiction annual funding requirement of approximately \$14 million.

The 2017 nuclear decommissioning filing, effective Jan. 1, 2019, has been approved by the MPUC. In March 2020, the MPUC approved for NSP-Minnesota to delay any increase to the annual funding requirement until 2021. In December 2020, the MPUC verbally approved for NSP-Minnesota to delay any increase to the annual funding requirement until 2022. Also, as of December 2020, NSP-Minnesota submitted a Petition for approval of the 2022 - 2024 Nuclear Decommissioning Study and Assumptions. Contemplated but not proposed in this filing, was the 10-year extension of the license to operate the Monticello Plant, moving the planned retirement date from 2030 to 2040. The 2019 Preferred Integrated Resource Plan Supplement does include a 10-year extension of the license. On Feb. 8, 2022, the MPUC ruled on and approved the 10-year extension for the Monticello nuclear facility.

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. A119-1-000, 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, 2021	Dec. 31, 2020

PPAS	550	550
Other	74	74
Gross operating lease ROU assets	630	632
Accumulated amortization	(222)	(144)
Net operating lease ROU assets	\$ 408	\$ 488

Components of lease expense:

(Millions of Dollars)	2021	2020
Operating leases		
PPA capacity payments	\$ 96	\$ 89
Other operating leases ^(a)	8	8
Total operating lease expense ^(b)	\$ 104	\$ 97

^(a) Includes short-term lease expense of \$2 million and \$2 million for 2021 and 2020, 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, 2021 in Accounts 227 and 243:

(Millions of Dollars)	PPA ^{(a) (b)} Operating Leases	Other Operating Leases	Total Operating Leases
2022	\$ 96	\$ 9	\$ 105
2023	98	12	110
2024	100	7	107
2025	80	7	87
2026	40	7	47
Thereafter	—	31	31
Total minimum obligation	414	73	487
Interest component of obligation	(32)	(12)	(44)
Present value of minimum obligation	\$ 382	\$ 61	\$ 443
Less current portion			(90)
Noncurrent operating lease liabilities			\$ 353

Weighted-average remaining lease term in years

8.5

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

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

PPAs and Fuel Contracts

Non-Lease PPAs — NSP-Minnesota has entered into PPAs with other utilities and energy suppliers for purchased power to meet system load and energy requirements, operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered and 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 \$149 million and \$112 million in 2021 and 2020, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of \$55 million and \$52 million in 2021 and 2020, 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	\$ 60	\$ 165
2023	61	169
2024	63	174
2025	26	53
2026	9	10
Thereafter	10	38
Total ^(b)	\$ 229	\$ 609

^(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 2022 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, 2021:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2022	\$ 219	\$ 89	\$ 95	\$ 128
2023	79	109	—	114
2024	48	82	—	108
2025	1	119	—	98
2026	1	29	—	97
Thereafter	1	309	—	107
Total ^(a)	\$ 349	\$ 737	\$ 95	\$ 652

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

10. Other Comprehensive Income

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

(Millions of Dollars)	2021		
	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.

(Millions of Dollars)	2020		
	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	\$ (20)	\$ (3)	\$ (23)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives, net of tax of \$—	1 (a)	—	1
Net current period other comprehensive income	1	—	1
Accumulated other comprehensive loss at Dec. 31	\$ (19)	\$ (3)	\$ (22)

(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)	2021		2020	
Operating revenues:				
Electric	\$	501	\$	440
Gas		1		1
Operating expenses:				
Purchased power		67		59
Transmission expense		121		109
Other operating expenses — paid to Xcel Energy Services Inc.		615		584

Accounts receivable and payable with affiliates at Dec. 31:

(Millions of Dollars)	2021		2020	
	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	\$ 13	\$ —	\$ 6	\$ —
PSCo	16	—	1	—
SPS	—	2	—	3
Other subsidiaries of Xcel Energy Inc.	—	64	36	64
	\$ 29	\$ 66	\$ 43	\$ 67

12. Supplementary Cash Flow Data

(Millions of Dollars)	Year Ended Dec. 31	
	2021	2020
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	\$ (248)	\$ (234)
Cash received (paid) for income taxes, net	11	(53)
Supplemental disclosure of non-cash investing transactions:		
Accrued property, plant and equipment additions	\$ 242	\$ 74
Inventory transfers to property, plant and equipment	8	24
Operating lease right-of-use assets	4	2
Allowances for funds used during construction	30	25

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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			(3,762,162)	(19,447,396)		(22,466,683)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				73,726	571,723		645,449		
3	Preceding Quarter/Year to Date Changes in Fair Value				(20,699)	192,717		172,018		
4	Total (lines 2 and 3)				53,027	764,440		817,467	590,558,316	591,375,783
5	Balance of Account 219 at End of Preceding Quarter/Year	742,875			(3,709,135)	(18,682,956)		(21,649,216)		
6	Balance of Account 219 at Beginning of Current Year	742,875			(3,709,135)	(18,682,956)		(21,649,216)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				222,356	762,254		984,610		
8	Current Quarter/Year to Date Changes in Fair Value				275,443	(161)		275,282		
9	Total (lines 7 and 8)				497,799	762,093		1,259,892	606,222,513	607,482,405
10	Balance of Account 219 at End of Current Quarter/Year	742,875			(3,211,336)	(17,920,863)		(20,389,324)		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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)	21,359,285,305	18,765,424,461	1,695,411,108				898,449,736
4	Property Under Capital Leases	407,610,757	359,780,430					47,830,327
5	Plant Purchased or Sold							
6	Completed Construction not Classified	3,072,099,746	2,810,866,573	171,868,443				89,364,730
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	24,838,995,808	21,936,071,464	1,867,279,551				1,035,644,793
9	Leased to Others							
10	Held for Future Use							
11	Construction Work in Progress	999,457,600	805,727,561	65,131,865				128,598,174
12	Acquisition Adjustments	77,527,252	77,527,252					
13	Total Utility Plant (8 thru 12)	25,915,980,660	22,819,326,277	1,932,411,416				1,164,242,967
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	10,022,602,588	8,868,786,556	706,806,524				447,009,508
15	Net Utility Plant (13 less 14)	15,893,378,072	13,950,539,721	1,225,604,892				717,233,459
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	9,432,752,289	8,610,857,019	700,095,292				121,799,978

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	586,618,452	(b)254,697,690	6,711,232			325,209,530
22	Total in Service (18 thru 21)	10,019,370,741	8,865,554,709	706,806,524			447,009,508
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	3,231,847	(b)3,231,847				
33	Total Accum Prov (equals 14) (22,26,30,31,32)	10,022,602,588	8,868,786,556	706,806,524			447,009,508

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.

Account 101.1	
Finance Lease Asset	\$ —
Operating Right of Use Asset	407,610,757
Total	\$ 407,610,757

(b) Concept: AmortizationOfOtherUtilityPlantUtilityPlantInService

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

Intangible Plant	\$ 128,058,427
Nuclear Production Plant	116,710,028
Other Production	7,136,874
Hydraulic Production Plant-Conventional	2,792,361
Total Amort of Other Utility Plant - Electric	\$ 254,697,690

(c) Concept: AmortizationOfPlantAcquisitionAdjustment

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

Other Production	\$ 1,718,480
Transmission	1,513,367
Total Amort of Plant Acquisition Adj - Electric	\$ 3,231,847

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication	3,255,645	30,156,101		\$27,513,063	5,898,683
3	Nuclear Materials	117,202,601	72,891,266		\$106,949,390	83,144,477
4	Allowance for Funds Used during Construction	15,350,007	8,678,144		\$11,857,166	12,170,985
5	(Other Overhead Construction Costs, provide details in footnote)	(11,120)	20,336		\$38,017	\$(28,801)
6	SUBTOTAL (Total 2 thru 5)	135,797,133	111,745,847		146,357,636	101,185,344
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)		\$146,042,344		\$146,042,344	
9	In Reactor (120.3)	559,743,218	146,056,840		\$140,999,558	\$564,800,500
10	SUBTOTAL (Total 8 & 9)	559,743,218	292,099,184		287,041,902	564,800,500
11	Spent Nuclear Fuel (120.4)	2,274,128,026	140,999,558			\$2,415,127,584
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,659,339,314		(114,109,922)		2,773,449,236
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	310,329,063				307,664,192
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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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 Administration 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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

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

- Report below the original cost of electric plant in service according to the prescribed accounts.
- In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
- Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
- For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
- For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	242,914,008	9,156,425				252,070,433
4	(303) Miscellaneous Intangible Plant	146,378,757	38,904,318	2,327,510			182,955,565
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	389,292,765	48,060,743	2,327,510			435,025,998
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	10,034,634	92,314				10,126,948
9	(311) Structures and Improvements	292,341,489	2,134,796	404,091			294,072,194
10	(312) Boiler Plant Equipment	1,485,210,368	33,209,635	5,806,427			1,512,613,576
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	318,360,826	4,002,441	442,717			321,920,550

13	(315) Accessory Electric Equipment	187,297,955	722,607	475,710			187,544,852
14	(316) Misc. Power Plant Equipment	54,142,197	236,901	519,846			53,859,252
15	(317) Asset Retirement Costs for Steam Production	20,325,456	(1,798,003)	(1,713,416)			20,240,869
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,367,712,925	38,600,691	5,935,375			2,400,378,241
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	1,757,711					1,757,711
19	(321) Structures and Improvements	581,439,221	24,961,342	917,031			605,483,532
20	(322) Reactor Plant Equipment	1,919,965,851	27,792,238	104,174			1,947,653,915
21	(323) Turbogenerator Units	592,848,966	28,500,749	1,741			621,347,974
22	(324) Accessory Electric Equipment	534,996,989	4,243,389	236,030			539,004,348
23	(325) Misc. Power Plant Equipment	206,832,865	885,657	323,610			207,394,912
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)	3,615,294,009	86,383,375	1,582,586			3,700,094,798
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					1,467,522
29	(332) Reservoirs, Dams, and Waterways	11,086,237					11,086,237
30	(333) Water Wheels, Turbines, and Generators	10,156,576					10,156,576
31	(334) Accessory Electric Equipment	3,274,337	6,020	1,118			3,279,239
32	(335) Misc. Power Plant Equipment	60,825					60,825
33	(336) Roads, Railroads, and Bridges	143,714	8,361				152,075
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	27,882,287	14,381	1,118			27,895,550
36	D. Other Production Plant						
37	(340) Land and Land Rights	33,316,378	297,572			(14,802)	33,599,148

38	(341) Structures and Improvements	381,106,390	103,056,640	200,822			483,962,208
39	(342) Fuel Holders, Products, and Accessories	26,957,487	1,127,880	148,851			27,936,516
40	(343) Prime Movers	141,324,864	2,644,680	306,594			143,662,950
41	(344) Generators	3,129,049,687	771,880,734	10,811,737			3,890,118,684
42	(345) Accessory Electric Equipment	317,161,136	11,659,701	52,215			328,768,622
43	(346) Misc. Power Plant Equipment	33,488,192	25,574,797	110,047			58,952,942
44	(347) Asset Retirement Costs for Other Production	238,060,947	107,047,709				345,108,656
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)	4,304,593,983	1,023,289,713	11,630,266		(14,802)	5,316,238,628
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	10,315,483,204	1,148,288,160	19,149,345		(14,802)	11,444,607,217
47	3. Transmission Plant						
48	(350) Land and Land Rights	168,440,877	295,527	102,682		14,802	168,648,524
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	141,011,014	14,218,324	516,337			154,713,001
50	(353) Station Equipment	1,362,183,856	97,350,332	6,437,226			1,453,096,962
51	(354) Towers and Fixtures	117,886,517	8,705,836	65,537			126,526,816
52	(355) Poles and Fixtures	1,453,162,808	94,526,604	779,079			1,546,910,333
53	(356) Overhead Conductors and Devices	609,857,358	62,682,174	483,745			672,055,787
54	(357) Underground Conduit	29,130,918	3,050,664				32,181,582
55	(358) Underground Conductors and Devices	37,343,416	(1,501,588)	393,943			35,447,885
56	(359) Roads and Trails						
57	(359.1) Asset Retirement Costs for Transmission Plant	173,429					173,429
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	3,919,190,193	279,327,873	8,778,549		14,802	4,189,754,319
59	4. Distribution Plant						

60	(360) Land and Land Rights	19,768,013	110				19,768,123
61	(361) Structures and Improvements	57,589,750	5,624,891	134,570			63,080,071
62	(362) Station Equipment	702,049,877	32,442,468	1,941,950		388,913	732,939,308
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	524,161,123	48,322,782	490,709			571,993,196
65	(365) Overhead Conductors and Devices	552,110,793	38,595,329	2,880,479		4,611	587,830,254
66	(366) Underground Conduit	345,479,374	14,467,684	250,624			359,696,434
67	(367) Underground Conductors and Devices	1,304,152,430	53,775,559	3,163,637		1,005	1,354,765,357
68	(368) Line Transformers	492,922,483	24,933,564	12,842,532		(390,366)	504,623,149
69	(369) Services	360,387,946	26,301,393	738,625			385,950,714
70	(370) Meters	103,685,390	6,155,278	9,878,242		(132,680)	99,829,746
71	(371) Installations on Customer Premises					128,517	128,517
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	79,575,752	6,912,647	985,678			85,502,721
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)	4,554,113,969	257,531,705	33,307,046			4,778,338,628
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	4,723,352	716,877				5,440,229
87	(390) Structures and Improvements	75,908,249	389,272	21,520		(48,277)	76,227,724
88	(391) Office Furniture and Equipment	90,589,967	17,410,831	15,319,339		48,277	92,729,736
89	(392) Transportation Equipment	197,758,517	9,105,752	14,288,024			192,576,245
90	(393) Stores Equipment	1,624,278					1,624,278
91	(394) Tools, Shop and Garage Equipment	106,479,924	13,636,857	3,454,346			116,662,435
92	(395) Laboratory Equipment	2,962,117	348,218	445,689			2,864,646
93	(396) Power Operated Equipment	53,291,601	395,857				53,687,458
94	(397) Communication Equipment	124,478,342	62,172,155	4,018,471		2,217,581	184,849,607
95	(398) Miscellaneous Equipment	4,369,619	(283,080)	2,184,025			1,902,514
96	SUBTOTAL (Enter Total of lines 86 thru 95)	662,185,966	103,892,739	39,731,414		2,217,581	728,564,872
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)	662,185,966	103,892,739	39,731,414		2,217,581	⁹¹ 728,564,872
100	TOTAL (Accounts 101 and 106)	19,840,266,097	1,837,101,220	103,293,864		2,217,581	21,576,291,034
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)	19,840,266,097	1,837,101,220	103,293,864		2,217,581	21,576,291,034

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: TransmissionPlant

Transmission Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 350 - Land & Land Rights	\$ 157,969	\$ —	\$ —	\$ —	\$ —	\$ 157,969
Account 352 - Structures & Improvements	19,753,395	—	2,755,918	—	(40,295)	22,469,018
Account 353 - Station Equipment	93,436,743	29,083,262	—	(490,300)	—	122,029,705
Account 354 - Towers & Fixtures	4,916,560	—	—	—	—	4,916,560
Account 355 - Poles & Fixtures	11,944,574	—	6,848,464	—	—	18,793,038
Account 356 - Overhead Conductors & Devices	5,283,788	—	8,549,197	—	—	13,832,985

(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	2,663,159	1,561,024	—	—	—	4,224,183

(c) Concept: IntangiblePlant

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

(d) Concept: ProductionPlant

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

(e) Concept: TransmissionPlant

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

(f) Concept: DistributionPlant

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

(g) Concept: GeneralPlant

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						

22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL					

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				

21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	TOTAL			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	DKR0 Dakota Range Wind Turbines	392,871,563
2	NBL Nobles Wind Repower	101,114,428
3	PI TN-40 Casks (48-64)	29,787,273
4	NRW Northern Wind Farms	18,423,995
5	DEMS Ph4 HW MN-10756	11,541,417
6	DKR0 Dakota Range Wind TSG Sub	9,254,619
7	Chanhassen Land Acquisition	9,140,701
8	LINE Relocation 4th Street Road Pro	9,062,492
9	GDM Grand Meadow Repower	8,998,098
10	LINE Install Wilson WIL TR4 & Feede	8,885,230
11	MN-Dist Fleet NewUnit Prchse EI Ops	8,862,915
12	MT Cooling Tower Upgrades Ph III	7,189,454
13	AGIS Meter Data Mgmt (MDM) SW MN	5,702,898
14	Relocation MPLS SWLRT Road Project	4,982,320
15	PI Operating Cycle	4,440,219
16	Sioux Falls Property Acquisition -	4,038,413
17	LINE Plymouth-Area Power Grid Upgra	3,995,361
18	MT 2nd License Renewal	3,927,500
19	LINE Relocation Hennepin Ave Road P	3,701,374
20	LINE Install Elm Creek ECK 34.5kV T	3,532,701
21	Edina Service Center Renovatio	3,528,894

22	ITC ISO Intrfc & Stlmt Rpl SW MN-20	3,227,427
23	HW BTF STF Parcel 15, 16, 17 Land	3,046,377
24	ITC-Nuclear APM Phase 2 SW MN	2,636,480
25	PI 121-128 Intake Travelling Screen	2,459,722
26	Rebuild Downtown St. Paul Manholes	2,243,801
27	ITC-Purch DEMS HW MN	2,195,509
28	PI NI Channel Bypass Panel	2,167,415
29	MN Install Viper Reclosers CSG Blk	2,166,793
30	SE Region Reliability Initiative	2,153,966
31	NSPM S&E 115kV Line	2,101,507
32	MT #12 EDG Voltage Regulator	2,090,470
33	PI CT11,CT12 Transformer Repl	2,007,050
34	SUB MN Feeder Load Monitoring	1,904,533
35	LINE Install Great Plains Area Sub	1,900,033
36	MNGP Off-Gas H2 & O2 Monitorin	1,865,802
37	AMI-Meter-Data-Lake-BS-SW-NSPM	1,826,113
38	MN Transportation Units Over 50K	1,761,519
39	AMI-DI-BS-HW-NSPM	1,630,185
40	AMI-DIST-NSPM-MN Full AMI	1,542,664
41	MINNESOTA MAJOR STORM RECOVERY	1,532,455
42	ADMS Data - NSPM	1,529,195
43	SUB Install Elm Creek ECK 34.5kV TR	1,470,425
44	Relocate Daytons Bluff DBL061	1,460,137
45	Pot Parallel Removal Monticello	1,452,057
46	ITC-SAS BookRunner Upgra SW 200134	1,444,342
47	COMM MN Fiber Buildout	1,438,254
48	Purch Synchrophasor Net HW MN	1,405,490
49	Relocation EDINA SWLRT Road Project	1,389,099

50	MN EV Fleet - Infrastructure	1,345,398
51	SHC Cmbnd-Cycle Gen Plant Other Pro	1,316,036
52	ITC-Monticello Server Refresh HW MN	1,294,351
53	Reserve Low Impedance Mobile	1,260,326
54	MN Veg Mgmt Data Analytics	1,222,139
55	New Belle Plaine SC Land Acquistion	1,176,513
56	ELR STP Vault Tops	1,134,813
57	PI Analog Proc Controls Repl-Ph II	1,090,986
58	RLK 115 kV Bus Expansion	1,064,645
59	MT #11 EDG Voltage Regulator	1,049,749
60	MN-Solar Garden Sub Work	1,040,410
61	ELR ND Sub VARIOUS	1,021,975
62	ANS2-C-U2 replace vanes and bl	1,013,873
63	Relocate Glen Lake GNL071	1,005,701
64	SE Solar Garden Extensions	(7,836,942)
65	Minor Projects	90,496,903
66	[a] (footnote to page 106)	
43	Total	805,727,561

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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.

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	7,995,323,556	7,995,323,556		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	693,127,798	693,127,798		
4	(403.1) Depreciation Expense for Asset Retirement Costs	(9,255,001)	(9,255,001)		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	14,954,032	14,954,032		
7	Other Clearing Accounts	826,229	826,229		
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)	699,653,058	699,653,058		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(102,679,770)	(102,679,770)		
13	Cost of Removal	(36,506,857)	(36,506,857)		
14	Salvage (Credit)	3,612,651	3,612,651		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(135,573,976)	(135,573,976)		

16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	49,740,963	(a)49,740,963		
18	Book Cost or Asset Retirement Costs Retired	1,713,417	1,713,417		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	(b)8,610,857,018	8,610,857,018		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	1,756,654,436	(c)1,756,654,436		
21	Nuclear Production	2,269,545,185	(d)2,269,545,185		
22	Hydraulic Production-Conventional	16,434,025	(e)16,434,025		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,374,462,761	(f)1,374,462,761		
25	Transmission	1,054,472,605	(g),(h)1,054,472,605		
26	Distribution	1,806,660,671	(i),(j)1,806,660,671		
27	Regional Transmission and Market Operation				
28	General	332,627,335	(k)332,627,335		
29	TOTAL (Enter Total of lines 20 thru 28)	(l)8,610,857,018	8,610,857,018		

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToAccumulatedDepreciation

Net change in RWIP	\$	(15,872,757)
Net Transfers and Adjustments		65,521,861
(Gain)/Loss		102,682
Common Expense Allocation		(10,823)
Total	\$	49,740,963

(b) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

	"Non-Legal" ARO Balances	
Steam Production	\$	134,912,048
Nuclear Production		(75,728,141)
Hydraulic Production-Conventional		2,859,412
Other Production		79,896,279
Transmission		148,651,099
Distribution		229,164,134
General		(1,552,149)
Total	\$	518,202,682

(c) Concept: AccumulatedDepreciationSteamProduction

Schedule Page: 219
Line No.: 20-26, 28
Column: C

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

Schedule Page: 219
Line No.: 20-26, 28
Column: C

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

Schedule Page: 219
Line No.: 20-26, 28
Column: C

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

Schedule Page: 219
Line No.: 20-26, 28
Column: C

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	\$	42,594,939
Transmission Serving Production RWIP	\$	208,260

(h) Concept: AccumulatedDepreciationTransmission

Schedule Page: 219
Line No.: 20-26, 28
Column: C

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

Distribution Serving Production	\$	2,668,079
---------------------------------	----	-----------

(j) Concept: AccumulatedDepreciationDistribution

Schedule Page: 219
Line No.: 20-26, 28
Column: C

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.

(k) Concept: AccumulatedDepreciationGeneral

Schedule Page: 219
Line No.: 20-26, 28
Column: C

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	\$	134,912,048
Nuclear Production		(75,728,141)
Hydraulic Production-Conventional		2,859,412
Other Production		79,896,279
Transmission		148,651,099
Distribution		229,164,134
General		(1,552,149)
Total	\$	518,202,682

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

- Report below investments in Account 123.1, Investments in Subsidiary Companies.
- Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
- Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
- For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
- If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
- Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
- In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
- Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	UNITED POWER & LAND CO.			972,243	668,740	(23)	1,641,006	
2	UNITED POWER & LAND CO. - Capital Stock			4,020,000			4,020,000	
3	UNITED POWER & LAND CO. - Paid-In-Capital			749,554		(23)	749,577	
4	UNITED POWER & LAND CO. - Unappropriated Undistributed Subsidiary Earnings			(3,797,311)	668,740		(3,128,571)	
5	NSP NUCLEAR CO.			1,580,362	227		1,580,589	
6	NSP NUCLEAR CO. - Capital Contribution			962,698			962,698	
7	NSP NUCLEAR CO. - Unappropriated Undistributed Subsidiary Earnings			617,664	227		617,891	
42	Total Cost of Account 123.1 \$ 5,732,275.00		Total	2,552,605	668,967	(23)	3,221,595	

FOOTNOTE DATA

(a) Concept: InterestAndDividendRevenueFromInvestments

Annual allocation of unitary tax (benefit)/detriment.

FERC FORM No. 1 (ED. 12-89)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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)	92,325,796	82,320,015	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)	^{fb} 29,520,422	^{fb} 34,820,007	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	149,452,684	146,323,646	Electric
8	Transmission Plant (Estimated)	1,477,064	868,918	Electric
9	Distribution Plant (Estimated)	2,586,011	3,045,262	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	^{fb} (5,229,257)	^{fb} (4,327,880)	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	177,806,924	180,729,953	
13	Merchandise (Account 155)	284,535	916,230	
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	^{fb} note re: page 106 formula rates			0
20	TOTAL Materials and Supplies	270,417,255	263,966,198	



Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction

	Electric	Gas
Production	\$ 13,119,582	\$ —
Transmission	5,383,427	—
Distribution	9,980,583	1,036,830
Total	\$ 28,483,592	\$ 1,036,830

(b) 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

(c) Concept: PlantMaterialsAndOperatingSuppliesOther

Includes a credit of \$2,663,768 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of \$2,565,489 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.

(d) Concept: PlantMaterialsAndOperatingSuppliesOther

Includes a credit of \$2,746,302 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.

(e) Concept: DescriptionOfMaterialsAndSuppliesOtherClasses

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

15	Total	(6,253)								(6,253)		
16												
17	Relinquished During Year:											
18	Charges to Account 509	(9,929)								(9,929)		
19	Other:											
20	Allowances Used											
20.1	Allowances Used											
21	Cost of Sales/Transfers:											
22	Beginning Balance Adj.	30								30		
23												
24												
25												
26												
27												
28	Total											
29	Balance-End of Year	1,044,187		93,200		93,200		93,016		1,870,074		3,193,677
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		42,545		46,249
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		41,619		44,397

41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)	926	21								926	21	
45	Gains		21										21
46	Losses												

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AllowancesReturnedByEnvironmentalProtectionAgencyNumber

The amount reported for the Returned by EPA in line 5 is subject to change due to the EPA finalizing their allowances in May 2022 for the prior year.

FERC FORM No. 1 (ED. 12-95)

Page 228(ab)-229(ab)a

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AllowancesReturnedByEnvironmentalProtectionAgencyNumber

The amount reported for the Returned by EPA in line 5 is subject to change due to the EPA finalizing their allowances in May 2022 for the prior year.

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						

22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	Prairie Island Extended Power Uprate Project MN Docket E-002/CN-08-509	78,884,915		Various	3,423,115	49,181,430
22	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	4,677,889	31,522,990
49	TOTAL	126,929,210			8,101,004	80,704,420

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

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

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

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

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

(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	(429,432)
	\$ 3,423,115

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	SISA-T-L-NSP-678-Shakopee West Sub 600101743358			22	242.0
3	East River System Impact Study Agreement 600101757358			(5,000)	242.0
4	East River System Impact Study Agreement 600101757358 Cost	4,626	562	4,626	562
5	Chaska System Impact Study NSP-694 600101758358			15,000	242
20	Total	4,626		14,648	
21	Generation Studies				
22	J399 Facility Study-600101715133			(3,402)	242.0
23	J432 Facility Study-600101721362			14,614	242.0
24	J460 Facility Study-600101721363			8,056	242.0
25	A698/F115 Facility Study-PO 21555-600101721378			9,737	242.0
26	J460/J526 Hazel Creek Trnsfm Upgrade-600101726363			5,510	242.0
27	J523 Adams Substation Line Termination-600101726364			5,531	242.0
28	J523 Adams SubTransformer Replace-600101726365			7,841	242.0
29	J526 Line 0900 rebuild-600101726366			2,500	242.0
30	XES-J732 Stone Lake-Transformer Replace			(1,623)	242.0
31	J926 PNL-APR Line #3209			(1,200)	242.0
32	XES-J1106 Wind Interc on line #0957			(66,656)	242.0

33	XES-J1106 Wind Interc on line #0957 Cost	3,085	561.7	3,085	561.7
34	J1445 Mayhew Lake Sub Solar			(34,627)	242.0
35	J1445 Mayhew Lake Sub Solar Cost	34,627	561.7	34,627	561.7
36	J1446 Lake Pulaski Sub Solar			(53,362)	242.0
37	J1446 Lake Pulaski Sub Solar Cost	53,361	561.7	53,361	561.7
38	J1395 CapX Hawks Nest L-LYN 345KV In Sub			(71,173)	242.0
39	J1395 CapX Hawks Nest L-LYN 345KV In Sub Cost	71,173	561.7	71,173	561.7
40	J898 NU-Adam 345/161 kV TR9 Rplcmt			(28,580)	242.0
41	J898 NU-Adam 345/161 kV TR9 Rplcmt Cost	28,580	561.7	28,580	561.7
42	J946 NU - Sheyenne 115 kV Ln Rbld			(22,528)	242.0
43	J946 NU - Sheyenne 115 kV Ln Rbld Cost	22,528	561.7	22,528	561.7
44	J901 NU - Helena Chub Lk 345 kV Ln Rbld			(7,352)	242.0
45	J901 NU - Helena Chub Lk 345 kV Ln Rbld Cost	7,352	561.7	7,352	561.7
46	J1468 West Hastings 115 KV Sub battery			(72,098)	242.0
47	J1468 West Hastings 115 KV Sub battery Cost	72,098	561.7	72,098	561.7
48	J1315 CapX Lyon Cty-CMT 345KV In Sub			(2,021)	242.0
49	J1315 CapX Lyon Cty-CMT 345KV In Sub Cost	2,021	561.7	2,021	561.7
50	J1312 Grant Sub solar			(805)	242.0
51	J1312 Grant Sub solar Cost	805	561.7	805	561.7
52	J803 Tracy Sub FaS Restudy			(18,117)	242.0
53	J803 Tracy Sub FaS Restudy Cost	18,117	561.7	18,117	561.7
54	J1473 Lawrence Crk line 115 KV Sub			(717)	242.0
55	J1473 Lawrence Crk line 115 KV Sub Cost	717	561.7	717	561.7
56	J1349 Crandall Sub Hybrid			(35,700)	242.0
57	J1349 Crandall Sub Hybrid Cost	35,700	561.7	35,700	561.7
58	J569/J587/J590 HLN-SCO LN #0982 Faci Stu			(59)	242.0
59	J569/J587/J590 HLN-SCO LN #0982 Faci Stu Cost	59	561.7	59	561.7
60	G621 Chanarambie Sub FaS Restudy			(37,314)	242.0

61	G621 Chanarambie Sub FaS Restudy Cost	37,314	561.7	37,314	561.7
62	G057/Viking Chanarambie Sub FaS			(15,998)	242.0
63	G057/Viking Chanarambie Sub FaS Cost	15,998	561.7	15,998	561.7
39	Total	403,535		(16,008)	
40	Grand Total	408,161		(1,360)	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	2019 Minnesota Revenue Decoupling-MN Docket E-002/GR-15-826-Amortized over 1 year (04-2020-03/2021)	5,661,851		407.3	5,661,851	
2	2019 Minnesota Sales True Up - MN Docket E-002/GR-15-826 - Amortized over 1 year (04-2020-03/2021)	10,546,496		407.3	10,546,496	
3	2020 Minnesota Sales True Up - MN Docket E-002/GR-19-688 - Amortized over 1 year (04-2021-03/2022)	112,965,709	5,450,668	407.3	93,261,770	25,154,607
4	2021 Minnesota Sales True Up-MN Docket E-002/GR-20-743- Amortization begins 04/2022 over 12-24 months based on customer class		64,112,588			64,112,588
5	Asset Retirement Recovery	2,446,354,058	107,124,621			2,553,478,679
6	Benefit Cost Recovery Deficit	377,911,231	46,153,206	184	112,863,064	311,201,373
7	Benson Biomass PPA Termination - MN Docket E-002/GR-17-530 - ND Docket PU-17-271 - SD Docket EL 18-027	38,036,323		557	4,913,144	33,123,179
8	Business Incentive and Sustainability Rider Pandemic Discount - MN Docket E-002/M-20-436	664,690	1,968,230			2,632,920
9	Conservation and Energy Management Program Costs Minnesota Electric - MN Docket E-002/M-21-226 - Generally amortized over 12 month period following the expenditure	6,494,074	140,983,423	(b) Various	147,477,497	
10		104,992	1,008,280	908	1,000,692	112,580

	Conservation and Energy Management Program Costs South Dakota Electric - SD Docket EL 21-014 - Generally amortized over 12 month period following the expenditure					
11	Costs to Relocate Facilities Underground - MN Docket E-002/M-99-799 - MN Docket E-002/M-15-826	1,575,867	808,352	142	542,375	1,841,844
12	COVID-19 Public Health Emergency - SD - SD Docket GE 20-002	741,405	757,095	904	1,498,500	
13	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	38,092,928	(a)55,352,800	(g) Various	39,708,275	53,737,453
14	Deferred Tax Collected in Rates in Excess of Current Tax Accrual Levels		165,462			165,462
15	Derivatives & Hedging - Retail Electric & Gas		4,066,466			4,066,466
16	Gas Utility Infrastructure Cost Rider - MN Docket E-002/GR-21-765	26,134,783	25,608,669	407.4	18,989,244	32,754,208
17	Laurentian Biomass PPA Termination - MN Electric E-002/GR-17-551 - ND Docket PU-17-322 - SD Docket EL 18-027	54,250,001		557	18,083,333	36,166,668
18	Mankato/Cannon Falls Lease Normalization	36,433,464	1,518,792	101.1	5,651,519	32,300,737
19	Minnesota Deferred Electric Commodity Costs - 2020 - MN Docket E-002/AA-19-293	6,523,188		142	6,523,188	
20	Minnesota Deferred Electric Commodity Costs - 2021 - MN Docket E-002/AA-20-417		893,682,476	557	808,532,966	85,149,510
21	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	1,471,489	1,170,516			2,642,005
22	Minnesota LED Streetlighting Deferral - MN Docket E-002/M-15-826	534,623		407.3	166,265	368,358
23	Minnesota Renewable Energy Standard - MN Docket E-002/M-19-732 - MN Docket E-002/M-20-815 - MN Docket E-002/M-21-794	100,148,730	117,765,467	407.4	76,701,631	141,212,566
24	Net of Tax AFUDC in Plant Adjustments	112,772,624	784,885			113,557,509
25	Nonplant Excess ADIT	132,036,230	264,349	283	9,905,823	(g)122,394,756
26	North Dakota AGIS Deferral - ND Docket PU-20-441		689,892			689,892
27	North Dakota Deferred Electric Commodity Costs - ND Docket PU-12-813		65,430,905	557	62,534,768	2,896,137

28	North Dakota Environmental Cleanup - ND Docket PU-17-894	10,441,052	135,303	(g) Various	6,004,918	4,571,437
29	North Dakota Transmission Cost Recovery Rider - ND Docket PU-21-396	288,643	6,686,165	407.3	6,699,852	274,956
30	Power Contract Valuation Adjustment	64,320,996		244	16,019,627	48,301,369
31	Renewable Development Fund Rider - MN Docket E-002/M-21-708	29,168,081	49,541,107	407.3	50,316,249	28,392,939
32	Renewable*Connect Classic - MN Docket E-002/GR-21-234	6,747,522	7,972,182	142	5,586,125	9,133,579
33	Renewable*Connect Government - MN Docket E-002/GR-21-234	245,326	414,879	142	339,249	320,956
34	Sherco 3 Depreciation Deferral - MN Docket E-002/GR-15-826 - Amortized over 21 years (01/2014-12/2035)	7,043,815		407.3	503,130	6,540,685
35	South Dakota Property Tax Collected in the Fuel Clause Adjustment - SD Docket EL 14-058		278,091			278,091
36	South Dakota Ratemaking Differences - SD Docket F-3382 - SD Docket F-3422	3,420,250	439,000	405	490,000	3,369,250
37	Theoretical Depreciation Reserve Surplus - MN Docket E-002/GR-17-147	247,754,202		407.3	10,039,728	237,714,474
38	Transmission Formula Rates	12,065,449	5,386,125	565	6,541,330	10,910,244
44	TOTAL	3,890,950,092	1,605,719,994		1,527,102,609	3,969,567,477

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: IncreaseDecreaseInOtherRegulatoryAssets

Accounts charged:

517		\$	3,194,280
519			785,670
520			7,421,769
523			430,789
524			1,950,822
528			973,711
530			22,766,878
531			3,585,895
532			14,242,986
Total		\$	55,352,800

(b) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:

456		\$	20,659,568
908			126,817,929
Total		\$	147,477,497

(c) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:

517		\$	2,091,016
519			628,027
520			5,143,949
523			438,782
524			1,480,554
528			1,191,659
530			14,875,772
531			2,430,953
532			11,427,563
Total		\$	39,708,275

(d) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:

131		\$	4,111,273
242			851,978
735			1,041,667
Total		\$	6,004,918

(e) Concept: OtherRegulatoryAssets

	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Total
Electric	\$ 84,627,943 \$	32,963,130 \$	117,591,073
Gas	3,457,115	1,346,568	4,803,683
Total	\$ 88,085,058 \$	34,309,698 \$	122,394,756

*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 12/31/2020	Amortization 2021	Excess Balance 12/31/2021
Bad Debts	\$ 1,023,518 \$	(511,758) \$	511,760
Deferred Rent	546,503	(273,251)	273,252
Deferred Revenues	115,932	(57,966)	57,966
Economic Development Securities - Write-Off	19,114	(9,556)	9,558
Employee Incentive Plans	796,567	(398,283)	398,284
Environmental Remediation	8,916	(4,457)	4,459
Federal Net Operating Loss	83,893,606	(4,194,680)	79,698,926
Fuel Tax Credit - Income Addback	904	(452)	452
Inventory Reserve	198,026	(99,014)	99,012
Litigation Reserve	21,525	(10,763)	10,762
Medical Deductions - Self Insured	93,126	(46,564)	46,562
North Dakota Investment Tax Credit	(6,076,087)	3,038,043	(3,038,044)
North Dakota Investment Tax Credit - Valuation Allowance	6,076,087	(3,038,043)	3,038,044
Performance Recognition Awards	2,186	(1,092)	1,094
Post Employment Benefits - Long Term Disability	1,534,749	(127,896)	1,406,853
Post Employment Benefits - Retiree Medical	4,922,321	(410,193)	4,512,128
Purchased Power Capacity	10,316	(5,158)	5,158
Rate Refund	1,196,545	(598,273)	598,272
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	732,394	(366,197)	366,197
Regulatory Asset/Liability - Transmission Cost Recovery Rider	382,430	(191,214)	191,216
Regulatory Asset/Liability - Prairie Island Extended Power Uprate Cancellation	204,208	(102,104)	102,104
Sale of Emission Allowances	4,083	(2,042)	2,041
South Dakota Infrastructure Rider	52,443	(26,221)	26,222
Section 174 - Section 59(e) Adjustment	2,766,572	(1,383,286)	1,383,286
Severance Accrual	12,165	(6,082)	6,083
Solar Rewards Program	1,352,938	(676,470)	676,468
State Research and Experimental Credit	(407,150)	203,576	(203,574)
State Research Credit - Valuation Allowance	78,119	(39,059)	39,060
Vacation	908,094	(454,046)	454,048
VEBA	254,423	(127,211)	127,212
Workers Compensation	4,731	(2,365)	2,366
Total Electric	\$ 100,729,304 \$	(9,922,077) \$	90,807,227

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	IPP Power Contract Billing Adjustments	807,352		[a] Various	9,270	798,082
2	Conservation and Energy Management Program Costs Minnesota Electric (Docket E-002/M-21-226)	27,334,823	27,263,078	182.3	30,500,073	24,097,828
3	Conservation and Energy Management Program Costs Minnesota Gas Incentive (Docket G-002/M-21-227)	3,247,552	4,798,143	182.3	3,247,552	4,798,143
4	Federal and State Income Taxes Receivable		396,690			396,690
5	Federal and State Income Tax Interest Receivable	5,383,381	388,301	171	174,573	5,597,109
6	North Dakota Electric Retail Rate Case (Docket PU-20-441)	760,577	385,763	[a] 928	355,540	790,800
7	Future South Dakota Electric Retail Rate Case Expenses (Docket EL14-058)	113,169				113,169
8	Notes Receivable - 3rd Party	3,122,883	131,207	143	510,739	2,743,351
9	Prepays - Facility Fees	1,329,681		431	391,910	937,771
10	JOA & Rate Payer Share MTM	6,125,450	14,945,671			21,071,121
11	2021 Minnesota Electric Retail Rate Case Expenses (Docket E-002/GR-21-630)		612,407			612,407
12	2021 Minnesota Gas Retail Rate Case Expenses (Docket G-002/GR-21-678)		306,260			306,260
13	2021 North Dakota Gas Retail Rate Case Expenses (Docket PU-21-381)		484,898	928	68,000	416,898
14	Loan Receivable - 3rd Party		5,168,947			5,168,947

47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	48,224,868				67,848,576

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged

Accounts charged:			
232		\$	20
555			9,250
Total		\$	9,270

(b) Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged

Includes demand allocator study and rate case expenses per North Dakota Electric Rate Case Docket PU-20-441.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	219,609,223	227,384,879
3	Electric - Non-Plant	810,816,034	967,920,958
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,030,425,257	1,195,305,837
9	Gas		
10		31,097,228	32,370,045
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	31,097,228	32,370,045
17.1	Other (Specify)	27,319,884	41,781,926
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,088,842,369	1,269,457,808

Notes

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Decommissioning	\$ —	\$ —
Electric Distribution Plant	129,645,549	134,908,217
Electric General Plant	454,596	461,788
Electric Intangible Plant	3,264,501	2,934,406
Electric Nuclear Fuel	28,550,159	29,352,046
Electric Nuclear Production Plant	54,660,249	49,521,279
Electric Production Plant	48,745,536	50,587,382
Electric Transmission Plant	47,099,187	46,449,218
Electric Transmission-Production Plant	876,239	2,187,661
Common (Allocation to Electric)	922,333	818,921
Regulatory Differences - Effect of Rate Changes	(101,825,134)	(96,482,375)
Regulatory Differences - Investment Tax Credit Gross-Up	7,216,008	6,646,336
Total Electric Plant Related Only	<u>\$ 219,609,223</u>	<u>\$ 227,384,879</u>

(b) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Electric:		
Avoided Tax Interest	\$ 134,899,447	\$ 133,799,625
Bad Debts	8,838,412	12,162,564
Customer Advances	2,966,561	2,504,403
Deferred Connection Fees	125,867,575	132,080,516
Deferred Rent	2,663,369	2,482,814
Deferred Revenue	755,119	544,405
Economic Development Securities - Write-Off	101,966	103,628
Electric Vehicle Credit	6,925	6,912
Employee Incentive Plans	4,090,503	3,589,458
Employee Retention	—	3,160
Employee Stock Ownership Program Dividends	6,498,813	6,504,761
End of Life Nuclear Fuel Amortization	28,550,159	29,352,046
Environmental Remediation	1,862,962	1,638,646
Excess Nonplant Accumulated Deferred Income Taxes	9,601,482	7,868,974
Federal Net Operating Loss	—	15,014,069
Fuel Tax Credit - Income Addback	4,823	12,882
Inventory Reserve	675,664	652,061
Investment Tax Credit	2,071,062	2,071,062
Litigation Reserve	111,157	84,762
Mark to Market Adjustment	557,869	—
Medical Deductions - Self Insured	945,044	570,405

Monticello Extended Power Uprate Writedown	15,435,794	12,979,567
New Hire Retention Credit	51,331	51,388
North Dakota Investment Tax Credit	65,307,530	71,044,542
North Dakota Investment Tax Credit - Valuation Allowance	(58,407,586)	(63,267,486)
North Dakota Investment Tax Credit - Federal Gross-Up	2,241,085	2,468,865
North Dakota Production Tax Credit - Levelization	—	1,568,199
Operating Lease Liabilities	135,702,623	113,770,244
Payroll Tax Deferral	4,503,442	2,265,208
Performance Recognition Awards	96,963	112,475
Post Employment Benefits - Retiree Medical	10,407,460	8,636,859
Post Employment Benefits - Long Term Disability	3,142,522	3,003,275
Rate Refund	6,735,975	11,074,002
Regulatory Asset/Liability - Miscellaneous	—	1,906,917
Regulatory Asset/Liability - Transmission Cost Recovery Rider	13,745,260	6,512,912
Regulatory Asset/Liability - Windsource	514,707	—
Regulatory Difference - Effect of Rate Changes	(101,825,134)	(96,482,375)
Regulatory Difference - Investment Tax Credit Gross-Up	7,216,008	6,646,336
Research and Experimentation Credit	43,534,582	49,467,526
Section 174 - Section 59(e) Adjustment	30,344,521	37,015,541
Severance Accrual	23,345	23,396
Solar Rewards Program	3,485,920	1,929,164
South Dakota Infrastructure Tracker	524,561	721,804
State Research Credit	7,355,549	8,492,229
State Research Credit - Valuation Allowance	(433,170)	(235,508)
State Tax Deduction Cash vs. Accrual	1,731,094	623,819
Texas Gross Margin Tax	—	500
Vacation Accrual	5,327,369	5,320,422
Wind Production Tax Credit	502,454,040	658,446,267
Workers Compensation	140,554	162,596
Total Electric	<u>\$ 1,030,425,257</u>	<u>\$ 1,195,305,837</u>

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 \$3,700,742 for 2020 and \$3,652,382 for 2021.

	2020 ARAM	2021 ARAM
Unprotected ARAM:		
Decommissioning	\$ —	\$ —
Electric Distribution Plant	1,450,064	1,403,133
Electric General Plant	42,664	33,819
Electric Intangible Plant	38,521	140,742
Electric Nuclear Fuel	—	—
Electric Production Plant	1,791,880	1,710,753
Electric Transmission Plant	364,542	350,353
Electric Transmission-Production Plant	4,568	4,723
Common (Allocation to Electric)	8,503	8,859
Total Electric	\$ 3,700,742	\$ 3,652,382

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

Common (Unallocated)	\$9,430	\$9,705
----------------------	---------	---------

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.

	12/31/2021 Excess	12/31/2021 Gross up	12/31/2021 Total Regulatory
Excess (Electric only)			
Flow Through	\$ 448,628	\$ 174,743	623,371
Other Basis Differences (Unprotected)	(69,885,063)	(27,220,683)	(97,105,746)
	\$ (69,436,435)	\$ (27,045,940)	(96,482,375)

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)	\$ (138,473)	\$ (53,936)	(192,409)
	\$ (138,473)	\$ (53,936)	(192,409)
Common (unallocated)			
Other Basis Differences (Unprotected)	\$ (285,246)	\$ (111,105)	(396,351)
	\$ (285,246)	\$ (111,105)	(396,351)

(c) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Gas:		
Avoided Tax Interest	\$ 2,542,666	\$ 3,543,827
Bad Debts	628,446	910,064
Deferred Connection Fees	11,726,650	12,354,273
Deferred Rent	221,250	209,244
Economic Development Securities - Write-Off	9,294	7,754
Electric Vehicle Credit	575	588
Employee Incentive Plans	372,086	322,182
Employee Retention	—	1,163
Employee Stock Ownership Program Dividends	2,495,280	2,548,291
Environmental Remediation	600,443	147,056
Excess Nonplant Accumulated Deferred Income Taxes	507,481	445,839
Federal Net Operating Loss	—	1,123,428
Fuel Tax Credit - Income Addback	401	1,096
Inventory Reserve	56,128	54,704
Litigation Reserve	7,848	6,342
Lower of Cost or Market on Gas Inventories	279,605	313,178
Medical Deduction - Self Insured	85,964	51,198
New Hire Retention Credit	4,669	4,612
Operating Lease Liabilities	11,273,033	9,543,614
Payroll Tax Deferral	409,649	169,494
Performance Recognition Awards	8,820	10,096
Post Employment Benefits - Retiree Medical	946,698	775,226
Post Employment Benefits - Long Term Disability	285,855	269,568
Public Utility Conservation Investment Programs	604,143	—
Rate Refund	34,061	—
Regulatory Asset/Liability - Miscellaneous	—	593,887
Regulatory Difference - Effect of Rate Changes	(5,524,503)	(5,327,162)
Regulatory Difference - Investment Tax Credit Gross-Up	383,310	342,229
Research and Experimentation Credit	—	247,500
Section 174 - Section 59(e) Adjustment	2,520,768	3,148,892
Severance Accrual	2,123	2,100
State Research Credit	—	49,059
State Tax Deduction Cash vs. Accrual	117,104	8,559
Vacation Accrual	484,596	477,550
Workers Compensation	12,785	14,594
Total Gas	<u>\$ 31,097,228</u>	<u>\$ 32,370,045</u>

(d) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year	Balance at End of Year
Other:		
Avoided Tax Interest	\$ 72	\$ 78
Contributions Carryover	—	406,079
Deferred Compensation Plan Reserve	4,224,511	4,431,231
Low Income Housing Credit	331	331
Minnesota Alternative Minimum Tax Credit	163,039	158,238
Minnesota Net Operating Loss	12,204,380	26,927,340
North Dakota Net Operating Loss	16,087	151,441
Nonqualified Pension Plans	340,523	241,588
Other Comprehensive Income	8,432,807	7,951,338
Partnership Passthrough	363,488	364,244
Performance Share Plan	1,397,276	971,740
Regulatory Difference - Effect of Rate Changes	(16)	(15)
State Tax Deduction Cash vs. Accrual	177,386	178,293
Total Other	<u>\$ 27,319,884</u>	<u>\$ 41,781,926</u>

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

5	Total									
---	-------	--	--	--	--	--	--	--	--	--

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2022-04-14	Year/Period of Report End of: 2021/ 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.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.

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.

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.

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	4,105,547,671
15.1	Increases (Decreases) due to contribution of capital by parent	616,789,013
16	Ending Balance Amount	4,722,336,684
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	4,722,336,684

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		

21		
22	TOTAL	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

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

- 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.
- 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.
- 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.
- 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.
- 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.
- 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.
- 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.
- 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.
- 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 Year Amount (m)
1	Bonds (Account 221)												
2	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	300,000,000	6,450,
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,
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,
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,
6			400,000,000		4,877,065		1,404,000	05/25/2006	06/01/2036	05/25/2006	06/01/2036	400,000,000	(\$24,455,

	6.25% Jun 1, 2036 First Mortgage Bonds												
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,
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	(a)16,156,
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,
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	(a)18,496,
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,
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,
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,
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,
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,
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,
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,

18	(a) 2.25% Apr 1, 2031 First Mortgage Bonds		425,000,000		5,063,883		1,776,500	03/30/2021	04/01/2031	03/30/2021	04/01/2031	425,000,000	7,198,
19	(b) 3.20% Apr 1, 2052 First Mortgage Bond		425,000,000		6,020,133		1,576,750	03/30/2021	04/01/2052	03/30/2021	04/01/2052	425,000,000	10,237,
20	Subtotal		6,850,000,000		88,195,720		56,201,751					6,850,000,000	262,082,
21	Reacquired Bonds (Account 222)												
22													
23													
24													
25	Subtotal												
26	Advances from Associated Companies (Account 223)												
27													
28													
29													
30	Subtotal												
31	Other Long Term Debt (Account 224)												
32	Right of Way Debt											3,227,041	38,
33	Interest on Debt to Associated Companies												395,
34	Subtotal											3,227,041	434,
33	TOTAL		6,850,000,000									6,853,227,041	262,516,

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription

Minnesota Public Utilities Commission Docket No. E, G-002/S-20-768. Order dated February 23, 2021.

In March 2021, NSPM issued \$425,000,000 of 2.25 percent First Mortgage Bonds, due April 1, 2031. NSPM used the net proceeds to finance or refinance, existing and future Eligible Green Expenditures

(b) Concept: ClassAndSeriesOfObligationCouponRateDescription

Minnesota Public Utilities Commission Docket No. E, G-002/S-20-768. Order dated February 23, 2021.

In March 2021, NSPM issued \$425,000,000 of 3.20 percent First Mortgage Bonds, due April 1, 2052. NSPM 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		106,993
	\$	16,156,993

(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, 2020	Additions	Reductions	Balance Dec. 31, 2021
Right of Way Debt	\$514,916	\$2,901,137	\$(189,012)	\$3,227,041

(g) Concept: InterestExpenseOtherLongTermDebt

Xcel Energy Service Inc	\$	390,141
NSP Nuclear Corp		1,095
Money Pool		4,221
	\$	395,457

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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 filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	606,222,513
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		35,877,473
9	Deductions Recorded on Books Not Deducted for Return	
10		1,378,848,723
14	Income Recorded on Books Not Included in Return	
15		(127,766,017)
19	Deductions on Return Not Charged Against Book Income	
20		(1,858,702,816)
21	Equity in Earnings of Subsidiary Companies	(668,967)
22	Total Income Tax Expense	(48,141,196)
27	Federal Tax Net Income	(14,330,287)
28	Show Computation of Tax:	
29	Federal Income Tax at 21 percent	(3,009,360)
30	Other	(4,932,227)
31	Total Federal Income Tax Payable	(7,941,587)



Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

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

TAXABLE INCOME NOT REPORTED ON BOOKS:	
Contributions in Aid of Construction	\$ 35,877,473
	<u>\$ 35,877,473</u>

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

DEDUCTIONS RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:	
Avoided Cost Interest	\$ 29,280,689
Bad Debts	12,825,782
Book Amortization - Acquisition Adjustments	14,976
Book Amortization - Computer Software	67,847,291
Book Amortization - Other	17,017,655
Book Depreciation	789,818,105
Book Income - Wisconsin/South Dakota Allowance for Funds During Construction	6,000
Book Rent Expense - Capitalized for Tax - Railcars	414,479
Book Unamortized Cost of Reacquired Debt	1,495,459
Capitalization of Software Expense - Books	344,613
Clearing Account Book Expense	19,615,759
Contributions Carryover	1,448,625
Crown Ridge Allowance for Funds During Construction	10,565
Deferred Compensation Plan Reserve	720,813
Employee Retention	144,844

Employee Stock Ownership Plan Dividends	1,529,757
Executive Officer Nondeductible Compensation	1,154,440
Interest Income/Expense on Disputed Tax	758,691
Lobbying Expenses	1,538,000
Medical Deduction - Self Insured	555,670
Meals & Entertainment	160,000
Net Operating Loss	76,845,226
Nuclear Decommissioning	22,345,232
Nuclear Fuel Expense	113,628,677
Operating Lease Assets	84,980,944
Penalties	1,091,874
Pension and Benefit Capitalized	1,128,725
Performance Recognition Awards	59,472
Prairie Island Extended Power Uprate Writedown Amortization	3,852,547
Public Utility Conservation Investments Programs Adjustment	2,949,750
Rate Refund	15,327,108
Rate Surcharge	61,238,091
Regulatory Asset/Liability - Emergency Special Response	741,405
Regulatory Asset/Liability Cancellation	4,248,467
Regulatory Asset - Miscellaneous	8,921,246
Regulatory Asset/Liability - Transmission Attach O	3,087,755
Regulatory Reserve - Environmental	5,869,615
Renewable Energy Standard/Credit	4,742
Section 174 - Section 59(e) Adjustment	24,085,933
South Dakota Infrastructure Tracker	701,570
State Tax Deduction	396,651
Suite and Entertainment Tickets	557,000
Workers Compensation	84,480
	\$ 1,378,848,723

(c) Concept: IncomeRecordedOnBooksNotIncludedInReturn

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:

Allowance for Funds During Construction - Equity (Non-Conservation Improvement Program)	\$ (34,525,761)
Deferred Revenue - Investment Tax Credit Grant	(173,548)
Insurance Fund Income (Cash Value)	(2,510,938)
Operating Lease Liabilities	(84,988,550)
Solar Rewards Program	(5,567,220)
	\$ (127,766,017)

(d) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:

Allowance for Funds During Construction - Debt (Non-Conservation Improvement Program)	\$	(15,194,870)
Deferred Fuel Costs		(301,621,888)
Deferred Rent		(698,290)
Deferred Revenue		(754,662)
Electric Vehicle Charging Tariff		(1,170,516)
Employee Incentive Plans		(1,982,998)
Environmental Remediation		(2,427,305)
External Qualified Nuclear Decommissioning Fund		(22,345,232)
Gain/(Loss) on Dispositions (Tax)		(7,675,975)
Internally Developed Software		(234,000)
Interest Expense - Capital Leases		(118,675)
Inventory Reserve		(92,163)
Litigation Reserve		(100,000)
Mark to Market Adjustment		(15,973,754)
Nonqualified Pension Plan		(354,276)
Payroll Tax Deferral		(8,860,624)
Performance Share Plan		(1,682,449)
Prepaid Advertising		(31,429)
Pension Expense		(5,696,375)
Post Employment Benefits - Long Term Disability		(568,343)
Post Employment Benefits - Retiree Medical		(6,972,757)
Prepaid Insurance		(6,742,160)
Rate Case/Restructuring Expense		(1,502,506)
Regulatory Asset - Gas Safety Deferrals		(6,619,425)
Regulatory Asset - Nuclear Refueling Outage Costs		(15,644,525)
Regulatory Asset/Liability - Property Tax		(278,091)
Regulatory Asset/Liability - Renewable Energy Standard Rider		(33,977,696)
Regulatory Asset/Liability - Transmission Cost Recovery Rider		(25,854,438)
Regulatory Asset/Liability - Windsource		(7,233,560)
Repair Expenditures		(55,500,000)
Section 174		(45,900,000)
Tax Amortization - Monticello Rerate		(6,295,644)
Tax Amortization - Computer Software		(55,281,295)
Tax Amortization - Pollution Control Facilities		(472,705)
Tax Expense - Ash Pond & Landfills		(204,573)
Tax Depreciation		(1,146,346,612)
Tax Removal Cost Over Book		(56,220,208)
Vacation Accrual		(72,797)
	\$	(1,858,702,816)

(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 2021. The other members of the affiliated group and the federal income tax provision of each are:

Xcel Energy Inc.	(4,448,070)
NSP Nuclear Corporation	103
United Power and Land Company	177,602
Northern States Power Company (Wisconsin) and Subsidiaries	16,846,746
Public Service Company of Colorado and Subsidiaries	17,846,321
Southwestern Public Service Company	(10,742,409)
Nicollet Holdings Company, LLC and Subsidiaries	942,162
Nicollet Project Holdings LLC and Subsidiaries	(1,393,822)
Xcel Energy Communications Group Inc. and Subsidiaries	(19,387)
Xcel Energy Markets Holdings Inc. and Subsidiaries	309,449
Xcel Energy International Inc.	(998)
Xcel Energy Retail Holdings Inc. and Subsidiaries	(6,989)
Xcel Energy Transmission Holding Company, LLC and Subsidiaries	(43,890)
Xcel Energy Ventures Inc. and Subsidiaries	92,528
Xcel Energy Venture Holdings, Inc. and Subsidiaries	173,514
Xcel Energy Wholesale Group Inc. and Subsidiaries	14,872
Xcel Energy WYCO Inc.	5,853,301
WestGas Interstate, Inc.	(6,228)
Xcel Energy Services Inc.	1,894,740

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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 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.
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 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 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. Earning (Account 439) (n)
1	Income	Federal Tax			1,981,401		(9,928,072)	(10,401,425)	^(d) 3,193,400	5,648,154		35,227,942		
2	Income Tax Adjustment	Federal Tax					1,986,485		^(e) (1,986,485)			1,898,455		
3	FICA	Federal Tax		2020	19,725,775			19,725,775						
4	FICA	Federal Tax		2021			34,341,014	23,942,462		10,398,552		27,615,539		
5	Unemployment	Federal Tax		2020	3,639			3,639						
6	Unemployment	Federal Tax		2021			185,170	179,698		5,472		158,571		
7	Subtotal Federal Tax				21,710,815		26,584,597	33,450,149	1,206,915	16,052,178		64,900,507		
8	Income	State Tax	Minnesota		5,517,520		(1,107,215)	(560,845)	^(f) (4,429,583)	541,567		610,657		

9	Income Tax Adjustment	State Tax	Minnesota				617,220		(617,220)			591,256		
10	Unemployment	State Tax	Minnesota	2020	224,187			224,187						
11	Unemployment	State Tax	Minnesota	2021			4,507,822	4,364,338		143,484		2,722,732		
12	Property Tax	State Tax	Minnesota	2020	209,778,320		(5,665,218)	204,113,102				(5,180,908)		
13	Property Tax	State Tax	Minnesota	2021			213,540,000	(11,061)		213,551,061		193,830,000		
14	Property Tax MN Settlement	State Tax	Minnesota	2021			11,868,457		(11,868,457)			11,868,457		
15	Income	State Tax	North Dakota		127,945		1,812	5,125	(120,187)	4,445		265,097		
16	Income Tax Adjustment	State Tax	North Dakota				97		(97)					
17	Unemployment	State Tax	North Dakota	2020	1,039			1,039						
18	Unemployment	State Tax	North Dakota	2021			32,308	31,008		1,300		18,340		
19	Property Tax	State Tax	North Dakota	2020	6,930,000		82,491	7,012,491				64,505		
20	Property Tax	State Tax	North Dakota	2021			6,906,000			6,906,000		5,806,800		
21	Unemployment	State Tax	South Dakota	2020	(1,379)			(1,379)						
22	Unemployment	State Tax	South Dakota	2021			31,595	31,462		133		17,935		
23	Personal Property	State Tax	South Dakota	2020	4,740,000		(281,932)	4,458,068				(281,932)		
24	Personal Property	State Tax	South Dakota	2021			4,890,000			4,890,000		4,890,000		
25	(a) Personal Property FCA	State Tax	South Dakota	2021			(362,444)	(362,444)				(362,444)		
26	Personal Property	State Tax	Kansas	2021			519,865	519,865						
27	Income	State Tax	Wisconsin	2021			(1,080)	(209)	(871)			(1,080)		

28	Unemployment	State Tax	Wisconsin	2021			15,665	16,141		(476)		8,893		
29	Income	State Tax	Texas	2021			51,041	46,824	(3,997)	220		54,471		
30	Unemployment	State Tax	Georgia	2021	22		271	293				154		
31	Subtotal State Tax				227,317,654		235,646,755	219,888,005	(17,038,670)	226,037,734		214,922,933		
32	Denver Occ'l Privilege	Other Taxes		2021								6,153		
33	Miscellaneous Income	Other Taxes		2021	335,024		(224,570)	112,454	2,000					
34	(b) Property Tax on Rail Car	Other Taxes		2020	3,485		868	4,353						
35	(c) Property Tax on Rail Car	Other Taxes		2021			4,800			4,800				
36	Other	Other Taxes		2021			358,864	358,864				337,128		
37	Use	Other Taxes		2021	956,860		23,242,370	22,818,004		1,381,226				
38	Subtotal Other Tax				1,295,369		23,382,332	23,293,675	2,000	1,386,026		343,281		
40	TOTAL				250,323,838		285,613,684	276,631,829	(15,829,755)	243,475,938		280,166,721		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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)	\$ 2,081,343
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (211)	1,112,058
Rounding	(1)
Total	\$ 3,193,400
(e) Concept: TaxAdjustments	
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	\$ (3,370,641)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	1,384,156
Total	\$ (1,986,485)
(f) Concept: TaxAdjustments	
Annual allocation of unitary benefit/detriment for Minnesota income taxes accrued as additional paid in capital (211)	\$ (5,152,542)
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)	334,990
Rounding	(1)
Total	\$ (4,429,583)
(g) Concept: TaxAdjustments	
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	\$ (460,312)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	(156,908)
Total	\$ (617,220)
(h) Concept: TaxAdjustments	
Annual allocation of unitary benefit/detriment for North Dakota income taxes accrued as additional paid in capital (211)	\$ (139,843)
State income tax expense (409.1 and 409.2) accrued for long term income tax payable (253)	10,936
State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)	8,720
Total	\$ (120,187)
(i) Concept: TaxAdjustments	

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	\$	(81)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)		(16)
Total	\$	(97)
(j) Concept: TaxAdjustments		
Annual allocation of unitary benefit/detriment for Wisconsin income taxes accrued as additional paid in capital (211)	\$	870
Rounding		1
Total	\$	871
(k) Concept: TaxAdjustments		
Annual allocation of unitary benefit/detriment for Texas income tax accrued as additional paid in capital (211)	\$	(3,997)
(l) Concept: TaxAdjustments		
State income tax benefit (accrual and cash) in other accounts receivable (143)	\$	2,000
(m) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	(40,652,178)
Other income and deductions (Account No. 409.2)		(4,503,836)
Total	\$	(45,156,014)
(n) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	86,628
Other income and deductions (Account No. 409.2)		1,402
Total	\$	88,030
(o) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	2,771,583
Other income and deductions (Account No. 408.2)		238,032
Other		3,715,860
Total	\$	6,725,475
(p) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	15,897
Other income and deductions (Account No. 408.2)		1,443
Other		9,259
Total	\$	26,599
(q) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	(20,066,906)
Other income and deductions (Account No. 409.2)		18,349,034
Total	\$	(1,717,872)
(r) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	21,743
Other income and deductions (Account No. 409.2)		4,221
Total	\$	25,964
(s) Concept: TaxesIncurredOther		

Gas (Account No. 408.1)	\$	274,903
Other income and deductions (Account No. 408.2)		16,329
Other		1,493,858
Total	\$	<u>1,785,090</u>
(t) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	(482,584)
Other income and deductions (Account No. 408.2)		(1,726)
Total	\$	<u>(484,310)</u>
(u) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	19,644,000
Other income and deductions (Account No. 408.2)		66,000
Total	\$	<u>19,710,000</u>
(v) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	(428,406)
Other income and deductions (Account No. 409.2)		165,121
Total	\$	<u>(263,285)</u>
(w) Concept: TaxesIncurredOther		
Other income and deductions (Account No. 409.2)	\$	<u>97</u>
(x) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	1,855
Other income and deductions (Account No. 408.2)		98
Other		12,015
Total	\$	<u>13,968</u>
(y) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	<u>17,986</u>
(z) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	<u>1,099,200</u>
(aa) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	1,814
Other income and deductions (Account No. 408.2)		95
Other		11,751
Total	\$	<u>13,660</u>
(ab) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	<u>519,865</u>
(ac) Concept: TaxesIncurredOther		

Gas (Account No. 408.1)	\$	898
Other income and deductions (Account No. 408.2)		47
Other		5,827
Total	\$	<u>6,772</u>
(ad) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	(6,103)
Other income and deductions (Account No. 409.2)		2,673
Total	\$	<u>(3,430)</u>
(ae) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	16
Other income and deductions (Account No. 408.2)		1
Other		100
Total	\$	<u>117</u>
(af) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	606
Other income and deductions (Account No. 408.2)		102
Other		(6,861)
Total	\$	<u>(6,153)</u>
(ag) Concept: TaxesIncurredOther		
Other income and deductions (Account No. 409.2)	\$	<u>(224,570)</u>
(ah) Concept: TaxesIncurredOther		
Other	\$	<u>868</u>
(ai) Concept: TaxesIncurredOther		
Other	\$	<u>4,800</u>
(aj) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	<u>21,736</u>
(ak) Concept: TaxesIncurredOther		
Total	\$	<u>23,242,370</u>

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%	42,941			411.4	4,717		38,224	56 Years	
4	7%									
5	10%	15,866,393			411.4	1,208,092		14,658,301	52 Years	
6	30%	1,284,518			411.4	97,312		1,187,206	21 Years	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	17,193,852				1,310,121		15,883,731		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
11	Gas Utility									
12	4%	1,425			411.4	63		1,362	70 Years	
13	10%	977,163			411.4	106,293		870,870	50 Years	
14	TOTAL Gas Utility	978,588				106,356		872,232		
15	Common Utility									
16	4%	2,939			411.4	776		2,163	50 Years	
17	10%	79,973			411.4	6,565		73,408	50 Years	
18	TOTAL Common Utility	82,912				7,341		75,571		

47	OTHER TOTAL									
48	GRAND TOTAL	18,255,352				1,423,818		16,831,534		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredInvestmentTaxCredits

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

(b) Concept: AccumulatedDeferredInvestmentTaxCredits

(a) Common Allocation	
Electric - 93.64%	\$70,764
Gas - 6.36%	4,807
	\$75,571
	\$75,571

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Unfunded Nonqualified Pension Benefit Costs	3,284,098	232	1,275,996	315,995	2,324,097
2	Deferred Compensation - Employees	10,181,620	131	1,309,108	2,379,240	11,251,752
3	Deferred Compensation - Employees (Wealth Op)	4,905,328	232	479,215	129,896	4,556,009
4	Postemployment Benefit-Injury Compensation	12,243,721	^(b) Various	1,853,730	1,285,387	11,675,378
5	Environmental & Regulatory Reserves	2,500,468	242	2,366,511	2,095,168	2,229,125
6	Nuclear Waste Strategy Coalition	69,132	232	13,418		55,714
7	Renewable Development Fund Obligations	15,825,885	232	15,397,851	34,000,000	34,428,034
8	Long-Term Income Tax & Interest Payable	12,211,500			576,715	12,788,215
9	Customer Prepayments	90,000				90,000
10	Deferred Revenue	2,696,746	^(g) Various	1,430,480	675,819	1,942,085
11	Pre-Funded AFUDC: Metro Emissions Reduction Rider	50,110,309	405	2,236,183		47,874,126
12	Pre-Funded AFUDC: Mercury Emission Reduction Rider	321,153	405	48,418		272,735
13	Pre-Funded AFUDC: Minnesota Transmission Cost Recovery Rider	35,533,961	^(g) Various	7,174,921	9,444,403	37,803,443
14	Pre-Funded AFUDC: FERC Transmission	37,717,874	405	^(g) 669,244	^(h) 0	37,048,630
15	Pre-Funded AFUDC: Renewable Energy Standards Rider	75,027,211	^(g) Various	9,744,047	27,261,889	92,545,053
16		1,911,723			151,644	2,063,367

	Pre-Funded AFUDC: South Dakota Transmission Cost Recovery Rider					
17	Pre-Funded AFUDC: North Dakota Transmission Cost Recovery Rider	1,465,020	^(f) Various	24	143,473	1,608,469
18	Executive PSP - Long Term	2,740,316	232	2,140,798	464,024	1,063,542
19	Deferred Revenue-ITC Grant	1,284,125	405	382,754		901,371
20	Coal Car Residual Value Deficit	3,258,393			398,986	3,657,379
21	401 Nicollet Lease Credit	7,831,599	101	757,897		7,073,702
22	Laurentian Biomass PPA Termination	36,166,668	182.3	18,083,333		18,083,335
23	FERC Hydro Assessments	9,611	242	38,444	42,586	13,753
24	Shared Network Upgrade	1,050,868	565	57,061		993,807
25	CapX2020 Promissory Notes	442,127	232	211,032		231,095
26	Security Deposits				1,500	1,500
27	^(g) **Footnote from page 106b					
47	TOTAL	318,879,456		65,670,465	79,366,725	332,575,716

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: DescriptionOfOtherDeferredCredits

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

(b) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:		
131	\$	1,140,194
232		713,536
Total	\$	<u>1,853,730</u>

(c) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:		
447	\$	959,748
456		470,732
Total	\$	<u>1,430,480</u>

(d) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:		
405	\$	1,031,358
419.1		4,160,049
432		1,983,514
Total	\$	<u>7,174,921</u>

(e) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:		
405	\$	3,331,088
419.1		4,451,291
432		1,961,668
Total	\$	<u>9,744,047</u>

(f) Concept: DecreaseInOtherDeferredCreditsContraAccount

Accounts charged:		
419.1	\$	16
432		8
Total	\$	<u>24</u>

(g) 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 \$991,617.

(h) 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.

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

Page 269

16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	24,566,414	(2,477,318)								22,089,096
18	Classification of TOTAL										
19	Federal Income Tax	19,128,629	(1,922,057)								17,206,572
20	State Income Tax	5,437,785	(555,261)								4,882,524
21	Local Income Tax										

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	2,289,172,125	66,738,709				182,3254	614,763	182,3254	154,730,221	2,510,026,292
3	Gas	140,663,524	6,631,447				182,3254		182,3254	6,586,344	153,881,315
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	2,429,835,649	73,370,156					614,763		161,316,565	2,663,907,607
6	Other (Non-Operating)	(45,388)			10,249						(35,139)
9	TOTAL Account 282 (Total of Lines 5 thru 8)	2,429,790,261	73,370,156		10,249			614,763		161,316,565	2,663,872,468
10	Classification of TOTAL										
11	Federal Income Tax	1,658,901,744	28,017,327		7,130			533,399		120,368,438	1,806,761,240
12	State Income Tax	770,888,517	45,352,829		3,119			81,364		40,948,127	857,111,228
13	Local Income Tax										

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

	Dec. 31, 2020	410.1 & Adjustments	Dec. 31, 2021
Decommissioning Nonqualified	\$ —		\$ —
Electric Distribution Plant	808,043,305	1,420,945	809,464,250
Electric General Plant	80,129,513	(258,804)	79,870,709
Electric Intangible Plant	7,039,492	110,171	7,149,663
Electric Nuclear Fuel	21,977,185	(2,927,850)	19,049,335
Electric Nuclear Production Plant	573,848,305	(37,023,030)	536,825,275
Electric Production Plant	808,205,299	80,003,531	888,208,830
Electric Transmission Plant	877,161,047	13,433,847	890,594,894
Electric Transmission-Production Plant	17,052,348	2,241,001	19,293,349
Common (Allocation to Electric)	24,800,632	9,738,898	34,539,530
Regulatory Differences - Prior Flow Thru / Rate Change	(1,309,239,871)	66,179,650	(1,243,060,221)
Regulatory Differences - AFUDC Equity	108,476,159	(614,763)	107,861,396
Decommissioning Qualified	271,678,711	88,550,571	360,229,282
Total Electric Plant Related Only	\$ 2,289,172,125	\$ 220,854,167	\$ 2,510,026,292

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 \$47,617,484 for 2020 and \$45,942,238 for 2021.

	2020 ARAM	2021 ARAM
Protected ARAM:		
Decommissioning	\$ —	\$ —
Electric Distribution Plant	5,213,996	4,099,198
Electric General Plant	2,228,990	2,669,382
Electric Intangible Plant	308,509	69,909
Electric Nuclear Fuel	4,052,440	2,246,548
Electric Production Plant	16,719,320	18,816,459
Electric Transmission Plant	1,182,100	1,443,703
Electric Transmission-Production Plant	50,187	48,046
Common (Allocation to Electric)	3,119,757	3,540,197
Total Protected ARAM	32,875,299	32,933,442
Unprotected ARAM:		
Decommissioning	—	—
Electric Distribution Plant	3,234,480	3,016,103
Electric General Plant	174,739	140,041
Electric Intangible Plant	280,285	323,958
Electric Nuclear Fuel	313,063	119,742
Electric Production Plant	8,504,195	7,584,083
Electric Transmission Plant	1,884,766	1,501,240
Electric Transmission-Production Plant	8,775	4,844
Common (Allocation to Electric)	342,449	318,652
Total Unprotected ARAM	14,742,752	13,008,663
Non Utility	(567)	133
Total Electric	\$ 47,617,484	\$ 45,942,238
Common allocation for financial reporting may be different than for rate making.		
Common (Unallocated)	\$ 3,839,647	\$ 3,839,647

The Flowback of permanent items included above in 410.1 is \$8,502,657 for 2020 and \$8,762,526 for 2021 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, 2021	Dec. 31, 2021	Dec. 31, 2021
Excess (Electric only)	Excess	Gross up	Total Regulatory
Flow Through	\$ (3,685,200)	\$ (1,435,409)	\$ (5,120,609)
Method Life (Protected)	(736,571,145)	(286,899,210)	(1,023,470,355)
Other Basis Differences (Unprotected)	(154,349,235)	(60,120,022)	(214,469,257)
	\$ (894,605,580)	\$ (348,454,641)	\$ (1,243,060,221)

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	\$	99,536	\$	138,306
Method Life (Protected)		1,062	414	1,476
Other Basis Differences (Unprotected)		6	2	8
	\$	100,604	\$	139,790
Common (allocated)				
Flow Through	\$	21,952	\$	30,502
Method Life (Protected)		(10,581,157)	(4,121,429)	(14,702,586)
Other Basis Differences (Unprotected)		(712,129)	(277,379)	(989,508)
	\$	(11,271,334)	\$	(15,661,592)
Common (unallocated)				
Flow Through	\$	27,931	\$	38,810
Method Life (Protected)		(13,463,356)	(5,244,064)	(18,707,420)
Other Basis Differences (Unprotected)		(906,106)	(352,934)	(1,259,040)
	\$	(14,341,531)	\$	(19,927,650)

NOTES

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

	Balance at Beginning of Year	410.1 & Adjustments	Balance at End of Year
Electric Distribution Plant	\$ 151,447	\$ (6,135)	145,312
Electric General Plant	688,393	(61,379)	627,014
Electric Intangible Plant	2,942,442	563,947	3,506,389
Electric Nuclear Production Plant	2,808,168	(383,464)	2,424,704
Electric Production Plant	9,846	(9,846)	—
Electric Transmission Plant	(592,842)	159,563	(433,279)
Common (Allocation to Electric)	45,649,580	(4,331,073)	41,318,507
Regulatory Differences - AFUDC Equity	1,330,169	(17,825)	1,312,344
Total Electric Plant Related Only	\$ 52,987,203	\$ (4,086,212)	48,900,991

(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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	2020 Minnesota Deferred Property Tax - MN Docket E-003/GR-19-688	7,875,840			4,666,716	12,542,556
2	2021 Minnesota Deferred Property Tax - MN Docket E-002/GR-20-743				7,492,534	7,492,534
3	Conservation and Energy Management Program Costs Minnesota Electric - MN Docket G-002/M-21-226 - Generally amortized over 12 month period following the expenditure				353,912	353,912
4	Conservation and Energy Management Program Costs Minnesota Natural Gas - MN Docket G-002/M-21-227 - Generally amortized over 12 month period following the expenditure	5,405,123	232	23,023,820	17,966,175	347,478
5	Deferred Tax Collected in Rates in Excess of Current Tax Accrual Levels	1,297,300,137	282	65,642,959		1,231,657,178
6	Department of Energy Settlement Payment - MN Docket E-002/M-21-062	9,600,174	142	9,591,213	12,119,275	12,128,236
7	Derivatives and Hedging - Retail Electric & Gas	11,641,811			17,696,047	29,337,858
8	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	6,001,396	Various	17,267,774	22,101,336	10,834,958
9	Gas Low Income Discount Program - MN Docket G-002/GR-06-1429	2,257,940	Various	1,748,155	2,653,541	3,163,326
10	ITC Gross-Up to Pre-Tax Rate Levels	7,599,318	190	610,753		6,988,565
11	Minnesota Gas Rate Case Deferral - MN Docket G-002/GR-09-1153	2,784,018			399,252	3,183,270
12	Minnesota Gas State Energy Policy Rider - MN Docket G-002/M-21-151	335,068	407.4	1,253,583	981,084	62,569

13	Minnesota AIP Refund- MN Docket E-002/M-21-369	1,761,208	407.3	122,944	2,095,543	3,733,807
14	Minnesota Purchased Gas Costs - MN Docket G-002/GR-09-1153	8,820,993	142	8,820,993		
15	Minnesota Service Quality Program - MN Docket E-002/M-19-261	486,075	142	694,459	1,908,594	1,700,210
16	Minnesota Transmission Cost Recovery Rider - MN Docket E-002/GR-21-814	9,364,444	407.4	90,662,532	84,833,029	3,534,941
17	Nonplant Excess ADIT	36,102,022	190	7,053,511	613,351	29,661,862
18	North Dakota Deferred Electric Commodity Cost- ND Docket PU-12-813	264,230	182.3	264,230		
19	North Dakota Earnings Sharing - ND Docket PU-18-155				7,740,150	7,740,150
20	North Dakota ITC	10,671,831			1,084,668	11,756,499
21	North Dakota Production Tax Credit Levelization - ND Docket PU-20-426 - ND Docket PU-20-441				10,133,407	10,133,407
22	North Dakota Purchased Gas Costs - ND Docket PU-400-00-521					
23	North Dakota Renewable Energy Rider - ND Docket PU-21-389	4,508,939	407.3	13,481,553	10,434,286	1,461,672
24	North Dakota Retail Asset and Non-Asset Margin Sharing - ND Docket PU-10-657	2,539,052	557	6,348,291	9,979,725	6,170,486
25	Northern Natural Gas Refund -MN Docket G002-/M-20-633-ND Docket PU-21-087	4,971,529	142	4,971,529		
26	Power Purchase Agreement	807,352	555	9,271		798,081
27	Pre-ARO Decommissioning	1,774,157,329			161,795,037	1,935,952,366
28	Residential Payment Plan Credit Program - MN Docket E-002/M-20-760	17,500,000	142	12,203,313		5,296,687
29	South Dakota Deferred Electric Commodity Costs - SD EL 14-058	2,741,053	557	65,027,977	65,210,302	2,923,378
30	South Dakota Infrastructure - SD Docket EL 21-028	1,873,358	407.3	25,372,377	26,073,947	2,574,928
31	South Dakota Production Tax Credit Sharing - SD Docket EL 12-046	1,652,721	557	10,241,229	11,253,300	2,664,792
32	South Dakota Property Tax Collected in the Fuel Clause Adjustment - SD Docket EL 14-058	84,352	408.1	84,352		
33		968,878	557	6,249,663	7,554,991	2,274,206

	South Dakota Retail Asset and Non-Asset Margin Sharing - SD Docket EL 12-046					
34	South Dakota Transmission Cost Recovery Rider - SD Docket EL 21-025	830,995	407.3	7,334,401	7,547,774	1,044,368
35	Transmission Formula Rates	8,466,104	456	6,676,962	8,609,512	10,398,654
36	Unrealized Gains on Decommissioning Trust	704,178,734			229,519,009	933,697,743
37	Wescott Asset Sale-MN Docket G-002/M-01-1479-ND Docket PU-19-103	13,127	142	13,127		
38	WindsorSource- MN Docket E-002/M-01-1479 - MN Docket E-002/GR-13-868	6,046,997	(a) Various	18,187,205	16,199,352	4,059,144
41	TOTAL	3,949,612,148		402,958,176	749,015,849	4,295,669,821

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Accounts charged:		
142	\$	16,709,829
232		557,945
Total	\$	<u>17,267,774</u>

(b) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

142	\$	1,651,243
232		96,912
Total	\$	<u>1,748,155</u>

(c) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

Accounts charged:		
142	\$	6,005,356
555		12,169,197
921		12,652
Total	\$	<u>18,187,205</u>

(d) Concept: OtherRegulatoryLiabilities

--	--	--

	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Total
Electric	\$ 20,202,423 \$	7,868,974 \$	28,071,397
Gas	1,144,626	445,839	1,590,465
Total	\$ 21,347,049 \$	8,314,813 \$	29,661,862

*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 12/31/2020	Amortization 2021	Excess Balance 12/31/2021
Book Unamortized Cost of Reaquired Debt	\$ 952,275 \$	(476,137) \$	476,138
Deferred Fuel Costs	232,268	(116,134)	116,134
Electric Vehicle Charging Tariff	9,270	(4,636)	4,634
Employee Retention	5,260	(2,631)	2,629
Interest Income/Expense on Disputed Tax	93,435	(46,717)	46,718
Low Income Discount Program	8,246	(4,122)	4,124
Mark to Market Adjustment	525,438	(262,720)	262,718
Nuclear Refueling	3,514,293	(1,757,147)	1,757,146
Partnership Passthrough	63,578	(31,790)	31,788
Pension Expense	18,132,129	(1,511,011)	16,621,118
Prepaid Insurance	1,015,994	(507,998)	507,996
Property Tax - LT Total	833,438	(416,718)	416,720
Public Utility Conservation Investment Programs	3,247,130	(1,623,564)	1,623,566
Rate Case / Restructuring Expense	186,315	(93,158)	93,157
Rate Surcharge	2,571,202	(1,285,601)	1,285,601
Renewable Energy Standard/Credit	1,438	(718)	720
Transmission Attachment O	84,196	(42,098)	42,098
State Tax Deduction Cash vs Accrual	210,636	(105,317)	105,319
Windsorce	12,328	(6,165)	6,163
Total Electric	\$ 31,698,869 \$	(8,294,382) \$	23,404,487

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

Electric Operating Revenues

- The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
- If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.
- Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
- See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
- For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
- Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	1,486,050,261	1,418,149,670	10,846,862	10,615,287	1,353,504	1,337,252
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	1,607,362,856	1,421,422,728	14,170,236	13,875,471	160,691	159,212
5	Large (or Ind.) (See Instr. 4)	\$709,762,530	\$612,760,671	7,921,431	7,725,641	549	552
6	(444) Public Street and Highway Lighting	25,208,248	24,938,674	113,332	121,140	6,386	6,195
7	(445) Other Sales to Public Authorities	9,982,991	9,358,966	80,587	78,556	1,616	1,683
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales	403,692	688,543	3,359	6,785		
10	TOTAL Sales to Ultimate Consumers	3,838,770,578	3,487,319,252	33,135,807	32,422,880	1,522,746	1,504,894
11	(447) Sales for Resale	291,393,346	204,096,054	15,696,940	13,612,202		
12	TOTAL Sales of Electricity	4,130,163,924	3,691,415,306	48,832,747	46,035,082	1,522,746	1,504,894
13	(Less) (449.1) Provision for Rate Refunds	\$(1,720,403)	\$(6,703,707)				

14	TOTAL Revenues Before Prov. for Refunds	4,131,884,327	3,698,119,013	48,832,747	46,035,082	1,522,746	1,504,894
15	Other Operating Revenues						
16	(450) Forfeited Discounts	606,228	2,430,449				
17	(451) Miscellaneous Service Revenues	(2,456,276)	(2,265,455)				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	(5,630,823)	(5,270,727)				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	(443,892,912)	(454,746,027)				
22	(456.1) Revenues from Transmission of Electricity of Others	(302,783,596)	(286,347,566)				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	755,369,835	751,060,224				
27	TOTAL Electric Operating Revenues	4,887,254,162	4,449,179,237				

Line 12, column (b) includes \$ 35,437,075 of unbilled revenues.

Line 12, column (d) includes 268,272 MWH relating to unbilled revenues

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
FOOTNOTE DATA			

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue		
Commercial and industrial sales are classified as "Large" for purposes of this report if the customer has a twelve month average minimum registered demand of 1,000 kilowatts or more.		
(b) Concept: ProvisionForRateRefunds		
Credit balance due to accrual reversal.		
(c) Concept: MiscellaneousServiceRevenues		
Connection charges	\$	2,138,326
NSF Check Fees		289,875
Other, less than \$250,000 each		28,075
	<u>\$</u>	<u>2,456,276</u>
(d) Concept: RentFromElectricProperty		
Rent from Electric Property (Account No. 454). The rent revenue credit from electric property included in the formula is income directly related to transmission facilities, such as pole attachments, rentals and special use.		
(e) Concept: OtherElectricRevenue		
Includes reimbursement from NSP-Wisconsin for production costs shared under the FERC-approved Interchange Agreement between the companies. See Note 1 to the Financial Statements.		
Fixed Production Expense	\$	241,617,825
Variable Production Expense		197,336,757
Total Interchange Agreement	<u>\$</u>	<u>438,954,582</u>
Also includes the following items:		
Windsor 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
	<u>\$</u>	<u>443,892,912</u>

(f) 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.		
(g) Concept: LargeOrIndustrialSalesElectricOperatingRevenue		
Commercial and industrial sales are classified as "Large" for purposes of this report if the customer has a twelve month average minimum registered demand of 1,000 kilowatts or more.		
(h) Concept: ProvisionForRateRefunds		
Credit balance due to accrual reversal.		
(i) Concept: MiscellaneousServiceRevenues		
Connection charges	\$	2,007,215
NSF Check Fees		302,395
Other, less than \$250,000 each		(44,155)
	<u>\$</u>	<u>2,265,455</u>
(j) 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.		
(k) 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	\$	223,594,481
Variable Production Expense		160,740,529
Total Interchange Agreement	<u>\$</u>	<u>384,335,010</u>
Also includes the following items:		
2019 Minnesota Deferred Property Tax Refund*	\$	13,238,257
Change in net over-recovered electric commodity costs		11,859,677
2018 Minnesota Deferred Property Tax Refund*		9,112,538
Windsorce Program		8,684,337
Fees charged to burn Refuse Derived Fuel		8,102,172
Renewable*Connect		7,456,305
Minnesota Incentive Compensation Refund*		4,055,466
Conservation Improvement Program incentive, net of accruals and recoveries		2,401,255
Net distribution of commodity trading margins under Joint Operating Agreement		2,066,944
NOL Tracker*		2,028,105
Purchased Power Reimbursement		794,724
Distribution Facility Fixed Charges		720,361
Facilities Agreement		381,297
Solar Gardens-Subscribed		358,000
EEL Mutual Aid Revenue		326,819
Manitoba Hydro Energy Service Agreement		300,000
Work on Customers' Equipment		243,580
Service Quality Plans		(125,489)
Solar Energy Standard Exclusion		(591,680)
Customer refunds due to 2017 Tax Cuts and Jobs Act		(1,557,271)
Other less than \$250,000 each		555,620
	<u>\$</u>	<u>454,746,027</u>
*Represents reclass between FERC 440-448 and FERC 456		
(l) Concept: RevenuesFromTransmissionOfElectricityOfOthers		
Includes \$55,486,529 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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (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					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					

22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46	TOTAL			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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	159	20,149	39	4,077	0.1267
4	A01 Residential	5,163,185	725,933,434	770,907	6,698	0.1406
5	A02 Residential Time of Day	4,875	611,649	434	11,233	0.1255
6	A03 Residential Underground	3,955,781	544,919,668	401,720	9,847	0.1378
7	A04 Residential TOD Underground	5,847	745,198	415	14,089	0.1274
8	A05 Energy Control	35,094	2,976,713	3,119	11,252	0.0848
9	A06 Limited Off Peak	2,391	231,086	366	6,533	0.0966
10	A07 Auto Protective Lighting	5,701	1,095,335			0.1921
11	A08 Residential Electric Vehicle	3,384	351,679			0.1039
12	A72 Resid TOU Pilot-Overhead	32,707	4,652,546	5,647	5,792	0.1422
13	A74 Resid TOU Pilot-Underground	33,610	4,728,230	3,548	9,473	0.1407
14	A80 Resid EV Pilot Bundled	757	97,826			0.1292
15	A81 Resid EV Pilot Pre-Pay	379	274,771			0.7250
16	A82 Resid EV Pilot Bundled Subs	576	65,205			0.1132
17	A83 Resid EV Pilot Pre-Pay Subs	90	8,057			0.0895

18	Unbilled-MN-Residential Sales	31,623	4,588,122			0.1451
19	North Dakota					
20	D01 Residential	592,696	70,588,855	68,474	8,656	0.1191
21	D02 Residential Time of Day	814	84,069	32	25,438	0.1033
22	D03 Residential Underground	164,944	18,482,754	12,705	12,983	0.1121
23	D04 Residential TOD Underground	129	13,469	7	18,429	0.1044
24	D05 Energy Control	3,157	265,256	292	10,812	0.0840
25	D10 Limited Off Peak	653	49,619	100	6,530	0.0760
26	D11 Auto Protective Lighting	318	59,263			0.1864
27	Unbilled-ND-Residential Sales	3,340	1,042,031			0.3120
28	South Dakota					
29	E01 Residential	343,954	44,878,518	45,645	7,535	0.1305
30	E02 Residential Time of Day	92	10,634	8	11,500	0.1156
31	E03 Residential Underground	456,161	58,211,688	39,837	11,451	0.1276
32	E04 Residential Time of Day	96	11,711	6	16,000	0.1220
33	E06 Residential Heat Pump	1,663	155,057	100	16,630	0.0932
34	E10 Energy Control	1,163	94,230	102	11,402	0.0810
35	E11 Limited Off Peak	8	509	1	8,000	0.0636
36	E12 Auto Protective Lighting	329	63,804			0.1939
37	Unbilled-SD-Residential Sales	1,186	739,126			0.6232
41	TOTAL Billed Residential Sales	10,810,713	1,479,680,982	1,353,504	7,987	0.1369
42	TOTAL Unbilled Rev. (See Instr. 6)	36,149	6,369,279			0.1762
43	TOTAL	10,846,862	1,486,050,261	1,353,504	8,014	0.1370

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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						
14						
15						
16						
17						

18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed Small or Commercial					
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)					
43	TOTAL Small or Commercial	14,170,236	1,607,362,856	160,691		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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						
14						
15						
16						
17						

18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed Large (or Ind.) Sales					
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)					
43	TOTAL Large (or Ind.)	7,921,431	(a)709,762,530	549		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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	1,863	166,047	111	16,784	0.0891
3	A06 Limited Off Peak	1,489	190,498	81	18,383	0.1279
4	A07 Auto Protective Lighting	22,997	3,666,021			0.1594
5	A09 Small General Service	24	12,841	99	242	0.5350
6	A10 Small General Service	728,278	100,052,992	75,592	9,634	0.1374
7	A11 Water Heating	191	24,357	73	2,616	0.1275
8	A12 Small General TOD Service	39,240	4,922,124	3,019	12,998	0.1254
9	A13 Direct Current	5	7,146	2	2,500	1.4292
10	A14 General Service	7,539,009	884,216,265	42,474	177,497	0.1173
11	A15 General TOD Service	7,357,643	689,199,016	4,880	1,507,714	0.0937
12	A16 Small General kWh metered	16,007	2,246,073	3,103	5,159	0.1403
13	A18 Small General TOD Service	26,429	3,497,317	4,229	6,249	0.1323
14	A22 Small General TOD Low Wattage	2,353	341,916	732	3,214	0.1453
15	A23 Peak Control Tiered	1,039,183	115,821,330	1,334	778,998	0.1115
16	A24 Peak Control Time of Day	2,258,734	200,546,641	332	6,803,416	0.0888
17	A27 Tier 1 Energy Control	257,955	17,075,456	10	25,795,500	0.0662

18	A29 Hiawatha Light Rail	38,383	4,125,428	30	1,279,433	0.1075
19	A62 Firm Real Time Pricing	21,862	2,150,779	3	7,287,333	0.0984
20	A87 - EV Fleet Pilot Service	150				
21	Unbilled-MN-Commercial Sales	27,565	17,857,958			0.6478
22	North Dakota					
23	D05 Energy Control	1,281	106,305	53	24,170	0.0830
24	D10 Limited Off Peak	457	44,199	33	13,848	0.0967
25	D11 Auto Protective Lighting	2,574	374,785	0		0.1456
26	D12 Small General Service	93,604	11,350,660	8,081	11,583	0.1213
27	D14 Small General TOD Service	2,297	268,132	202	11,371	0.1167
28	D16 General Service	654,385	71,009,686	3,824	171,126	0.1085
29	D17 General TOD Service	203,917	18,424,547	205	994,717	0.0904
30	D18 Small General TOD Service	557	72,178	101	5,515	0.1296
31	D19 Small General kWh metered	957	136,305	209	4,579	0.1424
32	D20 Peak Control	30,818	3,216,762	49	628,939	0.1044
33	D21 Peak Control Time of Day	122,581	10,303,199	15	8,172,067	0.0841
34	D22 Tier 1 Energy Control	222,549	17,827,208	64	3,477,328	0.0801
35	D34 Sm General TOD Low Wattage	91	11,506	23	3,957	0.1264
36	Unbilled-ND-Commercial Sales	3,123	1,472,289			0.4714
37	South Dakota					
38	E10 Energy Control	94	7,531	11	8,545	0.0801
39	E11 Limited Off Peak	309	29,139	8	38,625	0.0943
40	E12 Auto Protective Lighting	2,138	356,908	0		0.1669
41	E13 Small General Service	80,505	9,833,807	7,562	10,646	0.1222
42	E14 Small General TOD Service	2,417	299,089	363	6,658	0.1237
43	E15 General Service	668,200	70,420,154	3,920	170,459	0.1054
44	E16 General TOD Service	482,379	41,523,109	245	1,968,894	0.0861
45	E18 Small General TOD Service	59	8,374	66	894	0.1419
46	E20 Peak Control	57,149	6,193,804	77	742,195	0.1084

47	E21 Peak Control Time of Day	59,111	4,813,003	11	5,373,727	0.0814
48	E22 Energy Control	22,275	1,842,671	14	1,591,071	0.0827
49	Unbilled-SD-Commercial Sales	(1,520)	1,059,831			(0.6973)
41	TOTAL Billed Commercial and Industrial Sales	22,062,499	2,296,735,308	161,240	136,830	0.1041
42	TOTAL Unbilled Rev. (See Instr. 6)	29,168	20,390,078			0.6991
43	TOTAL	22,091,667	2,317,125,386	161,240	137,011	0.1049

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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	32,130	17,645,359	2,121	15,149	0.5492
3	A32 Street Lighting Customer Owned	23,770	1,854,537	416	57,139	0.0780
4	A34 Street Lighting Metered	34,831	2,735,872	3,089	11,276	0.0785
5	A37 Street Lighting St Paul	841	125,600	1	841,000	0.1493
6	Unbilled-MN-Street Lighting Sales	(3,234)	(594,930)			0.1840
7	North Dakota					
8	D30 Street Lighting Company Owned	848	556,465	62	13,677	0.6562
9	D31 Street Lighting Customer Owned	10,326	899,485	33	312,909	0.0871
10	D32 Street Lighting Ornamental	24	2,239	2	12,000	0.0933
11	D33 Street Lighting Metered	2,580	196,941	148	17,432	0.0763
12	Unbilled-ND-Street Lighting Sales	(88)	3,331			(0.0379)
13	South Dakota					
14	E30 Street Lighting Company Owned	796	775,093	117	6,803	0.9737
15	E31 Street Lighting Customer Owned	3,357	329,797	16	209,813	0.0982
16	E32 Street Lighting Metered	6,246	569,958	290	21,538	0.0913
17	E33 Street Lighting Ornamental	808	74,064	91	8,879	0.0917

18	Unbilled-SD-Street Lighting Sales	97	34,437			0.3550
41	TOTAL Billed Public Street and Highway Lighting	116,557	25,765,410	6,386	18,252	0.2211
42	TOTAL Unbilled Rev. (See Instr. 6)	(3,225)	(557,162)			0.1728
43	TOTAL	113,332	25,208,248	6,386	17,747	0.2224

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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	5,505	773,338	884	6,227	0.1405
3	A41 Municipal Pumping	60,339	7,441,882	576	104,755	0.1233
4	A42 Fire Siren		34,695			
5	Unbilled-MN-Other Sales	1,144	201,832			0.1764
6	North Dakota					
7	D40 Small Municipal Pumping	548	71,352	66	8,303	0.1302
8	D41 Municipal Pumping	13,063	1,436,173	90	145,144	0.1099
9	D42 Fire Siren		1,186			
10	Unbilled-ND-Other Sales	(12)	19,569			(1.6308)
11	South Dakota					
12	E40 Fire Siren		2,964			
41	TOTAL Billed Other Sales to Public Authorities	79,455	9,761,590	1,616	49,168	0.1229
42	TOTAL Unbilled Rev. (See Instr. 6)	1,132	221,401			0.1956
43	TOTAL	80,587	9,982,991	1,616	49,868	0.1239

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	Interdepartmental					
2	Interdepartmental Sales	3,359	403,692			0.1202
41	TOTAL Billed Interdepartmental Sales	3,359	403,692			0.1202
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	3,359	403,692			0.1202

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	^(a) (Footnote for Instruction 5)					
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		^(b) (1,720,403)			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

A00		\$	4,581
A01			147,169,677
A02			121,758
A03			113,943,313
A04			156,818
A05			1,021,650
A06			105,680
A07			642,724
A08			94,555
A09			725
A10			20,952,226
A11			5,623
A12			1,135,709
A13			156
A14			215,649,226
A15			200,999,913
A16			464,531
A17			—
A18			777,193
A21			887
A22			69,221
A23			29,542,594
A24			61,915,313
A27			6,945,599
A29			1,089,933
A30			716,144
A32			532,523
A34			759,291
A37			18,705
A40			155,745
A41			1,650,741
A62			604,087
A72			895,668
A74			956,595
A80			22,070
A81			10,868
A82			302
A83			16
A87			5,327
Minnesota jurisdiction			809,137,686

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

D01		\$	14,992,979
D02			20,208
D03			4,172,162
D04			3,210
D05			109,662
D10			27,248
D11			54,564
D12			2,445,865
D14			60,489
D16			17,019,429
D17			5,101,125
D18			14,520
D19			24,873
D20			797,302
D21			3,055,748
D22			5,642,436
D30			15,905
D31			193,534
D32			445
D33			47,837
D34			2,483
D40			14,119
D41			337,471
North Dakota jurisdiction		\$	54,153,616

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

E01			\$ 7,921,954
E02			2,153
E03			10,497,838
E04			2,201
E06			35,945
E10			26,970
E11			6,423
E12			40,162
E13			1,809,361
E14			53,388
E15			14,921,860
E16			10,443,844
E18			1,275
E20			1,284,673
E21			1,291,490
E22			489,117
E30			12,833
E31			53,474
E32			99,959
E33			13,014
South Dakota jurisdiction			\$ 49,007,934
Total Company			\$ 912,299,236

(b) Concept: ProvisionForRateRefunds

Credit balance due to accrual reversal.



Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.

3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.

4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	33,072,583	3,812,346,982	1,522,746	21,719	0.1153
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	63,224	26,423,596			0.4179
43	TOTAL - All Accounts	33,135,807	3,838,770,578	1,522,746	21,719	0.1158

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	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)	

1	NSP- Wisconsin	RQ									0.00
2	BP Energy CO	OS	V6				428,800			11,677,468	11,677,468
3	BP Energy CO	SF	V6				37,600		1,505,335		1,505,335
4	Citigroup Energy, Inc.	OS	V6				109,200			6,031,069	6,031,069
5	Citigroup Energy, Inc.	SF	V6				43,600			3,897,798	3,897,798
6	City of Ada, MN	OS	V6				0	47,475			47,475
7	City of Ada, MN	SF	V6				5,343		245,229		245,229
8	City of Ada, MN	AD	V6				0		276,252		276,252
9	City of Kasota, MN	OS	V6				0	25,425			25,425
10	City of Kasota, MN	SF	V6				4,110		197,260		197,260
11	City of Kasota, MN	AD	V6				0		58,428		58,428
12	Dahlberg Light and Power Co	OS	V6				2,512	192,200	60,145		252,345
13	Dahlberg Light and Power Co	SF	V6				114,404		6,374,263		6,374,263
14	Dahlberg Light and Power Co	AD	V6				0		156,314		156,314
15	Direct Energy Marketing	SF	V6				368		88,304		88,304
16	EDF Trading North America, LLC	OS	V6				80,800			3,209,212	3,209,212
17	EDF Trading North America, LLC	SF	V6				6,400			373,011	373,011
18	ETC Endure Energy LLC	OS	V6				64,000			1,731,184	1,731,184
19	Exelon Generation Co LLC	AD	V6				0			2	2
20	Great Lakes Utilities	OS	V6				0			300,000	300,000
21	ICE NGX Canada Inc	OS	V6				446,400			19,080,950	19,080,950
22	ICE NGX Canada Inc	SF	V6				85,960		5,330,857		5,330,857
23	ICE NGX Canada Inc	AD	V6				0				
24	Lubbock Power and Light	SF	V6				0			4,000,000	4,000,000
25	Metropolitan Edison Company	SF	V6				75,438			3,994,841	3,994,841

26	Metropolitan Edison Company	AD	V6				18,823			9,143	9,143
27	Midcontinent Independent System Operator	OS	V6				10,699,647	570,378	51,675,357	6,197,949	58,443,684
28	Midcontinent Independent System Operator	AD	V6				1,940,524	159,338	76,617,862	76,435	76,853,635
29	Morgan Stanley Capital Group, Inc.	OS	V6				139,200			3,798,550	3,798,550
30	Morgan Stanley Capital Group, Inc.	SF	V6				26,600			2,177,709	2,177,709
31	NextEra Energy Power Marketing, LLC	OS	V6				438,400			19,848,345	19,848,345
32	NextEra Energy Power Marketing, LLC	SF	V6				116,560		6,426,672		6,426,672
33	NextEra Energy Power Marketing, LLC	AD	V6				0				
34	NRG Power Marketing LLC	OS	V6				16,032			613,979	613,979
35	NRG Power Marketing LLC	SF	V6				1,488		83,888		83,888
36	North Central Power Company, Inc.	OS	V6				6,073	49,625	109,096		158,721
37	North Central Power Company, Inc.	SF	V6				26,077		997,441		997,441
38	North Central Power Company, Inc.	AD	V6				(3,086)		(48,114)		(48,114)
39	Northwestern Wisconsin Electric Company	OS	V6				19,531	290,880	358,921		649,801
40	Northwestern Wisconsin Electric Company	SF	V6				164,518		6,271,715		6,271,715
41	Northwestern Wisconsin Electric Company	AD	V6				(5,375)	4,020	(87,715)		(83,695)
42	Ohio Power Company	SF	V6				88,209			4,104,358	4,104,358
43	Ohio Power Company	AD	V6				20,616			53,409	53,409
44	Pennsylvania Electric Company	SF	V6				55,068			2,753,937	2,753,937
45	Pennsylvania Electric Company	AD	V6				11,487			9,203	9,203
46	PJM Interconnection, LLC	SF	V6				13,223		369,210		369,210

47	PJM Interconnection, LLC	AD	V6				1,593		39,772		(a)39,772
48	Shelleneno	OS	V6				378,400			22,792,836	(a)22,792,836
49	Shelleneno	SF	V6				18,397			1,616,125	(a)1,616,125
50	Shelleneno	AD	V6				0				
51	Taygete Energy Project, LLC	OS	V6				0			14,600,000	(a)14,600,000
52	(a) (Footnote for 106b)										
15	Subtotal - RQ						6,108,092				
16	Subtotal-Non-RQ						15,696,940	1,339,341	157,106,492	132,947,513	291,393,346
17	Total						15,696,940	1,339,341	157,106,492	132,947,513	291,393,346

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

<p>(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale</p> <p>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.</p>
<p>(b) Concept: RevenueFromSalesOfElectricityForResale</p> <p>Ownership interest or affiliation per instruction 2:</p> <p>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.</p> <p>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 6,108,092 Mwh in column G, \$371,455,737 in column I, and \$371,455,737 in column K. See Note 1 to the Financial Statements.</p>
<p>(c) Concept: RevenueFromSalesOfElectricityForResale</p>
<p>Financial Trading</p>
<p>(d) Concept: RevenueFromSalesOfElectricityForResale</p>
<p>Financial Trading</p>
<p>(e) Concept: RevenueFromSalesOfElectricityForResale</p>
<p>Financial Trading</p>
<p>(f) Concept: RevenueFromSalesOfElectricityForResale</p>
<p>Financial Trading</p>
<p>(g) Concept: RevenueFromSalesOfElectricityForResale</p>
<p>Prior Period Adjustment</p>
<p>(h) Concept: RevenueFromSalesOfElectricityForResale</p>
<p>Prior Period Adjustment</p>
<p>(i) Concept: RevenueFromSalesOfElectricityForResale</p>
<p>Prior Period Adjustment</p>
<p>(j) Concept: RevenueFromSalesOfElectricityForResale</p>
<p>Financial Trading</p>
<p>(k) Concept: RevenueFromSalesOfElectricityForResale</p>
<p>Financial Trading</p>
<p>(l) Concept: RevenueFromSalesOfElectricityForResale</p>
<p>Financial Trading</p>
<p>(m) Concept: RevenueFromSalesOfElectricityForResale</p>
<p>Prior Period Adjustment</p>
<p>(n) Concept: RevenueFromSalesOfElectricityForResale</p>
<p>Financial Trading</p>
<p>(o) Concept: RevenueFromSalesOfElectricityForResale</p>

Financial Trading
(p) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(q) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(r) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(s) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(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
Prior Period Adjustment
(aa) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(ab) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(ac) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(ad) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(ae) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(af) Concept: RevenueFromSalesOfElectricityForResale
Financial Trading
(ag) Concept: RevenueFromSalesOfElectricityForResale
Prior Period Adjustment
(ah) Concept: RevenueFromSalesOfElectricityForResale

Financial Trading

(a) Concept: RevenueFromSalesOfElectricityForResale

Financial Trading

(a) Concept: RevenueFromSalesOfElectricityForResale

Financial Trading

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

Page 310-311

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	3,340,408	3,743,604
5	(501) Fuel	232,681,698	209,722,460
6	(502) Steam Expenses	17,515,825	18,130,663
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	4,307,877	3,303,932
10	(506) Miscellaneous Steam Power Expenses	13,819,285	14,412,588
11	(507) Rents	1,468,987	1,906,451
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	273,134,080	251,219,698
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,542,150	1,685,793
16	(511) Maintenance of Structures	4,343,962	4,793,012
17	(512) Maintenance of Boiler Plant	19,972,701	21,090,323
18	(513) Maintenance of Electric Plant	7,600,877	5,815,433
19	(514) Maintenance of Miscellaneous Steam Plant	7,380,213	9,076,136
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	40,839,903	42,460,697
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	313,973,983	293,680,395

22	<u>B. Nuclear Power Generation</u>		
23	<u>Operation</u>		
24	<u>(517) Operation Supervision and Engineering</u>	39,028,000	42,626,097
25	<u>(518) Fuel</u>	114,109,922	123,483,842
26	<u>(519) Coolants and Water</u>	8,366,224	7,517,716
27	<u>(520) Steam Expenses</u>	48,946,966	48,337,462
28	<u>(521) Steam from Other Sources</u>		
29	<u>(Less) (522) Steam Transferred-Cr.</u>		
30	<u>(523) Electric Expenses</u>	2,483,948	2,797,631
31	<u>(524) Miscellaneous Nuclear Power Expenses</u>	125,082,191	129,962,270
32	<u>(525) Rents</u>	5,360,174	8,509,009
33	<u>TOTAL Operation (Enter Total of lines 24 thru 32)</u>	343,377,425	363,234,027
34	<u>Maintenance</u>		
35	<u>(528) Maintenance Supervision and Engineering</u>	7,690,102	8,157,881
36	<u>(529) Maintenance of Structures</u>		
37	<u>(530) Maintenance of Reactor Plant Equipment</u>	32,883,569	36,338,333
38	<u>(531) Maintenance of Electric Plant</u>	12,513,587	13,215,566
39	<u>(532) Maintenance of Miscellaneous Nuclear Plant</u>	24,961,813	26,910,874
40	<u>TOTAL Maintenance (Enter Total of lines 35 thru 39)</u>	78,049,071	84,622,654
41	<u>TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)</u>	421,426,496	447,856,681
42	<u>C. Hydraulic Power Generation</u>		
43	<u>Operation</u>		
44	<u>(535) Operation Supervision and Engineering</u>	88,626	24,273
45	<u>(536) Water for Power</u>	59,158	
46	<u>(537) Hydraulic Expenses</u>		
47	<u>(538) Electric Expenses</u>	328,332	523,108
48	<u>(539) Miscellaneous Hydraulic Power Generation Expenses</u>	93,789	310,612
49		34,834	59,870

	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	604,739	917,863
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	882	739
54	(542) Maintenance of Structures	45,690	29,164
55	(543) Maintenance of Reservoirs, Dams, and Waterways	66,760	126,204
56	(544) Maintenance of Electric Plant	180,673	151,124
57	(545) Maintenance of Miscellaneous Hydraulic Plant	4,031	2,894
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	298,036	310,125
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	902,775	1,227,988
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	4,162,274	3,494,429
63	(547) Fuel	222,898,257	130,345,825
64	(548) Generation Expenses	6,709,961	6,021,095
64.1	(548.1) Operation of Energy Storage Equipment	668,658	
65	(549) Miscellaneous Other Power Generation Expenses	13,207,667	11,771,663
66	(550) Rents	13,356,428	7,265,247
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	261,003,245	158,898,259
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,828,452	1,949,100
70	(552) Maintenance of Structures	6,916,872	5,776,245
71	(553) Maintenance of Generating and Electric Plant	10,741,953	9,492,999
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	11,789,212	6,266,881
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	31,276,489	23,485,225
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	292,279,734	182,383,484

75	E. Other Power Supply Expenses		
76	(555) Purchased Power	936,152,706	819,754,957
76.1	(555.1) Power Purchased for Storage Operations	0	
77	(556) System Control and Load Dispatching	1,214,953	1,442,425
78	(557) Other Expenses	\$80,110,978	\$99,640,865
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	1,017,478,637	920,838,247
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	2,046,061,625	1,845,986,795
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	9,056,290	10,169,049
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	5,058,224	4,720,501
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	8,456,229	7,640,727
89	(561.5) Reliability, Planning and Standards Development	9,061	13,108
90	(561.6) Transmission Service Studies	\$(21,770)	51,939
91	(561.7) Generation Interconnection Studies	507,498	437,972
92	(561.8) Reliability, Planning and Standards Development Services	3,194,344	3,108,714
93	(562) Station Expenses	5,528,565	3,441,285
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	697,406	829,768
95	(564) Underground Lines Expenses	13,395	6,747
96	(565) Transmission of Electricity by Others	\$348,602,482	\$316,122,584
97	(566) Miscellaneous Transmission Expenses	8,803,522	8,252,591
98	(567) Rents	1,194,543	1,168,489
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	391,099,789	355,963,474
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		7,611

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	3,437,754	3,945,927
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	5,961,980	4,689,490
109	(572) Maintenance of Underground Lines	42,829	83,419
110	(573) Maintenance of Miscellaneous Transmission Plant	51,022	62,930
111	TOTAL Maintenance (Total of Lines 101 thru 110)	9,493,585	8,789,377
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	400,593,374	364,752,851
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	184,986	186,874
116	(575.2) Day-Ahead and Real-Time Market Facilitation	153,516	121,069
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		234
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	10,318,466	10,824,357
122	(575.8) Rents	10,183	16,109
123	Total Operation (Lines 115 thru 122)	10,667,151	11,148,643
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)	10,667,151	11,148,643
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	13,890,964	11,066,496
135	(581) Load Dispatching	918,297	671,930
136	(582) Station Expenses	3,113,343	2,535,205
137	(583) Overhead Line Expenses	2,633,788	377,057
138	(584) Underground Line Expenses	9,426,088	8,106,221
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	605,065	619,985
140	(586) Meter Expenses	542,356	730,273
141	(587) Customer Installations Expenses	1,783,791	1,638,807
142	(588) Miscellaneous Expenses	20,336,023	24,129,792
143	(589) Rents	2,639,657	4,104,362
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	55,889,372	53,980,128
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	16,230	33,428
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	2,309,146	3,273,402
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	47,889,439	37,246,402
150	(594) Maintenance of Underground Lines	7,055,503	6,475,899
151	(595) Maintenance of Line Transformers	6,426	132,106
152	(596) Maintenance of Street Lighting and Signal Systems	1,540,440	1,319,279

153	(597) Maintenance of Meters	284,499	151,472
154	(598) Maintenance of Miscellaneous Distribution Plant	252,217	224,611
155	TOTAL Maintenance (Total of Lines 146 thru 154)	59,353,900	48,856,599
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	115,243,272	102,836,727
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	127,217	120,461
160	(902) Meter Reading Expenses	23,634,718	28,680,430
161	(903) Customer Records and Collection Expenses	23,064,885	20,848,510
162	(904) Uncollectible Accounts	22,002,181	19,909,049
163	(905) Miscellaneous Customer Accounts Expenses	129,519	17,646,104
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	68,958,520	87,204,554
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	128,982,197	105,141,678
169	(909) Informational and Instructional Expenses	944,211	902,758
170	(910) Miscellaneous Customer Service and Informational Expenses	285,129	142,448
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	130,211,537	106,186,884
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	2,866,012	2,403,900
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	33,090	29,350
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	2,899,102	2,433,250
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		

181	(920) Administrative and General Salaries	89,687,743	108,409,356
182	(921) Office Supplies and Expenses	63,562,361	57,478,099
183	(Less) (922) Administrative Expenses Transferred-Credit	60,175,636	54,423,313
184	(923) Outside Services Employed	19,474,893	20,505,925
185	(924) Property Insurance	(1,497,249)	2,056,266
186	(925) Injuries and Damages	14,306,151	14,898,526
187	(926) Employee Pensions and Benefits	80,397,090	76,039,532
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	8,302,819	11,694,771
190	(929) (Less) Duplicate Charges-Cr.	5,449,179	5,091,443
191	(930.1) General Advertising Expenses	3,376,810	3,830,009
192	(930.2) Miscellaneous General Expenses	4,129,842	3,387,061
193	(931) Rents	46,128,785	38,797,494
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	262,244,430	277,582,283
195	Maintenance		
196	(935) Maintenance of General Plant	763,087	186,066
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	263,007,517	277,768,349
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	3,037,642,098	2,798,318,053

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) 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.
(b) 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.
(c) 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.
(d) Concept: TransmissionExpenses
Total Transmission Expense as reported in the Form 1, page 321, line 112 is reduced by amounts related to transactions with an affiliated Company based on the FERC-approved Interchange Agreement.
(e) Concept: PropertyInsurance
Credit balance due to nuclear insurance distribution.
(f) Concept: OtherExpensesOtherPowerSupplyExpenses
Includes \$43,628,471 of fixed costs and \$15,468,274 of variable costs reimbursed to NSP-Wisconsin for production costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.
(g) Concept: TransmissionOfElectricityByOthers
Includes \$109,147,471 of fixed costs reimbursed to NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

	Name of Company or Public Authority (Footnote Affiliations) (a)	(b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Tc (k+h) Settled (i) (n)
1	ACE Lincoln Heights Wind Holdings, LLC	LU					21,135					697,457		6
2	Adams Wind Generations	LU					53,238					3,561,875		3,5
3	AEP Ohio Power Company	OS					4,210						\$195,984	1
4	Agassiz Beach, LLC	LU					4,921					122,119		1
5	Aurora Distributed Solar, LLC	LU					185,635					19,262,838		19,2
6	Best Power International LLC	LU					1,966					192,222		1
7	Big Blue Wind Farm, LLC	LU					69,638					6,389,682		6,3
8	Bisson Windfarm, LLC	LU					3,268					111,122		1
9	Boeve Windfarm, L.L.C.	LU					4,967					166,405		1
10	Byllesby	LU		2			337				35,238	5,026		
11	Calpine Energy Services, L.P.	OS					30,400						\$3,601,639	3,6
12	Cannon Falls Energy Center	LU		345			381,447				29,144,364	20,022,978		49,1
13	Carleton College	LU					4,170					137,615		1
14	CG Windfarm, LLC	LU					1,675					56,938		
15	Chanarambie Power Partners, L.L.C.	LU					222,046					5,884,207		5,8

16	Cisco Wind Energy, L.L.C.	LU					18,169					597,767		5
17	Covanta Hennepin Energy Resource Co LP	LU	34				215,708					7,952,069		7,9
18	Crowned Ridge Wind, LLC	LU					750,063					16,871,050		16,8
19	Dairyland Electric Cooperative Incorporated	LU					17,152					(17,782)		(
20	Dakota Range III, LLC	LU					326,154					2,873,200		2,8
21	Danielson Wind Farms, LLC	LU					54,983					3,675,491		3,6
22	Deuel Harvest Wind Energy LLC	LU					104,838					2,090,199		2,0
23	Dragonfly Solar, LLC	LU					1,109					94,247		
24	East Ridge group	LU					18,962					625,748		6
25	EDF Trading North America, LLC	OS					44,000						1,351,181	1,3
26	ERCOT	OS					(104,558)						(73,129,795)	(73,12
27	Ewington Energy Systems, LLC	LU					23,626					826,895		8
28	Exelon Generation Company, LLC	OS					203,600						5,181,668	5,1
29	Fenton Power Partners I, L.L.C.	LU					308,668					30,564,698		30,5
30	Fey Windfarm, L.L.C.	LU					4,503					157,591		1
31	FPL Energy Mower County, L.L.C.	LU					33,061					1,476,570		1,4

32	Garwin McNeilus	LU					77,152					2,532,439		2,5
33	Grant County Windfarm, LLC	LU					47,453					3,226,812		3,2
34	Great American West Wind, LLC	LU					392,604					6,713,799		6,7
35	Hastings Lock & Dam	LU		2			24,977				383,786	346,185		7
36	Hilltop Power, L.L.C.	LU					4,121					181,335		1
37	J. Aron & Company LLC	OS					50,800						1,615,621	1,6
38	Jeffers Wind Energy Center	LU					1,786					60,210		
39	JJN Windfarm, LLC	LU					4,154					146,180		1
40	JPMorgan Chase Bank New York	OS					243,383						7,605,719	7,6
41	Kas Brothers Windfarm, L.L.C.	LU					3,540					139,339		1
42	K-Brink Windfarm, L.L.C.	LU					4,323					144,822		1
43	KODA Energy, LLC	LU					873					46,315		
44	Lake Benton Power Partners, L.L.C.	LU					237,212					6,989,958		6,9
45	LCO Hydro	LU					7,238					83,437		
46	Lower Colorado River Authority	OS					52,000						2,839,775	2,8
47	LSP Cottage Grove Incorporated	LU		245			750,440				7,272,181	28,062,486		35,3
48		OS					140,400						5,709,635	5,7

	Luminant Energy Company LLC												
49	Manitoba Hydro	AD				0				(1,116,100)			(1,116,100)
50	Manitoba Hydro	LU		350		1,817,582				47,156,954	149,228,141		196,385,096
51	Mankato Energy Center I, L.L.C.	AD				0					(24,619)		(24,619)
52	Mankato Energy Center I, L.L.C.	LU		375		1,300,594				39,207,227	54,657,445		93,864,672
53	Mankato Energy Center II, L.L.C.	LU		345		1,609,156				27,161,248	43,514,041		70,675,299
54	Marshall Solar	LU				97,260					7,403,750		7,403,750
55	Metro Wind LLC	LU				641					15,919		15,919
56	Metropolitan Edison Company	OS				1,224						(65,132)	(65,132)
57	Midcontinental ISO	SF				3,468,211					21,117,052		21,117,052
58	MinnDakota Wind LLC	LU				286,280					19,556,447		19,556,447
59	Miscellaneous	AD				0						1,654,639	1,654,639
60	Miscellaneous	OS				44,982						(453,613)	(453,613)
61	Moraine Wind, L.L.C.	LU				89,807					2,762,219		2,762,219
62	N A E Lakota Ridge, LLC	LU				16,423					180,654		180,654
63	N A E Shaokatan Hills, LLC	LU	NAEMA			30,670					337,372		337,372
64	NAE Shaokatan, LLC	LU				26,855					664,314		664,314
65	Natural Gas Exchange Inc.	OS				835,160						(36,653,216)	(36,653,216)

84	Shane's Wind Machine LLC	LU					6,169					203,588		2
85	Shell Energy North America US LP	OS					58,560						2,266,432	2,2
86	Slayton Solar, LLC	LU					2,860					326,036		3
87	South Ridge Power Partners, LLC	LU					6,293					68,086		
88	Southwest Power Pool, Inc.	OS					4,287					(9,654,149)		(9,654,149)
89	St Cloud	LU		7			38,897				1,281,933	906,794		2,1
90	St. Olaf College	LU					20					667		
91	St. Paul Cogeneration	LU					154,204					23,467,304		23,4
92	Taygete Energy Project, LLC	OS					565,516						14,420,773	14,4
93	TG Windfarm, LLC	LU					3,268					111,122		1
94	Tholen Transmission-Trust	LU					41,337					1,364,116		1,3
95	Tofteland Windfarm, LLC	LU					3,268					111,122		1
96	Uilk Wind Farm, LLC	LU					12,885					919,932		9
97	University of Minnesota	LU					3,786					202,550		2
98	Valley View Transmission	LU					24,897					1,587,164		1,5
99	Velva Windfarm, LLC	LU					27,852					919,117		9
100	Viking Wind Partners	LU					35,178					18,097		
101	Vitol Inc.	OS					34,400						3,784,000	3,7
102		LU					11,787					283,032		2

	Western Area Power Administration		NAEMA, WSPP											
103	Westridge Windfarm, LLC	LU					1,675					56,938		
104	Windcurrent Farms, L.L.C.	LU					4,044					141,526	1	
105	Windvest Power Partners, LLC	LU					4,012					30,189		
106	Winona County Wind LLC	LU					4,016					271,564	2	
107	WM Renewable Energy, LLC	LU					(137)					8,325		
108	Woodstock Hills, L.L.C.	LU					34,004					732,802	7	
109	Woodstock Municipal Wind, LLC	LU					463					30,966		
110	Zephyr Wind LLC	LU					50,107					5,562,467	5,5	
15	TOTAL						19,515,231	0	0	0	150,526,831	753,586,969	32,038,906	936,1

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

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

(q) Concept: OtherChargesOfPurchasedPower

Financial Trading

(r) Concept: OtherChargesOfPurchasedPower

Financial Trading

(s) Concept: OtherChargesOfPurchasedPower

Financial Trading

(t) Concept: OtherChargesOfPurchasedPower

Financial Trading

(u) Concept: OtherChargesOfPurchasedPower

Financial Trading

(v) Concept: OtherChargesOfPurchasedPower

Financial Trading

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS				
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenue (\$) (n)	
1	East Grand Forks, City of	WAPA	East Grand Forks, City of	OS	483	WAPA	East Grand Forks							54,883	
2	Granite Falls, City of	WAPA	Granite Falls, City of	OS	436	WAPA	Granite Falls, City							17,486	
3	Great River Energy	Various	Various	FNO	28,304 and OA97-25-000 et al.	Various	Various				44,367,459			126,983	44,416,445

35	TOTAL							0	0	0	228,231,375	72,723,052	1,829,169	302,7
----	-------	--	--	--	--	--	--	---	---	---	-------------	------------	-----------	-------

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

<p>(a) Concept: PaymentByCompanyOrPublicAuthority</p>
<p>Affiliate - Generation Function of Northern States Power - MN</p>
<p>(b) Concept: PaymentByCompanyOrPublicAuthority</p>
<p>Northern States Power Company (a Minnesota Corporation) and Northern States Power Company (a Wisconsin Corporation) are both operating company subsidiaries of Xcel Energy, Inc.</p>
<p>(c) Concept: PaymentByCompanyOrPublicAuthority</p>
<p>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.</p>
<p>(d) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName</p>
<p>Reimbursement from NSP-Wisconsin for transmission costs shared through the FERC- approved Interchange Agreement. See Note 1 to the Financial Statements.</p>
<p>(e) Concept: StatisticalClassificationCode</p>
<p>FNO, LFP, SFP, NF</p>
<p>(f) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers</p>
<p>MISO Schedule 26-A revenue</p>
<p>(g) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers</p>
<p>Facilities Charge</p>
<p>(h) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers</p>
<p>Facilities Charge</p>
<p>(i) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers</p>
<p>Schedule 2 Revenue</p>
<p>(j) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers</p>
<p>Interconnection Network Upgrade revenue</p>
<p>(k) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers</p>
<p>Affiliate - Interconnection Network Upgrade revenue</p>
<p>(l) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers</p>
<p>Facilities Charge</p>
<p>(m) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers</p>
<p>Facilities Charge</p>
<p>(n) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers</p>
<p>Interconnection Network Upgrade revenue</p>
<p>(o) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers</p>
<p>Facilities Charge</p>
<p>(p) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers</p>
<p>Meter Charge</p>



Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) 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.
4. In column (c) 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 (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					

18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					

46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Basin Electric Power	OS					2,400	2,400
2	Central MN Municipal Pw	FNS			1,436,695			1,436,695
3	Dairyland Power	OS					19,744	19,744
4	Great River Energy	FNS			38,523,329			38,523,329
5	ITC Midwest	OS					533,888	533,888
6	McLeod Coop Power	OLF			24,093			24,093
7	Midcontinent ISO (MISO)	LFP			91,461,674	69,637,839	1,000	161,100,513
8	MN Municipal Pwr Agy	FNS			1,220,054			1,220,054
9	Minnkota Power Coop	OLF				20,177	780,000	800,177
10	Missouri Riv Engy Serv	FNS			1,601,903			1,601,903
11	Montana-Dakota Util Co	OS					1,119,122	1,119,122
12	Northwestern Wis Elect	FNS			560,010			560,010

13	(b) Northern States Pwr-MN	OS					(b) 176,024	176,024
14	Otter Tail Pwr Co	OS					(b) 1,661,523	1,661,523
15	PJM Interconnection	FNS			1,494,320			1,494,320
16	Rochester Public Util	FNS			1,961,575			1,961,575
17	Southern MN Muncipl Pwr	FNS			14,859,606			14,859,606
18	Southwest Power Pool	FNS			62,421	341		62,762
19	Stearns Coop Electric	(b) OS				2,796	(b) 508	3,304
20	Verendrye Electric Coop	(b) OLF				138,311		138,311
21	(b) Northern States Pwr-WI	(b) OLF			121,303,129			121,303,129
	TOTAL		0	0	274,508,809	69,799,464	4,294,209	348,602,482

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

2021 MISO Annual Membership

(n) Concept: OtherChargesTransmissionOfElectricityByOthers

Fixed Transmission Service Charge

(o) Concept: OtherChargesTransmissionOfElectricityByOthers

Interconnection upgrade charge

(p) Concept: OtherChargesTransmissionOfElectricityByOthers

Affiliate - Interconnection upgrade charge

(q) Concept: OtherChargesTransmissionOfElectricityByOthers

Interconnection upgrade charge

(r) Concept: OtherChargesTransmissionOfElectricityByOthers

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,529,683
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	150,298
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000	
6	Director Fees & Expenses	1,426,756
7	SEC Filing Expenses	23,105
46	<u>TOTAL</u>	4,129,842

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

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

- Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
- Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
- Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
- If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			26,294,814	(15,101)	26,279,713
2	Steam Production Plant	105,239,320	(713,856)		(1,053,208)	103,472,256
3	Nuclear Production Plant	177,894,156	(28,364,124)			149,530,032
4	Hydraulic Production Plant-Conventional	1,487,259			(67,063)	1,420,196
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	190,075,056	19,572,842	745,069	(4,454,966)	205,938,001
7	Transmission Plant	78,208,307	5,255		(1,247,688)	76,965,874
8	Distribution Plant	130,117,822	234,059			130,351,881
9	Regional Transmission and Market Operation					
10	General Plant	32,451,118			(369,693)	32,081,425
11	Common Plant-Electric	35,900,887	10,823	47,701,306	(1,243)	83,611,773
12	TOTAL	751,373,925	(9,255,001)	74,741,189	(7,208,962)	809,651,151

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

ACCOUNT 405 Column (e) Prefunded AFUDC

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No.	Depreciable Plant Base (in Thousands)	Estimated Avg. Service Life	Net Salvage (Percent)	Applied Depr. Rates (Percent)	Mortality Curve Type	Average Remaining Life
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
12	Steam Production						
13	310	10,081					0 years
14	311	293,207		(11.8)	2.59		8 years, 30 days
15	312	1,498,912		(11.5)	4.33		9 years, 4 months, 25 days
16	314	320,141		(11.7)	5.39		7 years, 6 months, 20 days
17	315	187,421		(10.6)	4.01		10 years, 26 days
18	316	54,001		(10.4)	2.82		9 years, 10 months, 10 days
19	317	20,283					0 years
20	Subtotal Steam Prod	2,384,046					
21	Nuclear Production						
22	320	1,758					0 years
23	321	593,461			3.21		11 years, 3 months, 28 days
24	322	1,933,810			4.17		11 years, 8 months, 27 days
25	323	607,098			4.42		11 years, 7 months, 24 days
26	324	537,001			4		11 years, 21 days
27	325	207,114			3.08		11 years, 7 months, 7 days
28	326	(222,548)					0 years
29	Subtotal Nuclear Prod	3,657,694					
30	Hydro Production						
31	330	1,693					0 years
32	331	1,468		(26.4)	4.84		13 years, 2 months, 15 days
33	332	11,086		(24.4)	5.26		10 years, 9 months, 4 days

34	333	10,157		(26.7)	5.86		13 years, 2 months, 12 days
35	334	3,277		(26.7)	5.63		13 years, 2 months, 12 days
36	335	61		(26.7)	1.03		13 years, 2 months, 12 days
37	336	148					0 years
38	337						
39	Subtotal Hydro Prod	27,890					
40	Other Production						
41	340	33,400			4.32		14 years, 4 months, 3 days
42	341	432,619		(9.5)	3.03		24 years, 1 month, 21 days
43	342	27,447		(10.7)	2.63		20 years, 10 months, 25 days
44	343	142,494		(8)	0.03		23 years, 7 months, 4 days
45	344	3,510,945		(10.1)	3.96		19 years, 3 months, 2 days
46	345	322,983		(9.6)	3.6		20 years, 3 months, 28 days
47	346	46,225		(9.7)	1.69		24 years, 8 months, 29 days
48	347	291,585					0 years
49	348	4,129		(135.6)			3 years
50	Subtotal Other Prod	4,811,827					
51	Transmission						
52	350	168,545					
53	352	147,862	70 years	(5)	1.51	R5	57 years, 25 days
54	353	1,407,640	56 years	(15)	2.08	R2	42 years, 4 months, 23 days
55	354	122,207	75 years	(35)	1.84	R4	39 years, 7 days
56	355	1,500,037	62 years	(50)	2.44	R2	53 years, 1 month, 10 days
57	356	640,957	67 years	(35)	2.03	R1	56 years, 5 months, 21 days
58	357	30,656	73 years		1.38	R4	59 years, 10 months, 3 days
59	358	36,396	50 years	(5)	2.09	R3	37 years, 6 months, 3 days
60	359.1	173					
61		4,054,473					

	Subtotal Transmission						
62	Distribution						
63	360	19,768					
64	361	60,335	63 years	(30)	2.09	R2.5	45 years, 9 months, 17 days
65	362	717,495	53 years	(25)	2.32	R2	37 years, 2 months, 20 days
66	364	548,077	47 years	(120)	4.65	R1	34 years, 1 month, 28 days
67	365	569,971	39 years	(25)	3.19	L0	29 years, 7 months, 11 days
68	366	352,588	56 years	(20)	2.15	R3	40 years, 6 months, 10 days
69	367	1,329,459	49 years	(10)	2.23	R1.5	34 years, 9 months, 29 days
70	^{fsl} 368	470,200	32 years	(5)	3.23		18 years, 8 days
71	^{fl} 368	28,573	25 years	(7)	3.98		12 years, 4 months, 20 days
72	^{fl} 369	90,777	42 years	(85)	4.33	R1.5	22 years, 11 months, 8 days
73	^{fl} 369	282,392	44 years	(5)	2.39	R4	24 years, 7 months, 10 days
74	370	101,758	15 years	(5)	5.84		7 years, 5 months, 21 days
75	371	4,581	10 years		10	SQ	10 years
76	373	82,539	29 years	(40)	5.87	L0	22 years, 5 months, 4 days
77	374	12,231					
78	Subtotal Distribution	4,670,744					
79	General						
80	389	5,082					
81	^{fl} 390	74,993	55 years	(20)	2.28	R1.5	36 years, 10 months, 28 days
82	^{fl} 390	1,075	^{fl} 0 years			SQ	^{fl} 0 years
83	^{fl} 391	34,203	20 years		4.83		7 years, 11 months, 9 days
84	^{fl} 391	57,457	6 years		16.56		2 years, 7 days
85	^{fl} 392	7,238	10 years	5	9.76		6 years, 7 months, 27 days

86	(b) 392	37,622	10 years	10	9.38		3 years, 6 months, 11 days
87	(b) 392	24,737	12 years	20	6.17		5 years, 3 months, 26 days
88	(b) 392	125,570	12 years	15	6.88		5 years, 14 days
89	393	1,624	20 years		4.5		7 years, 8 months, 21 days
90	394	111,571	15 years		6.5		7 years, 8 months, 5 days
91	395	2,913	10 years		10.36		3 years, 5 months, 20 days
92	396	53,490	12 years	15	5.4		4 years, 7 months, 16 days
93	(b) 397	33,642	10 years		10.09		1 year, 11 months, 27 days
94	(b) 397	63,345	10 years		10.24		6 years, 6 months, 25 days
95	(b) 397	8,697	15 years		6.24		3 years, 10 months, 13 days
96	(b) 397	43,885	15 years		6.26		8 years, 7 months, 2 days
97	(b) 397	5,094	15 years		10		8 years, 6 months
98	398	3,136	15 years		6.74		8 years, 9 months, 1 day
99	Subtotal General	695,374					
100	TOTAL	(b) 20,302,048					

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AmortizationOfLimitedTermPlantOrProperty

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

Intangible Plant	\$	13,030,147
Nuclear Production Plant		13,157,839
Hydraulic Production Plant - Conventional		106,828
Total	\$	26,294,814

(b) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

Transmission Serving Production	\$	3,277,064
---------------------------------	----	-----------

(c) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

Distribution Serving Production	\$	115,736
---------------------------------	----	---------

(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	\$	(5,615,398)
Transmission Plant		(4,171,205)
General Plant		(253,125)
Total	\$	(10,039,728)

(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	\$	12,038,502	\$ 195,167,000
396 Power Operated Equipment		2,915,530	53,490,000
Total	\$	<u>14,954,032</u>	<u>\$ 248,657,000</u>
(q) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
397 Communication Equipment			
(r) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
397 Communication Equipment - Two Way			
(s) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
397 Communication Equipment - AMR			
(t) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
397 Communication Equipment - EMS			
(u) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
397 Communication Equipment - Smart Grid			
(v) Concept: DepreciablePlantBase			

(1) Column (b) Computation:
Depreciable Plant Balances are an average of the beginning and ending plant balance for the year.

(2) Column (c) through (g):
Subaccounts 311-348: A remaining life technique is applied to each generating facility.

Black Dog Unit 6 was added in 2018, subaccounts 341-346. The approved life for Black Dog Unit 6 as of March 2018 is 40 years with a -5% net salvage (Docket No. EG002-D-18-162).

The following life changes were approved during 2019 (Docket No. E,G-002/D-19-161):

1. Angus Anson Units 2&3 were extended 15 years. 22 year approved remaining life as of 01/01/2019.
2. Angus Anson Unit 4 and Blue Lake 7&8 were extended 10 years. 26.4 year approved remaining life as of 01/01/2019.
3. Blue Lake Units 1-4 were extended 4 years. 4.5 year approved remaining life as of 01/01/2019.
4. Black Dog Unit 5 was extended for FERC Account 341 only. 39.3 year remaining life as of 01/01/2019.

The following new wind production assets have been added with a 25 year life: Lake Benton (Nov. 2019), Foxtail (Dec. 2019), Blazing Star 1 (April 2020), Crowned Ridge (Dec. 2020), Jeffers (Dec. 2020), and Community Wind North.

No other changes to the underlying factors presented in columns (c) through (g) for Subaccounts 311-348 have occurred since filing the 2016 FERC Form 1.

For subaccounts 350-398, the parameters as approved by the Minnesota Jurisdiction are reported. Columns (c), (d), and (f) were approved in Docket No. E,G002/D-17-581. Columns (e) and (g) were approved in Docket No. E,G002-D-20-635.

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

(w) Concept: UtilityPlantEstimatedAverageServiceLife

Account 390 Structures and Improvements - Leasehold Improvements is computed using an end of life method rather than a specific rate.

(x) Concept: UtilityPlantWeightedAverageRemainingLife

Account 390 Structures and Improvements - Leasehold Improvements is computed using an end of life method rather than a specific rate.

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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.

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)	EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR			
						CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
						Department (f)	Account No. (g)	Amount (h)				
1	MINNESOTA PUBLIC UTILITIES COMMISSION											
2	Electric Assessments	7,489,162		7,489,162		Elec	928	6,825,144				
3	Gas Assessments					Gas	928	664,018				
4	Investigation of Cost Overruns at PI		32,201	32,201		Elec	928	32,201				
5	CI-20-800 Distribution Grid and Customer Security		26,021	26,021		Elec	928	26,021				
6	CI-21-135 & CI-21-610 February 2021 Natural Gas Price Investigation		618,522	618,522		Gas	928	618,522				
7	GR-20-723 Rate Case Stay Out	40,898		40,898		Elec	928	40,898				
8	GR-21-63 Audit & Assurance Services	70,000		70,000		Elec	928	70,000				
9	RP-19-368 2020-2034 Upper Midwest Integrated Resource Plan		68,212	68,212		Elec	928	68,212				

10	Electric Miscellaneous - Minnesota	20,282	25,242	45,524		Elec	928	35,489				
11	Gas Miscellaneous - Minnesota					Gas	928	10,035				
12	NORTH DAKOTA PUBLIC SERVICE COMMISSION											
13	Gross Receipts Tax Assessment Electric	25,361		25,361		Elec	928	22,774				
14	Gross Receipts Tax Assessment Gas					Gas	928	2,587				
15	PU-20-192 & PU-20-220 COVID-19 Request for Def Accounting - Electric	(19,872)		(19,872)		Elec	928	(9,936)				
16	PU-20-192 & PU-20-220 COVID-19 Request for Def Accounting - Gas					Gas	928	(9,936)				
17	PU-20-406 Transmission Cost Recovery Rider	(9,842)		(9,842)		Elec	928	(9,842)				
18	PU-20-426 Renewable Energy Rider	(9,835)		(9,835)		Elec	928	(9,835)				
19	PU-20-433 Heartland Divide PPA ADP		88,075	88,075		Elec	928	88,075				
20	PU-20-441 2021 Electric Rate Increase	355,540		355,540		Elec	928			186	355,540	
21	PU-21-381 2021 Gas Rate Increase	68,000		68,000		Gas	928			186	68,000	
22	PU-21-389 Renewable Energy Rider	10,000		10,000		Elec	928	10,000				
23	PU-21-396 Transmission Cost Recovery Rider	10,000		10,000		Elec	928	10,000				
24	Electric Miscellaneous - North Dakota	10,396		10,396		Elec	928	7,618				
25	Gas Miscellaneous - North Dakota					Gas	928	2,778				
26	SOUTH DAKOTA PUBLIC UTILITIES COMMISSION											
27	Gross Receipts Tax Assessment	663,067		663,067		Elec	928	663,067				

28	EL20-025 Transmission Cost Recovery Rider	2,563		2,563		Elec	928	2,563				
29	EL20-026 Infrastructure Rider	5,489		5,489		Elec	928	5,489				
30	EL21-025 Transmission Cost Recovery Rider	3,067		3,067		Elec	928	3,067				
31	EL21-028 Infrastructure Rider	3,738		3,738		Elec	928	3,738				
32	Miscellaneous - South Dakota	850		850		Elec	928	850				
33	FEDERAL ENERGY REGULATORY COMMISSION											
34	ER22-80 Coyote Ridge Wind & ER22-93 Tatanka Ridge Wind		37,620	37,620		Elec	928	37,620				
35	Miscellaneous		24,066	24,066		Elec	928	24,066				
46	TOTAL	8,738,864	919,959	9,658,823				9,235,283				423,540

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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:

Electric R, D and D Performed Internally:

Generation

hydroelectric

Recreation fish and wildlife
Other hydroelectric

Fossil-fuel steam
Internal combustion or gas turbine
Nuclear
Unconventional generation
Siting and heat rejection

Transmission

Overhead

Underground

Distribution
Regional Transmission and Market Operation
Environment (other than equipment)
Other (Classify and include items in excess of \$50,000.)
Total Cost Incurred

Electric, R, D and D Performed Externally:

Research Support to the electrical Research Council or the Electric Power Research Institute
Research Support to Edison Electric Institute
Research Support to Nuclear Power Groups
Research Support to Others (Classify)
Total Cost Incurred

3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.

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

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

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

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

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	B(1)	Electric Power Research Institute		3,385,520	^(a) Various	3,385,520	
2	B(2)	Edison Electric Institute		920,972	^(b) Various	920,972	
3	B(4)	Renewable Development Fund		328,708	^(c) 253	328,708	

4	B(5)	Total		4,635,200		4,635,200	
---	------	-------	--	-----------	--	-----------	--

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Accounts charged:			
506		\$	300
524			2,292,284
930.2			1,092,936
		<u>\$</u>	<u>3,385,520</u>

(b) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Accounts charged:			
426.4		\$	126,370
930.2			794,602
		<u>\$</u>	<u>920,972</u>

(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-Torrefact		\$	74,393
City of Red Wing			200,000
Interphases Solar			136,095
University of Minnesota			(81,780)
		<u>\$</u>	<u>328,708</u>

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	177,308,928		
4	Transmission	17,194,037		
5	Regional Market	326,787		
6	Distribution	29,829,520		
7	Customer Accounts	13,817,750		
8	Customer Service and Informational	1,166,138		
9	Sales	1,101,853		
10	Administrative and General	89,335,410		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	330,080,423		
12	Maintenance			
13	Production	71,420,472		
14	Transmission	2,619,706		
15	Regional Market			
16	Distribution	20,947,438		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	94,987,616		
19	Total Operation and Maintenance			

20	Production (Enter Total of lines 3 and 13)	248,729,400		
21	Transmission (Enter Total of lines 4 and 14)	19,813,743		
22	Regional Market (Enter Total of Lines 5 and 15)	326,787		
23	Distribution (Enter Total of lines 6 and 16)	50,776,958		
24	Customer Accounts (Transcribe from line 7)	13,817,750		
25	Customer Service and Informational (Transcribe from line 8)	1,166,138		
26	Sales (Transcribe from line 9)	1,101,853		
27	Administrative and General (Enter Total of lines 10 and 17)	89,335,410		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	425,068,039	9,007,948	434,075,987
29	Gas			
30	Operation			
31	Production - Manufactured Gas	37,528		
32	Production-Nat. Gas (Including Expl. And Dev.)	14,270		
33	Other Gas Supply	150,908		
34	Storage, LNG Terminaling and Processing	756,948		
35	Transmission	601,330		
36	Distribution	17,781,352		
37	Customer Accounts	3,412,636		
38	Customer Service and Informational	916,292		
39	Sales	141		
40	Administrative and General	7,088,485		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	30,759,890		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	1,878,101		
47	Transmission	52,110		

48	Distribution	6,043,114		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	7,973,325		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	37,528		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	14,270		
54	Other Gas Supply (Enter Total of lines 33 and 45)	150,908		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru	2,635,049		
56	Transmission (Lines 35 and 47)	653,440		
57	Distribution (Lines 36 and 48)	23,824,466		
58	Customer Accounts (Line 37)	3,412,636		
59	Customer Service and Informational (Line 38)	916,292		
60	Sales (Line 39)	141		
61	Administrative and General (Lines 40 and 49)	7,088,485		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	38,733,215	1,343,648	40,076,863
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	463,801,254	10,351,596	474,152,850
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	131,781,179	47,503,345	179,284,524
69	Gas Plant	11,281,301	10,501,123	21,782,424
70	Other (provide details in footnote):	861,124	29,423	890,547
71	TOTAL Construction (Total of lines 68 thru 70)	143,923,604	58,033,891	201,957,495
72	Plant Removal (By Utility Departments)			
73	Electric Plant	11,095,789	3,821,859	14,917,648
74	Gas Plant	483,515	844,863	1,328,378
75	Other (provide details in footnote):			

76	TOTAL Plant Removal (Total of lines 73 thru 75)	11,579,304	4,666,722	16,246,026
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Regulatory Assets (Acct No. 182.3)	8,675,487	249,709	8,925,196
80	Preliminary Survey and Investigation (Acct No. 183)	78,785	4,767	83,552
81	Miscellaneous Deferred Debits (Acct No. 186)		11,807	11,807
82	Miscellaneous Deferred Credits (Acct No. 253)	3,639	1,150	4,789
83	Regulatory Liabilities (Acct No. 254)	172,240	2,281	174,521
84	Non-utility (Accts No. 416-417.1)	3,324,906	37,690	3,362,596
85	Miscellaneous Income and Deductions (Accts No. 426.1-426.5)	246,237	3,378	249,615
86	Non-utility CWP and RWP	2,041,803		2,041,803
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	14,543,097	310,782	14,853,879
96	TOTAL SALARIES AND WAGES	633,847,259	73,362,991	707,210,250

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: SalariesAndWagesUtilityPlantConstructionOther
E120.1 Nuclear fuel in process of refinement, conversion, enrichment and fabrication

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

Page 354-355

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

COMMON UTILITY PLANT AND EXPENSES

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

Instruction 1:

Account	Allocated to Utility Departments		Cost at Dec. 31, 2021
	Electric	Gas	
COMMON UTILITY PLANT IN SERVICE AND COMPLETED NOT CLASSIFIED (ACCOUNTS 101 AND 106)			
301 Organization	90,940	9,668	100,608
303 Computer Software	512,005,155	54,434,888	566,440,043
Total intangible plant	512,096,095	54,444,556	566,540,651
389 Land and land rights	5,799,971	396,937	6,196,908
390 Structures and improvements	208,835,771	14,292,242	223,128,013
391 Office furniture and equipment	158,139,487	10,822,704	168,962,191
392 Transportation equipment	10,107,464	2,086,788	12,194,252
393 Stores equipment	230,394	15,768	246,162
394 Tools/shop/garage equipment	7,686,615	526,054	8,212,669
395 Laboratory equipment	—	—	—
396 Power operated equipment	1,126,454	183,232	1,309,686
397 Communications equipment	417,705	28,587	446,292
398 Miscellaneous equipment	220,516	15,092	235,608
399.1 Asset retirement costs for general plant	320,125	21,909	342,034
Total	904,980,597	82,833,869	987,814,466
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	117,767,345	10,830,829	128,598,174

Instruction 2:

COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (ACCOUNT 108 AND 111)			
General Plant	407,277,098	39,732,410	447,009,508

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.

	<u>"Non-Legal" ARO Balance</u>
Common General	\$ (5,980,034)
Common Intangible	—
Total Common	<u>(5,980,034)</u>

Instruction 3:

Common Utility Plant Expenses

		Electric	Gas	Total
403	Depreciation Expense	35,900,887	2,659,517	38,560,404
403.1	Depreciation Expense - ARC	10,823	739	11,562
404	Amortization of limited term plant	47,701,306	5,213,735	52,915,041
405	Amortization of other plant	(1,243)	(84)	(1,327)
407.4	Amortization of regulatory credits	(40,552)	(2,770)	(43,322)
411.1	Accretion expense	29,729	2,030	31,759
Total		<u>83,600,950</u>	<u>7,873,167</u>	<u>91,474,117</u>

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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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)	12,345,772	34,690,371	47,536,794	78,316,695
9	MISO - Net Sales (Account 447)	(61,636,288)	(59,128,594)	(87,386,096)	(135,235,514)
10	MISO - Transmission Rights	(6,889,942)	(22,010,868)	(47,924,840)	(59,817,726)
11	MISO - Ancillary Services	512,839	801,436	1,071,554	1,212,505
12	MISO - Other Items				
13	MISO - Admin Fees	2,248,052	4,921,132	7,381,273	9,974,916
14	MISO - Net Purchases for Storage Operations				
15	ERCOT				
16	ERCOT - Net Purchases (Account 555)	(71,925,262)	(71,075,143)	(69,889,870)	(74,422,732)
17	ERCOT - Net Sales (Account 447)				
18	ERCOT - Transmission Rights				
19	ERCOT - Ancillary Services				

20	ERCOT - Other Items				
21	ERCOT - Uplift Charges	1,284,637	1,284,840	1,288,372	1,292,937
22	NEISO				
23	NEISO - Net Purchases (Account 555)				
24	NEISO - Net Sales (Account 447)				
25	NEISO - Ancillary Services				
26	NEISO - Other Items				
27	NEISO - Admin Fees	741	5,697	8,761	11,695
28	NEISO - Uplift Charges				
29	NYISO				
30	NYISO - Net Purchases (Account 555)				
31	NYISO - Transmission Rights				
32	NYISO - Admin Fees	(493)	(493)	(493)	(493)
33	PJM				
34	PJM - Net Purchases (Account 555)	4,577,674	7,075,893	7,128,271	7,130,668
35	PJM - Net Sales (Account 447)				
36	PJM - Transmission Rights	(7,719)	(14,891)	(15,422)	(15,422)
37	PJM - Ancillary Services				
38	PJM - Other Items				
39	PJM - Admin Fees	120,649	205,040	205,467	205,635
40	PJM - Uplift Charges	1,040,448	1,799,714	1,685,137	1,689,102
41	SPP				
42	SPP - Net Purchases (Account 555)	(10,868,253)	(10,480,760)	(10,443,147)	(10,393,074)
43	SPP - Transmission Rights				
44	Admin Fees		579	762	949
45	SPP - Uplift Charges	467,997	672,182	671,339	735,128
46	SPP - Ancillary Services	2,143	2,373	2,925	3,805
46	TOTAL	(128,727,005)	(111,251,492)	(148,679,213)	(179,310,926)



Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	0	0	8,738,447	0	0	570,924
2	Reactive Supply and Voltage	0	0	10,195,977	0	0	8,630,672
3	Regulation and Frequency Response	0	0	2,058,357	0	0	5,053,144
4	Energy Imbalance	0	0		0	0	
5	Operating Reserve - Spinning	0	0	2,062,035	0	0	3,784,930
6	Operating Reserve - Supplement	0	0	702,418	0	0	890,177
7	Other	0	0	145,423	0	0	240,056
8	Total (Lines 1 thru 7)			23,902,657			19,169,903

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits
Number of units is not available
(b) Concept: AncillaryServicesPurchasedNumberOfUnitsPower
Unit of measure is not available
(c) Concept: AncillaryServicesSoldNumberOfUnits
Volume of units is not available
(d) Concept: AncillaryServicesSoldUnitsOfMeasure
Unit of measure is not available
(e) Concept: AncillaryServicesPurchasedNumberOfUnits
Number of units is not available
(f) Concept: AncillaryServicesPurchasedNumberOfUnitsPower
Unit of measure is not available
(g) Concept: AncillaryServicesSoldNumberOfUnits
Volume of units is not available
(h) Concept: AncillaryServicesSoldUnitsOfMeasure
Unit of measure is not available
(i) Concept: AncillaryServicesPurchasedNumberOfUnits
Number of units is not available
(j) Concept: AncillaryServicesPurchasedNumberOfUnitsPower
Unit of measure is not available
(k) Concept: AncillaryServicesSoldNumberOfUnits
Volume of units is not available
(l) Concept: AncillaryServicesSoldUnitsOfMeasure
Unit of measure is not available
(m) Concept: AncillaryServicesPurchasedNumberOfUnits
Number of units is not available
(n) Concept: AncillaryServicesPurchasedNumberOfUnitsPower
Unit of measure is not available
(o) Concept: AncillaryServicesSoldNumberOfUnits

Volume of units is not available		
(p) Concept: AncillaryServicesSoldUnitsOfMeasure		
Unit of measure is not available		
(q) Concept: AncillaryServicesPurchasedNumberOfUnits		
Number of units is not available		
(r) Concept: AncillaryServicesPurchasedNumberOfUnitsPower		
Unit of measure is not available		
(s) Concept: AncillaryServicesSoldNumberOfUnits		
Volume of units is not available		
(t) Concept: AncillaryServicesSoldUnitsOfMeasure		
Unit of measure is not available		
(u) Concept: AncillaryServicesPurchasedAmount		
NSPP Real-Time Short-Term Reserve Cost Distribution Amount	\$	145,423
(v) Concept: AncillaryServicesSoldAmount		
NSPP Real-Time Ramp Capability Amount	\$	38,385
NSPP Day-Ahead Ramp Capability Amount	\$	146,480
NSPP Day-Ahead Short-Term Reserve Amount	\$	65,436
NSPP Real-Time Short-Term Reserve Amount	\$	(10,245)
		240,056

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	6,855	19	18	5,669	1,490				
2	February	7,298	11	11	5,981	1,636				
3	March	6,479	1	19	5,360	1,395				
4	Total for Quarter 1				17,010	4,521	0			0
5	April	6,192	13	12	5,099	1,325				
6	May	8,271	25	16	6,789	1,731				
7	June	10,302	9	17	8,590	2,043				
8	Total for Quarter 2				20,478	5,099	0			0
9	July	10,190	27	18	8,487	2,042				
10	August	9,924	19	17	8,219	2,063				
11	September	8,362	16	17	6,867	1,774				
12	Total for Quarter 3				23,573	5,879	0			0
13	October	7,236	1	16	5,918	1,527				
14	November	6,609	17	18	5,414	1,449				
15	December	7,276	6	18	5,979	1,599				
16	Total for Quarter 4				17,311	4,575	0			0

17	Total				78,372	20,074	0	0	0	0
----	-------	--	--	--	--------	--------	---	---	---	---

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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			318
February			335
March			290
April			246
May			266
June			351
July			358
August			377
September			297
October			226
November			268
December			317
Total			3,649

"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			63
February			66
March			58
April			45
May			42
June			59
July			58
August			66
September			39
October			44
November			50
December			59
Total			649

17	Total Year to Date/Year				0	0	0	0	0	0
----	-------------------------	--	--	--	---	---	---	---	---	---

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2022-04-14	Year/Period of Report End of: 2021/ 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)	33,135,807
3	Steam	9,382,731	23	Requirements Sales for Resale (See instruction 4, page 311.)	6,108,092
4	Nuclear	14,068,536	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	15,696,940
5	Hydro-Conventional	49,842	25	Energy Furnished Without Charge	282
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	48,197
7	Other	13,746,690	27	Total Energy Losses	1,773,712
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	37,247,799	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	56,763,030
10	Purchases (other than for Energy Storage)	19,515,231			
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)	56,763,030

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

Page 401a

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2022-04-14	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: OtherEnergyGeneration

Excludes test energy for wind farms located outside of the NSP LBA.

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	4,714,323	1,290,186	4,838	19	18
30	February	4,581,117	1,288,449	5,125	15	19
31	March	4,373,710	1,201,750	4,576	1	19
32	April	3,925,031	1,016,721	4,464	13	12
33	May	4,201,148	1,123,338	5,861	25	16
34	June	5,255,035	1,252,916	7,507	9	17
35	July	5,234,257	1,189,592	7,548	27	18
36	August	5,511,813	1,523,084	7,216	19	17
37	September	4,391,224	1,131,286	6,008	16	17
38	October	4,438,711	1,322,602	5,119	1	16
39	November	4,888,053	1,606,883	4,643	17	18
40	December	5,248,608	1,750,133	5,108	6	18
41	Total	56,763,030	15,696,940			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: EnergyActivity

The Northern States Power Co. Integrated System refers to the interconnected production and transmission facilities of both Northern States Power Co. (a Minnesota corporation) which has customers in Minnesota, North Dakota and South Dakota, and Northern States Power Co. (a Wisconsin corporation) which has customers in Michigan and Wisconsin. The construction, operation and maintenance of the two companies' systems is coordinated. This table shows the integrated system peak and the demand of each jurisdiction at the time of the integrated system peak. The monthly peaks reported in column d of page 401b are the sums of the monthly peaks for the states of Minnesota, North Dakota and South Dakota shown below.

Day	Hour	Integrated System	Northern States Power Co. (a Minnesota corporation)			Northern States Power Co. (a Wisconsin corporation)		
			Minnesota	North Dakota	South Dakota	Wisconsin	Michigan	
	19-Jan	1800	5,863	4,203	338	297	1,001	24
	15-Feb	1900	6,221	4,418	375	332	1,071	25
	1-Mar	1900	5,557	3,969	326	281	961	20
	13-Apr	1200	5,301	3,899	287	278	819	18
	25-May	1600	6,918	5,240	259	362	1,037	20
	9-Jun	1700	8,836	6,604	419	484	1,303	26
	27-Jul	1800	8,760	6,610	411	527	1,191	21
	19-Aug	1700	8,448	6,337	400	479	1,210	22
	16-Sep	1700	7,004	5,292	263	453	977	19
	1-Oct	1600	6,111	4,536	263	320	972	20
	17-Nov	1800	5,593	4,049	308	286	929	21
	6-Dec	1800	6,169	4,436	356	316	1,037	24

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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 Turbines	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	194
4	Year Last Unit was Installed	1968	2005	2018	2005	2008	1972	1971	1974	2009	1987	195
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	25.0
6		547	353	530	384	621	396	664	1,121	508	1,889	2

	Net Peak Demand on Plant - MW (60 minutes)												
7	Plant Hours Connected to Load	3,101	1,228	6,778	842	6,699	832	7,962	8,760	3,774	8,737	7,83	
8	Net Continuous Plant Capability (Megawatts)	511	386	526	543	580	348	646	1,092	500	1,879	1	
9	When Not Limited by Condenser Water	511	386	526	543	580	348	646	1,092	500	1,879	1	
10	When Limited by Condenser Water	511	327	494	447	530	252	617	1,040	454	1,879	1	
11	Average Number of Employees	68	8	21	5	24	6	342	432	21	230	2	
12	Net Generation, Exclusive of Plant Use - kWh	1,307,583,500	159,141,412	1,859,208,000	145,239,000	3,143,817,000	89,164,000	4,993,372,000	9,075,164,000	1,361,055,881	7,848,688,672	94,372,76	
13	Cost of Plant: Land and Land Rights	1,335,100	1,155,577	952,692	141,878	528,150	351,801	778,651	969,282	450,133	7,516,615	499,77	
14	Structures and Improvements	39,721,551	8,235,254	57,237,064	1,703,454	71,147,957	1,617,415	254,231,324	351,252,208	52,858,845	228,847,957	11,645,69	
15	Equipment Costs	671,242,436	124,998,463	284,742,696	103,506,592	338,048,620	56,507,767	1,312,651,043	2,002,750,106	281,669,715	1,290,492,831	52,942,66	
16	Asset Retirement Costs	4,604,709	712,520	64,419	170,055	20,138	26,851	68,805,022	(291,352,616)	421,964	11,627,501	1,935,84	
17	Total cost (total 13 thru 20)	716,903,796	135,101,815	342,996,871	105,521,979	409,744,865	58,503,834	1,636,466,040	2,063,618,980	335,400,657	1,538,484,904	67,023,98	
18	Cost per KW of Installed Capacity (line 17/5) Including	1,198.0344	333.0420	618.8040	188.6612	636.1905	208.5698	2,389.1062	1,739.6889	572.4538	738.0771	2,680.959	

19	Production Expenses: Oper, Supv, & Engr	551,352	125,903	190,844	32,690	551,451	31,900	16,836,102	22,191,898	558,192	2,185,707	423,41
20	Fuel	29,501,147	8,708,216	63,475,519	8,811,998	89,727,726	9,874,045	37,863,607	76,246,315	55,334,112	168,658,094	575,92
21	Coolants and Water (Nuclear Plants Only)							3,905,302	4,460,922			
22	Steam Expenses	4,929,288						22,706,206	26,240,760		8,519,907	2,279,74
23	Steam From Other Sources											
24	Steam Transferred (Cr)											
25	Electric Expenses	5,178	48,365	2,095,323	113,312	1,772,563	261,796	134,362	2,349,586	1,837,533	4,296,019	5,00
26	Misc Steam (or Nuclear) Power Expenses	2,173,263	594,049	380,072	108,089	331,614	64,850	54,574,340	70,507,851	583,937	9,333,779	1,348,00
27	Rents	257,248	27,480	35,337	16,665	76,024	16,262	2,190,229	3,169,945	125,559	949,947	131,74
28	Allowances											
29	Maintenance Supervision and Engineering	455,086	41,393	189,478	25,102	275,185	24,496	4,507,362	3,182,740	189,128	878,133	16,68
30	Maintenance of Structures	1,192,325	625,001	1,290,387	176,821	1,266,306	533,134			1,259,989	1,973,841	468,44
31	Maintenance of Boiler (or reactor) Plant	2,888,006						13,219,612	19,663,957		13,655,120	1,738,89
32	Maintenance of Electric Plant	630,411	523,791	2,168,953	736,486	1,195,136	246,665	4,440,266	8,073,321	4,429,208	5,758,106	327,85
33	Maintenance of Misc Steam (or Nuclear) Plant	1,138,015	19,054	145,167	6,760	78,696	7,443	9,861,329	15,100,484	177,682	5,023,043	560,01
34	Total Production Expenses	43,721,319	10,713,251	69,971,080	10,027,923	95,274,701	11,060,591	170,238,717	251,187,779	64,495,340	221,231,696	7,875,73

35	Expenses per Net kWh	0.0334	0.0673	0.0376	0.0690	0.0303	0.1240	0.0341	0.0277	0.0474	0.0282	0.083				
35	Plant Name	A S King	A S King	A S King	Angus Anson	Angus Anson	Angus Anson	Black Dog 2, 5, & 6	Blue Lake	Blue Lake	Blue Lake	High Bridge 7,8,9	Inver Hills	Inver Hills	Monticello	Prairie Island
36	Fuel Kind	Coal	Gas	Oil	Coal	Gas	Oil	Gas	Coal	Gas	Oil	Gas	Gas	Oil	Nuclear	Nuclear
37	Fuel Unit	T	Mcf	bbl	T	Mcf	bbl	Mcf	T	Mcf	bbl	Mcf	Mcf	bbl	g	g
38	Quantity (Units) of Fuel Burned	774,233	100,757	56		1,723,319	20,843	16,288,033		1,570,331	15,262	20,518,821	999,572	65,655	474,758	851,90
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12,045	945	112,725		973	138,395	763		169	170,642	1,072	1,139	278,749	111,214	111,8!
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	36.981	8.415	(185.720)		4.119	77.264	3.897		4.684	95.481	4.373	4.357	84.056		
41	Average Cost of Fuel per Unit Burned	37.022	8.415	(185.720)		4.119	77.264	3.897		4.684	95.481	4.373	4.357	84.056		
42	Average Cost of Fuel Burned per Million BTU	1.537	8.901	(39.227)		4.231	13.293	5.110		27.780	13.322	4.079	3.825	7.180	0.723	0.8!
43	Average Cost of Fuel Burned per kWh Net Gen		0.020		0.050			0.030	0.070			0.030	0.100		0.010	0.0!
44	Average BTU per kWh Net Generation		9,905.25		10,540.99			5,212.62	2,806.48			7,210.51	19,661.03		10,573.99	10,619.!

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

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 UO2 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 85 metric tons of uranium metal with a nominal U-235 enrichment of 4.0 weight percent in the fresh fuel. The reactor is licensed to operate at 2,004 MWt.

(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 UO2 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 47 metric tons of uranium metal with a nominal U-235 enrichment of 4.95 weight percent in the fresh fuel. The reactor is licensed to operate at 1677 MWt.

(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 4 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 "Average Heat Content of Fuel Burned" is calculated as:

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

(g) Concept: FuelBurnedAverageHeatContent

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

(h) Concept: AverageCostOfFuelBurnedPerMillionBritishThermalUnit

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

(i) Concept: AverageCostOfFuelBurnedPerMillionBritishThermalUnit

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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		7,845
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		49,841,982
13	Cost of Plant		
14	Land and Land Rights		1,548,707
15	Structures and Improvements		1,429,599
16	Reservoirs, Dams, and Waterways		8,889,960
17	Equipment Costs		13,496,640

18	<u>Roads, Railroads, and Bridges</u>		152,075
19	<u>Asset Retirement Costs</u>		
20	<u>Total cost (total 13 thru 20)</u>		25,516,981
21	<u>Cost per KW of Installed Capacity (line 20 / 5)</u>		1,837.076
22	<u>Production Expenses</u>		
23	<u>Operation Supervision and Engineering</u>		88,626
24	<u>Water for Power</u>		59,158
25	<u>Hydraulic Expenses</u>		
26	<u>Electric Expenses</u>		328,332
27	<u>Misc Hydraulic Power Generation Expenses</u>		93,789
28	<u>Rents</u>		34,834
29	<u>Maintenance Supervision and Engineering</u>		882
30	<u>Maintenance of Structures</u>		45,690
31	<u>Maintenance of Reservoirs, Dams, and Waterways</u>		66,760
32	<u>Maintenance of Electric Plant</u>		180,673
33	<u>Maintenance of Misc Hydraulic Plant</u>		4,031
34	<u>Total Production Expenses (total 23 thru 33)</u>		902,776
35	<u>Expenses per net kWh</u>		0.0181

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. 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 8 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. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demand on Plant-Megawatts (60 minutes)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	0
15	Reservoirs, Dams, and Waterways	0

16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	0
25	Water for Power	0
26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per kWh of Generation and Pumping (line 37/(line 9 + line 10))	0

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1	STEAM PLANTS												
2	Red Wing	1949	23.00	24	132,086,104	72,672,124	3,159,658	3,060,762	615,324	4,131,811	RDF, Gas	0.26	
3	WIND TURBINES												
4	Blazing Star Wind 1	2020	182.00	209	818,802,625	349,417,260	1,919,875	4,013,057		55,845			Wind
5	Lake Benton Wind	2019	100.20	101	441,174,799	181,066,003	1,807,046	1,367,979		1,152,973			Wind
6	Ben Fowke Wind Energy Center	2008	100.50	99	213,101,428	226,013,629	2,248,892	1,522,928		960,632			Wind
7	Nobles Wind	2010	201.00	200	344,136,223	556,100,108	2,766,667	3,168,027		1,114,681			Wind
8	Borders Wind	2015	150.00	147	633,603,405	282,932,875	1,886,219	1,504,656		1,382,128			Wind
9	Pleasant Valley Wind	2015	200.00	195	707,782,712	366,344,777	1,831,724	3,368,852		1,891,777			Wind
10	Courtenay Wind	2016	200.00	193	744,602,599	306,964,811	1,534,824	2,997,533		1,601,520			Wind
11	Foxtail Wind	2019	163.60	150	620,945,968	247,958,922	1,515,641	(877,631)		1,343,486			Wind
12	Blazing Star Wind 2	^(a) 2020	218.00	200	786,672,431	384,349,598	1,763,072	3,584,827		1,767,445			Wind

13	Community Wind North	2020	26.00	26	106,063,982	36,261,351	1,394,667	510,293		298,246			Wind
14	Crowned Ridge	2020	200.60	198	822,722,981	343,150,397	1,710,620	1,815,535		1,639,072			Wind
15	Jeffers	2020	44.00	44	173,225,765	52,338,787	1,189,518	853,946		524,350			Wind
16	Mower County	(b) 2020	98.90	91	254,172,000	225,434,420	2,279,418	812,473		747,849			Wind
17	Freeborn	(b) 2021	218.00	199	475,598,958	360,692,212	1,654,551	2,814,043		1,164,251			Wind
18	Dakota Range 1 & 2	(b) 1905	304.00	101	(b)166,022,804								

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: YearPlantOriginallyConstructed Commercial Operations Date January 28, 2021
(b) Concept: YearPlantOriginallyConstructed Commercial Operations Date March 23, 2021
(c) Concept: YearPlantOriginallyConstructed Commercial Operations Date May 27, 2021
(d) Concept: YearPlantOriginallyConstructed Not in commercial operation at year end 2021
(e) Concept: NetGenerationExcludingPlantUse Test energy prior to commercial operation

13														
14														
15														
16														
17														
18														
19														
20														
21														
22														
23														
24														
25														
26														
27														
28														
29														
30														
31														
32														
33														
34														

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

TRANSMISSION LINE STATISTICS

- Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below the If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
- Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line 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 remain
- 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 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: the expenses reported for the line designated.
- Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher v structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
- Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and at 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 ar 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 affect party is an associated company.
- Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated com
- 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)			EXPI
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
1	(5703;01) CHISAGO CO.	FORBES	500.0	500.0	TOWER	61.45	0.00	1	9-1192 ACSR	2,237,403	16,180,329	18,417,732	
2	(5702;01) FORBES	RIEL (MH)	500.0	500.0	TOWER	203.63	0.00	1	9-1192.5 ACSR	1,723,645	84,490,053	86,213,698	
3	(0998;01) SIOUX CITY (WAPA)	SPLIT ROCK	345.0	345.0	SINGLE POLE	0.00	4.43	1	6-954 ACSS		670,200	670,200	
4	(0998;01) SIOUX CITY (WAPA)	SPLIT ROCK	345.0	345.0	SINGLE POLE	0.00	0.63		6-954 ACSS/TW				
5	(0997;01) SPLIT ROCK	WHITE (WAPA)	345.0	345.0	SINGLE POLE	4.91	0.24	1	6-954 ACSS/TW	139,860	8,455,822	8,595,682	
6		PARKERS LAKE	345.0	345.0	TOWER	0.13	9.62	1	6-954 ACSR		564,837	564,837	

	(0996;01) DICKINSON SW STA (GRE)												
7	(0994;01) ALLEN S KING	CHISAGO CO.	345.0	345.0	SINGLE POLE	0.00	31.56	1	6-954 ACSR		1,648,291	1,648,291	
8	(0994;01) ALLEN S KING	CHISAGO CO.	345.0	345.0	TOWER	0.00	6.66		6-795 ACSR				
9	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	16.94	0.66	1	6-954 ACSR	472,775	4,401,876	4,874,651	
10	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	0.00	14.18		6-954 ACSR				
11	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	0.00	11.63		6-954 ACSR				
12	(0991;01) MONTICELLO SUB	SHERBURNE CO.	345.0	345.0	TOWER	0.07	5.76	1	6-954 ACSR		196,978	196,978	
13	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	K-FRAME	0.78	0.00	1	6-795 ACSR	80,238	1,436,429	1,516,667	
14	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	SINGLE POLE	0.00	0.83		6-795 ACSR				
15	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	TOWER	3.52	17.16		6-795 ACSR				
16	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	H-FRAME	0.52	0.00	1	6-795 ACSR	272,767	1,672,480	1,945,247	
17	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	K-FRAME	2.00	0.00		6-795 ACSR				
18	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	TOWER	5.98	0.00		6-795 ACSR				
19	(0988;01) BLUE LAKE	PARKERS LAKE	345.0	345.0	SINGLE POLE	0.00	2.11	1	6-795 ACSR		478,209	478,209	
20	(0988;01) BLUE LAKE	PARKERS LAKE	345.0	345.0	TOWER	0.00	12.67		6-795 ACSR				
21	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	K-FRAME	20.69	0.59	1	6-795 ACSR		3,070,872	3,070,872	
22	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	SINGLE POLE	0.00	5.91		6-795 ACSR				

23	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.00	2.28		6-795 ACSR			
24	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.15	2.34		6-954 ACSR			
25	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	K-FRAME	21.26	0.00	1	6-795 ACSR	661,692	7,250,762	7,912,454
26	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	SINGLE POLE	5.91	0.00		6-795 ACSR			
27	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	2.28	0.00		6-795 ACSR			
28	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.12	2.37		6-954 ACSR			
29	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	H-FRAME	16.26	1.12	1	6-954 ACSR	17,816	14,641,383	14,659,199
30	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	3.36	0.00		6-954 ACSR			
31	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	0.29	0.51		6-954 ACSR			
32	(0985;01) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	5.82	5.79		6-954 ACSR			
33	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	19.80	0.00	1	6-954 ACSR	506,296	7,836,081	8,342,377
34	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	14.81	0.00		6-954 ACSR			
35	(0984;03) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	8.84	0.00		6-954 ACSR			
36	(0984;01) COON CREEK	TERMINAL	345.0	345.0	SINGLE POLE	0.00	4.62	1	6-795 ACSR	160,760	3,883,156	4,043,916
37	(0984;01) COON CREEK	TERMINAL	345.0	345.0	TOWER	0.00	9.07		6-795 ACSR			
38	(0982;01) BLUE LAKE	SCOTT CO.	345.0	345.0	TOWER	8.16	0.00	1	6-795 ACSR	285,057	3,412,458	3,697,515
39	(0982;01) CRANDALL	LAKEFIELD GENERATING	345.0	345.0	K-FRAME	2.20	0.00	1	6-795 ACSR	24,675	406,619	431,294
40		WILMARTH	345.0	345.0	K-FRAME	29.15	0.00	1		587,597	10,636,835	11,224,432

	(0982;01) CRANDALL								6-795 ACSR				
41	(0982;01) CRANDALL	WILMARTH	345.0	345.0	SINGLE POLE	1.82	21.43		6-556.5 ACSR-T2				
42	(0982;01) HELENA	SCOTT CO.	345.0	345.0	3 POLE	1.42	0.00	1	6-397.5 ZTACSR		20,299,857	20,299,857	
43	(0982;01) HELENA	SCOTT CO.	345.0	345.0	H-FRAME	15.73	0.00		6-397.5 ZTACSR				
44	(0982;01) HELENA	SHEAS LAKE	345.0	345.0	K-FRAME	7.45	0.00	1	6-795 ACSR	95,480	1,602,336	1,697,816	
45	(0982;01) LAKEFIELD JCT (IPW)	LAKEFIELD GENERATING	345.0	345.0	K-FRAME	18.70	0.00	1	6-795 ACSR	214,005	7,381,501	7,595,506	
46	(0982;01) SHEAS LAKE	WILMARTH	345.0	345.0	K-FRAME	23.61	0.00	1	6-795 ACSR	271,747	4,686,721	4,958,468	
47	(0982;01) SHEAS LAKE	WILMARTH	345.0	345.0	TOWER	1.11	0.00		6-795 ACSR				
48	(0981-MN;01) ALLEN S KING	EAU CLAIRE	345.0	345.0	K-FRAME	3.69	0.00	1	6-795 ACSR	24,099	872,818	896,917	
49	(0981-MN;01) ALLEN S KING	EAU CLAIRE	345.0	345.0	TOWER	1.01	15.19		6-795 ACSR				
50	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.0	345.0	SINGLE POLE	31.48	0.56	1	6-954 ACSR	4,408,021	10,856,196	15,264,217	
51	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.0	345.0	TOWER	0.00	5.59		6-795 ACSR				
52	(0980;01) COON CREEK	KOHLMAN LAKE	345.0	345.0	SINGLE POLE	4.62	2.82	1	6-795 ACSR	1,384,573	2,657,526	4,042,099	
53	(0980;01) COON CREEK	KOHLMAN LAKE	345.0	345.0	TOWER	6.87	5.62		6-795 ACSR				
54	(0979;01) ADAMS	PLEASANT VALLEY (GRE)	345.0	345.0	K-FRAME	16.85	0.00	1	6-795 ACSR	41,979	5,206,476	5,248,455	
55	(0979;01) BYRON (SMMPA)	NORTH ROCHESTER	345.0	345.0	K-FRAME	13.54	0.00	1	6-795 ACSR	35,037	4,307,001	4,342,038	
56	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	345.0	345.0	H-FRAME	1.10	0.00	1	6-795 ACSR	43,098	5,272,671	5,315,769	
57			345.0	345.0	K-FRAME	15.19	0.00						

	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)							6-795 ACSR			
58	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	H-FRAME	1.99	0.00	1	6-795 ACSR	67,126	8,541,478	8,608,604
59	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	K-FRAME	25.23	0.00		6-795 ACSR			
60	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	TOWER	2.40	0.00		6-954 ACSR			
61	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	H-FRAME	16.90	0.00	1	6-954 ACSR	868,700	13,977,619	14,846,319
62	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	K-FRAME	3.37	0.00		6-954 ACSR			
63	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	TOWER	5.83	0.00		6-954 ACSR			
64	(0978;01) ELM CREEK	PARKERS LAKE	345.0	345.0	SINGLE POLE	0.59	0.00	1	6-954 ACSR	13,498	914,131	927,629
65	(0978;01) ELM CREEK	PARKERS LAKE	345.0	345.0	TOWER	10.46	0.00		6-954 ACSR			
66	(0977;01) ALLEN S KING	KOHLMAN LAKE	345.0	345.0	TOWER	12.71	0.00	1	6-795 ACSR	1,136,939	2,280,784	3,417,723
67	(0977;01) KOHLMAN LAKE	TERMINAL	345.0	345.0	SINGLE POLE	2.82	0.00	1	6-795 ACSR	1,136,938	2,189,075	3,326,013
68	(0977;01) KOHLMAN LAKE	TERMINAL	345.0	345.0	TOWER	7.38	0.00		6-795 ACSR			
69	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.0	345.0	SINGLE POLE	3.73	0.00	1	6-795 ACSR	104,148	593,836	697,984
70	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.0	345.0	TOWER	1.81	0.00		6-795 ACSR			
71	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	2 POLE	0.66	0.00	1	6-954 ACSR	873,092	4,579,023	5,452,115
72	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	K-FRAME	9.08	0.00		6-954 ACSR			
73	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	SINGLE POLE	0.83	0.00		6-795 ACSR			

74	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	SINGLE POLE	0.37	0.00		6-954 ACSR			
75	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	TOWER	17.12	0.00		6-795 ACSR			
76	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	TOWER	5.77	0.00		6-954 ACSR			
77	(0976;01) EDEN PRAIRIE	PARKERS LAKE	345.0	345.0	TOWER	9.47	0.00	1	6-795 ACSR	45,639	521,262	566,901
78	(0976;01) HAMPTON	PRAIRIE ISLAND	345.0	345.0	K-FRAME	16.00	0.00	1	6-795 ACSR	1,296,677	6,949,323	8,246,000
79	(0976;01) HAMPTON	PRAIRIE ISLAND	345.0	345.0	TOWER	3.55	0.00		6-795 ACSR			
80	(0975;01) ALLEN S KING	RED ROCK	345.0	345.0	K-FRAME	3.54	0.00	1	6-795 ACSR	401,128	2,690,176	3,091,304
81	(0975;01) ALLEN S KING	RED ROCK	345.0	345.0	TOWER	21.83	0.00		6-795 ACSR			
82	(0974;01) MANKATO ENERGY CENTER	WILMARTH	345.0	345.0	SINGLE POLE	0.22	0.00	1	6-795 ACSR		888,655	888,655
83	(0973;01) MONTICELLO SUB	QUARRY	345.0	345.0	SINGLE POLE	30.04	0.00	1	6-954 ACSS/TW	5,368,656	10,969,295	16,337,951
84	(0972-MN;01) BROOKINGS CO.	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	8.86	0.00	1	6-954 ACSS/TW	4,413,692	57,301,946	61,715,638
85	(0972-SD;01) BROOKINGS CO.	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	10.19	0.00	1	6-954 ACSS/TW	509,810	20,993,906	21,503,716
86	(0972;01) HAWKS NEST LAKE	LYON CO.	345.0	345.0	SINGLE POLE	30.55	0.00	1	6-954 ACSS/TW		135,628	135,628
87	(0972;01) HAWKS NEST LAKE	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	9.96	0.00	1	6-954 ACSS/TW		530,922	530,922
88	(0971;01) BROOKINGS CO.	WHITE (WAPA)	345.0	345.0	SINGLE POLE	0.42	0.00	1	6-795 ACSS	13,748	933,240	946,988
89	(0970;02) BROOKINGS CO.	WHITE (WAPA)	345.0	345.0	SINGLE POLE	0.38	0.00	1	6-795 ACSS		1,215,849	1,215,849

90	(0969;02) BLAZING STAR 1	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	0.08	0.00	1	6-954		7,782	7,782
91	(0968;01) BLAZING STAR 1	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	0.08	0.00	1	6-954 Unknown			
92	(0967;01) HUNTLEY (ITC)	WILMARTH	345.0	345.0	SINGLE POLE	52.03	0.00	1	6-556.5 ACSR-T2	2,692,737	48,698,762	51,391,499
93	(0966;01) BROOKINGS CO.	BIG STONE SOUTH	345.0	345.0	SINGLE POLE	71.98	0.00	1	6-556.5 ACSR/T2	3,526,999	57,810,786	61,337,785
94	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.0	345.0	2 POLE	3.12	0.00	1	6-954 ACSS/TW	5,358,507	59,722,203	65,080,710
95	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.0	345.0	SINGLE POLE	40.07	0.00		6-954 ACSS/TW			
96	(0964;01) HAMPTON	NORTH ROCHESTER	345.0	345.0	SINGLE POLE	37.85	0.00	1	6-397.5 TACSR/VR2	9,430,408	54,553,588	63,983,996
97	(0962;01) HAZEL CREEK	LYON CO.	345.0	345.0	SINGLE POLE	24.54	0.00	1	6-954 ACSS/TW	2,289,672	26,971,692	29,261,364
98	(0961;01) CHUB LAKE (GRE)	HAMPTON	345.0	345.0	SINGLE POLE	18.10	0.00	1	6-954 ACSS/TW	7,244,068	37,681,201	44,925,269
99	(0960;01) CHUB LAKE (GRE)	HELENA	345.0	345.0	SINGLE POLE	20.87	0.00	1	6-954 ACSS/TW	9,545,985	36,282,633	45,828,618
100	(0959;02) CEDAR MTN. (GRE)	HELENA	345.0	345.0	SINGLE POLE	0.00	73.06	1	6-954 ACSS/TW			
101	(0958;01) CEDAR MTN. (GRE)	HELENA	345.0	345.0	SINGLE POLE	73.10	0.00	1	6-954 ACSS/TW	15,584,347	112,135,762	127,720,109
102	(0957;02) CEDAR MTN. (GRE)	LYON CO.	345.0	345.0	SINGLE POLE	0.00	49.49	1	6-954 ACSS/TW			
103	(0956;01) CEDAR MTN. (GRE)	LYON CO.	345.0	345.0	SINGLE POLE	49.49	0.00	1	6-954 ACSS/TW	5,315,434	65,839,990	71,155,424
104	(0955-MN;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	2 POLE	2.06	0.00	1	6-954 ACSS/TW	6,637,015	84,241,012	90,878,027

105	(0955-MN;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	SINGLE POLE	102.33	0.00		6-954 ACSS/TW			
106	(0955-ND;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	SINGLE POLE	34.38	0.00	1	6-954 ACSS/TW	1,513,232	22,705,097	24,218,329
107	(0954;01) ALEXANDRIA SW. ST.	RIVERVIEW (GRE)	345.0	345.0	SINGLE POLE	45.16	0.00	1	6-954 ACSS/TW	2,327,849	37,137,830	39,465,679
108	(0954;01) QUARRY	RIVERVIEW (GRE)	345.0	345.0	SINGLE POLE	36.09	0.00	1	6-954 ACSS/TW	1,860,437	29,680,864	31,541,301
109	(0953;01) LAKEFIELD JCT (IPW)	NOBLES CO.	345.0	345.0	SINGLE POLE	22.67	0.00	1	6-397.5 ACSR/T2	3,515,668	54,827,644	58,343,312
110	(0953;01) LAKEFIELD JCT (IPW)	NOBLES CO.	345.0	345.0	SINGLE POLE	13.27	0.00		6-954 ACSS/TW			
111	(0953-MN;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	10.69	0.00	1	6-397.5 ZTACSR	3,623,388	65,272,679	68,896,067
112	(0953-MN;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	32.04	0.00		6-954 ACSS/TW			
113	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	4.43	0.00	1	6-954 ACSR	554,100	4,451,932	5,006,032
114	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	5.07	0.00		6-954 ACSS/TW			
115	(0963;01) HAZEL CREEK	MINNESOTA VALLEY	230.0	345.0	SINGLE POLE	4.97	0.00	1	6-954 ACSS/TW	655,395	9,176,023	9,831,418
116	(0929;01) BORDER WIND FARM (RES)	PEACE GARDEN	230.0	230.0	2 POLE	0.04	0.00	1	6-		98,889	98,889
117	(0928;01) CROWNED RIDGE 1	CROWNED RIDGE 2	230.0	230.0	SINGLE POLE	4.76	0.00	1	3- ACSR		3,179,541	3,179,541
118	(0927;01) FOXTAIL	FOXTAIL	230.0	230.0	SINGLE POLE	0.12	0.00	1	3-795 ACSR		144,808	144,808
119	(0924;01) MCHENRY (GRE)	MAGIC CITY	230.0	230.0	SINGLE POLE	20.57	0.00	1	6-477 ACSR/VR2	844,717	26,291,811	27,136,528
120	(0923;01) CASS LAKE (OTP)	WILTON (MPC)	230.0	230.0	SINGLE POLE	19.32	0.00	1	3-795 ACSS	884,508	9,194,724	10,079,232

121	(0922;01) BOSWELL (MINNESOTA POWER)	CASS LAKE (OTP)	230.0	230.0	SINGLE POLE	51.46	0.00	1	3-795 ACSS	1,023,124	23,387,110	24,410,234
122	(0920;01) GLENBORO (MHEB)	PEACE GARDEN	230.0	230.0	H-FRAME	1.99	0.00	1	3-954 ACSR	1,288,507	12,521,625	13,810,132
123	(0920;01) PEACE GARDEN	RUGBY (OTP)	230.0	230.0	H-FRAME	54.67	0.00	1	3-954 ACSR			
124	(0919;01) PAYNESVILLE TRANS. S	WILLMAR (GRE)	230.0	230.0	H-FRAME	2.49	0.00	1	3-795 ACSR	302,577	7,615,686	7,918,263
125	(0919;01) PAYNESVILLE TRANS. S	WILLMAR (GRE)	230.0	230.0	SINGLE POLE	27.24	0.00		3-795 ACSR			
126	(0918;01) SIOUX FALLS (WAPA)	SPLIT ROCK	230.0	230.0	SINGLE POLE	0.95	0.00	1	3-795 ACSS	531,676	605,867	1,137,543
127	(0916;01) GRAND FORKS (WAPA)	PRAIRIE	230.0	230.0	H-FRAME	6.35	0.00	1	3-954 ACSR	24,662	1,531,625	1,556,287
128	(0916;01) GRAND FORKS (WAPA)	PRAIRIE	230.0	230.0	SINGLE POLE	0.48	0.00		3-954 ACSR			
129	(0915;01) FARGO (WAPA)	SHEYENNE	230.0	230.0	H-FRAME	4.04	0.21	1	3-795 ACSR	21,223	806,965	828,188
130	(0912;01) DRAYTON (MINNKOTA)	LETELLIER (MANITOBA HYDRO)	230.0	230.0	3 POLE	0.07	0.00	1	3-954 ACSR	57,281	3,010,357	3,067,638
131	(0912;01) DRAYTON (MINNKOTA)	LETELLIER (MANITOBA HYDRO)	230.0	230.0	H-FRAME	28.66	0.00		3-954 ACSR			
132	(0911;01) AUDUBON (OTP)	SHEYENNE	230.0	230.0	H-FRAME	1.41	0.00	1	3-795 ACSR	10,733	237,425	248,158
133	(0911;01) MAPLE RIVER	SHEYENNE	230.0	230.0	H-FRAME	2.80	0.00	1	3-795 ACSR	21,002	597,200	618,202
134	(0911;01) MAPLE RIVER	SHEYENNE	230.0	230.0	TOWER	0.05	3.72		3-795 ACSR			
135			230.0	230.0	TOWER	3.59	0.00	1		55,625	283,964	339,589

	(0910;01) MAPLE RIVER	WHPETON (MINNKOTA)								3-795 ACSR			
136	(0909;01) AUDUBON (OTP)	HUBBARD (GRE)	230.0	230.0	H-FRAME	38.56	0.00	1	3-795 ACSR	57,863	7,828,503	7,886,366	
137	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	SINGLE POLE	10.89	0.09	1	3-1272 ACSR	407,857	8,813,393	9,221,250	
138	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	SINGLE POLE	53.91	0.00		3-795 ACSR				
139	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	TOWER	2.78	0.00		3-1272 ACSR				
140	(0902;01) BEAR CREEK (GRE)	ROCK CREEK	230.0	230.0	SINGLE POLE	12.55	0.00	1	3-795 ACSR	29,881	1,250,116	1,279,997	
141	(0900;01) BLUE LAKE	MCLEOD (MUNI)	230.0	230.0	H-FRAME	1.35	0.00	1	3-795 ACSR	371,590	5,207,737	5,579,327	
142	(0900;01) BLUE LAKE	MCLEOD (MUNI)	230.0	230.0	SINGLE POLE	0.73	0.00		3-795 ACSR				
143	(0900;01) BLUE LAKE	MCLEOD (MUNI)	230.0	230.0	TOWER	44.38	0.00		3-795 ACSR				
144	(0900;02) GRANITE FALLS (WAPA)	PANTHER (GRE)	230.0	230.0	TOWER	32.84	0.00	1	3-795 ACSR	5,902	1,585,657	1,591,559	
145	(0900;01) MCLEOD (MUNI)	PANTHER (GRE)	230.0	230.0	TOWER	28.45	0.00	1	3-795 ACSR	59,673	1,569,115	1,628,788	
146	(5313;01) FREEBORN	GLENWORTH (ITC)	161.0	161.0	SINGLE POLE	7.12	0.00	1	3-1272 ACSR		6,203,947	6,203,947	
147	(5312;01) ADAMS	MOWER CO. WIND FARM	161.0	161.0	2 POLE	0.20	0.00	1	3-477 ACSR		1,024,202	1,024,202	
148	(5312;01) ADAMS	MOWER CO. WIND FARM	161.0	161.0	SINGLE POLE	7.73	0.00		3-477 ACSR				
149	(5311;01) PLEASANT VALLEY (GRE)	PLEASANT VALLEY WIND FARM	161.0	161.0	SINGLE POLE	4.98	0.00	1	3-954 ACSR		2,268,717	2,268,717	
150	(5310;01) NORTHERN HILLS	NORTH ROCHESTER	161.0	161.0	SINGLE POLE	15.51	0.00	1	3-795 ACSS	1,314,415	9,559,156	10,873,571	
151	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.0	161.0	SINGLE POLE	11.41	0.00	1	6-397.5 TACSR/TW	567,003	12,379,705	12,946,708	

152	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.0	161.0	SINGLE POLE	(ab)1.15	(ab)15.11		6-954 ACSS/TW			
153	(5308;01) GRAND MEADOW	PLEASANT VALLEY (GRE)	161.0	161.0	SINGLE POLE	5.70	0.00	1	6-795 ACSS		1,399,017	1,399,017
154	(5306;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	161.0	161.0	SINGLE POLE	16.60	0.00	1	3-795 ACSS	477,246	6,134,098	6,611,344
155	(5305-MN;01) LAWRENCE CREEK	ST CROIX FALLS	161.0	161.0	SINGLE POLE	1.57	0.00	1	3-795 ACSS	52,746	10,276,772	10,329,518
156	(5305-MN;01) LAWRENCE CREEK	ST CROIX FALLS	161.0	161.0	UNDERGROUND	0.58	0.00		3-3000 CU			
157	(5301;01) ELK (ALLIANT)	ROCK CO.	161.0	161.0	H-FRAME	5.26	0.14	1	3-477 ACSR	16,110	545,815	561,925
158	(5301-MN;01) ROCK CO.	SPLIT ROCK	161.0	161.0	H-FRAME	3.45	0.00	1	3-477 ACSR	17,390	603,450	620,840
159	(5301-MN;01) ROCK CO.	SPLIT ROCK	161.0	161.0	SINGLE POLE	0.08	0.00		3-477 ACSR			
160	(5301-SD;01) ROCK CO.	SPLIT ROCK	161.0	161.0	H-FRAME	10.27	0.00	1	3-477 ACSR	25,772	1,548,304	1,574,076
161	(5301-SD;01) ROCK CO.	SPLIT ROCK	161.0	161.0	SINGLE POLE	0.87	0.00		3-2312 ACSR			
162	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.0	161.0	H-FRAME	29.95	0.20	1	3-477 ACSR	143,079	1,941,549	2,084,628
163	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.0	161.0	SINGLE POLE	0.00	1.36		3-565.3 ACSS/TW			
164	SUMMARY OF 115 KV SYSTEM		115.0	115.0	Overhead	1,479.40	152.85			23,714,014	727,950,044	751,664,058
165	SUMMARY OF 115 KV SYSTEM		115.0	115.0	Underground	13.22	0.00					
166	SUMMARY OF 69 KV SYSTEM		69.0	69.0	Overhead	1,489.02	98.29			6,269,578	311,492,443	317,762,021
167	SUMMARY OF 69 KV SYSTEM		69.0	69.0	Underground	1.53	0.00					

168	SUMMARY OF 34.5 KV SYSTEM		34.5	34.5	Overhead	60.05	32.40			436,068	27,979,942	28,416,010	
169	SUMMARY OF 34.5 KV SYSTEM		34.5	34.5	Underground	0.59	0.00						
170	Expenses, except depreciation and taxes												7
36	TOTAL					5,225	631	102		150,645,474	2,414,949,680	2,565,595,154	7

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

<p>(a) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(b) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(c) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(d) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(e) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(f) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(g) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(h) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(i) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(j) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(k) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(l) Concept: LengthForStandAloneTransmissionLines</p>
<p>NSM ((0961;01) CHUB LAKE (GRE)-HAMPTON) : Xcel Energy owns 67.8%(12.27 miles) of 18.1 miles of this circuit: remaining 32.2%(5.83 miles) is owned by other members of a joint venture partnership</p>
<p>(m) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(n) Concept: LengthForStandAloneTransmissionLines</p>
<p>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>
<p>(o) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>
<p>(p) Concept: LengthForStandAloneTransmissionLines</p>
<p>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</p>

(q) 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
(r) 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
(s) 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
(t) 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
(u) 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
(v) 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
(w) 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
(x) 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
(y) 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
(z) 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
(aa) 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
(ab) 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
(ac) 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
(ad) 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
(ae) 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
(af) 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
(ag) 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
(ah) 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
(ai) 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

(aj) 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
(ak) 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
(al) 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
(am) 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
(an) 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
(ao) 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
(ap) 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
(aq) 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
(ar) 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
(as) 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
(at) 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
(au) 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
(av) 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
(aw) 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
(ax) 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
(ay) 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
(az) 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
(ba) 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
(bb) 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

(bc) 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

(bd) 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

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

Page 422-423

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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 completed construction are not readily available for reporting (c) 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
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		
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Cost
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	(5702;01) FORBES	RIE	2.86	TOWER	4	1	1	9-1192.5	ACSR	45/7	500.0	1,723,645	59,235,464	25
2	(0968;01) BLAZING STAR 1	STEEP BANK LAKE	0.08	SINGLE POLE	13	1	1	6-954	TSG	TSG	345.0			
3	(0969;02) BLAZING STAR 1	STEEP BANK LAKE	0.08	SINGLE POLE	13	1	1	6-954	TSG	TSG	345.0			
4	(0967;01) HUNTLEY (ITC)	WILMARTH	52.03	SINGLE POLE	5	2	2	6-556.5	ACSR-T2	26/7	345.0	2,692,737	35,063,109	13
5	(5312;01) ADAMS	MOWER CO. WIND FARM	0.20	2 POLE	17	1	1	3-477	ACSR	26/7	161.0		850,094	
6	(5312;01) ADAMS	MOWER CO. WIND FARM	7.73	SINGLE POLE	17	1	1	3-477	ACSR	26/7	161.0			
7	(5313;01) FREEBORN	GLENWORTH (ITC)	7.12	SINGLE POLE	11	1	1	3-1272	ACSR	45/7	161.0		5,054,765	1
8	(5576;01) BLAZING STAR 1	BLAZING STAR 2	7.75	SINGLE POLE	12	1	1	3-1590	ACSR	54/19	115.0		1,034,616	7
9	(0879,0880;01) CHERRY CREEK	MITCHELL (NWPS)	1.99	SINGLE POLE	7	1	1	3-477	ACSR	26/7	115.0	299,639	2,866,772	
10	(0817-MN;01) CRYSTAL CAVE	RAPTOR	0.03	H-FRAME	8	1	1	3-795	ACSR	26/7	115.0		343,533	
11	(0817;01) RAPTOR	RED ROCK	0.03	H-FRAME	8	1	1	3-795	ACSR	26/7	115.0		155,508	
12		WINTHROP	4.27		32	1	1	3-477	ACSR	26/7	69.0	192,840	3,973,174	1

	(0721;01) FRANKLIN			SINGLE POLE											
13	(0703,0742,0780;01) FARMINGTON	PINE BEND	0.02	SINGLE POLE	34	1	1	3- 336.4	ACSR	18/1	69.0				
14	(0752;01) GROVE LAKE SW. ST.	PAYNESVILLE TRANS. S	0.05	TRIANGULAR	34	1	1	3-2/0	ACSR	6/1	69.0	8,248	8,267,264	3	
15	(5409;01) HOLLYDALE	MEDINA (GRE)	0.03	SINGLE POLE	34	1	1	3- 397.5	ACSR	26/7	69.0	116,504	382,826		
44	TOTAL		84		249	16	16					5,033,613	117,227,125	53	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: NumberOfTransmissionCircuitsPerStructurePresent
(0967;01) HUNTLEY (ITC) to WILMARTH: 21.22 miles=Double Circuit, 30.81 miles= Single Circuit
(b) Concept: NumberOfTransmissionCircuitsPerStructureUltimate
(0967;01) HUNTLEY (ITC) to WILMARTH: 21.22 miles=Double Circuit, 30.81 miles= Single Circuit

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

SUBSTATIONS

- Report below the information called for concerning substations of the respondent as of the end of the year.
- Substations which serve only one industrial or street railway customer should not be listed below.
- 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.
- 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).
- Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
- Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1	ADAMS-TR09	Transmission	Unattended	345.00	161.00	13.80	300.00	1				
2	ADA-TR01	Distribution	Unattended	69.00	23.00	4.16	14.00	1				
3	AFTON-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
4	AFTON-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
5	AIR LAKE-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
6	AIR LAKE-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
7	AIRPORT-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
8	AIRPORT-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
9	ALBANY-TR02	Distribution	Unattended	69.00	12.50		10.50	1				
10	ALDRICH-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
11	ALDRICH-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
12	ALDRICH-TR04	Distribution	Unattended	115.00	13.80		70.00	1				
13		Distribution	Unattended	34.50	4.16		2.00	3				

	ALEXANDRIA-TR01ABC											
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	13.80	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	13.80	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	4.16	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	13.80	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	13.80	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	BROOK-TR01ABC	Distribution	Unattended	34.50	4.16		2.50	3				
49	BROOTEN-TR01	Distribution	Unattended	69.00	12.50		6.00	1				
50	BROWNTON-TR01	Distribution	Unattended	69.00	2.40		1.40	1				
51	BUFFALO LAKE-TR01	Distribution	Unattended	69.00	12.50		5.60	1				
52	BUFFALO RIDGE-TR01	Distribution	Unattended	115.00	34.50	13.80	120.00	1				
53	BUFFALO RIDGE-TR02	Distribution	Unattended	115.00	34.50	13.80	120.00	1				
54	BURNSIDE-TR01	Distribution	Unattended	69.00	12.50		28.00	1				
55	BURNSIDE-TR02	Distribution	Unattended	69.00	12.50		10.50	1				
56	BUTTERFIELD-TR01	Distribution	Unattended	69.00	4.16		1.50	1				
57	CANISTOTA JCT-TR01	Distribution	Unattended	69.00	13.80		8.00	1				
58	CANISTOTA-TR01ABC	Distribution	Unattended	69.00	4.16		3.00	3				
59	CANNON FALLS XMSN-TR06	Transmission	Unattended	115.00	69.00	13.80	112.00	1				
60	CANNON FALLS XMSN-TR07	Transmission	Unattended	115.00	69.00	13.80	112.00	1				
61	CANNON FALLS-TR01	Distribution	Unattended	69.00	12.50		10.50	1				

62	CANTON-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
63	CANTON-TR02	Distribution	Unattended	69.00	13.80		14.00	1				
64	CARVER COUNTY-TR01	Transmission	Unattended	115.00	69.00	34.50	70.00	1				
65	CARVER COUNTY-TR02	Transmission	Unattended	115.00	69.00	34.50	70.00	1				
66	CASS COUNTY-TR01XY	Distribution	Unattended	115.00	23.00	2.50	50.00	2				
67	CASS COUNTY-TR02	Distribution	Unattended	115.00	23.00		47.00	1				
68	CASS COUNTY-TR03	Distribution	Unattended	115.00	23.00	13.80	46.70	1				
69	CASTLE ROCK-TR01	Distribution	Unattended	69.00	4.00		1.00	1				
70	CEDAR LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
71	CEDAR LAKE-TR02	Distribution	Unattended	115.00	13.80		50.00	1				
72	CEDARVALE-TR01	Distribution	Unattended	115.00	13.80		20.00	1				
73	CEDARVALE-TR02	Distribution	Unattended	115.00	13.80		23.00	1				
74	CENTERVILLE-TR01	Distribution	Unattended	69.00	13.80		7.00	1				
75	CHANARAMBIE-TR01	Distribution	Unattended	115.00	34.50	13.80	120.00	1				
76	CHANARAMBIE-TR02	Distribution	Unattended	115.00	34.50	13.80	120.00	1				
77	CHANARAMBIE-TR04	Distribution	Unattended	115.00	34.50	13.80	120.00	1				
78	CHEMOLITE-TR01	Distribution	Unattended	115.00	13.80		50.00	1				
79	CHEMOLITE-TR02	Distribution	Unattended	115.00	13.80		50.00	1				
80	CHERRY CREEK-TR01	Distribution	Unattended	115.00	13.80		37.00	1				
81	CHERRY CREEK-TR03	Distribution	Unattended	115.00	34.50		70.00	1				
82	CHISAGO COUNTY-TR02	Distribution	Unattended	115.00	34.50		47.00	1				
83	CHISAGO COUNTY-TR05	Transmission	Unattended	345.00	115.00	34.50	448.00	1				
84	CHISAGO COUNTY-TR06	Transmission	Unattended	345.00	115.00	34.50	448.00	1				
85	CHISAGO COUNTY-TR09ABC	Transmission	Unattended	500.00	345.00	34.50	1203.00	3				

86	CHISAGO COUNTY-TR10ABC	Transmission	Unattended	500.00	345.00	34.50	1203.00	3				
87	CLARA CITY-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
88	CLARA CITY-TR02	Distribution	Unattended	69.00	23.00		14.00	1				
89	CLARKS GROVE-TR01	Distribution	Unattended	69.00	7.20		2.00	1				
90	CLIFF AVENUE-TR01	Distribution	Unattended	69.00	4.16		7.00	1				
91	CLIFF AVENUE-TR02	Distribution	Unattended	69.00	13.80		10.50	1				
92	COKATO-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
93	COLVILL-TR04	Transmission	Unattended	115.00	69.00	13.80	112.00	1				
94	COLVILL-TR05	Transmission	Unattended	161.00	115.00	13.80	187.00	1				
95	COON CREEK-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
96	COON CREEK-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
97	COON CREEK-TR09	Transmission	Unattended	345.00	115.00	34.50	672.00	1				
98	COON CREEK-TR10	Transmission	Unattended	345.00	115.00	34.50	672.00	1				
99	COTTAGE GROVE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
100	COTTAGE GROVE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
101	CREDIT RIVER-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
102	CREDIT RIVER-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
103	CROOKED LAKE-TR01	Distribution	Unattended	119.00	13.80		46.70	1				
104	CROOKED LAKE-TR02	Distribution	Unattended	119.00	13.80		46.70	1				
105	CROOKED LAKE-TR03	Distribution	Unattended	115.00	12.50		28.00	1				
106	CROOKED LAKE-TR65ABC	Distribution	Unattended	13.80	12.50		10.00	3				
107	CROSSROADS-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
108	CROSSROADS-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
109	CROSSROADS-TR03	Distribution	Unattended	115.00	13.80		22.00	1				
110		Distribution	Unattended	69.00	13.80		14.00	1				

	CRYSTAL FOODS-TR01											
111	DAHLGREN-TR01	Distribution	Unattended	115.00	13.80		14.00	1				
112	DANUBE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
113	DASSEL-TR01	Distribution	Unattended	69.00	13.80		6.00	1				
114	DAYTONS BLUFF-TR01	Distribution	Unattended	115.00	13.80		63.00	1				
115	DAYTONS BLUFF-TR02	Distribution	Unattended	115.00	13.80		63.00	1				
116	DAYTONS BLUFF-TR03	Distribution	Unattended	115.00	13.80		63.00	1				
117	DEEPHAVEN-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
118	DEEPHAVEN-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
119	DELANO-TR01XY	Distribution	Unattended	69.00	7.20		0.40	2				
120	DELL RAPIDS-TR02	Distribution	Unattended	34.50	12.50		10.50	1				
121	DODGE CENTER-TR01	Distribution	Unattended	69.00	23.00		5.00	1				
122	DODGE CENTER-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
123	DODGE CENTER-TR03	Distribution	Unattended	69.00	12.50		10.50	1				
124	DOME PIPELINE-TR01	Distribution	Unattended	115.00	4.16		8.00	1				
125	DOUGLAS COUNTY-TR01	Transmission	Unattended	115.00	69.00	34.50	46.70	1				
126	DOUGLAS COUNTY-TR02	Transmission	Unattended	115.00	69.00	13.80	70.00	1				
127	DOUGLAS COUNTY-TR03	Distribution	Unattended	69.00	13.80		7.20	1				
128	DUNDAS-TR01	Distribution	Unattended	69.00	13.80		20.00	1				
129	DUNDAS-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
130	EAGLE LAKE-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
131	EAST BLOOMINGTON-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
132		Distribution	Unattended	115.00	13.80		46.70	1				

	EAST BLOOMINGTON-TR02											
133	EAST BLOOMINGTON-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
134	EAST WINONA-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
135	EASTWOOD-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
136	EASTWOOD-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
137	EASTWOOD-TR03	Distribution	Unattended	115.00	13.80		52.50	1				
138	EDEN PRAIRIE-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
139	EDEN PRAIRIE-TR03	Distribution	Unattended	115.00	13.80		47.00	1				
140	EDEN PRAIRIE-TR04	Distribution	Unattended	115.00	13.80		51.00	1				
141	EDEN PRAIRIE-TR09	Transmission	Unattended	345.00	115.00	13.80	448.00	1				
142	EDEN PRAIRIE-TR10	Transmission	Unattended	345.00	115.00	13.80	448.00	1				
143	EDGERTON-TR01	Distribution	Unattended	23.00	4.16		2.00	1				
144	EDINA-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
145	EDINA-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
146	EDINA-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
147	ELLIOT PARK-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
148	ELLIOT PARK-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
149	ELLIOT PARK-TR03	Distribution	Unattended	115.00	13.80		72.50	1				
150	ELM CREEK-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
151	ELM CREEK-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
152	ELM CREEK-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
153	ELM CREEK-TR09	Transmission	Unattended	345.00	115.00	13.80	448.00	1				
154	EMERY-TR01ABC	Distribution	Unattended	34.50	4.16		1.50	3				
155	ESSIG-TR01ABC	Distribution	Unattended	69.00	2.40		0.45	3				
156	EXCELSIOR-TR01	Distribution	Unattended	69.00	13.80		19.00	1				
157	FAIR PARK-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
158	FAIR PARK-TR02	Distribution	Unattended	69.00	13.80		14.00	1				

159	FALLS-TR01	Distribution	Unattended	115.00	13.80		62.60	1				
160	FALLS-TR02	Distribution	Unattended	115.00	13.80		62.60	1				
161	FARIBAULT-TR01	Distribution	Unattended	69.00	13.80		22.40	1				
162	FARIBAULT-TR02	Distribution	Unattended	69.00	13.80		14.00	1				
163	FARMINGTON-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
164	FARMINGTON-TR02	Distribution	Unattended	69.00	13.80		10.50	1				
165	FENTON-TR01	Distribution	Unattended	115.00	34.50	13.80	120.00	1				
166	FENTON-TR02	Distribution	Unattended	115.00	34.50	13.80	120.00	1				
167	FENTON-TR05	Transmission	Unattended	115.00	69.00	13.80	46.70	1				
168	FIESTA CITY-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
169	FIESTA CITY-TR02	Distribution	Unattended	69.00	12.50		28.00	1				
170	FIFTH STREET-TR01	Distribution	Unattended	115.00	13.80		84.00	1				
171	FIFTH STREET-TR02	Distribution	Unattended	115.00	13.80		84.00	1				
172	FIFTH STREET-TR03	Distribution	Unattended	115.00	13.80		84.00	1				
173	FIFTH STREET-TR04	Distribution	Unattended	115.00	13.80		84.00	1				
174	FIRST LAKE-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
175	FOLEY-TR01	Distribution	Unattended	34.50	4.16		3.00	1				
176	FORBES-TR09	Distribution	Unattended	500.00	20.00		168.00	1				
177	FORT RIDGELY-TR05	Transmission	Unattended	115.00	69.00	13.80	70.00	1				
178	FRANKLIN-TR04	Distribution	Unattended	69.00	23.00		7.00	1				
179	FRANKLIN-TR05	Transmission	Unattended	115.00	69.00	13.80	70.00	1				
180	FRANKLIN-TR06	Transmission	Unattended	115.00	69.00	13.80	70.00	1				
181	FRANKLIN-TR07	Distribution	Unattended	69.00	4.16		2.00	1				
182	FRONTENAC-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
183	GATEWAY-TR01	Distribution	Unattended	69.00	12.50		28.00	1				
184	GATEWAY-TR02	Distribution	Unattended	69.00	12.50		28.00	1				
185	GAYLORD-TR01	Distribution	Unattended	69.00	4.00		5.00	1				
186	GIBBON-TR01	Distribution	Unattended	69.00	12.50		3.00	1				

187	GLEASON LAKE-TR01	Transmission	Unattended	115.00	69.00	13.80	112.00	1				
188	GLEASON LAKE-TR03	Distribution	Unattended	34.50	13.80		28.00	1				
189	GLEASON LAKE-TR04	Distribution	Unattended	115.00	34.50		70.00	1				
190	GLEASON LAKE-TR07	Distribution	Unattended	115.00	13.80		47.00	1				
191	GLEASON LAKE-TR08	Distribution	Unattended	115.00	13.80		70.00	1				
192	GLEN LAKE-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
193	GLEN LAKE-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
194	GLENWOOD-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
195	GLENWOOD-TR02	Distribution	Unattended	69.00	12.50		5.00	1				
196	GOODVIEW-TR01	Distribution	Unattended	69.00	12.50		28.00	1				
197	GOODVIEW-TR02	Distribution	Unattended	69.00	12.50		28.00	1				
198	GOOSE LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
199	GOOSE LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
200	GOPHER-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
201	GOPHER-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
202	GRANITE CITY-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
203	GRANITE CITY-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
204	GRANITE CITY-TR03	Distribution	Unattended	115.00	34.50		70.00	1				
205	GRANT-TR01	Transmission	Unattended	115.00	69.00	13.80	25.00	1				
206	GRANT-TR03	Distribution	Unattended	115.00	34.50		46.70	1				
207	GREEN ISLE-TR01	Distribution	Unattended	69.00	4.16		2.00	1				
208	GREENFIELD-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
209	HADLEY-TR01	Distribution	Unattended	69.00	13.80		2.80	1				
210	HASSAN-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
211	HASSAN-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
212	HASTINGS-TR01	Distribution	Unattended	69.00	12.50		28.00	1				

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

240	KIMBALL-TR01	Distribution	Unattended	69.00	12.50		7.00	1			
241	KOCH REFINERY-TR11	Distribution	Unattended	115.00	13.80		46.70	1			
242	KOCH REFINERY-TR12	Distribution	Unattended	115.00	13.80		46.70	1			
243	KOCH REFINERY-TR13	Distribution	Unattended	115.00	13.80		46.70	1			
244	KOCH REFINERY-TR14	Distribution	Unattended	115.00	13.80		46.70	1			
245	KOCH REFINERY-TR15	Distribution	Unattended	115.00	13.80		46.70	1			
246	KOCH REFINERY-TR16	Distribution	Unattended	115.00	13.80		46.70	1			
247	KOHLMAN LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1			
248	KOHLMAN LAKE-TR02	Distribution	Unattended	115.00	13.80		50.00	1			
249	KOHLMAN LAKE-TR09	Transmission	Unattended	345.00	115.00	13.80	448.00	1			
250	KOHLMAN LAKE-TR10	Transmission	Unattended	345.00	115.00	13.80	450.00	1			
251	LA CRESCENT-TR01	Distribution	Unattended	69.00	13.80		16.00	1			
252	LAFAYETTE-TR01	Distribution	Unattended	69.00	4.16		1.00	1			
253	LAKE BAVARIA-TR01	Distribution	Unattended	115.00	34.50		73.50	1			
254	LAKE EMILY-TR01	Distribution	Unattended	69.00	13.80		14.00	1			
255	LAKE LILLIAN-TR01	Distribution	Unattended	69.00	12.50		4.00	1			
256	LAKE PULASKI-TR03	Distribution	Unattended	115.00	34.50		28.00	1			
257	LAKE PULASKI-TR05	Transmission	Unattended	115.00	69.00	34.50	46.70	1			
258	LAKE PULASKI-TR06	Transmission	Unattended	115.00	69.00	13.80	46.70	1			
259	LAKE YANKTON-TR01	Distribution	Unattended	115.00	34.50	13.80	120.00	1			
260	LAKE YANKTON-TR02	Transmission	Unattended	115.00	69.00	13.80	15.00	1			
261	LAKE YANKTON-TR03	Distribution	Unattended	69.00	13.80		10.50	1			
262	LARIMORE-TR01	Distribution	Unattended	69.00	4.16		4.00	1			

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

288	LOWRY-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
289	LYON COUNTY-TR01	Transmission	Unattended	115.00	69.00	13.80	70.00	1				
290	LYON COUNTY-TR09	Transmission	Unattended	345.00	115.00	34.50	270.00	1				
291	M E INTERNATIONAL- TR01	Distribution	Unattended	115.00	13.80		46.70	1				
292	M E INTERNATIONAL- TR02	Distribution	Unattended	115.00	13.80		46.70	1				
293	MAIN STREET-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
294	MAIN STREET-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
295	MAPLE LAKE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
296	MAPLE RIVER-TR05	Transmission	Unattended	230.00	115.00	13.80	187.00	1				
297	MAPLE RIVER-TR06	Transmission	Unattended	230.00	115.00	13.80	187.00	1				
298	MAPLETON-TR01	Distribution	Unattended	69.00	13.80		6.00	1				
299	MARION-TR01	Distribution	Unattended	23.00	4.16		4.00	1				
300	MAXWELL-TR01	Distribution	Unattended	115.00	4.16		25.00	1				
301	MAYHEW LAKE-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
302	MAYNARD TRANSMISSION- TR01	Transmission	Unattended	115.00	69.00		46.70	1				
303	MAYNARD-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
304	MAYVILLE-TR01	Distribution	Unattended	69.00	4.16		6.00	1				
305	MAYVILLE-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
306	MAZEPPA-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
307	MEDFORD JUNCTION-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
308	MEDICINE LAKE- TR01	Distribution	Unattended	115.00	13.80		70.00	1				
309	MEDICINE LAKE- TR02	Distribution	Unattended	115.00	13.80		70.00	1				
310	MEDICINE LAKE- TR03	Distribution	Unattended	115.00	13.80		70.00	1				
311	MEIRE GROVE-TR01	Distribution	Unattended	69.00	12.50		2.00	1				

312	MERIDEN-TR01	Distribution	Unattended	69.00	12.50		3.00	1			
313	MERRIAM PARK-TR01	Distribution	Unattended	115.00	13.80		63.00	1			
314	MERRIAM PARK-TR02	Distribution	Unattended	115.00	13.80		72.00	1			
315	MERRIAM PARK-TR03	Distribution	Unattended	115.00	13.80		70.00	1			
316	MIDTOWN-TR01	Distribution	Unattended	115.00	13.80		70.00	1			
317	MINNEHAHA-TR01	Distribution	Unattended	115.00	13.80		28.00	1			
318	MINNEHAHA-TR02	Distribution	Unattended	115.00	13.80		28.00	1			
319	MINNESOTA LAKE-TR01	Distribution	Unattended	69.00	4.16		2.00	1			
320	MINNESOTA PIPELINE-TR01	Distribution	Unattended	115.00	4.16		8.00	1			
321	MINNESOTA VALLEY-TR02	Distribution	Unattended	69.00	23.00		14.00	1			
322	MINNESOTA VALLEY-TR05	Transmission	Unattended	230.00	115.00	13.80	187.00	1			
323	MINNESOTA VALLEY-TR06	Transmission	Unattended	230.00	115.00	13.80	187.00	1			
324	MINNESOTA VALLEY-TR11	Transmission	Unattended	115.00	69.00	13.80	46.70	1			
325	MINNESOTA VALLEY-TR12	Transmission	Unattended	115.00	69.00	13.80	46.70	1			
326	MONTEVIDEO-TR01	Distribution	Unattended	69.00	4.16		6.00	1			
327	MONTEVIDEO-TR02	Distribution	Unattended	69.00	12.50		5.00	1			
328	MONTICELLO-TR06	Transmission	Unattended	345.00	230.00	13.80	336.00	1			
329	MONTICELLO-TR10	Transmission	Unattended	345.00	115.00	13.80	345.00	1			
330	MONTROSE-TR01	Distribution	Unattended	69.00	12.50		7.00	1			
331	MOORE LAKE-TR01	Distribution	Unattended	115.00	13.80		70.00	1			
332	MOORE LAKE-TR02	Distribution	Unattended	115.00	13.80		70.00	1			
333	MOORE LAKE-TR03	Distribution	Unattended	115.00	13.80		46.70	1			
334	MORGAN-TR01	Distribution	Unattended	69.00	23.00		14.00	1			

335	MORRISTOWN-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
336	MOUND-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
337	MOUND-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
338	NERSTRAND-TR01XY	Distribution	Unattended	69.00	12.50		3.00	2				
339	NINE MILE CREEK-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
340	NINE MILE CREEK-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
341	NOBLES COUNTY-TR01	Distribution	Unattended	115.00	34.50	13.80	120.00	1				
342	NOBLES COUNTY-TR02	Distribution	Unattended	115.00	34.50	13.80	120.00	1				
343	NOBLES COUNTY-TR09	Transmission	Unattended	345.00	115.00	34.50	672.00	1				
344	NOBLES COUNTY-TR10	Transmission	Unattended	345.00	115.00	34.50	672.00	1				
345	NORDIC-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
346	NORDIC-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
347	NORTH BROADWAY-TR01	Distribution	Unattended	23.00	4.16		5.00	1				
348	NORTH BROADWAY-TR02	Distribution	Unattended	23.00	4.16		5.00	1				
349	NORTH ROCHESTER-TR09	Transmission	Unattended	345.00	161.00	34.50	672.00	1				
350	NORTH STAR STEEL-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
351	NORTH STAR STEEL-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
352	NORTH STAR STEEL-TR03	Distribution	Unattended	115.00	13.80		50.00	1				
353	NORTHFIELD-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
354	NORTHFIELD-TR02	Distribution	Unattended	69.00	13.80		17.00	1				
355	OAK PARK-TR01	Distribution	Unattended	115.00	23.00	13.80	28.00	1				
356	OAK PARK-TR07	Distribution	Unattended	115.00	13.80		46.70	1				
357	OAK PARK-TR08	Distribution	Unattended	115.00	13.80		46.70	1				

358	OAKDALE-TR01	Distribution	Unattended	115.00	13.80		46.70	1			
359	OAKDALE-TR02	Distribution	Unattended	115.00	13.80		46.70	1			
360	ORONO-TR01	Distribution	Unattended	115.00	13.80		28.00	1			
361	OSSEO-TR01	Distribution	Unattended	115.00	13.80		70.00	1			
362	OSSEO-TR02	Distribution	Unattended	115.00	13.80		70.00	1			
363	PARKERS LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1			
364	PARKERS LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1			
365	PARKERS LAKE-TR03	Distribution	Unattended	115.00	13.80		50.00	1			
366	PARKERS LAKE-TR09ABC	Transmission	Unattended	345.00	115.00	13.80	450.00	3			
367	PARKERS LAKE-TR10ABC	Transmission	Unattended	345.00	115.00	13.80	450.00	3			
368	PAYNESVILLE XMSN-TR01	Transmission	Unattended	115.00	69.00	13.80	70.00	1			
369	PAYNESVILLE XMSN-TR02	Transmission	Unattended	115.00	69.00	13.80	70.00	1			
370	PAYNESVILLE XMSN-TR04	Distribution	Unattended	115.00	34.50		28.00	1			
371	PAYNESVILLE XMSN-TR09	Transmission	Unattended	230.00	115.00	13.80	336.00	1			
372	PINE BEND-TR03	Distribution	Unattended	69.00	13.80		14.00	1			
373	PINE ISLAND-TR01	Distribution	Unattended	69.00	12.50		7.00	1			
374	PINE ISLAND-TR02	Distribution	Unattended	69.00	12.50		7.00	1			
375	PIPESTONE-TR01	Distribution	Unattended	69.00	13.80		14.00	1			
376	PIPESTONE-TR02	Distribution	Unattended	69.00	4.16		9.00	1			
377	PIPESTONE-TR03	Distribution	Unattended	69.00	25.00		6.00	1			
378	PIPESTONE-TR05	Transmission	Unattended	115.00	69.00	2.50	25.00	1			
379	PIPESTONE-TR06	Transmission	Unattended	115.00	69.00	13.80	25.00	1			
380	PLATO-TR01	Distribution	Unattended	115.00	12.50		15.00	1			
381		Transmission	Unattended	345.00	161.00	13.80	224.00	1			

	PRAIRIE ISLAND-TR10											
382	PRAIRIE-TR01	Transmission	Unattended	115.00	69.00	13.80	70.00	1				
383	PRAIRIE-TR03	Transmission	Unattended	115.00	69.00	13.80	70.00	1				
384	PRAIRIE-TR05	Transmission	Unattended	230.00	115.00	13.80	336.00	1				
385	PRAIRIE-TR07	Transmission	Unattended	230.00	115.00	13.80	336.00	1				
386	PRAIRIE-TR08	Transmission	Unattended	230.00	115.00	13.80	336.00	1				
387	PRIOR-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
388	QUARRY-TR09	Transmission	Unattended	345.00	115.00	34.50	448.00	1				
389	RAMSEY-TR01	Distribution	Unattended	115.00	13.80		50.00	1				
390	RAMSEY-TR02	Distribution	Unattended	115.00	13.80		50.00	1				
391	RAPIDAN-TR01	Distribution	Unattended	69.00	13.80		3.00	1				
392	RED RIVER-TR01	Distribution	Unattended	115.00	23.00	13.80	91.00	1				
393	RED RIVER-TR02	Distribution	Unattended	115.00	23.00	13.80	91.00	1				
394	RED RIVER-TR03	Distribution	Unattended	115.00	23.00	4.80	91.00	1				
395	RED ROCK-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
396	RED ROCK-TR02	Distribution	Unattended	115.00	13.80		20.00	1				
397	RED ROCK-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
398	RED ROCK-TR05	Transmission	Unattended	345.00	230.00	13.80	336.00	1				
399	RED ROCK-TR09	Transmission	Unattended	345.00	115.00	13.80	448.00	1				
400	RED ROCK-TR10	Transmission	Unattended	345.00	115.00	13.80	448.00	1				
401	RED WING-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
402	RED WING-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
403	RENVILLE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
404	REYNOLDS-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
405	RICH SPRING-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
406	RICH VALLEY-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
407	RICHMOND-TR01	Distribution	Unattended	69.00	13.80		5.00	1				
408	RIVERSIDE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				

409	RIVERSIDE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
410	RIVERWOOD-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
411	RIVERWOOD-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
412	ROCK RIVER-TR01	Distribution	Unattended	69.00	23.00		8.00	1				
413	ROGERS LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
414	ROGERS LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
415	ROSE PLACE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
416	ROSE PLACE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
417	ROSEMOUNT-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
418	SACRED HEART-TR01	Distribution	Unattended	69.00	13.80	4.36	5.00	1				
419	SALEM-TR01ABC	Distribution	Unattended	69.00	34.50	2.50	4.00	3				
420	SALEM-TR02	Distribution	Unattended	69.00	13.80		7.00	1				
421	SALIDA CROSSING-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
422	SALIDA CROSSING-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
423	SARTELL-TR01	Distribution	Unattended	34.50	12.50	2.16	7.00	1				
424	SAUK RIVER-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
425	SAUK RIVER-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
426	SAVAGE-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
427	SAVAGE-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
428	SCANDIA-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
429	SCOTT COUNTY-TR01	Transmission	Unattended	115.00	69.00	13.80	70.00	1				
430	SCOTT COUNTY-TR02	Transmission	Unattended	115.00	69.00	13.80	70.00	1				
431	SCOTT COUNTY-TR09	Transmission	Unattended	345.00	115.00	34.50	672.00	1				
432	SCOTT COUNTY-TR10	Transmission	Unattended	345.00	115.00	34.50	672.00	1				
433	SEDAN-TR01 AB	Distribution	Unattended	69.00	7.20		0.30	1				

434	SHEAS LAKE-TR05	Transmission	Unattended	115.00	69.00	13.80	112.00	1				
435	SHEAS LAKE-TR09	Transmission	Unattended	345.00	115.00	34.50	336.00	1				
436	SHEPARD-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
437	SHEPARD-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
438	SHERBURNE COUNTY-TR09	Transmission	Unattended	345.00	115.00	13.80	448.00	1				
439	SHEYENNE-TR05	Transmission	Unattended	230.00	115.00	13.80	187.00	1				
440	SHEYENNE-TR06	Transmission	Unattended	230.00	115.00	13.80	187.00	1				
441	SIBLEY PARK-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
442	SIBLEY PARK-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
443	SLAYTON WEST-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
444	SOURIS-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
445	SOURIS-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
446	SOURIS-TR03	Distribution	Unattended	115.00	13.80		52.50	1				
447	SOUTH BEND-TR05	Transmission	Unattended	115.00	69.00	13.80	46.70	1				
448	SOUTH BEND-TR06	Transmission	Unattended	161.00	115.00	13.80	187.00	1				
449	SOUTH HAVEN-TR01	Distribution	Unattended	69.00	34.50		1.00	1				
450	SOUTH RENNER-TR01	Distribution	Unattended	115.00	34.50		73.50	1				
451	SOUTH RIDGE-TR01	Distribution	Unattended	69.00	23.00		5.00	1				
452	SOUTH SIOUX FALLS-TR01	Distribution	Unattended	69.00	4.16		6.70	1				
453	SOUTH SIOUX FALLS-TR02	Distribution	Unattended	69.00	4.16		6.00	1				
454	SOUTH SIOUX FALLS-TR03	Distribution	Unattended	69.00	13.80		28.00	1				
455	SOUTH SIOUX FALLS-TR04	Distribution	Unattended	69.00	13.80		28.00	1				
456	SOUTHTOWN-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
457	SOUTHTOWN-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
458	SOUTHTOWN-TR03	Distribution	Unattended	115.00	13.80		62.50	1				

459	SOUTH-TR01ABC	Distribution	Unattended	69.00	2.40		1.00	3				
460	SPLIT ROCK-TR06	Transmission	Unattended	161.00	115.00	34.50	187.00	1				
461	SPLIT ROCK-TR07	Transmission	Unattended	230.00	115.00	13.80	336.00	1				
462	SPLIT ROCK-TR10	Transmission	Unattended	345.00	115.00	13.80	448.00	1				
463	SPLIT ROCK-TR11	Transmission	Unattended	345.00	115.00	13.80	448.00	1				
464	ST CLOUD-TR01	Distribution	Unattended	115.00	34.50		42.00	1				
465	ST CLOUD-TR02	Distribution	Unattended	115.00	34.50		42.00	1				
466	ST JAMES MUNICIPAL-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
467	ST JOHNS-TR01	Distribution	Unattended	69.00	4.16		4.00	1				
468	ST JOSEPH-TR01	Distribution	Unattended	69.00	4.16		7.00	1				
469	ST LOUIS PARK-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
470	ST LOUIS PARK-TR04	Distribution	Unattended	115.00	13.80		70.00	1				
471	ST LOUIS PARK-TR05	Distribution	Unattended	115.00	13.80		70.00	1				
472	ST LOUIS PARK-TR06	Distribution	Unattended	115.00	13.80		70.00	1				
473	ST. PAUL WATER-TR01	Distribution	Unattended	13.80	4.16		5.00	1				
474	STEWART-TR01	Distribution	Unattended	69.00	12.50		6.00	1				
475	STOCKYARDS-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
476	STOCKYARDS-TR02	Distribution	Unattended	118.00	13.80		46.70	1				
477	SUMMIT AVENUE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
478	SUMMIT AVENUE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
479	SWAN LAKE-TR01	Distribution	Unattended	115.00	12.50		10.50	1				
480	TANNERS LAKE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
481	TANNERS LAKE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
482		Distribution	Unattended	13.80	12.50		10.00	3				

	TANNERS LAKE-TR23A1B1C1											
483	TANNERS LAKE-TR23A2B2C2	Distribution	Unattended	13.80	12.50		10.00	3				
484	TANNERS LAKE-TR32A1B1C1	Distribution	Unattended	13.80	12.50		10.00	3				
485	TANNERS LAKE-TR32A2B2C2	Distribution	Unattended	13.80	12.50		10.00	3				
486	TANNERS LAKE-TR34A1B1C1	Distribution	Unattended	13.80	12.50		10.00	3				
487	TANNERS LAKE-TR34A2B2C2	Distribution	Unattended	13.80	12.50		10.00	3				
488	TERMINAL-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
489	TERMINAL-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
490	TERMINAL-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
491	TERMINAL-TR09	Transmission	Unattended	345.00	115.00	34.50	672.00	1				
492	TERMINAL-TR10	Transmission	Unattended	345.00	115.00	34.50	672.00	1				
493	THOMPSON-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
494	TRACY SWITCHING-TR01	Distribution	Unattended	69.00	13.80		5.00	1				
495	TRACY-TR01	Distribution	Unattended	69.00	4.16	2.40	5.00	1				
496	TWIN LAKES-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
497	TWIN LAKES-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
498	TWIN LAKES-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
499	UPPER LEVEE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
500	UPPER LEVEE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
501	UPPER LEVEE-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
502	VERMILLION RIVER-TR03	Distribution	Unattended	115.00	13.80		28.00	1				
503	VESELI-TR01	Distribution	Unattended	69.00	12.50		8.00	1				
504	VIKING-TR01	Distribution	Unattended	115.00	13.80		72.50	1				
505	VILLARD-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
506	WABASHA-TR01	Distribution	Unattended	69.00	13.80		10.50	1				

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

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

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

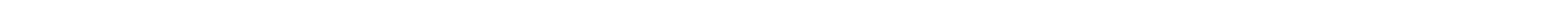
602	MGRV-E4990			118	25		90		1		
603	MGRV-WTO4771			118	14		70		1		
604	MGRV-WTO4921			118	14		70		1		
605	MGRV-50939-1			118	14		47		1		
606	MGRV-N2219			118	34		70		1		
607	MGRV-91F0693			71	36		17		1		
608	MGRV-J9E1054			69	35		5		1		
609	MGRV-282210982			70	24		14		1		
610	MGRV-GT-3547			71	14		14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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ 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	^(a) see note	188,801,975
3	Receipts from Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	(821,000,000)
4	Services provided by Xcel Energy Services Inc.	Xcel Energy Services Inc.	^(b) see note	615,273,401
5	Contribution of Capital	Xcel Energy Inc.	207	(648,404,269)
6	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	(434,000,000)
7	Wind farm materials, financing charges, storage fees	Capital Services LLC	E107	64,411,605
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Interchange agreement	NSP-Wisconsin	^(c) see note	(501,337,845)
22	Gas dispatch and SCADA system agreement	NSP-Wisconsin	G495	(505,917)
23	Vehicle and equipment use	NSP-Wisconsin	^(d) see note	(5,284,015)
24	Company labor, benefits, and related payments	NSP-Wisconsin	^(e) see note	(17,838,992)
25	Repayments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	434,000,000
26	Investments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	730,000,000
27	Dividends on Common Stock	Xcel Energy Inc.	215/216	430,677,450
42				



Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/14/2022	Year/Period of Report End of: 2021/ Q4
--	---	-------------------------------	---

FOOTNOTE DATA

(a) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

E557	\$ 67,498,845
E565	121,303,130
	188,801,975

(b) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Service Function Group	Updated FERC Group	Total
Accounting, Financial Reporting & Taxes	107-CWIP	\$ 40,719
	408-409-Taxes	31,976
	417-421-Other Income	(3,083,049)
	426.1-426.5-Other Income Deductions	19,919
	427-432-Interest Charges	130,710
	500-514-Steam Power Generation	9,491
	517-532-Nuclear Power Generation	(85)
	546-557-Other Power Generation	102,520
	560-573-Transmission Expenses	(287)
	580-598-Distribution Expenses	850
	710-742-Manufactured Gas Production	2,176
	800-813-Other Gas Supply Expenses	15,187
	850-870-Transmission Expenses	22
	871-893-Distribution Expenses	256
	920-935-Administrative and General Expense	28,589,682
Accounting, Financial Reporting & Taxes Total		25,860,087
Aviation Services	426.1-426.5-Other Income Deductions	14
	920-935-Administrative and General Expense	1,488,229
Aviation Services Total		1,488,243
Business Systems	107-CWIP	132,282,669
	130-176-Current and Accrued Assets	321
	181-190-Deferred Debits	2,825
	252-283-Deferred Credits	17
	408-409-Taxes	112
	417-421-Other Income	176,191
	426.1-426.5-Other Income Deductions	73,804
	500-514-Steam Power Generation	919,548

	517-532-Nuclear Power Generation	3,966,362
	535-545-Hydraulic Power Generation	4,603
	546-557-Other Power Generation	685,563
	560-573-Transmission Expenses	6,472,086
	580-598-Distribution Expenses	4,663,250
	710-742-Manufactured Gas Production	39
	800-813-Other Gas Supply Expenses	316,682
	840-843-Other Storage Expense	18
	844-847-Liquified Natural Gas Terminaling Expenses	44
	850-870-Transmission Expenses	81,850
	871-893-Distribution Expenses	1,224,399
	901-905-Customer Accounts Expenses	11,341,945
	908-910-Customer Service and Informational Expenses	33
	911-916-Sales Expense	89
	920-935-Administrative and General Expense	129,176,798
Business Systems Total		291,389,248
Claims Services	920-935-Administrative and General Expense	558,737
Claims Services Total		558,737
Corporate Communications	181-190-Deferred Debits	2,898,620
	252-283-Deferred Credits	1,060
	417-421-Other Income	3,297
	426.1-426.5-Other Income Deductions	44,564
	580-598-Distribution Expenses	208,711
	908-910-Customer Service and Informational Expenses	325,877
	911-916-Sales Expense	39
	920-935-Administrative and General Expense	2,844,994
Corporate Communications Total		6,327,162
Corporate Strategy & Business Development	181-190-Deferred Debits	5,818
	417-421-Other Income	416
	426.1-426.5-Other Income Deductions	70,248
	908-910-Customer Service and Informational Expenses	9,731
	911-916-Sales Expense	4,553
	920-935-Administrative and General Expense	1,558,348
Corporate Strategy & Business Development Total		1,649,114
Customer Service	107-CWIP	243,943
	181-190-Deferred Debits	775,321
	252-283-Deferred Credits	153,304
	417-421-Other Income	45,927
	426.1-426.5-Other Income Deductions	384
	901-905-Customer Accounts Expenses	12,884,790
	908-910-Customer Service and Informational Expenses	258,826
	911-916-Sales Expense	64,631
	920-935-Administrative and General Expense	4,394
Customer Service Total		14,431,520
Employee Communications	920-935-Administrative and General Expense	627,988
Employee Communications Total		627,988

Energy Delivery - Engineering/Design	107-CWIP	24,383,326
	130-176-Current and Accrued Assets	16,475
	181-190-Deferred Debits	(647)
	408-409-Taxes	493
	426.1-426.5-Other Income Deductions	23,709
	500-514-Steam Power Generation	410,873
	517-532-Nuclear Power Generation	213
	535-545-Hydraulic Power Generation	3,395
	546-557-Other Power Generation	194,774
	560-573-Transmission Expenses	8,274,862
	580-598-Distribution Expenses	2,938,797
	840-843-Other Storage Expense	13,778
	844-847-Liquefied Natural Gas Terminaling Expenses	882
	850-870-Transmission Expenses	1,640,623
	871-893-Distribution Expenses	579,943
	920-935-Administrative and General Expense	371,944
Energy Delivery - Engineering/Design Total		38,853,440
Energy Delivery Construction, Operations & Maintenance (COM)	107-CWIP	36,159
	426.1-426.5-Other Income Deductions	16,943
	560-573-Transmission Expenses	11,947
	580-598-Distribution Expenses	2,989,702
	814-837-Underground Storage Expenses	26,135
	840-843-Other Storage Expense	547,644
	850-870-Transmission Expenses	512,832
	871-893-Distribution Expenses	484,918
	908-910-Customer Service and Informational Expenses	262
	920-935-Administrative and General Expense	504,282
Energy Delivery Construction, Operations & Maintenance (COM) Total		5,130,824
Energy Markets - Fuel Procurement	426.1-426.5-Other Income Deductions	392
	500-514-Steam Power Generation	666,597
	920-935-Administrative and General Expense	109,866
Energy Markets - Fuel Procurement Total		776,855
Energy Markets Regulated Trading & Marketing	426.1-426.5-Other Income Deductions	3,621
	535-545-Hydraulic Power Generation	1,729
	546-557-Other Power Generation	3,750,645
	560-573-Transmission Expenses	453,617
	575.1-575.8-Regional Market Expenses	292,230
	800-813-Other Gas Supply Expenses	153,880
	920-935-Administrative and General Expense	817,239
Energy Markets Regulated Trading & Marketing Total		5,472,961
Energy Supply Business Resources	107-CWIP	564,890
	181-190-Deferred Debits	49,726
	408-409-Taxes	529
	426.1-426.5-Other Income Deductions	3,065
	500-514-Steam Power Generation	4,103,156
	517-532-Nuclear Power Generation	1,054,848

	535-545-Hydraulic Power Generation	42,246
	546-557-Other Power Generation	5,070,843
	920-935-Administrative and General Expense	88,443
Energy Supply Business Resources Total		10,977,746
Energy Supply Engineering & Environmental	107-CWIP	8,956,257
	181-190-Deferred Debits	136,674
	408-409-Taxes	42
	426.1-426.5-Other Income Deductions	19,960
	500-514-Steam Power Generation	3,996,648
	517-532-Nuclear Power Generation	62,352
	535-545-Hydraulic Power Generation	6,468
	546-557-Other Power Generation	981,913
	560-573-Transmission Expenses	42,990
	580-598-Distribution Expenses	93,121
	871-893-Distribution Expenses	197,852
	920-935-Administrative and General Expense	823,435
Energy Supply Engineering & Environmental Total		15,317,712
Executive Management Services	426.1-426.5-Other Income Deductions	340,561
	580-598-Distribution Expenses	73
	850-870-Transmission Expenses	137,875
	920-935-Administrative and General Expense	5,522,698
Executive Management Services Total		6,001,207
Facilities & Real Estate	107-CWIP	1,470,120
	130-176-Current and Accrued Assets	3,637
	181-190-Deferred Debits	13,566
	252-283-Deferred Credits	159
	417-421-Other Income	184,036
	426.1-426.5-Other Income Deductions	14,118
	500-514-Steam Power Generation	2,565,071
	517-532-Nuclear Power Generation	9,410,486
	535-545-Hydraulic Power Generation	46,538
	546-557-Other Power Generation	1,289,234
	560-573-Transmission Expenses	1,508,224
	575.1-575.8-Regional Market Expenses	18,385
	580-598-Distribution Expenses	3,951,772
	710-742-Manufactured Gas Production	3,868
	750-769-Natural Gas Production	1,511
	800-813-Other Gas Supply Expenses	9,938
	840-843-Other Storage Expense	35,588
	844-847-Liquefied Natural Gas Terminaling Expenses	80,004
	850-870-Transmission Expenses	103,874
	871-893-Distribution Expenses	1,876,039
	901-905-Customer Accounts Expenses	246,977
	908-910-Customer Service and Informational Expenses	34,039
	911-916-Sales Expense	18,750
	920-935-Administrative and General Expense	7,574,707

Facilities & Real Estate Total		30,460,641
Facilities Administrative Services	107-CWIP	175,470
Facilities Administrative Services Total		175,470
Finance & Treasury	107-CWIP	17,914,029
	130-176-Current and Accrued Assets	15,124
	181-190-Deferred Debits	2,770,611
	252-283-Deferred Credits	68,895
	408-409-Taxes	9,283,544
	417-421-Other Income	570,669
	426.1-426.5-Other Income Deductions	74,836
	427-432-Interest Charges	394,361
	500-514-Steam Power Generation	1,022,556
	517-532-Nuclear Power Generation	555,283
	535-545-Hydraulic Power Generation	8,184
	546-557-Other Power Generation	1,642,679
	560-573-Transmission Expenses	1,021,269
	575.1-575.8-Regional Market Expenses	34,839
	580-598-Distribution Expenses	691,019
	710-742-Manufactured Gas Production	5,493
	750-769-Natural Gas Production	5
	800-813-Other Gas Supply Expenses	17,070
	840-843-Other Storage Expense	36,580
	844-847-Liquified Natural Gas Terminaling Expenses	1,970
	850-870-Transmission Expenses	199,516
	871-893-Distribution Expenses	181,584
	901-905-Customer Accounts Expenses	1,540,886
	908-910-Customer Service and Informational Expenses	47,672
	911-916-Sales Expense	108,717
	920-935-Administrative and General Expense	48,450,134
Finance & Treasury Total		86,657,525
Fleet	107-CWIP	101,081
Fleet Total		101,081
Government Affairs	426.1-426.5-Other Income Deductions	679,201
	920-935-Administrative and General Expense	674,788
Government Affairs Total		1,353,989
Human Resources	107-CWIP	193,980
	130-176-Current and Accrued Assets	319
	181-190-Deferred Debits	4,448
	227-230-Other Noncurrent Liabilities	1,199,770
	231-245-Current and Accrued Liabilities	21,275,224
	252-283-Deferred Credits	38
	408-409-Taxes	16,969
	417-421-Other Income	1,716
	426.1-426.5-Other Income Deductions	32,062
	500-514-Steam Power Generation	9,580
	517-532-Nuclear Power Generation	579,158

	535-545-Hydraulic Power Generation	6
	546-557-Other Power Generation	2,976
	560-573-Transmission Expenses	1,122
	580-598-Distribution Expenses	96,283
	710-742-Manufactured Gas Production	56
	800-813-Other Gas Supply Expenses	22
	840-843-Other Storage Expense	20
	844-847-Liquefied Natural Gas Terminating Expenses	55
	850-870-Transmission Expenses	403
	871-893-Distribution Expenses	488
	901-905-Customer Accounts Expenses	2,369
	908-910-Customer Service and Informational Expenses	156,263
	911-916-Sales Expense	96
	920-935-Administrative and General Expense	10,541,029
Human Resources Total		34,114,452
Internal Audit	426.1-426.5-Other Income Deductions	239
	920-935-Administrative and General Expense	1,041,363
Internal Audit Total		1,041,602
Investor Relations	426.1-426.5-Other Income Deductions	404
	920-935-Administrative and General Expense	693,648
Investor Relations Total		694,052
Legal	107-CWIP	80,628
	181-190-Deferred Debits	12,530
	426.1-426.5-Other Income Deductions	20,293
	517-532-Nuclear Power Generation	344,052
	560-573-Transmission Expenses	25,197
	710-742-Manufactured Gas Production	31,079
	920-935-Administrative and General Expense	4,585,199
Legal Total		5,098,978
Marketing & Sales	181-190-Deferred Debits	6,930,937
	252-283-Deferred Credits	121,806
	408-409-Taxes	11
	417-421-Other Income	2,777,292
	426.1-426.5-Other Income Deductions	7,621
	908-910-Customer Service and Informational Expenses	212,358
	911-916-Sales Expense	1,527,245
	920-935-Administrative and General Expense	4,978,654
Marketing & Sales Total		16,555,924
Payment & Reporting	426.1-426.5-Other Income Deductions	131
	920-935-Administrative and General Expense	486,601
Payment & Reporting Total		486,732
Payroll	920-935-Administrative and General Expense	740,573
Payroll Total		740,573
Rates & Regulation	181-190-Deferred Debits	6,827
	426.1-426.5-Other Income Deductions	7,771
	920-935-Administrative and General Expense	1,716,420

Rates & Regulation Total		1,731,018
Receipts Processing	426.1-426.5-Other Income Deductions	1,429
	901-905-Customer Accounts Expenses	355,423
	920-935-Administrative and General Expense	455,455
Receipts Processing Total		812,307
Supply Chain	107-CWIP	7,231,583
	130-176-Current and Accrued Assets	38,691
	181-190-Deferred Debits	236,160
	252-283-Deferred Credits	3,837
	408-409-Taxes	99
	417-421-Other Income	13,410
	426.1-426.5-Other Income Deductions	29,629
	500-514-Steam Power Generation	(335,608)
	517-532-Nuclear Power Generation	(1,573,359)
	535-545-Hydraulic Power Generation	(12,191)
	546-557-Other Power Generation	340,373
	560-573-Transmission Expenses	163,919
	575.1-575.8-Regional Market Expenses	(4,324)
	580-598-Distribution Expenses	(295,454)
	710-742-Manufactured Gas Production	4,667
	750-769-Natural Gas Production	(579)
	800-813-Other Gas Supply Expenses	162
	840-843-Other Storage Expense	(5,611)
	844-847-Liquified Natural Gas Terminaling Expenses	(12,610)
	850-870-Transmission Expenses	53,800
	871-893-Distribution Expenses	(344,297)
	901-905-Customer Accounts Expenses	1,033,751
	908-910-Customer Service and Informational Expenses	(11,676)
	911-916-Sales Expense	(3,321)
	920-935-Administrative and General Expense	3,835,162
Supply Chain Total		10,386,213
Grand Total		615,273,401

(c) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

E456	\$	(438,954,583)
E456.1		(62,383,262)
		<u>(501,337,845)</u>

(d) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

107	\$	(4,717,498)
108		(531,068)
E502		(825)
E537		(453)
E553		(864)
E563		(27)

E570	(2,718)
E571	(7,593)
E583	(494)
E584	(128)
E587	(140)
E588	(3,186)
E592	(11,970)
E593	(6,113)
E594	(105)
G846.2	(445)
G847.2	(34)
G887	(324)
G892	(30)
	\$ (5,284,015)

(e) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

