THIS FILING IS

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)

Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)

Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

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-21-159 Filed 04/30/2021 Pages: 342
FERC Financial Report - FERC Form No. 1
Northern States Power Company

Exact Legal Name of Respondent (Company)	Year/Period of Report
Northern States Power Company (Minnesota)	End of 2019/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

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

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

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

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

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

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ____________ , we have also reviewed schedules ____________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

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

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

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

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

(4) 'Person' means an individual or a corporation;

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

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

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

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

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

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be 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 salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

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

FERC FORM NO. 1/3-Q:
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 2019/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 Jeffrey S. Savage	06 Title of Contact Person Sr. Vice Pres., Controller
07 Address of Contact Person *(Street, City, State, Zip Code)* 414 Nicollet Mall, Minneapolis, MN 55401	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(612) 330-5658	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Jeffrey S. Savage	Jeffrey S. Savage	03/30/2020
02 Title Senior Vice President, Controller		

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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".

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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.

Jeffrey S. Savage
Senior Vice President, Controller
414 Nicollet Mall
Minneapolis, MN 55401

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

Northern States Power Co. (a Minnesota corporation) was incorporated in the state of Minnesota on March 9, 2000.

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

Not applicable.

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

During the year 2019, 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...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Northern States Power Co. (a Minnesota corporation) is a first tier subsidiary of Xcel Energy Inc.

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	NSP Nuclear Corp	Nuclear generation support	100	
2	Private Fuel Storage, LLC	Nuclear waste storage	32.8	
3	United Power and Land Co.	Real estate holdings	100	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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)
1	Senior VP, Chief Nuclear Officer	Timothy J. O'Connor	545,000
2	Chairman of the Board, Chief Executive Officer	Ben Fowke	543,186
3	President	Christopher B. Clark	355,000
4	Executive VP, Chief Financial Officer	Robert C. Frenzel	261,534
5	Executive VP	Kent T. Larson	249,463
6	Executive VP, General Counsel	Scott M. Wilensky	239,197
7	Executive VP, Chief Customer and Innovations Officer	Brett Carter	221,298
8	Senior VP, Chief Human Resources Officer	Darla Figoli	206,479
9	Executive VP	David L. Eves	187,097
10	Senior VP, Corporate Secretary	Judy M. Poferl	144,850
11	Senior VP, Controller	Jeffrey S. Savage	130,673
12	VP, Treasurer	Sarah W. Soong	116,684
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14			
15	Salaries represent NSP-Minnesota's allocation of		
16	officers' salaries greater than $50,000 for the period		
17	of time that was served as an officer for		
18	NSP-Minnesota.		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Ben Fowke, Chairman of the Board, Chief Executive Officer	414 Nicollet Mall, Minneapolis, MN 55401
2	Robert C. Frenzel, Executive VP, CFO	414 Nicollet Mall, Minneapolis, MN 55401
3	Christopher B. Clark, President	414 Nicollet Mall, Minneapolis, MN 55401
4	David L. Eves, Executive VP	1800 Larimer Street, Suite 1100, Denver, CO 80202
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff, Third Revised Volume No. 1	ER07-1415-000 - Order Granting Incentives,
2	(Midwest Independent Transmission System	and Accepting Proposed Rate Formula
3	Operator, Inc. Open Access Transmission and	Modifications, Subject to Conditions, Issued
4	Energy Markets Tariff, Attachment O-NSP)	December 21, 2007, Accession No. 20071221-3012
5		
6	FERC Electric Tariff, Fourth Revised Volume No. 1	ER10-541-000 - Approval of Tariff Revisions to
7	(Midwest Independent Transmission System	Attachment O-NSP, Issued February 26, 2010,
8	Operator, Inc. Open Access Transmission and	Accession No. 20100226-3041
9	Energy Markets Tariff, Attachment O-NSP)	
10		
11	FERC Electric Tariff updated effective 01-01-2012	ER12-297-000 - Approval of Tariff Revisions to
12	(Midwest Independent Transmission System	Attachment O-NSP, Issued December 21, 2011,
13	Operator, Inc. Open Access Transmission and	Accession No. 20111221-3033
14	Energy Markets Tariff, Attachment O-NSP)	
15		
16	FERC Electric Tariff updated effective 01-01-2013	ER13-674-000/001/002 Approval of Tariff Revisions
17	(Midwest Independent Transmission System	to Attachment O-NSP, Issued March 20, 2013,
18	Operator, Inc. Open Access Transmission and	Accession No. 20130320-3014
19	Energy Markets Tariff, Attachment O-NSP)	
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21	FERC Electric Tariff updated effective 11-19-2013	ER14-421-000/001 Approval of Tariff Revisions
22	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued March 11, 2014,
23	Operator, Inc. Open Access Transmission and	Accession No. 20140311-3041
24	Energy Markets Tariff, Attachment O-NSP,	
25	Attachment GG-NSP; & Attachment MM)	
26		
27	FERC Electric Tariff updated effective 01-06-2015	ER15-358-000 Approval of Tariff Revisions
28	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued January 6, 2015,
29	Operator, Inc. Open Access Transmission and	Accession No. 20150105-3035
30	Energy Markets Tariff, Attachment O-NSP)	
31		
32	FERC Electric Tariff updated effective 01-01-2016	ER16-197-000 Approval of Tariff Revisions
33	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued December 30, 2015,
34	Operator, Inc. Open Access Transmission and	Accession No. 20151230-3075
35	Energy Markets Tariff, Attachment O-NSP)	
36		
37	FERC Electric Tariff updated effective 01-01-2017	ER17-305-000 Approval of Tariff Revisions
38	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued December 30, 2016,
39	Operator, Inc. Open Access Transmission and	Accession No. 20161230-3022
40	Energy Markets Tariff, Attachment O-NSP)	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

INFORMATION ON FORMULA RATES (continued)
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff updated effective 12-01-2017	ER18-12-000 Approval of Tariff Revisions
2	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued November 29, 2017,
3	Operator, Inc. Open Access Transmission and	Accession No. 20171129-3095
4	Energy Markets Tariff, Attachment O-NSP)	
5		
6	FERC Electric Tariff updated effective 1-01-2019	ER18-2322-000 Approval of Tariff Revisions
7	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued December 20, 2018,
8	Operator, Inc. Open Access Transmission and	Accession No. 20181220-3030
9	Energy Markets Tariff, Attachment O-NSP)	
10		
11	FERC Electric Tariff updated effective 1-01-2019	ER19-249-000 Approval of Tariff Revisions
12	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued December 20, 2018,
13	Operator, Inc. Open Access Transmission and	Accession No. 20181220-3011
14	Energy Markets Tariff, Attachment O-NSP)	
15		
16	FERC Electric Tariff updated effective 7-01-2019	ER19-2295-000 Approval of Tariff Revisions
17	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued August 23, 2019
18	Operator, Inc. Open Access Transmission and	Accession No. 20190823-3078
19	Energy Markets Tariff, Attachment O-NSP)	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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)?

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20170308-5088	03/08/2017	ER17-1120-000	See footnote	FERC Electric Tariff updated effective
2					01-01-2017 (Midcontinent Independent
3					System Operator, Inc. Open
4					Access Transmission and Energy
5					Markets Tariff, Attachment O-NSP)
6					
7	20180313-5128	03/13/2018	ER18-1004-000	See footnote	FERC Electric Tariff updated effective
8					01-01-2018 (Midcontinent Independent
9					System Operator, Inc. Open
10					Access Transmission and Energy
11					Markets Tariff, Attachment O-NSP)
12					
13	20190314-5169	03/14/2019	ER19-1310-000	See footnote	FERC Electric Tariff updated effective
14					01-01-2019 (Midcontinent Independent
15					System Operator, Inc. Open
16					Access Transmission and Energy
17					Markets Tariff, Attachment O-NSP)
18					
19	20200319-5161	03/19/2020	ER20-1354-000	See footnote	FERC Electric Tariff updated effective
20					01-01-2020 (Midcontinent Independent
21					System Operator, Inc. Open
22					Access Transmission and Energy
23					Markets Tariff, Attachment O-NSP)
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 1061 Line No.: 1 Column: d

Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin under ER17-1120-0000

Schedule Page: 1061 Line No.: 7 Column: d

Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin under ER18-1004-0000

Schedule Page: 1061 Line No.: 13 Column: d

Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin under ER19-1310-0000

Schedule Page: 1061 Line No.: 19 Column: d

Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin under ER20-1354-0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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).	Schedule	Column	Line No
1	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)	(d)	46
4	216.1	Construction Work in Progress- Electric (Acct 107)	(b)	41
5	219	Accum Prov for Depr- Elec Utility Plant (Acct 108)	(c)	20-26, 28
6	227	Materials and Supplies	(a)	18
7	232.1	Other Regulatory Assets	(f)	43
8	234	Accumulated Deferred Income Taxes (Acct 190)	(c)	8
9	267	Accum. Deferred Investment Tax Credits (Acct 225)	(h)	8
10	269	Other Deferred Credits (Acct 253)	(d), (e)	33
11	269.1	Other Deferred Credits (Acct 253)	(a)	39
12	273	Accumulated Deferred Income Taxes (Acct 281)	(k)	4
13	275	Accumulated Deferred Income Taxes (Acct 282)	(k)	2
14	277	Accumulated Deferred Income Taxes (Acct 283)	(k)	9
15	278.1	Other Regulatory Liabilities	(f)	39
16	300	Electric Operating Revenues (Acct 400)	(b)	19
17	310.2	Sales for Resale (Acct 447)	(a)	7
18	321	Electric Operation and Maintenance Expenses	(b)	112
19	328	Transmission of Electricity for Others	(a)	14
20	356	Common Utility Plant and Expenses	n/a	n/a
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 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.

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

The following important changes have been accumulated to date as of Q4 2019:

1. Franchise - The following franchises were acquired from the representative local government body without payment of consideration:

City	State	Utility	Expiration
Lake City	Minn.	Gas	Feb. 10, 2039
Baxter	Minn.	Gas	March 18, 2039
St. Stephen	Minn.	Gas	March 5, 2039
Pequot Lakes	Minn.	Gas	April 1, 2039
West St Paul	Minn.	Gas	April 7, 2039
Pine River	Minn.	Gas	May 14, 2039
Jenkins	Minn.	Gas	April 23, 2039
New Munich	Minn.	Electric	June 2 , 2039
Currie	Minn.	Electric	July 8, 2039
Montrose	Minn.	Gas	Sep 8, 2039
Dayton	Minn.	Electric	Sep 9, 2039
West Fargo	No. Dak.	Gas	Sep. 15, 2039
Chanhassen	Minn.	Electric	Oct. 27, 2039

2. Acquisitions

None

3. Purchase or sale of an operating unit or system

On June 29, 2018 NSP-Minnesota acquired the Benson Power Facility. As of Dec. 31, 2019, NSP-Minnesota has completed the dismantling and remediation of the former biomass generating facility and has sold the property.

Pursuant to the Commission's Order in Docket No. EC19-72-000 issued June 4, 2019, NSP-Minnesota purchased the Lake Benton Wind Generation Facility on Nov. 14, 2019. Lake Benton II is a Wind Farm located in Pipestone County in southwestern Minnesota. The repowered wind farm features 44 GE Wind Turbines with 100.2 MW Gross Capacity. The farm has a Net Capacity of 99.0 MWs, Gross Dependable Capacity of 15.7 MW and a Net Dependable Capacity of 15.5 MW.

NSP-Minnesota currently receives energy and capacity from Mankato Energy Center, LLC (Mankato 1) under a PPA expiring in 2026, and began receiving energy and capacity from Mankato Energy Center II, LLC, an expansion of the Mankato 1 facility, in June 2019. NSP-Minnesota planned to purchase both of the Mankato Energy Center units, subject to regulatory approvals. The Minnesota Public Utilities Commission denied regulatory approval of the acquisition on Sept. 27, 2019. Xcel Energy filed a petition with the FERC on Oct. 2, 2019 in Docket No. EC20-3-000 requesting approval to purchase the units by MEC Holdings LLC, a newly-formed, wholly-owned, indirect subsidiary of Xcel Energy. In January 2020, the MPUC approved Xcel Energy’s plan to acquire MEC as a non-regulated investment and step into the terms of the existing PPAs with NSP-Minnesota. A newly formed non-regulated subsidiary of Xcel Energy completed the transaction to purchase MEC on Jan. 17, 2020.

4. Important leaseholds acquired or given, assigned or surrendered

None

5. Important extension or reduction of transmission or distribution system

None

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

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

7. Changes in articles of incorporation and amendments to charter

None

8. Wage scale changes

Union Employees – 2.50 percent increase effective January 1, 2019.

Non-Union Employees – Base pay cycle increase of 3.00 percent effective March 16, 2019.

9. Legal proceedings

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

10. Other materially important transactions with associates

None

11. (Reserved)

12. Important changes

None

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

Effective May 3, 2019, Mary Schell resigned as Assistant Treasurer.

Effective June 3, 2019, Jodee Marble resigned as Assistant Corporate Secretary.

Effective September 9, 2019, Gioia M. Gentile elected as Assistant Corporate Secretary.

Effective October 1, 2019, Patricia L. Martin elected as Assistant Treasurer.

14. Cash management programs

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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)	200-201	21,736,345,281	20,215,132,001
3	Construction Work in Progress (107)	200-201	862,033,516	620,506,562
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		22,598,378,797	20,835,638,563
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	8,764,541,100	8,242,987,294
6	Net Utility Plant (Enter Total of line 4 less 5)		13,833,837,697	12,592,651,269
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	155,101,174	173,320,835
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		639,616,306	552,979,366
10	Spent Nuclear Fuel (120.4)		2,115,008,718	2,044,100,379
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	2,535,855,472	2,416,886,208
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		373,870,726	353,514,372
14	Net Utility Plant (Enter Total of lines 6 and 13)		14,207,708,423	12,946,165,641
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		12,655,865	9,702,989
19	(Less) Accum. Prov. for Depr. and Amort. (122)		8,919,855	9,224,397
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,554,655	2,518,302
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		55,595,145	52,504,848
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,439,576,155	2,054,708,655
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		9,236,042	17,038,034
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,510,698,007	2,127,248,431
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,386,897	7,338,625
36	Special Deposits (132-134)		33,430,194	0
37	Working Fund (135)		121,720	122,380
38	Temporary Cash Investments (136)		95,001,371	42,292,116
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		310,160,238	360,475,225
41	Other Accounts Receivable (143)		77,094,043	44,024,894
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		22,959,783	23,452,404
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		44,203,143	12,151,713
45	Fuel Stock (151)	227	104,964,238	90,364,543
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	174,000,028	175,243,410
49	Merchandise (155)	227	868,475	1,094,063
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	738,160	0

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

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)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		21,749,241	29,511,024
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		2,441,952	3,194,683
57	Prepayments (165)		18,600,951	22,914,668
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		186,872	0
60	Rents Receivable (172)		714,860	730,856
61	Accrued Utility Revenues (173)		250,698,276	270,264,268
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		41,721,833	42,846,565
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		9,236,042	17,038,034
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,147,886,667	1,062,078,595
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		47,723,599	42,195,057
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	96,600,152	106,326,485
72	Other Regulatory Assets (182.3)	232	3,765,742,401	3,733,740,125
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	3,550
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	37,462,823	40,891,771
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		15,504,676	17,590,485
82	Accumulated Deferred Income Taxes (190)	234	1,007,020,576	793,034,294
83	Unrecovered Purchased Gas Costs (191)		11,882,671	18,245,464
84	Total Deferred Debits (lines 69 through 83)		4,981,936,898	4,752,027,231
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		22,848,229,995	20,887,519,898

Schedule Page: 110 Line No.: 57 Column: c

Prepayments (Account No. 165). 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.

Schedule Page: 110 Line No.: 57 Column: d

NSP-Minnesota's Prepayments (Account No. 165) balance at Dec. 31, 2018, includes $2,677 for state income taxes. This balance was largely driven by a reserve for Wisconsin audits.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	end of 2019/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)	250-251	10,000	10,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		479,282,529	479,282,529
7	Other Paid-In Capital (208-211)	253	3,588,600,285	3,144,966,526
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	2,039,479,389	1,975,014,783
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-3,077,581	-3,014,557
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-22,466,683	-23,100,565
16	Total Proprietary Capital (lines 2 through 15)		6,081,827,939	5,573,158,716
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	5,600,000,000	5,000,000,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	8,843	9,208
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		30,976,065	20,644,869
24	Total Long-Term Debt (lines 18 through 23)		5,569,032,778	4,979,364,339
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		525,668,336	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		0	650,000
29	Accumulated Provision for Pensions and Benefits (228.3)		195,518,000	265,220,000
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		23,816,240	12,495,198
32	Long-Term Portion of Derivative Instrument Liabilities		110,219,460	112,165,303
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		2,280,306,478	2,177,887,158
35	Total Other Noncurrent Liabilities (lines 26 through 34)		3,135,528,514	2,568,417,659
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		30,000,000	150,000,000
38	Accounts Payable (232)		426,155,381	424,743,931
39	Notes Payable to Associated Companies (233)		1,450,000	1,450,000
40	Accounts Payable to Associated Companies (234)		78,479,095	110,678,085
41	Customer Deposits (235)		46,389,835	53,718,047
42	Taxes Accrued (236)	262-263	228,728,234	226,727,805
43	Interest Accrued (237)		70,651,448	65,915,275
44	Dividends Declared (238)		94,318,525	82,746,125
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

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)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		29,113,829	30,736,948
48	Miscellaneous Current and Accrued Liabilities (242)		38,116,391	41,744,471
49	Obligations Under Capital Leases-Current (243)		80,002,870	0
50	Derivative Instrument Liabilities (244)		135,263,248	128,645,253
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		110,219,460	112,165,303
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,148,449,396	1,204,940,637
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		11,059,858	13,745,986
57	Accumulated Deferred Investment Tax Credits (255)	266-267	19,679,171	21,103,317
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	335,156,217	385,835,916
60	Other Regulatory Liabilities (254)	278	3,772,735,275	3,672,887,991
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	26,891,855	28,895,301
63	Accum. Deferred Income Taxes-Other Property (282)		2,280,164,238	2,142,735,228
64	Accum. Deferred Income Taxes-Other (283)		467,704,754	296,434,808
65	Total Deferred Credits (lines 56 through 64)		6,913,391,368	6,561,638,547
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		22,848,229,995	20,887,519,898

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 112 Line No.: 26 Column: c

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.

Schedule Page: 112 Line No.: 49 Column: c

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) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/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
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin 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.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

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)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	5,072,495,689	5,081,006,064		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,058,001,086	3,094,259,618		
5	Maintenance Expenses (402)	320-323	251,989,031	266,599,697		
6	Depreciation Expense (403)	336-337	648,815,781	615,420,821		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	-10,987,780	-20,578,572		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	75,655,751	66,981,646		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	15,599			
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		8,688,551	5,611,685		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		64,291,584	100,577,135		
13	(Less) Regulatory Credits (407.4)		191,506,283	114,043,483		
14	Taxes Other Than Income Taxes (408.1)	262-263	261,423,117	257,502,968		
15	Income Taxes - Federal (409.1)	262-263	82,805,773	-10,243,165		
16	- Other (409.1)	262-263	16,709,862	10,529,309		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	372,973,100	396,415,383		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	422,523,436	368,704,355		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,424,146	-1,424,287		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		271,783	4,380,113		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		108,436,583	103,287,110		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,323,092,390	4,397,811,397		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		749,403,299	683,194,667		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
4,495,412,265	4,495,459,910	577,083,424	585,546,154			2
						3
2,623,643,569	2,635,598,688	434,357,517	458,660,930			4
240,955,564	256,882,995	11,033,467	9,716,702			5
608,310,715	578,296,877	40,505,066	37,123,944			6
-11,299,237	-20,958,982	311,457	380,410			7
70,098,131	62,262,405	5,557,620	4,719,241			8
15,599						9
8,688,551	5,611,685					10
						11
63,748,610	100,386,401	542,974	190,734			12
186,157,373	107,031,616	5,348,910	7,011,867			13
240,030,208	237,176,590	21,392,909	20,326,378			14
76,543,138	-14,206,390	6,262,635	3,963,225			15
15,258,749	8,120,814	1,451,113	2,408,495			16
338,517,703	372,652,811	34,455,397	23,762,572			17
392,886,452	348,856,318	29,636,984	19,848,037			18
-1,316,906	-1,316,708	-107,240	-107,579			19
						20
						21
271,783	4,380,113					22
						23
106,780,931	101,516,463	1,655,652	1,770,647			24
3,800,659,717	3,861,755,602	522,432,673	536,055,795			25
694,752,548	633,704,308	54,650,751	49,490,359			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		749,403,299	683,194,667		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		33,900,022	30,740,899		
34	(Less) Expenses of Nonutility Operations (417.1)		28,954,640	23,962,681		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-63,024	-77,812		
37	Interest and Dividend Income (419)		5,510,914	2,466,244		
38	Allowance for Other Funds Used During Construction (419.1)		24,819,621	24,141,506		
39	Miscellaneous Nonoperating Income (421)		-6,379,389	2,744,773		
40	Gain on Disposition of Property (421.1)		1,299,817	1,067,047		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		30,133,321	37,119,976		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		146,780	652,815		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		5,167,809	8,407,716		
46	Life Insurance (426.2)		-3,494,620	-2,015,174		
47	Penalties (426.3)		10,779	-33,489		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,085,005	1,652,354		
49	Other Deductions (426.5)		6,240,983	2,645,966		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		10,156,736	11,310,188		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	199,527	177,113		
53	Income Taxes-Federal (409.2)	262-263	578,289	-5,317,769		
54	Income Taxes-Other (409.2)	262-263	-8,268,777	-5,052,714		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	26,763,639	33,570,790		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	20,125,945	22,571,570		
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)		-853,267	805,850		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		20,829,852	25,003,938		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		221,011,431	215,646,430		
63	Amort. of Debt Disc. and Expense (428)		4,403,285	4,202,574		
64	Amortization of Loss on Reaquired Debt (428.1)		2,085,808	2,206,720		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		2,308,725	1,751,904		
68	Other Interest Expense (431)		10,244,102	4,582,028		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		12,386,283	12,526,182		
70	Net Interest Charges (Total of lines 62 thru 69)		227,667,068	215,863,474		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		542,566,083	492,335,131		
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)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		542,566,083	492,335,131		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 12 Column: c

	Electric	Gas
LED Streetlighting	$ 361,458	$ -
Minnesota AIP Refund	1,750,153	-
Minnesota Property Tax Amortization	8,180,122	-
Minnesota Renewable Development Fund	40,721,915	-
Minnesota State Energy Policy	-	542,974
Minnesota Transmission Cost Recovery	1,346,346	-
Sherco Unit 3 Depreciation Deferral	503,130	-
South Dakota Infrastructure	845,757	-
Theoretical Depreciation Reserve Surplus	10,039,729	-
	$63,748,610	$ 542,974

Schedule Page: 114 Line No.: 12 Column: d

	Electric	Gas
Minnesota Incentive Compensation Refund	$ 5,257,622	$ -
Minnesota Property Tax Amortization	8,180,122	-
Minnesota Renewable Development Fund	33,977,458	-
Minnesota Revenue Decoupling Mechanism	33,511,962	-
Minnesota State Energy Policy	-	190,734
Minnesota Transmission Cost Recovery	6,037,376	-
North Dakota Transmission Cost Recovery	1,476,081	-
Private Fuel Storage	2,641	-
Sherco Unit 3 Depreciation Deferral	667,355	-
South Dakota Infrastructure	309,549	-
South Dakota Transmission Cost Recovery	293,211	-
Theoretical Depreciation Reserve Surplus	10,673,024	-
	$100,386,401	$ 190,734

Schedule Page: 114 Line No.: 13 Column: c

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	$ 95,481,694	$1,967,107
Minnesota Gas Utility Infrastructure	-	3,381,803
Minnesota Renewable Energy Standard	50,065,943	-
Minnesota Revenue Decoupling Mechanism	31,483,965	-
Minnesota Sales True Up	7,460,574	-
North Dakota Renewable Energy Rider	86,694	-
North Dakota Transmission Cost Recovery	1,396,025	-
South Dakota Transmission Cost Recovery	102,373	-
Transco Amortization	80,105	-
	$186,157,373	$5,348,910

Schedule Page: 114 Line No.: 13 Column: d

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	$ 80,557,481	$2,151,056
LED Streetlighting	220,567	-
Minnesota Gas Utility Infrastructure	-	4,860,811
Minnesota Renewable Energy Standard	9,540,098	-
Minnesota Sales True Up	15,763,259	-
North Dakota Renewable Energy Rider	870,105	-
Transco Amortization	80,106	-
	$107,031,616	$7,011,867

Schedule Page: 114 Line No.: 46 Column: c

Income on Company Owned Life Insurance.

Schedule Page: 114 Line No.: 46 Column: d

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Income on Company Owned Life Insurance.

Schedule Page: 114 Line No.: 47 Column: d

Credit balance due to accrual reversal.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

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		1,974,937,160	1,922,721,680
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Reclassification of Tax Effects from Account 219			(2,363)
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			(2,363)
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		542,629,106	492,412,943
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-478,164,500	(440,195,100)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-478,164,500	(440,195,100)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,039,401,766	1,974,937,160
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

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)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		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)		2,039,479,389	1,975,014,783
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-3,014,557	(2,936,745)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-63,024	(77,812)
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-3,077,581	(3,014,557)

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction 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)	542,566,082	492,335,131
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	788,009,669	739,476,355
5	Amortization of Nuclear Fuel	118,969,264	121,888,518
6	Amortization of Premium, Discount and Debt Expense	6,489,093	6,409,294
7	Gain on Disposition of Property	-504,037	-1,038,017
8	Deferred Income Taxes (Net)	-42,912,642	38,710,248
9	Investment Tax Credit Adjustment (Net)	-1,424,146	-1,424,287
10	Net (Increase) Decrease in Receivables	24,403,483	-18,411,660
11	Net (Increase) Decrease in Inventory	-27,931,555	-21,460,083
12	Net (Increase) Decrease in Allowances Inventory	-738,160	28,206
13	Net Increase (Decrease) in Payables and Accrued Expenses	9,169,527	19,512,905
14	Net (Increase) Decrease in Other Regulatory Assets	-168,179,281	47,770,430
15	Net Increase (Decrease) in Other Regulatory Liabilities	-9,067,855	137,538,695
16	(Less) Allowance for Other Funds Used During Construction	24,819,621	23,843,506
17	(Less) Undistributed Earnings from Subsidiary Companies	-63,024	-77,812
18	Other: (Increase) Decrease in Accrued Utility Revenues	19,565,992	7,451,638
19	Other: Net Realized and Unrealized Hedging and Derivative Transactions	18,578,165	26,980,555
20	Other: Changes in Other Current Assets and Liabilities	-7,571,119	46,056,733
21	Other: Changes in Noncurrent Liabilities and Deferred Amounts	-66,082,576	-130,892,220
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,178,583,307	1,487,166,747
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,194,711,977	-1,012,808,420
27	Gross Additions to Nuclear Fuel	-139,325,618	-72,988,658
28	Gross Additions to Common Utility Plant	-111,471,285	-93,075,885
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-24,819,621	-23,843,506
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,420,689,259	-1,155,029,457
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Investments in Utility Money Pool Arrangement	-219,000,000	-805,000,000
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Repayments from Utility Money Pool Arrangement	219,000,000	805,000,000
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other: Miscellaneous Other Investing Activities	-3,093,297	-3,442,571
54	Other: Purchase of Investments in External Decommissioning Fund	-995,079,655	-852,939,312
55	Other: Proceeds from Sale of Investments in External Decomissioning	974,987,439	832,817,511
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,443,874,772	-1,178,593,829
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	579,739,967	
62	Preferred Stock		
63	Common Stock		
64	Other: Capital Contributions by Parent	354,334,013	108,751,434
65	Other: Borrowings under Utility Money Pool Arrangement	696,000,000	479,000,000
66	Net Increase in Short-Term Debt (c)		130,000,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,630,073,980	717,751,434
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-3,354	-25,835
74	Preferred Stock		
75	Common Stock		
76	Other: Repayments under Utility Money Pool Arrangement	-696,000,000	-564,000,000
77	Other: Miscellaneous Other Financing Activities		-93,741
78	Net Decrease in Short-Term Debt (c)	-120,000,000	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-466,592,100	-456,136,375
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	347,478,526	-302,504,517
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	82,187,061	6,068,401
87			
88	Cash and Cash Equivalents at Beginning of Period	49,753,121	43,684,720
89			
90	Cash and Cash Equivalents at End of period	131,940,182	49,753,121

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 21 Column: b

Changes in Noncurrent Liabilities and Deferred Amounts

Change in pension and employee benefit obligation	$ (49,510,713)
Change in deferred debits	1,732,285
Change in deferred credits	(28,975,190)
Change in noncurrent liabilities	10,671,042
	$ (66,082,576)

Schedule Page: 120 Line No.: 21 Column: c

Changes in Noncurrent Liabilities and Deferred Amounts

Change in pension and employee benefit obligation	$(76,320,539)
Change in deferred debits	10,284,557
Change in deferred credits	(62,149,121)
Change in noncurrent liabilities	(2,707,117)
	(130,892,220)

Schedule Page: 120 Line No.: 90 Column: b

Cash (131)	$3,386,897
Special Deposits (132-134)	33,430,194
Working Fund (135)	121,720
Temporary Cash Investments (136)	95,001,371
Cash and Cash Equivalents - End of Period	$131,940,182

Schedule Page: 120 Line No.: 90 Column: c

Cash (131)	$7,338,625
Working Fund (135)	122,380
Temporary Cash Investments (136)	42,292,116
Cash and Cash Equivalents - End of Period	$49,753,121

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 Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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

1. Summary of Significant Accounting Policies

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

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

Effective Jan. 1, 2018, NSP-Minnesota and NSP-Wisconsin changed its method of accounting for transmission related Interchange Agreement billings. NSP-Minnesota and NSP-Wisconsin historically had recorded the monthly transmission billings to each other in Account 456 and transmission related payments to each other in Account 566. To consistently account for the transmission related Interchange Agreement billings used for revenues and expenses from Midcontinent Independent System Operator, Inc. (MISO) and other third-parties' use of the NSP System transmission facilities, NSP-Minnesota and NSP-Wisconsin began recording the monthly transmission billings to each other in Account 456.1 and the transmission related payments to each other in Account 565 (see Docket No. AC18-55-000).

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.
- Removal costs for future removal obligations are classified as accumulated depreciation within the utility plant accounts 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 and 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 utility operating expenses 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 was 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, bringing FERC back into alignment with GAAP presentation over the average remaining life of the assets.
- Deferred financing costs are included as deferred debits in the FERC presentation, while GAAP presentation includes them with long-term liabilities.
- Non-service cost components of net periodic benefit costs that are reported on the income statement are recorded as operation expenses in the FERC presentation and as other income, net for GAAP presentation. Non-service costs that are eligible for capitalization are recorded as a component of net utility plant in the FERC presentation and as regulatory assets for GAAP.

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

(Millions of Dollars)		
Balance Sheet:		
Net utility plant	$	36.3
Current assets		321.6
Current liabilities		491.3
Other long-term assets		(3,289.7)
Long-term debt and other long-term liabilities		(3,423.1)
Statement of Income:		
Operating revenues	$	39.3
Operating expenses		1.8
Other income and deductions		3.2
Interest charges		(6.8)
Statement of Cash Flows:		
Cash provided by operating activities	$	(9.7)
Cash used in investing activities		3.8
Cash provided by financing activities		—

Use of Estimates — NSP-Minnesota uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used on items such as plant depreciable lives or potential disallowances, asset retirement obligations (ARO), 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; and
- 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 3 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 will be refundable to utility customers over the remaining life of the related assets. A tax rate increase would result in the establishment of a similar regulatory asset.

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 statement.

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

See Note 6 for further information.

Utility Plant and Depreciation in Regulated Operations — 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 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. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.7% for 2019 and 3.6% for 2018.

NSP-Minnesota has no material changes to utility plant in-service other than through typically recurring business activities in the normal course. Depreciation reserve and depreciation expense are impacted by composite depreciation rates and plant retirements. Any modifications to depreciation rates and plant retirements, such as changes in service lives, net salvage rates and mortality curves, are subject to approval by the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC) and the South Dakota Public Utilities Commission (SDPUC). The MPUC approved changes to NSP-Minnesota's depreciation rates in 2019, as discussed in NSP-Minnesota's 2020 Interchange Agreement Annual Update filed with the Commission on March 12, 2020 in Docket No. ER20-1249-000. For further information, see page 336, Depreciation and Amortization of Electric Plant.

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. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the amounts through the establishment of a regulatory asset and recovery in rates. NSP-Minnesota also recovers through rates certain future plant removal costs in addition to AROs.

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.

For ratemaking purposes, 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. If an environmental expense is related to facilities currently in use, such as 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. The depreciation expense levels recoverable in rates include a provision for removal expenses.

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 on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is 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 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, vehicle fuel 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; hedging transactions for vehicle fuel costs are recorded as a component of capital projects and operating expenses; 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.

See Note 7 for further information.

Commodity Trading Operations — Pursuant to the joint operating agreement (JOA) approved by the FERC, some of the commodity trading margins from Public Service Company of Colorado (PSCo) are apportioned to NSP-Minnesota and Southwestern Public Service Company (SPS). Commodity trading activities are not associated with energy produced from PSCo'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 discussion.

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 and conservation improvement programs (CIP)) 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. 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 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 consolidated statements of income.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2019 up to Feb. 21, 2020, the date NSP-Minnesota's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through March 30, 2020. 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%
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)	**2019**	**2018**
Current assets	$ (1.2)	$ 1.7
Other assets	3.9	1.0
Total assets	$ 2.7	$ 2.7
Current liabilities	$ 0.2	$ 0.2
Other liabilities	—	—
Equity	2.6	2.5
Total liabilities and equity	$ 2.8	$ 2.7

(Millions of Dollars)	**2019**	**2018**
Operating revenues	$ —	$ —
Operating loss	(0.1)	(0.1)
Net Loss	$ (0.1)	$ (0.1)

3. 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, 2019	Dec. 31, 2018
Regulatory Assets		
Asset retirement recovery	$ 2,336.3	$ 2,238.9
Pension and retiree medical obligations	396.6	447.4
Theoretical depreciation reserve surplus	257.8	267.8
Excess deferred taxes - Tax Cuts and Jobs Act (TCJA)	142.7	153.3
Recoverable deferred taxes on AFUDC recorded in plant	114.7	117.6
Purchased power agreement (PPA) termination	73.3	92.2
Contract valuation adjustments (a)	77.7	90.1
Nuclear refueling outage costs	60.3	50.2
Renewable resources and environmental initiatives	76.9	41.7
Purchased power contracts costs	39.1	39.3
Conservation programs (b)	13.6	27.3
Environmental remediation costs	13.1	15.5
Sherco Unit 3 Deferral	7.5	8.1
Other	156.1	144.3
Total regulatory assets	$ 3,765.7	$ 3,733.7

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

(b) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

Components of regulatory liabilities:

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Regulatory Liabilities		
Plant removal costs	$ 1,713.7	$ 1,623.0
Deferred income tax adjustments and TCJA refunds (a)	1,354.2	1,562.2
Investments	504.7	292.4
Excess deferred taxes - TCJA	43.7	51.3
Investment tax credit deferrals (b)	18.1	16.5
United States Department of Energy (DOE) Settlement	23.0	11.4
Contract valuation adjustments (c)	7.8	10.4
Deferred electric energy costs	24.2	22.8
Other	83.4	82.9
Total regulatory assets (d)	$ 3,772.8	$ 3,672.9

(a) Includes the revaluation of recoverable/regulated plant ADIT and revaluation impact of non-plant ADIT due to the TCJA.

(b) Includes impact of lower federal tax rate due to the TCJA.

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

(d) Revenue subject for refund of $23.8 million and $12.5 million for 2019 and 2018, respectively, is included in other current liabilities.

At Dec. 31, 2019 and 2018, NSP-Minnesota's regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations, net AROs and Laurentian biomass PPA termination costs/obligations. In addition, regulatory assets included $235.1 million and $190.2 million at Dec. 31, 2019 and 2018, respectively, of past expenditures not earning a return. Amounts primarily related to sales true-up and revenue decoupling, purchased natural gas and electric energy costs, various renewable resources and certain environmental initiatives.

4. Joint Ownership of Generation, Transportation and Gas Facilities

Jointly owned assets as of Dec. 31, 2019:

(Millions of Dollars)	Plant in Service	Accumulated Depreciation (a)	CWIP	Percent Owned
Electric generation:				
Sherco Unit 3	$ 603.0	$ 426.3	$ 3.8	59%
Sherco common facilities	144.7	102.7	1.9	80
Sherco substation	4.8	3.5	—	59
Electric transmission:				
CapX2020	972.5	91.6	2.2	51
Grand Meadow	10.7	2.6	—	50
Total	$ 1,735.7	$ 626.7	$ 7.9	

(a) ARO is not included.

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.

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 have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool borrowings for NSP-Minnesota were as follows:

(Millions of Dollars, Except Interest Rates)	Year Ended Dec. 31 2019	2018
Borrowing limit	$ 250	$ 250
Amount outstanding at period end	—	—
Average amount outstanding	32	17
Maximum amount outstanding	250	143

Weighted average interest rate, computed on a daily basis	2.05%	1.96 %
Weighted average interest rate at period end	N/A	N/A

Commercial Paper — Commercial paper outstanding for NSP-Minnesota was as follows:

(Millions of Dollars, Except Interest Rates)	Year Ended Dec. 31	
	2019	2018
Borrowing limit	$ 500	$ 500
Amount outstanding at period end	30	150
Average amount outstanding	71	38
Maximum amount outstanding	317	198
Weighted average interest rate, computed on a daily basis	2.59%	2.08 %
Weighted average interest rate at end of period	2.05	2.97

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, 2019 and 2018, there were $10 million and $37 million of letters of credit outstanding, respectively, under the credit facility. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facility — In order to use its commercial paper program to fulfill short-term funding needs, NSP-Minnesota must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper in an amount exceeding available capacity under this credit facility. The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Amended Credit Agreement — In June 2019, NSP-Minnesota entered into an amended five-year credit agreement with a syndicate of banks. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with the exception of the maturity, which was extended from June 2021 to June 2024.

Features of NSP-Minnesota's credit facility:

Debt-to-Total Capitalization Ratio (a)		Amount Facility May Be Increased (millions)	Additional Periods for Which a One-Year Extension May Be Requested (b)
2019	2018		
48%	48%	$ 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 will 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, 2019, NSP-Minnesota was in compliance with all financial covenants on its debt agreements.

NSP-Minnesota had the following committed credit facilities available as of Dec. 31, 2019 (in millions):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 500	$ 40	$ 460

(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, 2019 and 2018.

Bilateral Credit Agreement

In March 2019, NSP-Minnesota entered into a one-year uncommitted bilateral credit agreement. This facility is limited in use to support letters of credit.

As of Dec. 31, 2019, NSP-Minnesota's outstanding letters of credit under the Bilateral Credit Agreement were as follows (in millions):

Limit	Amount Used	Available
$ 75	$ 22	$ 53

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 (millions of dollars):

Financing Instrument	Interest Rate	Maturity Date	2019	2018
First mortgage bonds	2.20%	Aug. 15, 2020	$ 300	$ 300
First mortgage bonds	2.15%	Aug. 15, 2022	300	300
First mortgage bonds	2.60%	May 15, 2023	400	400
First mortgage bonds	7.13%	July 1, 2025	250	250
First mortgage bonds	6.50%	March 1, 2028	150	150
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	4.13%	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 [(a)]	2.90%	March 1, 2050	600	—
Unamortized discount			(31)	(21)

Unamortized debt issuance cost	(48)	(42)
Current maturities	(300)	—
Total long-term debt	$ 5,221	$ 4,937

(a) 2019 financing

Maturities of long-term debt are as follows:

(Millions of Dollars)	
2020	$ 300
2021	—
2022	300
2023	400
2024	—

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, 2019:

Equity to Total Capitalization Ratio - Required Range		Equity to Total Capitalization Ratio - Actual
Low	High	2019
47.1%	57.5%	52.3%

Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
$ 1.1billion	$ 11.6billion	$ 12.7billion

6. Income Taxes

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
2009 - 2013	June 2020
2014 - 2016	September 2020

In 2015, the IRS commenced an examination of tax years 2012 and 2013. In 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's net operating loss (NOL) and effective tax rate (ETR). Xcel Energy filed a protest with the IRS. As of Dec. 31, 2019, the case has been forwarded to the Office of Appeals and 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.

In 2018, the IRS began an audit of tax years 2014 - 2016. As of Dec. 31, 2019 no adjustments have been proposed.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2019, NSP-Minnesota's earliest open tax year subject to examination by state taxing authorities under applicable statutes of limitations is 2009. There are currently no state income tax audits in progress.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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

Uncertainty in Income Taxes — The FERC has not fully adopted the guidance for uncertainty in income taxes. Accordingly, NSP-Minnesota has recorded its unrecognized tax benefits for temporary adjustments, including NOL and tax credit carryforwards, in accounts established for accumulated deferred income taxes.

Unrecognized tax benefits - permanent vs temporary:

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Unrecognized tax benefit — Permanent tax positions	$ 14.8	$ 11.6
Unrecognized tax benefit — Temporary tax positions	4.9	5.3
Total unrecognized tax benefit	$ 19.7	$ 16.9

Changes in unrecognized tax benefits:

(Millions of Dollars)	2019	2018
Balance at Jan. 1	$ 16.9	$ 18.1
Additions based on tax positions related to the current year	2.6	2.0
Reductions based on tax positions related to the current year	(0.5)	(0.3)
Additions for tax positions of prior years	0.7	0.6
Reductions for tax positions of prior years	—	(1.1)
Settlements with taxing authorities	—	(2.4)
Balance at Dec. 31	$ 19.7	$ 16.9

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

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
NOL and tax credit carryforwards	$ (16.3)	$ (12.7)

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)	2019	2018
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (1.2)	$ (0.9)
Interest (expense) income related to unrecognized tax benefits	(0.4)	(0.3)
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (1.6)	$ (1.2)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2019 and 2018.

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)	2019	2018
Federal tax credit carryforwards	$ 459.8	$ 387.3
State NOL carryforwards	148.4	233.6
State tax credit carryforwards, net of federal detriment	79.0	89.2
Valuation allowances for state credit carryforwards, net of federal detriment	(65.9)	(78.5)

Federal carryforward periods expire between 2023 and 2039 and state carryforward periods expire between 2020 and 2035.

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:

	2019	2018 (a)
Federal statutory rate	21.0%	21.0%
State income tax on pretax income, net of federal tax effect	7.1	7.1
Increases (decreases) in tax from:		
Wind production tax credits (PTCs) recognized	(11.8)	(13.6)
Plant regulatory differences (b)	(7.4)	(8.8)
Other tax credits, net of NOL & tax credit allowances	(1.5)	(1.1)
Other, net	0.6	0.6
Effective income tax rate	8.0%	5.2%

(a) Prior periods have been reclassified to conform to current year presentation.

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

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

(Millions of Dollars)	2019	2018
Current federal tax expense (benefit)	$ 80.6	$ (16.8)
Current state tax expense	8.0	5.2
Current change in unrecognized tax expense	3.2	1.5
Deferred federal tax benefit	(86.1)	(3.4)
Deferred state tax expense	43.2	42.1
Deferred ITCs	(1.4)	(1.4)
Total income tax expense	$ 47.5	$ 27.2

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

(Millions of Dollars)	2019	2018
Deferred tax expense excluding items below	$ 92.7	$ 67.5
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(135.4)	(28.2)
Tax expense allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	(0.2)	(0.6)
Deferred tax expense	$ (42.9)	$ 38.7

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

(Millions of Dollars)	2019	2018 (a)
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 2,716.1	$ 2,597.4
Regulatory assets	(189.7)	(204.1)
Operating lease assets	169.6	—
Pension expense	68.4	64.7
Other	10.4	10.1
Total deferred tax liabilities	$ 2,774.8	$ 2,468.1
Deferred tax assets:		
Tax credit carryforward	$ 538.8	$ 476.5
Differences between book and tax bases of property	321.0	314.0
Operating lease liabilities	169.6	—
Regulatory liabilities	(82.2)	(84.5)
Tax credit valuation allowances	(65.9)	(78.5)
Other employee benefits	37.5	38.6
NOL carryforward	11.6	18.9
Rate refund	11.0	49.7
Deferred investment tax credits	5.9	6.4
Other	59.7	51.9
Total deferred tax assets	$ 1,007.0	$ 793.0
Net deferred tax liability	$ 1,767.8	$ 1,675.1

(a) Prior periods have been reclassified to conform to current year presentation.

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 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, 2019 and 2018 is reflected below:

(in millions)	**Dec. 31, 2019**		**Dec. 31, 2018**	
FERC Account	182.3	254	182.3	254
Protected				
Plant	$ —	$ 1,189.8	$ —	$ 1,232.5
Nonplant	113.8	—	119.5	—
Unprotected				
Plant	—	163	—	181.3
Nonplant	28.8	43.7	33.8	51.3
Total				
Plant	$ —	$ 1,352.8	$ —	$ 1,413.8
Nonplant	142.6	43.7	153.3	51.3

Excess and deficient accumulated deferred income taxes (ADITs) in 2019 were amortized in the Statement of Income as follows:

(in millions)	**Dec. 31, 2019**
Protected	
Plant	$ (32.7)
Nonplant	3.9
Unprotected	
Plant	(13.5)
Nonplant	(1.8)
Total	
Plant	$ (46.2)
Nonplant	2.1

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The 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; and
- 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.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted 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 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 important 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

Nuclear Decommissioning Fund — The Nuclear Regulatory Commission (NRC) 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 MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and 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 $705.5 million and $450.1 million as of Dec. 31, 2019 and 2018, respectively, and unrealized losses were $5.9 million and $44.8 million as of Dec. 31, 2019 and 2018, respectively.

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

	Dec. 31, 2019					
		Fair Value				
(Millions of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**NAV**	**Total**
Nuclear decommissioning fund						
Cash equivalents	$ 33.4	$ 33.4	$ —	$ —	$ —	$ 33.4
Commingled funds	732.8	—	—	—	934.9	934.9
Debt securities	489.2	—	495.2	12.7	—	507.9
Equity securities	484.6	962.0	1.4	—	—	963.4
Total	$ 1,740.0	$ 995.4	$ 496.6	$ 12.7	$ 934.9	$ 2,439.6

	Dec. 31, 2018					
		Fair Value				
(Millions of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**NAV**	**Total**
Nuclear decommissioning fund						
Cash equivalents	$ 24.3	$ 24.3	$ —	$ —	$ —	$ 24.3
Commingled funds	758.1	79.2	—	—	819.1	898.3
Debt securities	465.6	—	435.6	—	—	435.6
Equity securities	401.4	696.5	—	—	—	696.5
Total	$ 1,649.4	$ 800.0	$ 435.6	$ —	$ 819.1	$ 2,054.7

For the years ended Dec. 31, 2019 and 2018, 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, 2019:

	Final Contractual Maturity				
(Millions of Dollars)	**Due in 1 Year or Less**	**Due in 1 to 5 Years**	**Due in 5 to 10 Years**	**Due after 10 Years**	**Total**

Debt securities	$ (6.8)	$ 110.5	$ 246.1	$ 158.1	$ 507.9

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:

	December 31, 2019				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [a]					
Cash equivalents	$ 1.2	$ 1.2	$ —	$ —	$ 1.2
Mutual funds	11.4	13.1	—	—	13.1
Total	$ 12.6	$ 14.3	$ —	$ —	$ 14.3

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

	Dec. 31, 2018				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [a]					
Cash equivalents	$ 0.4	$ 0.4	$ —	$ —	$ 0.4
Mutual funds	10.8	10.7	—	—	10.7
Total	$ 11.2	$ 11.1	$ —	$ —	$ 11.1

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

Derivative 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 various instruments that effectively fix the interest payments on certain floating rate debt obligations or 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.

As of Dec. 31, 2019, accumulated other comprehensive losses related to interest rate derivatives included $0.8 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings.

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, 2019, NSP-Minnesota had no commodity derivative 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. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Immaterial amounts to income related to the ineffectiveness of cash flow hedges were recorded for the years ended Dec. 31, 2019 and 2018.

As of Dec. 31, 2019, there were immaterial net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses or related amounts expected to be reclassified into earnings during the next 12 months.

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 at Dec. 31:

(Amounts in Millions) (a) (b)	**2019**	**2018**
Megawatt hours of electricity	79.1	56.8
Million British thermal units of natural gas	77.8	42.7

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are 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 in the balance sheets.

NSP-Minnesota employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

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, 2019, eight of NSP-Minnesota's 10 most significant counterparties for these activities, comprising $54.2 million or 68% of this credit exposure, had investment grade credit ratings from Standard & Poor's Rating Services, Moody's Investor Services or Fitch Ratings.

Two of the 10 most significant counterparties, comprising $15.8 million or 20% of this credit exposure, were not rated by these external agencies, but based on NSP-Minnesota's internal analysis, had credit quality consistent with investment grade. Nine 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)	**2019**	**2018**
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (20.2)	$ (20.9)
After-tax net unrealized gains related to derivatives accounted for as hedges	—	—
After-tax net realized losses on derivative transactions reclassified into earnings	0.8	0.7
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (19.4)	$ (20.2)

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, 2019		
Other derivative instruments		
Electric commodity	$ —	$ 1.5
Natural gas commodity	—	(2.9)
Total	$ —	$ (1.4)
Year Ended Dec. 31, 2018		
Other derivative instruments		
Electric commodity	$ —	$ (5.5)
Natural gas commodity	—	1.8
Total	$ —	$ (3.7)

(Millions of Dollars)	Pre-Tax (Gains) Losses Reclassified into Income During the Period from: Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2019			
Derivatives designated as cash flow hedges			
Interest rate	$ 1.1 (a)	$ —	$ —
Total	$ 1.1	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ (0.7) (c)
Electric commodity	—	0.8 (d)	—
Natural gas commodity	—	0.9 (e)	(2.5) (e)
Total	$ —	$ 1.7	$ (3.2)
Year Ended Dec. 31, 2018			
Derivatives designated as cash flow hedges			
Interest rate	$ 1.1 (a)	$ —	$ —
Vehicle fuel and other commodity	(0.1) (b)	—	—
Total	$ 1.0	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 10.9 (c)
Electric commodity	—	3.3 (d)	—

Natural gas commodity	—	(1.9) (e)	(1.3) (e)
Total	$ —	$ 1.4	$ 9.6

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to operating expenses.

(c) Amounts are recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(d) Amounts are 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.

(e) 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, 2019 and 2018.

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, or for cross-default contractual provisions if there was a failure under other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2019 and 2018, there were $7.1 million and no derivative instruments in a liability position with such underlying contract provisions, respectfully.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that 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, 2019 and 2018.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, NSP-Minnesota's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2019 and 2018:

	Dec. 31, 2019						Dec. 31, 2018					
	Fair Value			Fair Value Total	Netting (a)		Fair Value			Fair Value Total	Netting (a)	
(Millions of Dollars)	Level 1	Level 2	Level 3			Total	Level 1	Level 2	Level 3			Total
Current derivative assets												
Other derivative instruments:												
Commodity trading	$ 1.6	$ 39.5	$ 23.6	$ 64.7	$ (42.1)	$ 22.6	$ 1.1	$ 27.1	$ 2.2	$ 30.4	$ (16.0)	$ 14.4
Electric commodity	—	—	8.7	8.7	(0.9)	7.8	—	—	10.5	10.5	(0.1)	10.4
Natural gas commodity	—	2.1	—	2.1	—	2.1	—	1.0	—	1.0	—	1.0
Total current derivative assets	$ 1.6	$ 41.6	$ 32.3	$ 75.5	$ (43.0)	32.5	$ 1.1	$ 28.1	$ 12.7	$ 41.9	$ (16.1)	25.8
PPAs (b)						—						—
Current derivative instruments						$ 32.5						$ 25.8
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 8.5	$ 29.4	$ 6.0	$ 43.9	$ (34.8)	$ 9.1	$ —	$ 25.3	$ 5.0	$ 30.3	$ (13.4)	$ 16.9

Total noncurrent derivative assets	$ 8.5	$ 29.4	$ 6.0	$ 43.9	$ (34.8)	9.1	$ —	$ 25.3	$ 5.0	$ 30.3	$ (13.4)	16.9
PPAs (b)						0.1						0.1
Noncurrent derivative instruments						$ 9.2						$ 17.0

	December 31, 2019						December 31, 2018					
	Fair Value			Fair Value Total	Netting (a)		Fair Value			Fair Value Total	Netting (a)	
(Millions of Dollars)	Level 1	Level 2	Level 3			Total	Level 1	Level 2	Level 3			Total
Current derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 2.2	$ 42.1	$ 15.0	$ 59.3	$ (49.8)	$ 9.5	$ 1.4	$ 23.9	$ 1.7	$ 27.0	$ (24.5)	$ 2.5
Electric commodity	—	—	1.0	1.0	(1.0)	—	—	—	0.1	0.1	(0.1)	—
Natural gas commodity	—	1.7	—	1.7	—	1.7	—	—	—	—	—	—
Total current derivative liabilities	$ 2.2	$ 43.8	$ 16.0	$ 62.0	$ (50.8)	11.2	$ 1.4	$ 23.9	$ 1.8	$ 27.1	$ (24.6)	2.5
PPAs (b)						13.8						14.0
Current derivative instruments						$ 25.0						$ 16.5
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 2.0	$ 32.3	$ 17.0	$ 51.3	$ (3.3)	$ 48.0	$ 0.1	$ 16.0	$ 1.6	$ 17.7	$ 17.9	$ 35.6
Total noncurrent derivative liabilities	$ 2.0	$ 32.3	$ 17.0	$ 51.3	$ (3.3)	48.0	$ 0.1	$ 16.0	$ 1.6	$ 17.7	$ 17.9	35.6
PPAs (b)						62.2						76.6
Noncurrent derivative instruments						$ 110.2						$ 112.2

(a) NSP-Minnesota nets derivative instruments and related collateral in its balance sheet 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, 2019 and 2018. At both Dec. 31, 2019 and 2018, derivative assets and liabilities include $31.5 million of obligations to return cash collateral, respectively. At Dec. 31, 2019 and 2018, derivative assets and liabilities include the rights to reclaim cash collateral of $7.9 million and $8.7 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, 2019 and 2018:

(Millions of Dollars)	Year Ended Dec. 31 2019	2018
Balance at Jan. 1	$ 14.3	$ 22.6
Purchases	16.7	26.4
Settlements	(27.5)	(17.2)
Net transactions recorded during the period:		
Gains (losses) recognized in earnings [(a)]	3.2	(1.5)
Net losses recognized as regulatory assets and liabilities	(1.4)	(16.0)
Balance at Dec. 31	$ 5.3	$ 14.3

(a) Amounts relate to commodity derivatives held at the end of the period.

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 2018 and 2019.

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)	2019 Carrying Amount	2019 Fair Value	2018 Carrying Amount	2018 Fair Value
Long-term debt	$ 5,569.0	$ 6,296.5	$ 4,979.4	$ 5,230.9

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, 2019 and 2018, 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, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service and average pay. 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 that were participants 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, 2019 and 2018 were $39 million and $33 million, respectively, of which $4 million was attributable to NSP-Minnesota in both years. In 2019 and 2018, Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million, of which $1 million was attributable to NSP-Minnesota in both years.

Xcel Energy and NSP-Minnesota base the investment-return assumption on expected long-term performance for each of the asset classes in its pension and postretirement health care portfolios.

For pension assets, Xcel Energy and NSP-Minnesota consider the historical returns achieved by their asset portfolio over the past 20 years or longer period, as well as the 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 2019 were above the assumed level of 7.10%;
- Investment returns in 2018 were below the assumed level of 7.10%;
- In 2020, NSP-Minnesota's expected investment-return assumption is 7.10%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's and NSP-Minnesota'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.

State agencies also have issued guidelines to the funding of postretirement benefit costs.

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:

	Dec. 31, 2019 (a)					Dec. 31, 2018 (a)				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 40.9	$ —	$ —	$ —	$ 40.9	$ 31.8	$ —	$ —	$ —	$ 31.8
Commingled funds	360.3	—	—	270.3	630.6	241.0	—	—	271.2	512.2
Debt securities	—	155.5	1.1	—	156.6	—	143.7	—	—	143.7
Equity securities	22.6	—	—	—	22.6	29.3	—	—	—	29.3
Other	(31.5)	1.2	—	(5.2)	(35.5)	0.5	1.3	—	(8.2)	(6.4)
Total	$ 392.3	$ 156.7	$ 1.1	$ 265.1	$ 815.2	$ 302.6	$ 145.0	$ —	$ 263.0	$ 710.6

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

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

	Dec. 31, 2019 (a)					Dec. 31, 2018 (a)				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 0.1	$ —	$ —	$ —	$ 0.1	$ 0.1	$ —	$ —	$ —	$ 0.1
Insurance contracts	—	0.3	—	—	0.3	—	0.3	—	—	0.3
Commingled funds	0.4	—	—	0.5	0.9	0.8	—	—	0.2	1.0
Debt securities	—	1.3	—	—	1.3	—	1.0	—	—	1.0
Equity securities	—	—	—	—	—	—	—	—	—	—
Total	$ 0.5	$ 1.6	$ —	$ 0.5	$ 2.6	$ 0.9	$ 1.3	$ —	$ 0.2	$ 2.4

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

Immaterial assets were transferred in or out of Level 3 for 2019. No assets were transferred in or out of Level 3 for 2018.

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

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2019**	**2018**	**2019**	**2018**
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 907.0	$ 1,035.1	$ 76.0	$ 88.8
Service cost	25.4	28.0	0.1	0.2
Interest cost	37.1	35.2	3.2	3.1
Plan amendments	1.0	—	—	—
Actuarial loss (gain)	61.7	(50.8)	3.8	(9.0)
Plan participants' contributions	—	—	0.3	0.4
Benefit payments (a)	(90.0)	(140.5)	(7.9)	(7.5)
Obligation at Dec. 31	$ 942.2	$ 907.0	$ 75.5	$ 76.0
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 710.6	$ 824.5	$ 2.4	$ 6.5
Actual return on plan assets	147.8	(36.5)	—	—
Employer contributions	46.8	63.1	7.7	3.0
Plan participants' contributions	—	—	0.3	0.4
Benefit payments	(90.0)	(140.5)	(7.8)	(7.5)
Fair value of plan assets at Dec. 31	$ 815.2	$ 710.6	$ 2.6	$ 2.4
Funded status of plans at Dec. 31	$ (127.0)	$ (196.4)	$ (72.9)	$ (73.6)
Amounts recognized in the Balance Sheet at Dec. 31:				
Noncurrent liabilities	$ (127.0)	$ (196.4)	$ (72.9)	$ (73.6)

(a) Includes approximately $105 million of lump-sum benefit payments used in the determination of a settlement charge in 2018.

	Pension 2019	Pension 2018	Postretirement 2019	Postretirement 2018
Significant Assumptions Used to Measure Benefit Obligations:				
Discount rate for year-end valuation	3.49%	4.31%	3.47%	4.32%
Expected average long-term increase in compensation level	3.75%	3.75%	N/A	N/A
Mortality table	Pri-2012	RP-2014	Pri-2012	RP-2014
Health care costs trend rate — initial: Pre-65 (before 65 years of age)	N/A	N/A	6.00 %	6.50%
Health care costs trend rate — initial: Post-65 (after 65 years of age)	N/A	N/A	5.10 %	5.30%
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	3	4

The accumulated benefit obligation for the pension plan was $872 million and $845 million as of Dec. 31, 2019 and 2018, respectively.

Net Periodic Benefit Cost — Net periodic benefit cost other than the service cost component is included in other income in the statement of income.

Components of net periodic benefit cost and the amounts recognized in other comprehensive income and regulatory assets and liabilities are as follows:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2019**	**2018**	**2019**	**2018**
Service cost	$ 25.4	$ 28.0	$ 0.1	$ 0.2
Interest cost	37.1	35.2	3.2	3.1
Expected return on plan assets	(54.3)	(58.2)	(0.1)	(0.4)
Amortization of prior service cost	(0.1)	(0.1)	(3.0)	(3.0)
Amortization of net loss	30.2	38.5	1.5	2.4
Settlement charge (a)	—	48.8	—	—
Net periodic pension cost	38.3	92.2	1.7	2.3
Costs not recognized due to effects of regulation	(5.2)	(66.0)	—	—
Net benefit cost recognized for financial reporting	$ 33.1	$ 26.2	$ 1.7	$ 2.3
Significant Assumptions Used to Measure Costs:				
Discount rate	4.31%	3.63 %	4.32%	3.62%
Expected average long-term increase in compensation level	3.75	3.75	—	—
Expected average long-term rate of return on assets	7.10	7.10	4.50	5.30

(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 2018 and 2017, as a result of lump-sum distributions during the 2018 and 2017 plan years, NSP-Minnesota recorded a total pension settlement charge of $48.8 million in 2018 and $48.2 million in 2017 , which was not recognized due to the effects of regulation.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2019**	**2018**	**2019**	**2018**
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 440.0	$ 502.0	$ 36.8	$ 34.3
Prior service credit	(0.2)	(1.2)	(9.4)	(12.4)
Total	$ 439.8	$ 500.8	$ 27.4	$ 21.9
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	$ 439.8	$ 500.8	$ 25.6	$ 20.5
Deferred income taxes	—	—	0.5	0.4
Net-of-tax accumulated other comprehensive income	—	—	1.3	1.0
Total	$ 439.8	$ 500.8	$ 27.4	$ 21.9
Measurement date	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2018 - 2020 to meet minimum funding requirements. Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $150 million in January 2020, of which $44 million is attributable to NSP-Minnesota;
- $154 million in 2019, of which $47 million was attributable to NSP-Minnesota; and
- $150 million in 2018, of which $63 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. Voluntary postretirement funding contributions:

- $10 million in January 2020, of which $7 million is attributable to NSP-Minnesota;
- $15 million in 2019, of which $8 million, was attributable to NSP-Minnesota; and
- $11 million in 2018, of which $3 million was attributable to NSP-Minnesota.

Target asset allocations:

	Pension Benefits		Postretirement Benefits	
	2019	2018	2019	2018
Domestic and international equity securities	37%	37%	15%	18%
Long-duration fixed income and interest rate swap securities	30	28	—	—
Short-to-intermediate fixed income securities	14	18	72	70
Alternative investments	17	15	9	8
Cash	2	2	4	4
Total	100%	100%	100%	100%

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 2019, there were no plan amendments made which affected the postretirement benefit obligation.

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
2020	$ 89.9	$ 6.9	$ —	$ 6.9
2021	82.4	6.6	—	6.6
2022	80.8	6.2	—	6.2
2023	78.5	5.9	—	5.9
2024	74.1	5.6	—	5.6
2025-2029	326.7	23.6	—	23.6

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 2019 and 2018, respectively.

Multiemployer Plans

NSP-Minnesota contributes to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees who may perform services for multiple employers and do not participate in the NSP-Minnesota sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota sponsored plans, in that if another participating employer ceases to contribute to a multiemployer 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 that are being defended and handled in the ordinary course of business. Assessing whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves complex judgments regarding future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation.

Management may be unable to estimate an amount or range of a reasonably possible loss in certain situations, including 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 of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate the ultimate liabilities, if any, arising from such current proceedings would have a material effect on NSP-Minnesota's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters

Mankato Energy Center (MEC) Acquisition — In November 2018, NSP-Minnesota reached an agreement with Southern Power Company (a subsidiary of Southern Company) to purchase MEC, a 760 MW natural gas combined cycle facility, with capacity and energy historically sold to NSP-Minnesota under PPAs expiring in 2026 and 2039, for approximately $650 million.

In September 2019, the MPUC denied NSP-Minnesota's request to purchase MEC as a rate base asset. In January 2020, the MPUC approved Xcel Energy's plan to acquire MEC as a non-regulated investment and step into the terms of the existing PPAs with NSP-Minnesota. A newly formed non-regulated subsidiary of Xcel Energy completed the transaction to purchase MEC on Jan. 17, 2020.

Sherco — In NSP-Minnesota's 2013 fuel reconciliation filing, the MPUC made recovery of replacement power costs associated with the 2011 incident at its Sherco Unit 3 plant provisional and subject to further review following conclusion of litigation commenced by NSP-Minnesota, Southern Minnesota Municipal Power Agency (SMMPA) (Co-owner of Sherco Unit 3) and insurance companies against GE.

In 2018, NSP-Minnesota and SMMPA reached a settlement with General Electric (GE). NSP-Minnesota notified the MPUC of its proposal to refund the GE settlement proceeds back to customers through the fuel clause adjustment (FCA). The insurance providers continued their litigation against GE and the case went to trial.

In 2018, GE prevailed in the lawsuit with the insurance companies, however, the jury found comparable fault, finding that GE was 52% and NSP-Minnesota was 48% at fault. At that point in the litigation, NSP-Minnesota was no longer involved in the case and was not present to make arguments about its role in the event. The specific issue leading to the fault apportionment was also not before the jury and not relevant to the outcome of the trial.

In January 2019, the Minnesota Department of Commerce (DOC) recommended that NSP-Minnesota refund $20 million of previously recovered purchased power costs to its customers, based on the jury's apportionment of fault. The Minnesota Office of the Attorney General (OAG) recommended the MPUC withhold any decision until the underlying litigation by the insurance providers (currently under appeal) is concluded. The DOC subsequently filed comments agreeing with the OAG's recommendation to withhold a decision pending the outcome of any appeals. NSP-Minnesota filed reply comments arguing that the DOC recommendations are without merit and that it acted prudently in operating the plant and its settlement with GE was reasonable.

In March 2019, MPUC approved NSP-Minnesota's proposal to refund the GE settlement proceeds back to customers through the FCA. It also decided to withhold any decision as to NSP-Minnesota's prudence in connection with the incident at Sherco Unit 3 until after conclusion of the pending litigation between GE and NSP-Minnesota's insurers.

MISO Return On Equity (ROE) Complaints — In November 2013 and February 2015, customers filed complaints against MISO TOs including NSP-Minnesota and NSP-Wisconsin. The first complaint argued for a reduction in the base ROE in MISO transmission formula rates from 12.38% to 9.15%, and removal of ROE adders (including those for RTO membership). The second complaint sought to reduce base ROE from 12.38% to 8.67%. In September 2016, the FERC issued an order granting a 10.32% base ROE (10.82% with the RTO adder) effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) subsequently vacated and remanded FERC Opinion No. 531, which had established the ROE methodology on which the September 2016 FERC order was based.

On March 21, 2019, FERC announced a notice of inquiry (NOI) seeking public comments on whether, and if so how, to revise ROE policies in light of the D.C. Circuit Court decision. FERC also initiated a NOI on whether to revise its policies on incentives for electric transmission investments, including the RTO membership incentive. In November 2019, the FERC issued an order adopting a new ROE methodology and settling the MISO base ROE at 9.88% (10.38% with the RTO adder), effective Sept. 28, 2016 and for the Nov. 12, 2013 to Feb. 11, 2015 refund period. The FERC also dismissed the second complaint. In December 2019, MISO TOs filed a request for rehearing. Customers also filed requests for rehearing claiming, among other points, that the FERC erred by dismissing the second complaint without refunds. NSP-Minnesota has recognized a liability for its best estimate of final refunds to customers. It is uncertain when the FERC will act on the requests for rehearing or any other pending matters related to the 2019 NOIs.

Environmental

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

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

MGP, Landfill or Disposal Sites — NSP-Minnesota is currently investigating or remediating seven MGP, landfill or other disposal sites across its service territories. NSP-Minnesota has recognized its best estimate of costs/liabilities that will result from final resolution of these issues, however, the outcome and timing is unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Water and Waste

Coal Ash Regulation — NSP-Minnesota's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. Under the Coal Combustion Residuals (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, where appropriate, initiating the assessment of corrective measures and evaluating whether corrective action is required at any CCR landfills or surface impoundments. To date, groundwater monitoring consistent with the CCR Rule has not identified results above the groundwater protection standards in the rule. Therefore, at this time no corrective action requirements have been triggered for these units under the rule.

In August 2018, the D.C. Circuit ruled that the United States Environmental Protection Agency (EPA) cannot allow utilities to continue to use unlined impoundments (including clay lined impoundments) for the storage or disposal of coal ash. In November 2019, the EPA proposed rules in response to this decision. If finalized in their current form, these rules would require NSP-Minnesota to expedite closure plans for one impoundment at an estimated cost of $2 million, and the construction of a new impoundment at an estimated cost of $8.6 million. In 2019, NSP-Minnesota initiated the construction of this new impoundment, an ash pond, expected to be in service in 2020. Upon placing the new ash pond in service, the existing ash pond will be taken out of service, and closure activities as prescribed by the CCR Rule and the facility's National Pollutant Discharge Elimination System permit will be initiated.

Closure costs for existing impoundments are included in the calculation of the ARO liability. See ARO section of Note 10 for further information.

Federal Clean Water Act (CWA) WOTUS Rule — In 2015, the EPA and the U.S. Army Corps of Engineers published a final rule that significantly broadened the scope of waters under the CWA that are subject to federal jurisdiction, referred to as "WOTUS". In 2019, the EPA repealed the 2015 rule and published a draft replacement rule. Until a final rule is issued, NSP-Minnesota cannot estimate potential impacts, but anticipates costs will be recoverable through regulatory mechanisms.

Federal 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 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport until November 2020. After 2020, NSP-Minnesota estimates that ELG compliance will cost approximately $10.0 million to complete. The EPA, however, is conducting a rulemaking process to revise certain effluent limitations and pretreatment standards, which may impact compliance costs. NSP-Minnesota anticipates these costs will be fully recoverable through regulatory mechanisms.

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 cost for complying with impingement and entrainment requirements is approximately $35.6 million, to be incurred between 2020 and 2028. NSP-Minnesota believes six plants could be required by state regulators 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 $191.6 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 reasonable further progress. The requirements of the first regional haze plans developed by Minnesota have been approved and implemented.

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

Aggregate fair value of NSP-Minnesota's legally restricted assets, for funding future nuclear decommissioning, was $2.4 billion and $2.1 billion for 2019 and 2018, respectively.

NSP-Minnesota's AROs were as follows:

	2019					
(Millions of Dollars)	**Jan. 1, 2019**	**Amounts Incurred** (a)	**Amounts Settled** (b)	**Accretion**	**Cash Flow Revisions** (c)	**Dec. 31, 2019**
Electric						
Nuclear	$ 1,968.3	$ —	$ —	$ 99.5	$ —	$ 2,067.8
Wind	104.9	10.3	—	4.8	(6.9)	113.1
Steam and other production	50.8	—	(3.2)	1.8	(2.6)	46.8
Distribution	14.5	—	—	0.6	—	15.1
Transmission	0.2	—	—	—	—	0.2
Natural gas						
Transmission and distribution	38.2	—	—	1.6	(3.6)	36.2
Gas storage	0.2	—	—	0.1	—	0.3
Common						
Common	0.8	—	—	—	—	0.8
Total liability	$ 2,177.9	$ 10.3	$ (3.2)	$ 108.4	$ (13.1)	$ 2,280.3

(a) Amounts incurred relate to the wind farms placed in service in 2019 (Lake Benton and Foxtail).

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

(c) In 2019, AROs were revised for changes in timing and estimates of cash flows. Changes in wind AROs were driven by new dismantling studies. Changes in gas transmission and distribution AROs were primarily related to increased gas line mileage and number of services, which were more than offset by decreased inflation rates. Changes in steam and other production AROs primarily related to the cost estimates to remediate ponds at production facilities.

	2018				
(Millions of Dollars)	**Jan. 1, 2018**	**Amounts Settled** (a)	**Accretion**	**Cash Flow Revisions** (b)	**Dec. 31, 2018** (c)
Electric					
Nuclear	$ 1,873.6	$ —	$ 94.7	$ —	$ 1,968.3
Wind	94.1	—	4.3	6.5	104.9
Steam and other production	65.7	(6.6)	2.1	(10.4)	50.8
Distribution	5.8	—	0.2	8.5	14.5
Transmission	0.2	—	—	—	0.2
Natural gas					

Transmission and distribution	43.6	—	1.8	(7.2)	38.2
Gas storage	0.2	—	—	—	0.2
Common					
Common	0.7	—	0.1	—	0.8
Total liability	$ 2,083.9	$ (6.6)	$ 103.2	$ (2.6)	$ 2,177.9

(a) Amounts settled related to asbestos abatement projects and closure of certain ash containment facilities.

(b) In 2018, AROs were revised for changes in timing and estimates of cash flows. Changes in gas transmission and distribution AROs were mainly related to increased gas line mileage and number of services, which were more than offset by increased discount rates. Changes in electric distribution AROs primarily related to increased labor costs.

(c) There were no ARO amounts incurred in 2018.

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, 2019. 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 $13.9 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $450.0 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.5 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 $137.6 million per reactor-incident for each of its three licensed reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $20.5 million per reactor-incident during any one year. Maximum assessments are subject to inflation adjustments by the NRC and state premium taxes. The NRC's last adjustment was effective November 2018.

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 $2.7 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage up to $350.0 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 approximately $12.0 million for business interruption insurance and $35.1 million for property damage insurance if losses exceed accumulated reserve funds.

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

NSP-Minnesota owns temporary on-site storage facilities for spent fuel at its Monticello and PI 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 44 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.

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 $2.4 billion of assets held in external decommissioning trusts at Dec. 31, 2019. 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.

	Regulatory Basis	
(Millions of Dollars)	**2019**	**2018**
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	$ 3,012.3	$ 3,012.3
Effect of escalating costs	688.2	538.9
Estimated decommissioning cost obligation (in current dollars)	3,700.5	3,551.2
Effect of escalating costs to payment date	7,505.0	7,654.3
Estimated future decommissioning costs (undiscounted)	11,205.5	11,205.5
Effect of discounting obligation (using average risk-free interest rate of 2.39% and 3.33% for 2019 and 2018, respectively)	(5,562.2)	(6,911.5)
Discounted decommissioning cost obligation	$ 5,643.3	$ 4,294.0
Assets held in external decommissioning trust	$ 2,439.6	$ 2,054.7
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	3,203.7	2,239.3

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)	**2019**	**2018**
Discounted decommissioning cost obligation - regulated basis	$ 5,643.3	$ 4,294.0
Differences in discount rate and market risk premium	(2,295.2)	(1,446.4)
Operating expenses not included for GAAP	(1,280.3)	(879.3)
Nuclear production decommissioning ARO - GAAP	$ 2,067.8	$ 1,968.3

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	**2019**	**2018**	**2017**
Annual decommissioning recorded as depreciation expense: (a) (b)	$ 20.4	$ 20.4	$ 20.4

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

(b) Decommissioning expenses in 2019 and 2018 include Minnesota's retail jurisdiction annual funding requirement of approximately $14.0 million.

The 2014 nuclear decommissioning filing, approved in 2015, was used for regulatory presentation in 2019 and 2018. The 2017 filing, effective Jan. 1, 2019, has been approved by the MPUC. In December 2019, the MPUC verbally approved for NSP-Minnesota to delay any increase to the annual funding requirement until 2021.

Leases

NSP-Minnesota evaluates a variety of contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. Under the Financial Accounting Standards Board Accounting Standards Codification Topic 842, adopted by NSP-Minnesota on Jan. 1, 2019, a contract contains a lease if it conveys the exclusive right to control the use of a specific asset. A contract determined to contain a lease is evaluated further to determine if the arrangement is a finance lease.

Right-of-use (ROU) assets represent NSP-Minnesota's rights to use leased assets. In accordance with FERC requirements as provided in Docket No. AI19-1-000, starting in 2019, the present value of future operating lease payments are recognized in Account 227 and Account 243. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets in Account 101.1.

Most of NSP-Minnesota's leases do not contain a readily determinable discount rate, and therefore the present value of future lease payments is calculated using the estimated incremental borrowing rate for similar borrowing periods. NSP-Minnesota has elected to utilize the practical expedient under which non-lease components, such as asset maintenance costs included in payments to the lessor, 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 consolidated balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	Dec. 31, 2019
PPAs	$ 556.3
Other	72.2
Gross operating lease ROU assets	628.5
Accumulated amortization	(64.7)
Net operating lease ROU assets	$ 563.8

Components of lease expense:

(Millions of Dollars)	2019	2018
Operating leases		
PPA capacity payments	$ 75.9	$ 62.5
Other operating leases (a)	9.1	13.7
Total operating lease expense (b)	$ 85.0	$ 76.2

(a) Includes short-term lease expense of $1.4 million, $2.0 million and $2.7 million for 2019, 2018 and 2017, respectively.

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

Commitments under operating leases as of Dec. 31, 2019:

(Millions of Dollars)	PPA (a) (b) Operating Leases	Other Operating Leases	Total Operating Leases
2020	$ 93.5	$ 7.9	$ 101.4
2021	94.9	8.0	102.9
2022	96.4	11.9	108.3
2023	97.9	7.0	104.9
2024	99.5	6.8	106.3

Thereafter	119.8	44.9	164.7
Total minimum obligation	602.0	86.5	688.5
Interest component of obligation	(66.2)	(16.7)	(82.9)
Present value of minimum obligation	$ 535.8	$ 69.8	605.6
Less current portion			(79.9)
Noncurrent operating lease liabilities			$ 525.7
Weighted-average remaining lease term in years			6.7

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

(b) PPA operating leases contractually expire at various dates through 2026.

Commitments under operating leases as of Dec. 31, 2018:

(Millions of Dollars)	PPA (a) (b) Operating Leases	Other Operating Leases	Total Operating Leases
2019	$ 65.0	$ 13.5	$ 78.5
2020	66.1	8.4	74.5
2021	67.1	8.4	75.5
2022	68.2	8.1	76.3
2023	69.3	7.3	76.6
Thereafter	143.5	36.0	179.5

(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 2026.

PPAs and Fuel Contracts

Non-Lease PPAs — NSP-Minnesota has entered into PPAs with other utilities and energy suppliers with various expiration dates through 2033 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 contain minimum energy purchase commitments, and total energy payments on those contracts were $102.4 million and $104.7 million in 2019 and 2018, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $53.8 million and $52.7 million in 2019 and 2018, 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, 2019, 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)]
2020	$ 54.5	$ 109.4
2021	62.2	157.3
2022	61.3	172.9
2023	62.8	176.9
2024	64.5	181.8
Thereafter	45.4	146.3
Total [(b)]	$ 350.7	$ 944.6

(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 2020 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, 2019:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2020	$ 171.3	$ 53.8	$ 36.8	$ 133.0
2021	85.2	102.5	1.4	129.8
2022	51.9	85.3	0.8	124.3
2023	35.1	103.0	—	107.8
2024	0.9	74.5	—	101.1
Thereafter	2.6	275.1	—	273.6
Total [(a)]	$ 347.0	$ 694.2	$ 39.0	$ 869.6

(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:

	2019		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (20.2)	$ (2.9)	$ (23.1)
Other comprehensive loss before reclassifications (net of taxes of $0 and $(0.1) respectively)	—	(0.4)	(0.4)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $0.3 and $0, respectively) [(a)]	0.8 (a)	— (	0.8

Amortization of net actuarial loss (net of taxes of $0 and $0.1, respectively)	—	0.2 (b)	0.2
Net current period other comprehensive income (loss)	0.8	(0.2)	0.6
Accumulated other comprehensive loss at Dec. 31	$ (19.4)	$ (3.1)	$ (22.5)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 8 for further information.

	2018			
(Millions of Dollars)	**Gains and Losses on Cash Flow Hedges**	**Unrealized Gains and Losses on Marketable Securities**	**Defined Benefit Pension and Postretirement Items**	**Total**
Accumulated other comprehensive (loss) income at Jan. 1	$ (20.9)	$ 0.1	$ (3.7)	$ (24.5)
Other comprehensive (loss) income before reclassifications (net of taxes of $0, $0 and $0.3, respectively)	—	(0.1)	0.6	0.5
Losses reclassified from net accumulated other comprehensive loss:				
Interest rate derivatives (net of taxes of $0.3, $0 and $0, respectively)	0.7 (a)	—	—	0.7
Amortization of net actuarial loss (net of taxes of $0, $0 and $0.1, respectively)	—	—	0.2 (b)	0.2
Net current period other comprehensive income (loss)	0.7	(0.1)	0.8	1.4
Accumulated other comprehensive loss at Dec. 31	$ (20.2)	$ —	$ (2.9)	$ (23.1)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 8 for further information.

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, 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)	2019	2018
Operating revenues:		
Electric	$ 457.4	$ 473.7
Gas	0.5	—
Operating expenses:		
Purchased power	60.5	61.1
Transmission expense	116.2	96.8
Other operating expenses — paid to Xcel Energy Services Inc.	533.2	534.8
Interest expense	0.7	0.3

Accounts receivable and payable with affiliates at Dec. 31 were:

	2019		2018	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	$ 7.9	$ —	$ 11.0	$ —
PSCo	—	18.8	—	17.9
SPS	—	4.2	—	4.7
Other subsidiaries of Xcel Energy Inc.	36.3	55.5	1.2	88.1
	$ 44.2	$ 78.5	$ 12.2	$ 110.7

12. Supplemental Cash Flow Data

	Year Ended Dec. 31	
(Millions of Dollars)	2019	2018
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (216.3)	$ (209.1)
Cash (paid) received for income taxes. net	(104.6)	88.9
Supplemental disclosure of non-cash investing transactions:		
Accrued property, plant and equipment additions	$ 94.5	$ 92.5
Inventory transfers to property, plant and equipment	23.5	60.8
Operating lease right-of-use assets	628.5	—
Allowances for funds used during construction	24.8	23.8

13. Energy Storage Assets (FERC Order No. 784)

The FERC issued Order No. 784, “Third-Party Provision of Ancillary Services; Accounting and Financial Reporting For New Electric Storage Technologies” in July 2013. In February 2014, FERC issued guidance on complying with Order No. 784’s new accounting and disclosure requirements until their Form 1 and Form 3 statements are revised to accommodate the changes. That guidance included a requirement to include disclosure information related to energy storage technologies in the notes to the financial statements. This information is presented below.

The Luverne Wind2Battery project is a one megawatt (MW) sodium sulfur battery storage facility that is operating in conjunction with the 11 MW Minwind wind power generating facility near Luverne, Minn. It is being used to store, control and dispatch energy when needed for supply or transmission stability purposes. The purpose of the facility is to provide NSP-Minnesota with experience and information that will allow NSP-Minnesota to assess and improve upon the viability of scaling up battery storage on the system as more wind power is added to meet the renewable policies.

Energy Plant Account

Energy storage assets are recorded in Account 348 in the amount of $4,128,902 at Dec. 31, 2019 and 2018. Due to FERC software limitations, these amounts are reported in Account 342.

Power Purchased Account

Energy storage-related purchased power costs are recorded in Account 555.1 in accordance with FERC Order No. 784 in the credit amount of $60,618 and $120,352 for the year ended Dec. 31, 2019 and 2018, respectively, reflecting true-up activity during the period. Due to FERC software limitations, these amounts are reported in Account 555.

Operation and Maintenance Expense Accounts

Energy storage-related operating expenses are recorded in Account 548.1 in accordance with FERC Order No. 784 in the amount of zero for the year ended Dec. 31, 2019 and 2018, respectively. Due to FERC software limitations, these amounts are reported in Account 548.

Energy storage-related maintenance expenses are recorded in Account 553.1 in accordance with FERC Order No. 784 in the amount of zero for the year ended Dec. 31, 2019 and 2018, respectively. Due to FERC software limitations, these amounts are reported in Account 553.

The following table presents NSP-Minnesota's Energy Storage Operations for small plants as of and for the year ended Dec. 31, 2019, as required by FERC Order No. 784:

Line No.	Name of Energy Storage Project	Functional Classification	Location of the Project	Project Cost	Operations (Excluding Fuel used in Storage Operations)	Maintenance	Cost of fuel used in storage operations	Account no. 555.1, Power Purchased or Storage Operations	Other Expenses
1	Luverne, Minn. Wind2Battery Project	Production	Luverne, Minn.	$ 4,128,902	$ —	$ —	$ —	$ (60,618)	$ —

The following table presents NSP-Minnesota's Energy Storage Operations for small plants as of and for the year ended Dec. 31, 2018, as required by FERC Order No. 784:

Line No.	Name of Energy Storage Project	Functional Classification	Location of the Project	Project Cost	Operations (Excluding Fuel used in Storage Operations)	Maintenance	Cost of fuel used in storage operations	Account no. 555.1, Power Purchased or Storage Operations	Other Expenses
1	Luverne, Minn. Wind2Battery Project	Production	Luverne, Minn.	$ 4,128,902	$ —	$ —	$ —	$ (120,352)	$ —

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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)
1	Balance of Account 219 at Beginning of Preceding Year	873,427			(4,514,546)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				219,948
3	Preceding Quarter/Year to Date Changes in Fair Value	(130,552)			659,828
4	Total (lines 2 and 3)	(130,552)			879,776
5	Balance of Account 219 at End of Preceding Quarter/Year	742,875			(3,634,770)
6	Balance of Account 219 at Beginning of Current Year	742,875			(3,634,770)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				179,980
8	Current Quarter/Year to Date Changes in Fair Value				(307,372)
9	Total (lines 7 and 8)				(127,392)
10	Balance of Account 219 at End of Current Quarter/Year	742,875			(3,762,162)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

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

Line No.	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 117, Line 78) (i)	Total Comprehensive Income (j)
1	(20,948,118)	52,751	(24,536,486)	[redacted]	[redacted]
2	762,466	(107,762)	874,652	[redacted]	[redacted]
3		31,993	561,269	[redacted]	[redacted]
4	762,466	(75,769)	1,435,921	492,335,131	493,771,052
5	(20,185,652)	(23,018)	(23,100,565)	[redacted]	[redacted]
6	(20,185,652)	(23,018)	(23,100,565)	[redacted]	[redacted]
7	738,256	23,018	941,254	[redacted]	[redacted]
8			(307,372)	[redacted]	[redacted]
9	738,256	23,018	633,882	542,566,082	543,199,964
10	(19,447,396)		(22,466,683)	[redacted]	[redacted]

Schedule Page: 122(a)(b) Line No.: 1 Column: g

Other cash flow hedging activity relates primarily to vehicle fuel and natural gas commodity derivatives.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/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)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	19,010,304,922	16,755,429,848
4	Property Under Capital Leases	563,804,868	507,075,729
5	Plant Purchased or Sold		
6	Completed Construction not Classified	2,148,142,058	1,963,237,271
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	21,722,251,848	19,225,742,848
9	Leased to Others		
10	Held for Future Use	13,560,939	13,560,939
11	Construction Work in Progress	862,033,516	780,244,634
12	Acquisition Adjustments	532,495	532,495
13	Total Utility Plant (8 thru 12)	22,598,378,798	20,020,080,916
14	Accum Prov for Depr, Amort, & Depl	8,764,541,100	7,747,420,418
15	Net Utility Plant (13 less 14)	13,833,837,698	12,272,660,498
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	8,318,260,646	7,544,020,099
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	446,042,470	203,162,335
22	Total In Service (18 thru 21)	8,764,303,116	7,747,182,434
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	Amort of Plant Acquisition Adj	237,984	237,984
33	Total Accum Prov (equals 14) (22,26,30,31,32)	8,764,541,100	7,747,420,418

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,498,029,313				756,845,761	3
				56,729,139	4
					5
65,876,475				119,028,312	6
					7
1,563,905,788				932,603,212	8
					9
					10
35,746,429				46,042,453	11
					12
1,599,652,217				978,645,665	13
654,540,362				362,580,320	14
945,111,855				616,065,345	15
					16
					17
649,953,722				124,286,825	18
					19
					20
4,586,640				238,293,495	21
654,540,362				362,580,320	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
654,540,362				362,580,320	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 200 Line No.: 21 Column: c

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

Intangible Plant	$104,306,524
Nuclear Production Plant	90,609,552
Other Production	5,667,553
Hydraulic Production Plant-Conventional	2,578,706
Total Amort of Other Utility Plant - Electric	$203,162,335

Schedule Page: 200 Line No.: 32 Column: c

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

Transmission	$ 237,984

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)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication	1,314,820	24,791,517
3	Nuclear Materials	153,855,645	103,499,686
4	Allowance for Funds Used during Construction	18,105,992	11,005,139
5	(Other Overhead Construction Costs, provide details in footnote)	44,378	53,577
6	SUBTOTAL (Total 2 thru 5)	173,320,835	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	552,979,366	241,040,845
10	SUBTOTAL (Total 8 & 9)	552,979,366	
11	Spent Nuclear Fuel (120.4)	2,044,100,379	70,908,339
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,416,886,208	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	353,514,372	
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) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
	24,467,736	1,638,601	2
	120,851,185	136,504,146	3
	12,198,695	16,912,436	4
	51,964	45,991	5
		155,101,174	6
			7
			8
	154,403,905	639,616,306	9
		639,616,306	10
		2,115,008,718	11
			12
-118,969,264		2,535,855,472	13
		373,870,726	14
			15
			16
			17
			18
			19
			20
			21
			22

Schedule Page: 202 Line No.: 2 Column: e

Classified to Account 120.2 and 120.3

Schedule Page: 202 Line No.: 3 Column: e

Classified to Account 120.2 and 120.3

Schedule Page: 202 Line No.: 4 Column: e

Classified to Account 120.2 and 120.3

Schedule Page: 202 Line No.: 5 Column: e

Classified to Account 120.2 and 120.3

Schedule Page: 202 Line No.: 5 Column: f

Consists of Adminstration and General costs

Schedule Page: 202 Line No.: 8 Column: c

Consists of transfers from 120.1, and direct trailing charges to asset after in-service

Schedule Page: 202 Line No.: 8 Column: e

Transferred to Account 120.3

Schedule Page: 202 Line No.: 9 Column: e

Transferred to Account 120.4

Schedule Page: 202 Line No.: 11 Column: e

Transferred to Account 120.3

Schedule Page: 202 Line No.: 15 Column: f

Not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982

Schedule Page: 202 Line No.: 16 Column: f

Not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	238,690,085	4,071,774
4	(303) Miscellaneous Intangible Plant	138,828,869	9,621,837
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	377,518,954	13,693,611
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,562,397	
9	(311) Structures and Improvements	291,941,495	1,317,811
10	(312) Boiler Plant Equipment	1,460,731,772	14,494,153
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	324,461,504	-3,951,899
13	(315) Accessory Electric Equipment	187,064,695	1,588,314
14	(316) Misc. Power Plant Equipment	53,887,694	186,592
15	(317) Asset Retirement Costs for Steam Production	2,301,622	-5,796,132
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,328,951,179	7,838,839
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	1,762,362	
19	(321) Structures and Improvements	569,741,486	3,289,708
20	(322) Reactor Plant Equipment	1,841,150,814	50,576,605
21	(323) Turbogenerator Units	580,849,329	13,709,657
22	(324) Accessory Electric Equipment	515,950,029	15,928,597
23	(325) Misc. Power Plant Equipment	206,624,848	2,446,280
24	(326) Asset Retirement Costs for Nuclear Production	-6,803,320	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	3,709,275,548	85,950,847
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	1,693,076	
28	(331) Structures and Improvements	1,388,479	
29	(332) Reservoirs, Dams, and Waterways	11,066,281	293
30	(333) Water Wheels, Turbines, and Generators	10,155,742	21,326
31	(334) Accessory Electric Equipment	3,256,971	
32	(335) Misc. Power PLant Equipment	60,825	
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	27,621,374	21,619
36	D. Other Production Plant		
37	(340) Land and Land Rights	30,541,830	1,252,187
38	(341) Structures and Improvements	266,641,116	66,938,770
39	(342) Fuel Holders, Products, and Accessories	31,560,978	361,734
40	(343) Prime Movers	139,802,454	652,252
41	(344) Generators	2,184,525,705	346,157,659
42	(345) Accessory Electric Equipment	286,326,329	11,916,587
43	(346) Misc. Power Plant Equipment	32,879,560	23,919
44	(347) Asset Retirement Costs for Other Production	84,243,488	3,348,403
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,056,521,460	430,651,511
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	9,122,369,561	524,462,816

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	155,390,691	9,977,541
49	(352) Structures and Improvements	116,971,980	6,999,774
50	(353) Station Equipment	1,252,054,233	36,091,018
51	(354) Towers and Fixtures	118,142,296	-21,127
52	(355) Poles and Fixtures	1,399,709,342	42,623,082
53	(356) Overhead Conductors and Devices	593,553,686	2,645,883
54	(357) Underground Conduit	28,941,147	942,259
55	(358) Underground Conductors and Devices	37,316,109	-330,140
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	173,429	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	3,702,252,913	98,928,290
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	17,603,983	1,544,495
61	(361) Structures and Improvements	53,188,659	2,003,597
62	(362) Station Equipment	653,669,870	31,263,243
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	440,954,406	31,634,674
65	(365) Overhead Conductors and Devices	491,409,493	27,330,150
66	(366) Underground Conduit	310,819,468	17,437,872
67	(367) Underground Conductors and Devices	1,188,718,642	45,024,333
68	(368) Line Transformers	468,849,399	21,008,938
69	(369) Services	319,058,505	19,189,931
70	(370) Meters	107,111,921	10,328,259
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	73,219,625	11,985,862
74	(374) Asset Retirement Costs for Distribution Plant	12,231,038	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,136,835,009	218,751,354
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	4,484,101	
87	(390) Structures and Improvements	74,711,760	3,116,833
88	(391) Office Furniture and Equipment	64,449,698	16,249,852
89	(392) Transportation Equipment	174,582,707	5,602,108
90	(393) Stores Equipment	1,631,738	
91	(394) Tools, Shop and Garage Equipment	98,586,471	7,273,710
92	(395) Laboratory Equipment	3,144,428	
93	(396) Power Operated Equipment	50,759,548	1,226,512
94	(397) Communication Equipment	118,029,396	6,124,399
95	(398) Miscellaneous Equipment	3,361,755	257,860
96	SUBTOTAL (Enter Total of lines 86 thru 95)	593,741,602	39,851,274
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)	593,741,602	39,851,274
100	TOTAL (Accounts 101 and 106)	17,932,718,039	895,687,345
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)	17,932,718,039	895,687,345

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			242,761,859		3
4,395,343			144,055,363		4
4,395,343			386,817,222		5
					6
					7
35,179			8,527,218		8
566,545		-783,616	291,909,145		9
10,197,440		-118,327	1,464,910,158		10
					11
1,472,027		-68,159	318,969,419		12
912,219			187,740,790		13
8,525			54,065,761		14
-4,353,238			858,728		15
8,838,697		-970,102	2,326,981,219		16
					17
			1,762,362		18
11,876,346		357,914	561,512,762		19
5,095,394			1,886,632,025		20
1,313,060			593,245,926		21
1,131,564			530,747,062		22
1,584,192		146,945	207,633,881		23
			-6,803,320		24
21,000,556		504,859	3,774,730,698		25
					26
			1,693,076		27
		57,124	1,445,603		28
			11,066,574		29
			10,177,068		30
			3,256,971		31
			60,825		32
					33
					34
		57,124	27,700,117		35
					36
			31,794,017		37
65,969		817,630	334,331,547		38
684,738			31,237,974		39
			140,454,706		40
11,429,551		186,485	2,519,440,298		41
2,626,774			295,616,142		42
			32,903,479		43
			87,591,891		44
14,807,032		1,004,115	3,473,370,054		45
44,646,285		595,996	9,602,782,088		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		45,179	165,413,411		48
164,469		2,059,336	125,866,621		49
6,069,396		472,749	1,282,548,604		50
		-98,889	118,022,280		51
1,364,944		56,834	1,441,024,314		52
630,832		32,203	595,600,940		53
			29,883,406		54
			36,985,969		55
					56
			173,429		57
8,229,641		2,567,412	3,795,518,974		58
					59
		-45,179	19,103,299		60
411,383		-540,289	54,240,584		61
8,041,562		-914,638	675,976,913		62
					63
1,039,341		9,852	471,559,591		64
3,818,961			514,920,682		65
291,794			327,965,546		66
3,535,303			1,230,207,672		67
12,970,738			476,887,599		68
239,523			338,008,913		69
8,225,453			109,214,727		70
					71
					72
9,359,556			75,845,931		73
			12,231,038		74
47,933,614		-1,490,254	4,306,162,495		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			4,484,101		86
1,654,214		-2,128,434	74,045,945		87
			80,699,550		88
			180,184,815		89
			1,631,738		90
2,721,004		8,920	103,148,097		91
159,528			2,984,900		92
			51,986,060		93
-5,835		441,889	124,601,519		94
			3,619,615		95
4,528,911		-1,677,625	627,386,340		96
					97
					98
4,528,911		-1,677,625	627,386,340		99
109,733,794		-4,471	18,718,667,119		100
					101
					102
					103
109,733,794		-4,471	18,718,667,119		104

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 204 Line No.: 5 Column: g

This footnote also applies to the following pages, lines and columns:
Schedule Page: 205 Line No: 46 Column: g
Schedule Page: 207 Line No: 58 Column: g
Schedule Page: 207 Line No: 75 Column: g
Schedule Page: 207 Line No: 99 Column: g

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.

Schedule Page: 204 Line No.: 39 Column: g

Account 342 Fuel Holders, Producers , and Accessories	$27,109,072
Account 348 Energy Storage, Equipment - Production	4,128,902
	$31,237,974

Schedule Page: 204 Line No.: 58 Column: b

Transmission Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 350 - Land & Land Rights	37,124	120,845	-	-	-	157,969
Account 352 - Structures & Improvements	14,149,096	1,263,920	(18,867)	-	-	15,394,149
Account 353 - Station Equipment	57,181,653	12,065,444	(249,674)	-	-	68,997,423
Account 354 - Towers & Fixtures	5,136,416	(120,967)	-	-	(98,889)	4,916,560
Account 355 - Poles & Fixtures	10,115,359	(95,421)	-	-	66,686	10,086,624
Account 356 - Overhead Conductors & Devices	3,398,368	359,994	-	-	32,203	3,790,565

Schedule Page: 204 Line No.: 75 Column: b

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	-	-	-	-	2,663,159

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

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	Nuclear Dry Storage Casks, Prairie Island Nuclear	2017	2020	13,560,939
23	Generating Plant			
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46	Footnote from page 106b			
47	Total			13,560,939

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 214 Line No.: 46 Column: d

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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	BS1-G100-Blazing Star I Wind Farm	284,718,878
2	BS2-G100-Blazing Star II Wind Farm	62,699,593
3	CRW G100-Crowned Ridge BOT Wind Far	58,114,465
4	DKR0 Dakota Range Wind Turbines	54,538,405
5	FBW G100-Freeborn Wind Farm	50,387,736
6	ADMS SW MN	32,624,796
7	BS1-Blazing Star I Wind Farm TSG SU	14,477,587
8	Wilson Breaker & 1/2 Sub	10,662,102
9	SE Solar Garden Extensions - E	10,395,948
10	J460 Blazing Star 1 Wind Interc	9,753,740
11	PI Proc Controls Repl	7,354,004
12	PI Security Protective Strategy	6,213,977
13	PI TN-40 Casks (48-64)	6,105,250
14	HBC7C U7 CT Turbine Parts R3 &	5,176,504
15	BS2-Blazing Star II Wind Farm TSG S	4,732,569
16	MINNESOTA MAJOR STORM RECOVERY	4,660,076
17	SOUTH DAKOTA MAJOR STORM RECOVERY	4,372,133
18	PI ISFSI Expansion	4,316,151
19	PI-9 TN-40 Casks(39-47)	4,094,409
20	Huntley Wilmarth 345 Line N S	3,195,630
21	DEMS Ph4 HW MN-10756	3,079,903
22	BS2-Blazing Star II TSG Tline 115k	2,903,434
23	NSPM Transmission UAV	2,743,180
24	MNGP EDG Rplc & Voltage Reg	2,355,833
25	NSPM Physical Security Sub Infrastr	2,187,629
26	Extend facilities to serve NW	2,086,893
27	NSM0793 Glenwood Douglas Co	2,037,341
28	J512 Zephyr Substation Network	1,738,014
29	MT Risk Informed Eng Prgm	1,701,565
30	Reinforce St Cloud SCL TR2	1,688,240
31	Purchase 90 MVA reserve XFMR	1,643,273
32	Install New Feedr at Sauk River #2	1,614,767
33	PI 10CFR50.69 Risk Informed Eng Pro	1,580,740
34	SUB Install Wilson WIL TR4 & Feeder	1,509,247
35	SUB Replace Fifth Street FST Switch	1,488,155
36	Salida Crossing feeder SDX311	1,420,448
37	SHC3C Unit Protection PLC Repl	1,415,955
38	Install circuit switchers RED	1,399,254
39	MNGP NEI 09-05 Security Compli	1,287,906
40	NSPM0729 CEN LCO 69kV Rebuild	1,279,206
41	Add Dundas 072 Feeder-dist	1,209,136
42	PI NUS Proc Controls Foxboro Mod Re	1,158,134
43	TOTAL	780,244,634

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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	PI ETAP Software Upgrade	1,146,269
2	Structural - Electric - MN - Routin	1,139,657
3	MT Obsolete EQ RFO30	1,116,848
4	Install feeder to TR3 Nordic S	1,099,956
5	SHCJC-Bottom Ash Pond 2	1,085,711
6	YLM211 and YLM212 Rebuild OH lines	1,068,094
7	AMI-DIST-NSPM-MN TOU	1,061,902
8	LINE Reinforce Medford Junction MDF	1,045,482
9	RIV9C U9 Major Inspection No. 1	1,030,559
10	Purch Synchrophasor Net HW MN	1,029,657
11	RIV0C -- U9 CT Compressor Upg	1,024,899
12	NSPM Physical Security Sub Infrastr	1,003,118
13	Minor Projects	89,270,276
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
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37		
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39		
40		
41	Footnote from Page 106b	
42		
43	TOTAL	780,244,634

Schedule Page: 216.1 Line No.: 41 Column: b

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	7,121,914,431	7,121,914,431		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	563,897,400	563,897,400		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-11,310,485	-11,310,485		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	13,484,969	13,484,969		
7	Other Clearing Accounts	162,411	162,411		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	566,234,295	566,234,295		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	109,691,685	109,691,685		
13	Cost of Removal	45,358,882	45,358,882		
14	Salvage (Credit)	6,933,530	6,933,530		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	148,117,037	148,117,037		
16	Other Debit or Cr. Items (Describe, details in footnote):	-364,828	-364,828		
17					
18	Book Cost or Asset Retirement Costs Retired	4,353,238	4,353,238		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	7,544,020,099	7,544,020,099		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,569,344,151	1,569,344,151		
21	Nuclear Production	2,033,127,709	2,033,127,709		
22	Hydraulic Production-Conventional	13,555,026	13,555,026		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,005,162,453	1,005,162,453		
25	Transmission	958,709,026	958,709,026		
26	Distribution	1,670,646,599	1,670,646,599		
27	Regional Transmission and Market Operation				
28	General	293,475,135	293,475,135		
29	TOTAL (Enter Total of lines 20 thru 28)	7,544,020,099	7,544,020,099		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 219 Line No.: 16 Column: c

Net change in RWIP	$ 855,893
Net Transfers	(1,953)
(Gain)/Loss	(1,217,938)
Gain shared with customers	(830)
Total	$ (364,828)

Schedule Page: 219 Line No.: 20 Column: c

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.

Schedule Page: 219 Line No.: 25 Column: c

Transmission Serving Production $ 38,380,008

Schedule Page: 219 Line No.: 26 Column: c

Distribution Serving Production $ 2,471,872

Schedule Page: 219 Line No.: 29 Column: b

	"Non-Legal" ARO Balances
Steam Production	$ 114,650,591
Nuclear Production	(84,475,279)
Hydraulic Production-Conventional	2,172,091
Other Production	53,044,223
Transmission	125,027,930
Distribution	221,470,339
General	(1,045,875)
Total	$ 430,844,020

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	UNITED POWER & LAND CO.			
2	Common Stock-par $100 per share			4,020,000
3	Additional Paid in Capital			549,662
4	Undistributed earnings (loss) since acquisition			-3,587,191
5	SUBTOTAL			982,471
6				
7	NSP NUCLEAR CO.			
8	Contributed Capital			963,198
9	Undistributed earnings (loss) since acquisition			572,633
10	SUBTOTAL			1,535,831
11				
12				
13				
14				
15				
16				
17				
18				
19				
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36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 5,632,237		TOTAL	2,518,302

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		4,020,000		2
	99,877	649,539		3
-101,871		-3,689,062		4
-101,871	99,877	980,477		5
				6
				7
	-500	962,698		8
38,847		611,480		9
38,847	-500	1,574,178		10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
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				40
				41
-63,024	99,377	2,554,655		42

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 224 Line No.: 3 Column: f

Contribution of Capital From Parent Company	$	100,000
Annual Allocation of Unitary Tax (Benefit)/Detriment		(123)
	$	99,877

Schedule Page: 224 Line No.: 8 Column: f

Contribution of Capital From Parent Company	$	0
Annual Allocation of Unitary Tax (Benefit)/Detriment		(500)
	$	(500)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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)	90,364,543	104,964,238	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)	46,024,126	40,192,034	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	132,176,539	136,755,040	Electric
8	Transmission Plant (Estimated)	1,296,801	1,020,870	Electric
9	Distribution Plant (Estimated)	1,269,220	880,341	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-5,523,276	-4,848,257	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	175,243,410	174,000,028	
13	Merchandise (Account 155)	1,094,063	868,475	
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				
18	note re: page 106 formula rates			
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	266,702,016	279,832,741	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 227 Line No.: 11 Column: b

Includes a credit of $2,829,233 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of $2,694,043 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.

Schedule Page: 227 Line No.: 11 Column: c

Includes a credit of $2,751,833 for inventory allocated to Southern Minnesota municipal Power Agency (41 percent owners of Sherco 3) and a credit of $2,096,424 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.

Schedule Page: 227 Line No.: 18 Column: a

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	914,789.00		95,710.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA	462.00			
6					
7					
8	Purchases/Transfers:	-5,392.00			
9					
10					
11					
12					
13					
14					
15	Total	-5,392.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	13,080.00			
19	Other:				
20		12,243.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	884,536.00		95,710.00	
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	926.00		926.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	926.00			
40	Balance-End of Year			926.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	926.00	71		
45	Gains		71		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2021		2022		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
93,200.00		93,200.00		1,800,812.00		2,997,711.00		1
								2
								3
				93,200.00		93,200.00		4
						462.00		5
								6
								7
						-5,392.00		8
								9
								10
								11
								12
								13
								14
						-5,392.00		15
								16
								17
						13,080.00		18
								19
						12,243.00		20
								21
								22
								23
								24
								25
								26
								27
								28
93,200.00		93,200.00		1,894,012.00		3,060,658.00		29
								30
								31
								32
								33
								34
								35
926.00		926.00		44,397.00		48,101.00		36
				1,850.00		1,850.00		37
								38
				926.00		1,852.00		39
926.00		926.00		45,321.00		48,099.00		40
								41
								42
								43
						926.00	71	44
							71	45
								46

FOOTNOTE DATA

Schedule Page: 228 Line No.: 29 Column: m

This amount will not agree to Account 158.1 on the Balance Sheet (see page 110-113) due to Renewable Energy Credits.

Schedule Page: 228 Line No.: 44 Column: m

Proceeds from SO2 allowance sales from plants owned by NSP-Minnesota. This amount will not agree to Account 411.8 on the Income Statement (see page 114-117) due to proceeds from the sale of Renewable Energy Credits, the sharing of the sale proceeds through the FERC-approved Interchange Agreement, and the specific regulatory treatment prescribed by the Minnesota, North Dakota, and South Dakota state regulatory commissions.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	43,902.00		18,041.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA	336.00			
6					
7					
8	Purchases/Transfers:	-1,218.00			
9					
10					
11					
12					
13					
14					
15	Total	-1,218.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	9,090.00			
19	Other:				
20		1,262.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	32,668.00		18,041.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2021		2022		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
16,659.00		16,659.00				95,261.00		1
								2
								3
				16,659.00		16,659.00		4
						336.00		5
								6
								7
						-1,218.00		8
								9
								10
								11
								12
								13
								14
						-1,218.00		15
								16
								17
						9,090.00		18
								19
						1,262.00		20
								21
								22
								23
								24
								25
								26
								27
								28
16,659.00		16,659.00		16,659.00		100,686.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (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	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Prairie Island	78,884,915		Various	3,147,594	55,687,092
22	Extended Power Uprate project					
23	MN Docket E-002/CN-08-509					
24						
25	Benson Biomass PPA Termination	48,078,137		407	4,860,239	40,913,060
26	MN Docket E-002/M-17-530					
27	ND Docket PU-17-270 and					
28	and PU-17-271					
29	SD Docket EL18-027					
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	126,963,052			8,007,833	96,600,152

Schedule Page: 230 Line No.: 21 Column: a

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.

NSP-Minnesota intends to seek recovery of North Dakota and South Dakota jurisdictional amounts in future rate proceedings.

Schedule Page: 230 Line No.: 21 Column: b

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

Schedule Page: 230 Line No.: 21 Column: d

Account No. 426.5 - accretion during 2019	(396,771)
Account No. 407 - amortization during 2019	3,544,365
	$ 3,147,594

Schedule Page: 230 Line No.: 25 Column: a

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	J399 Facility Study			(3,402)	242.0
23	J432 Facility Study			14,614	242.0
24	J432 Facility Study	65	561.7	65	561.7
25	J460 Facility Study			8,056	242.0
26	A698/F115 Facility Study			9,737	242.0
27	A698/F115 Facility Study	209	561.7	209	561.7
28	J460/J526 Hazel Creek Trnsfm Upgr			5,510	242.0
29	J460/J526 Hazel Creek Trnsfm Upgr	481	561.7	481	561.7
30	J523 Adams Substation Line Termin			5,531	242.0
31	J523 Adams SubTransformer Replace			7,841	242.0
32	J526 Line 0900 rebuild			2,500	242.0
33	J512 Wind Interco FaS			(56,040)	242.0
34	J512 Wind Interco FaS	49,668	561.7	49,668	561.7
35	J587 Blazing Star 2 Fas Wind			(18,681)	242.0
36	J587 Blazing Star 2 Fas Wind	16,910	561.7	16,910	561.7
37	J569 RCY Facilities Study-Restudy			(39,560)	242.0
38	J569 RCY Facilities Study-Restudy	39,560	561.7	39,560	561.7
39	J569/J587/J590 HLN-SCO LN #0982 F			(31,078)	242
40	J569/J587/J590 HLN-SCO LN #0982 F	31,078	561.7	31,078	561.7

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	J739 Lyon County Sub Facilities S8			(35,853)	242.0
23	J739 Lyon County Sub Facilities S8	35,853	561.7	35,853	561.7
24	XES-J732 Stone Lake-Transformer Re			(1,623)	242.0
25	XES-J732 Stone Lake-Transformer Re	1,623	561.7	1,623	561.7
26	'XES-J874 FTN-CHB Line #5537			(361)	242.0
27	XES-J874 FTN-CHB Line #5537	361	561.7	361	561.7
28	XES-J803 Tracy-Wlnut Grv Line #07r			(361)	242.0
29	XES-J803 Tracy-Wlnut Grv Line #07r	361	561.7	361	561.7
30	XES-J946 Bison Substation Intercnn			(829)	242.0
31	XES-J946 Bison Substation Intercnn	829	561.7	829	561.7
32	XES-J545/J905 Buffalo Ridge Sub Ic			(361)	242.0
33	XES-J545/J905 Buffalo Ridge Sub Ic	361	561.7	361	561.7
34	XES-J901 LYC-CMT Line #0956			(1,190)	242.0
35	XES-J901 LYC-CMT Line #0956	1,190	561.7	1,190	561.7
36	J926 PNL-APR Line #3209			(583)	242.0
37	J926 PNL-APR Line #3209	583	561.7	583	561.7
38					
39					
40					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	2016 Minnesota Deferred Property Tax	8,180,123		407.3	8,180,123	
2	- MN Docket E-002/GR-15-826					
3	- Amortized over 2 years (01/2018-12/2019)					
4						
5	2017 Minnesota Revenue Decoupling	5,732,441		407.3	5,732,441	
6	- MN Docket E-002/GR-15-826					
7	- Amortized over 1 year (04/2018-03/2019)					
8						
9	2017 Minnesota Sales True Up	4,985,400		407.4	4,985,400	
10	- MN Docket E-002/GR-15-826					
11	- Amortized over 1 year (04/2018-03/2019)					
12						
13	2017 Tax Cuts and Jobs Act - SD Electric	244,424		456	244,424	
14	- SD Docket GE17-003					
15						
16	2018 Minnesota Sales True Up	33,445,292	49,060	407.4	24,894,853	8,599,499
17	- MN Docket E-002/GR-15-826					
18	- Amortized over 1 year (04/2019-03/2020)					
19						
20	2019 Minnesota Revenue Decoupling		28,042,618			28,042,618
21	- MN Docket E-002/GR-15-826					
22	- Amortized over 1 year (04/2020-03/2021)					
23						
24	2019 Minnesota Sales True Up		37,291,767			37,291,767
25	- MN Docket E-002/GR-15-826					
26	- Amortized over 1 year (04/2020-03/2021)					
27						
28	Asset Retirement Recovery	2,238,858,565	97,448,802			2,336,307,367
29						
30	Benefit Cost Recovery Deficit	447,365,377	5,185,994	184	55,961,348	396,590,023
31						
32	Benson Biomass PPA Termination	48,073,770	(2,156,026)	557	4,792,704	41,125,040
33	- MN Docket E-002/GR-17-530					
34	- ND Docket PU-17-271					
35	- SD Docket EL 18-027					
36						
37	Conservation and Energy Management Program Costs	27,331,078	121,556,903	Various	135,297,187	13,590,794
38	Minnesota Electric					
39	- MN Docket E-002/M-18-240					
40	- MN Docket E-002/M-19-258					
41	- Generally amortized over 12 month					
42	period following the expenditure					
43						
44	TOTAL	3,733,740,125	467,217,304		435,215,028	3,765,742,401

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Conservation and Energy Management Program Costs	4,908	1,046,704	908	1,005,577	46,035
2	South Dakota Electric					
3	- SD Docket EL 19-019					
4	- Generally amortized over 12 month					
5	period following the expenditure					
6						
7	Costs to Relocate Facilities Underground	540,061	21,525	142	298,156	263,430
8	- MN Docket E-002/M-99-799					
9	- MN Docket E-002/M-15-826					
10						
11	Deferred Nuclear Outage Costs	50,167,021	60,744,756	Various	50,626,689	60,285,088
12	- Generally amortized over 23-24 months					
13	- MN Docket E-002/M-07-1489					
14	- ND Docket PU-07-774					
15	- SD Docket EL07-035					
16						
17	Gas Utility Infrastructure Cost Rider	27,398,377	21,511,188	Various	22,683,469	26,226,096
18	- MN Docket E-002/GR-17-787					
19	- MN Docket E-002/GR-18-692					
20						
21	Laurentian Biomass PPA Termination	91,398,817	910,159	Various	19,187,883	73,121,093
22	- MN Electric E-002/GR-17-551					
23	- ND Docket PU-17-322					
24	- SD Docket EL 18-027					
25						
26	Mankato/Cannon Falls Lease Normalization	39,342,558	3,441,051	101.1	3,653,725	39,129,884
27						
28	Minnesota Electric Vehicle Tariff	419,345	195,960			615,305
29	- MN Docket E-002/M-15-111					
30	- MN Docket E-002/M-17-879					
31						
32	Minnesota Gas State Energy Policy Rider	77,314	1,782,068	407.3	1,859,382	
33	- MN Docket E-002/M-19-200					
34						
35	Minnesota LED Streetlighting Deferral	907,178		407.3	361,458	545,720
36	- MN Docket E-002/M-15-826					
37						
38	Minnesota Renewable Energy Standard		41,772,412			41,772,412
39	- MN Docket E-002/M-17-818					
40						
41	Net of Tax AFUDC in Plant Adjustments	117,598,936		Various	2,852,580	114,746,356
42						
43	Nonplant Excess ADIT	153,335,219		Various	10,676,206	142,659,013
44	TOTAL	3,733,740,125	467,217,304		435,215,028	3,765,742,401

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	North Dakota Environmental Cleanup	15,501,699	291,461	735	2,704,943	13,088,217
2	- ND Docket PU-17-894					
3						
4	North Dakota Renewable Energy Rider		74,920			74,920
5	- ND Docket PU-18-368					
6						
7	Pind Bend Biomass PPA Termination	837,809	36,238	253	670,476	203,571
8	- MN Electric E-002/M-17-531					
9	- ND Docket PU-17-271					
10	- SD Docket EL18-027					
11						
12	Power Contract Valuation Adjustment	90,063,527	1,438,569	244	13,831,928	77,670,168
13						
14	Renewable Development Fund Rider	39,159,187	31,877,442	Various	40,638,061	30,398,568
15	- MN Docket E-002/M-19-609					
16						
17	Renewable*Connect Classic	2,400,704	7,825,382	142	5,709,346	4,516,740
18	- MN Docket E-002/GR-15-985					
19						
20	Renewable*Connect Government	108,001	394,317	142	322,549	179,769
21	- MN Docket E-002/GR-15-985					
22						
23	Sherco 3 Depreciation Deferral	8,050,075		407.3	503,130	7,546,945
24	- MN Docket E-002/GR-15-826					
25	- Amortized over 21 years (01/2014-12/2035)					
26						
27	South Dakota Propertry Tax Collected in the		464,076			464,076
28	Fuel Clause Adjustment					
29	- SD Docket EL 14-058					
30						
31	South Dakota Ratemaking Differences	3,420,250	458,000	405	452,000	3,426,250
32	- SD Docket F-3382					
33	- SD Docket F-3422					
34						
35	South Dakota REC Sales		720			720
36						
37	Theoretical Depreciation Reserve Surplus	267,833,659		407.3	10,039,729	257,793,930
38	- MN Docket E-002/GR-17-147					
39						
40	Transmission Formula Rates	10,959,010	5,511,238	Various	7,049,261	9,420,987
41						
42						
43						
44	TOTAL	3,733,740,125	467,217,304		435,215,028	3,765,742,401

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 37 Column: d

456	$29,383,769
908	105,913,418
Total	$135,297,187

Schedule Page: 232.1 Line No.: 11 Column: c

517	$2,888,579
519	697,418
520	7,500,314
523	554,352
524	1,853,202
528	4,049,037
530	22,944,313
531	3,216,888
532	17,040,653
Total	$60,744,756

Schedule Page: 232.1 Line No.: 11 Column: d

517	$2,809,321
519	845,384
520	6,451,644
523	432,962
524	2,019,774
528	1,630,195
529	8,311
530	19,454,580
531	2,208,270
532	14,766,248
Total	$50,626,689

Schedule Page: 232.1 Line No.: 17 Column: d

407.3	$18,129,386
856	594,033
863	227,292
870	527
874	3,553,320
880	123,202
887	39,452
892	3,733
893	12,524
Total	$22,683,469

Schedule Page: 232.1 Line No.: 21 Column: d

253	$18,083,333
557	1,104,550
Total	$19,187,883

Schedule Page: 232.1 Line No.: 41 Column: d

Accounts charged:

282	$2,840,730
283	11,850
Total	$2,852,580

Schedule Page: 232.1 Line No.: 43 Column: d

Accounts charged:

283	$3,039,637

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) _ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

410.1	7,636,569
Total	$10,676,206

Schedule Page: 232.1 Line No.: 43 Column: f

	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Total
Electric	$ 98,240,056	$ 38,411,721	$ 136,651,777
Gas	4,318,651	1,688,585	6,007,236
Total	$ 102,558,707	$ 40,100,306	$ 142,659,013

*Total nonplant excess ADIT including current and non-current is $102,558,707. This amount would be included as an increase to rate base for purposes of calculating the NSP companies formula rates, as applicable.

*For purposes of calculating the 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 12/31/2018	Amortization 2019	Excess Balance 12/31/2019
Bad Debts	$ 2,047,034	$ (511,758)	$ 1,535,276
Deferred Rent	1,093,005	(273,251)	819,754
Deferred Revenues	231,864	(57,966)	173,898
Economic Development Securities - Write-Off	38,226	(9,556)	28,670
Employee Incentive Plans	1,593,133	(398,283)	1,194,850
Environmental Remediation	17,830	(4,457)	13,373
Federal Net Operating Loss	92,282,966	(4,194,680)	88,088,286
Fuel Tax Credit - Income Addback	1,808	(452)	1,356
Inventory Reserve	396,054	(99,014)	297,040
Litigation Reserve	43,051	(10,763)	32,288
Medical Deductions - Self Insured	186,254	(46,564)	139,690
North Dakota Investment Tax Credit	(12,152,173)	3,038,043	(9,114,130)
North Dakota Investment Tax Credit - Valuation Allowance	12,152,173	(3,038,043)	9,114,130
Performance Recognition Awards	4,370	(1,092)	3,278
Post Employment Benefits - Long Term Disability	1,790,541	(127,896)	1,662,645
Post Employment Benefits - Retiree Medical	5,742,707	(410,193)	5,332,514
Purchased Power Capacity	20,632	(5,158)	15,474
Rate Refund	2,393,091	(598,273)	1,794,818
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	1,464,788	(366,197)	1,098,591
Regulatory Asset/Liability - Transmission Cost Recovery Rider	764,858	(191,214)	573,644
Regulatory Asset/Liability - Prairie Island Extended Power Uprate Cancellation	408,416	(102,104)	306,312
Sale of Emission Allowances	8,167	(2,042)	6,125
South Dakota Infrastructure Rider	104,885	(26,221)	78,664
Section 174 - Section 59(e) Adjustment	5,533,144	(1,383,286)	4,149,858
Severance Accrual	24,329	(6,082)	18,247
Solar Rewards Program	2,705,878	(676,470)	2,029,408
State Research and Experimental Credit	(814,302)	203,576	(610,726)
State Research Credit - Valuation	156,237	(39,059)	117,178

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) _ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Allowance			
Vacation	1,816,186	(454,046)	1,362,140
VEBA	508,845	(127,211)	381,634
Workers Compensation	9,461	(2,365)	7,096
Total Electric	$ 120,573,458	$(9,922,077)	$ 110,651,381

Schedule Page: 232.2 Line No.: 14 Column: d

Accounts charged:	
254	$538,704
407.3	40,099,357
Total	$40,638,061

Schedule Page: 232.2 Line No.: 40 Column: d

Accounts charged:	
456.1	$6,883,625
565	165,636
Total	$7,049,261

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	IPP Power Contract Billing	835,715		Various	19,541	816,174
2	Adjustments					
3						
4	Conservation and Energy	25,948,410	16,346,184	182.3	25,948,412	16,346,182
5	Management Program Costs					
6	Minnesota Electric Incentive					
7	(Docket E-002/M-19-258)					
8						
9	Conservation and Energy	2,344,688	1,592,770	254	2,344,687	1,592,771
10	Management Program Costs					
11	Minnesota Gas Incentive					
12	(Docket G-002/M-19-259)					
13						
14	Federal and State Income	1,365,198	437,244			1,802,442
15	Taxes Receivable					
16						
17	Federal and State Income	5,345,929	166,325			5,512,254
18	Tax Interest Receivable					
19						
20	Debt Issuance Costs	319,366	3,199,741	181	3,499,015	20,092
21						
22	2016 Minnesota Electric Retail	834,996		928	834,996	
23	Rate Case					
24	- Amortized through Dec. 2019					
25	(Docket E-002/GR-15-826)					
26						
27	North Dakota Electric	1,974,937				1,974,937
28	Retail Rate Case-Demand Study					
29	and Generation Restack					
30	(Docket PU-12-813)					
31						
32	Future South Dakota Electric	113,169				113,169
33	Retail Rate Case					
34	(Docket EL14-058)					
35						
36	Notes Receivable - 3rd Party		4,804,592	143	474,585	4,330,007
37						
38	2018 Minnesota Gas Retail Rate	8,279		928	8,279	
39	Case					
40						
41	Prepaids - Facility Fees	1,133,024	1,934,832	431	1,363,656	1,704,200
42						
43	JOA & Rate Payer Share MTM	357,636	1,413,456			1,771,092
44						
45	2018 North Dakota Electric	306,398		928	306,398	
46	Retail Rate Case					
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	40,891,771				37,462,823

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	FIN 48 Long Term Interest	4,026		232	4,026	
2	Receivable					
3						
4	Future Minnesota Electric		1,699,352	928	219,849	1,479,503
5	Retail Rate Case					
6						
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45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	40,891,771				37,462,823

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 1 Column: d

Accounts charged:

232	($1,210)
555	20,751
Total	$19,541

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric - Plant	195,829,217	205,614,110
3	Electric - Non-Plant	536,988,904	735,971,832
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	732,818,121	941,585,942
9	Gas		
10		20,204,873	33,190,963
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	20,204,873	33,190,963
17	Other (Specify)	40,011,300	32,243,671
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	793,034,294	1,007,020,576

Notes

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 234 Line No.: 2 Column: c

	Balance at Beginning of Year	Balance at End of Year
Electric Distribution Plant	$117,591,782	$123,944,250
Electric General Plant	548,166	448,363
Electric Intangible Plant	4,204,166	3,412,088
Electric Nuclear Fuel	26,652,048	27,574,348
Electric Nuclear Production Plant	65,274,613	59,970,872
Electric Production Plant	42,356,143	45,649,753
Electric Transmission Plant	40,450,403	41,239,498
Electric Transmission-Production Plant	537,870	605,418
Common (Allocation to Electric)	729,200	847,500
Regulatory Differences - Effect of Rate Changes	(110,946,257)	(105,915,793)
Regulatory Differences - Investment Tax Credit Gross-Up	8,431,083	7,837,813
Total Electric Plant Related Only	$195,829,217	$205,614,110

Schedule Page: 234 Line No.: 8 Column: c

Electric:	Balance at Beginning of Year	Balance at End of Year
Avoided Tax Interest	$134,316,526	$134,107,468
Bad Debts	6,163,082	6,028,221
Customer Advances	3,977,711	3,470,992
Deferred Connection Fees	105,938,424	113,946,120
Deferred Rent	2,924,005	2,819,639
Deferred Revenue	550,288	476,394
Economic Development Securities - Write-Off	104,417	102,410
Electric Vehicle Credit	6,956	126,938
Employee Incentive Plans	4,036,902	4,365,714
Employee Stock Ownership Program Dividends	6,670,645	6,550,738
End of Life Nuclear Fuel Amortization	26,652,048	27,574,348
Environmental Remediation	49,235	49,191
Excess Nonplant Accumulated Deferred Income Taxes	13,741,549	11,688,735
Fuel Tax Credit - Income Addback	4,985	5,868
Inventory Reserve	764,793	578,103
Investment Tax Credit	452,260	263,846
Litigation Reserve	170,814	229,736
Mark to Market Adjustment	0	98,156
Medical Deductions - Self Insured	611,383	305,056
Monticello Extended Power Uprate Writedown	20,789,037	18,042,424
New Hire Retention Credit	51,546	51,639
North Dakota Investment Tax Credit	82,647,239	72,220,557
North Dakota Investment Tax Credit - Valuation Allowance	(76,737,862)	(65,330,829)
North Dakota Investment Tax Credit - Federal Gross-Up	1,592,313	2,060,729
Operating Lease Assets	0	156,855,030
Performance Recognition Awards	47,757	66,481
Post Employment Benefits - Retiree Medical	13,356,931	11,774,594
Post Employment Benefits - Long Term Disability	3,978,153	3,088,470

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Purchased Power Capacity	56,972	0
Rate Refund	48,097,251	10,743,991
Regulatory Asset/Liability -Net Operating Loss Tracker	0	557,032
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	2,333,571	0
Regulatory Asset/Liability - Transmission Cost Recovery Rider	11,009,066	9,533,858
Regulatory Asset/Liability - Transmission Attach O	238,060	2,913,836
Regulatory Asset/Liability - Windsource	804,181	591,422
Regulatory Difference - Effect of Rate Changes	(110,946,257)	(105,915,793)
Regulatory Difference - Investment Tax Credit Gross-Up	8,431,083	7,837,813
Research and Experimentation Credit	56,204,033	60,540,768
Sale of Emission Allowances	31	47
Section 174 - Section 59(e) Adjustment	20,918,228	28,797,336
Severance Accrual	84,652	23,533
Solar Rewards Program	4,461,705	4,159,916
South Dakota Infrastructure Tracker	378,425	620,038
State Research Credit	6,351,862	6,661,820
State Research Credit - Valuation Allowance	(1,729,739)	(593,837)
State Tax Deduction Cash vs. Accrual	1,262,092	1,270,374
Vacation Accrual	4,860,479	4,949,374
VEBA	1,401,025	1,897,362
Wind Production Tax Credit	325,691,722	395,290,407
Workers Compensation	48,542	89,877
Total Electric	$732,818,121	$941,585,942

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.

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.

	12/31/2019 Excess	12/31/2019 Gross up	12/31/2019 Total Regulatory
Excess (Electric only)			
Flow Through	$496,981	$194,319	$691,300
Other Basis Differences	(76,640,691)	(29,966,402)	(106,607,093)
(Unprotected)	($76,143,710)	($29,772,083)	($105,915,793)

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

	12/31/2019 Excess	12/31/2019 Gross up	12/31/2019 Total Regulatory
Non-utility			
Other Basis Differences	($8)	($3)	($11)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

(Unprotected)	($8)	($3)	($11)
Common (allocated)			
Other Basis Differences)	($144,644)	($56,556)	($201,200)
(Unprotected)	($144,644)	($56,556)	($201,200)
Common (unallocated)			
Other Basis Differences	($302,216)	($118,166)	($420,382)
(Unprotected)	($302,216)	($118,166)	($420,382)

Schedule Page: 234 Line No.: 16 Column: c

Schedule Page: 234 Line No.: 16 Column: c

Gas:	Balance at Beginning of Year	Balance at End of Year
Avoided Tax Interest	$2,811,017	$2,824,494
Bad Debts	435,111	425,590
Deferred Connection Fees	10,516,629	12,077,859
Deferred Rent	228,561	222,473
Economic Development Securities - Write-Off	7,372	9,279
Electric Vehicle Credit	544	563
Employee Incentive Plans	348,780	377,189
Employee Stock Ownership Program Dividends	2,371,287	2,388,340
Environmental Remediation	1,701,973	1,319,025
Excess Nonplant Accumulated Deferred Income Taxes	688,148	598,747
Fuel Tax Credit - Income Addback	390	476
Inventory Reserve	59,782	45,189
Litigation Reserve	12,059	16,219
Lower of Cost or Market on Gas Inventories	387,258	271,653
Medical Deduction - Self Insured	52,822	23,826
New Hire Retention Credit	4,454	4,361
Operating Lease Assets	0	12,717,975
Performance Recognition Awards	4,126	5,744
Post Employment Benefits - Retiree Medical	1,154,011	1,017,301
Post Employment Benefits - Long Term Disability	343,704	266,838
Public Utility Conservation Investment Programs	819,898	600,768
Rate Refund	1,582,989	283,791
Regulatory Difference - Effect of Rate Changes	(6,049,098)	(5,745,538)
Regulatory Difference - Investment Tax Credit Gross-Up	469,397	426,882
Section 174 - Section 59(e) Adjustment	1,635,118	2,334,918
Severance Accrual	7,314	2,033
State Tax Deduction Cash vs. Accrual	66,052	79,233
Vacation Accrual	419,935	427,739
VEBA	121,046	160,231
Workers' Compensation	4,194	7,765
Total Gas	$20,204,873	$33,190,963

Schedule Page: 234 Line No.: 17 Column: c

Other:	Balance at Beginning of Year	Balance at End of Year
Avoided Tax Interest	$1,141	$85
Contributions Carryover	791,395	96,568
Deferred Compensation Plan Reserve	5,110,390	6,519,146
Federal Alternative Minimum Tax Credit	1,585,871	1,598,387
Federal Alternative Minimum Tax Credit - Valuation Allowance	(57,635)	0

Low Income Housing Credit	3,344,790	1,905,366
Minnesota Alternative Minimum Tax Credit	161,287	161,287
Minnesota Net Operating Loss	18,046,950	11,451,917
North Dakota Net Operating Loss	18,228	17,335
Nonqualified Pension Plans	592,440	297,936
Other Comprehensive Income	9,040,442	8,784,498
Partnership Passthrough	330,333	365,202
Performance Share Plan	900,276	887,954
Regulatory Difference - Effect of Rate Changes	(16)	(16)
State Tax Deduction Cash vs. Accrual	145,408	158,006
Total Other	$40,011,300	$32,243,671

	2018 ARAM	2019 ARAM
Electric Distribution Plant	$1,281,180	$1,455,450
Electric General Plant	8,250	33,458
Electric Intangible Plant	244,874	246,059
Electric Nuclear Fuel	0	0
Electric Production Plant	1,578,622	1,714,748
Electric Transmission Plant	364,453	370,469
Electric Transmission-Production Plant	3,137	4,106
Common (Allocation to Electric)	8,808	8,562
Total Electric	$3,489,324	$3,832,852

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

Common (Unallocated)	$9,593	$9,503

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock			
2	-All NSP-Minnesota common stock is owned by			
3	parent, Xcel Energy Inc.	5,000,000	0.01	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						2
1,000,000	10,000					3
						4
						5
						6
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OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211 - Miscellaneous Paid-in Capital	
2	Contribution of capital by parent company	3,588,600,285
3		
4		
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6		
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40	TOTAL	3,588,600,285

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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		
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7		
8		
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19		
20		
21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221		
2	FIRST MORTGAGE BONDS SERIES DUE:		
3			
4			
5	2.15% Aug. 15, 2022 First Mortgage Bonds	300,000,000	3,088,686
6			456,000 D
7			
8	7.125% July 1, 2025 First Mortgage Bonds	250,000,000	1,898,333
9			2,330,000 D
10			
11	6.50% March 1, 2028 First Mortgage Bonds	150,000,000	1,474,885
12			1,761,001 D
13			
14	5.25% July 15, 2035 First Mortgage Bonds	250,000,000	3,032,114
15			485,000 D
16			
17	6.25% June 1, 2036 First Mortgage Bonds	400,000,000	4,877,065
18			1,404,000 D
19			
20	6.20% July 1, 2037 First Mortgage Bonds	350,000,000	4,336,843
21			1,988,000 D
22			
23	5.35% Nov. 1, 2039 First Mortgage Bonds	300,000,000	4,153,918
24			570,000 D
25			
26	4.85% Aug. 15, 2040 First Mortgage Bonds	250,000,000	3,019,146
27			707,500 D
28			
29	3.40% Aug 15, 2042 First Mortgage Bonds	500,000,000	6,272,718
30			3,820,000 D
31			
32	2.60% May 15, 2023 First Mortgage Bonds	400,000,000	4,524,626
33	TOTAL	5,600,000,000	110,586,138

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			732,000 D
2			
3	4.125% May 15, 2044 First Mortgage Bonds	300,000,000	3,821,358
4			873,000 D
5			
6	3.60% Sep 15, 2047 First Mortgage Bond	600,000,000	8,795,587
7			5,982,000 D
8			
9	2.20% Aug. 15, 2020 First Mortgage Bonds	300,000,000	3,072,956
10			552,000 D
11			
12	4.00% Aug. 15, 2045 First Mortgage Bonds	300,000,000	3,897,956
13			4,899,000 D
14			
15	3.60% May 15, 2046 First Mortgage Bonds	350,000,000	5,404,423
16			2,093,000 D
17			
18	2.90% Mar. 1, 2050 First Mortgage Bonds	600,000,000	8,689,023
19			11,574,000 D
20	SUBTOTAL - ACCOUNT 221	5,600,000,000	110,586,138
21			
22	ACCOUNT 224		
23	OTHER LONG TERM DEBT		
24			
25	Right of Way debt		
26			
27	SUBTOTAL - ACCOUNT 224		
28			
29	Interest on Debt to Associated Companies		
30			
31			
32			
33	TOTAL	5,600,000,000	110,586,138

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
8/13/2012	8/15/2022	8/13/2012	8/15/2022	300,000,000	6,450,000	5
						6
						7
7/7/1995	7/1/2025	7/7/1995	7/1/2025	250,000,000	17,812,500	8
						9
						10
3/17/1998	3/1/2028	3/17/1998	3/1/2028	150,000,000	9,750,000	11
						12
						13
7/21/2005	7/15/2035	7/21/2005	7/15/2035	250,000,000	13,125,000	14
						15
						16
5/25/2006	6/1/2036	5/25/2006	6/1/2036	400,000,000	24,455,460	17
						18
						19
6/26/2007	7/1/2037	6/26/2007	7/1/2037	350,000,000	21,700,000	20
						21
						22
11/17/2009	11/1/2039	11/17/2009	11/1/2039	300,000,000	16,156,992	23
						24
						25
8/11/2010	8/15/2040	8/11/2010	8/15/2040	250,000,000	12,125,000	26
						27
						28
8/13/2012	8/15/2042	8/13/2012	8/15/2042	500,000,000	18,496,479	29
						30
						31
5/20/2013	5/15/2023	5/20/2013	5/15/2023	400,000,000	10,400,000	32
				5,600,008,843	223,320,156	33

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
5/13/2014	5/15/2044	5/13/2014	5/15/2044	300,000,000	12,375,000	3
						4
						5
09/13/2017	09/15/2047	09/13/2017	09/15/2047	600,000,000	21,600,000	6
						7
						8
8/11/2015	8/15/2020	8/11/2015	8/15/2020	300,000,000	6,600,000	9
						10
						11
8/11/2015	8/15/2045	8/11/2015	8/15/2045	300,000,000	12,000,000	12
						13
						14
5/31/2016	5/15/2046	5/31/2016	5/15/2046	350,000,000	12,600,000	15
						16
						17
9/10/2019	3/1/2050	9/10/2019	3/1/2050	600,000,000	5,365,000	18
						19
				5,600,000,000	221,011,431	20
						21
						22
						23
						24
				8,843		25
						26
				8,843		27
						28
					2,308,725	29
						30
						31
						32
				5,600,008,843	223,320,156	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 17 Column: i

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

Schedule Page: 256 Line No.: 23 Column: i

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

Schedule Page: 256 Line No.: 29 Column: i

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

Schedule Page: 256.1 Line No.: 18 Column: a

Minnesota Public Utilities Commission Case no. E, G-002/S-18-654. Order dated April 22, 2019

In September 2019, NSPMN issued $600,000,000 of 2.90 percent First Mortgage Bonds, due March 1, 2050. NSPMN used the net proceeds to finance or refinance, existing and future Eligible Green Expenditures.

Schedule Page: 256.1 Line No.: 25 Column: h

	Balance Dec. 31, 2018	Additions	Reductions	Balance Dec. 31, 2019
Right of Way debt	$ 9,208		$ (365)	$ 8,843

Schedule Page: 256.1 Line No.: 29 Column: i

Xcel Energy Services Inc	$1,613,527
NSP Nuclear Corp	$33,476
Money Pool	$661,722
	$2,308,725

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	542,566,082
2		
3		
4	Taxable Income Not Reported on Books	
5		47,128,911
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		1,024,070,966
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		-37,392,115
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-1,247,390,057
21		
22	Equity in Earnings of Subsidiary Companies	63,024
23		
24	Total Income Tax Expense	47,488,359
25		
26		
27	Federal Tax Net Income	376,535,171
28	Show Computation of Tax:	
29	Federal Income Tax at 21 Percent	79,072,386
30	Other	4,311,676
31	Total Federal Income Tax Payable	83,384,062
32		
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44		

Schedule Page: 261 Line No.: 5 Column: b

TAXABLE INCOME NOT REPORTED ON BOOKS:	
Contributions in Aid of Construction	$44,383,798
Gain/(Loss) on Dispositions (Tax)	2,745,113
	$47,128,911

Schedule Page: 261 Line No.: 10 Column: b

DEDUCTIONS RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:	
Avoided Cost Interest	$29,308,006
Book Amortization - Computer Software	66,662,152
Book Amortization - Other	13,590,691
Book Depreciation	641,542,593
Book Rent Expense - Capitalized for Tax - Railcars	576,077
Book Unamortized Cost of Reacquired Debt	2,085,808
Capitalization of Software Expense - Books	183,301
Clearing Account Book Expense	17,168,667
Deferred Compensation Plan Reserve	5,028,012
Deferred Fuel Costs	6,362,793
Employee Incentive Plans	1,284,807
Employee Stock Ownership Plan Dividends	1,302,572
Executive Officer Nondeductible Compensation	2,164,411
Litigation Reserve	225,000
Lobbying Expenses	1,636,000
Mark to Market Adjustment	8,121,550
Meals & Entertainment	1,393,000
Nuclear Decommissioning	20,371,744
Nuclear Fuel Expense	117,356,383
Penalties	40,233
Pension and Benefit Capitalized	4,188,192
Performance Recognition Awards	72,529
Prairie Island Extended Power Uprate Writedown Amortization	3,544,366
Public Utility Conservation Investments Programs Adjustment	21,549,729
Rate Surcharge	1,368,988
Regulatory Asset/Liability Cancellation	6,181,967
Regulatory Asset/Liability - Net Operating Loss Tracker	1,981,670
Regulatory Asset/Liability - Transmission Attach O	9,519,976
Regulatory Asset - Gas Safety Deferrals	1,172,281
Regulatory Asset - Property Tax	7,604,751
Regulatory Reserve - Environmental	2,413,482
Sale of Emission Allowances	56
Section 174 - Section 59(e) Adjustment	26,136,102
South Dakota Infrastructure Tracker	860,757
Suite and Entertainment Tickets	393,000
Tax Expense - Spent Fuel Isolation Devices	158,557
Vacation Accrual	360,833
Workers' Compensation	159,930
	$1,024,070,966

Schedule Page: 261 Line No.: 15 Column: b

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:	
Allowance for Funds During Construction (AFDC) - Equity (Non-Conservation Improvement Program)	($24,897,905)
Deferred Revenue - Investment Tax Credit (ITC) Grant	(173,547)
Gain/(Loss) on Dispositions (Book)	(7,661,548)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) _ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Insurance Fund Income (Cash Value)	(3,599,700)
Solar Rewards Program	(1,059,415)
	($37,392,115)

Schedule Page: 261 Line No.: 20 Column: b

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:

Allowance for Funds During Construction (AFDC) - Debt (Non-Conservation Improvement Program)	($12,958,269)
Bad Debts	(492,620)
Book Income - Wisconsin/South Dakota Allowance for Funds During Construction	(6,000)
Contributions Carryover	(1,919,561)
Deferred Rent	(382,899)
Deferred Revenue	(261,130)
Electric Vehicle Charging Tariff	(195,960)
Employee Retention	(238,213)
Environmental Remediation	(1,356,936)
External Qualified Nuclear Decommissioning Fund	(20,371,744)
Internally Developed Software	(172,872)
Interest Expense - Capital Leases	(252,428)
Interest Income/Expense on Disputed Tax	(600,333)
Inventory Reserve	(713,450)
Medical Deduction - Self Insured	(1,036,929)
Nonqualified Pension Plan	(1,045,828)
Pension Expense	(13,619,988)
Performance Share Plan	(40,966)
Post Employment Benefits - Retiree Medical	(6,069,357)
Post Employment Benefits - Long Term Disability	(3,424,781)
Prepaid Insurance	(9,598,092)
Purchased Power Capacity	(202,500)
Rate Case/Restructuring Expense	(330,551)
Rate Refund	(137,349,907)
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	(50,141,701)
Regulatory Asset/Liability - Transmission Cost Recovery Rider	(5,213,053)
Regulatory Asset/Liability - Windsource	(754,338)
Regulatory Asset - Nuclear Refueling Outage Costs	(10,118,067)
Renewable Energy Standard/Credit	(738,160)
Repair Expenditures	(51,100,000)
Section 174	(40,800,000)
Severance Accrual	(235,926)
State Tax Deduction	(26,493,748)
Tax Amortization - Monticello Rerate	(6,295,644)
Tax Amortization - Computer Software	(63,847,516)
Tax Amortization - Pollution Control Facilities	(515,551)
Tax Expense - Ash Pond & Landfills	(299,964)
Tax Depreciation	(723,340,122)
Tax Removal Cost Over Book	(54,854,953)
	($1,247,390,057)

Schedule Page: 261 Line No.: 31 Column: b

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 2019. The other members of the affiliated group and the federal income tax provision of each are:

Xcel Energy Inc.	($39,726,114)

NSP Nuclear Corporation	13,202
United Power and Land Company	(25,706)
Northern States Power Company (Wisconsin) and Subsidiaries	6,057,334
Public Service Company of Colorado and Subsidiaries	(6,866,138)
Southwestern Public Service Company	(3,315,946)
Nicollet Holdings Company, LLC and Subsidiaries	1,143,742
Nicollet Projects Holdings Company, LLC and Subsidiaries	(2,249,851)
Xcel Energy Communications Group Inc. and Subsidiaries	(53,676)
Xcel Energy Markets Holdings Inc. and Subsidiaries	(510,642)
Xcel Energy International Inc.	(344)
Xcel Energy Retail Holdings Inc. and Subsidiaries	(3,631)
Xcel Energy Transmission Holding Company, LLC and Subsidiaries	(38,874)
Xcel Energy Ventures Inc. and Subsidiaries	(24,540,198)
Xcel Energy Venture Holdings, Inc. and Subsidiaries	588,212
Xcel Energy Wholesale Group Inc. and Subsidiaries	(32,794,186)
Xcel Energy WYCO Inc.	5,104,227
WestGas Interstate, Inc.	23,638
Xcel Energy Services Inc.	4,350,474

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	FEDERAL TAXES					
2	Income	5,987,675		80,616,863	78,145,749	-3,793,605
3	Income Tax Adjustment			2,767,199		-2,767,199
4						
5	FICA 2018	2,383,367			2,383,367	
6	FICA 2019			33,550,964	31,024,899	
7						
8	Unemployment 2018	3,658			3,658	
9	Unemployment 2019			182,938	179,014	
10						
11	SUBTOTAL	8,374,700		117,117,964	111,736,687	-6,560,804
12						
13	STATE TAXES					
14	MINNESOTA					
15	Income	2,684,831		8,194,280	26,556,494	18,942,461
16	Income Tax Adjustment			448,425		-448,425
17						
18	Unemployment 2018	115,773			115,773	
19	Unemployment 2019			4,600,317	4,487,224	
20						
21	Property Taxes 2018	203,400,000		438,785	203,838,785	
22	Property Taxes 2019			204,960,000		
23	Property Tax MN Stlmt			10,074,618		-10,074,618
24						
25	Use					
26						
27	SUBTOTAL	206,200,604		228,716,425	234,998,276	8,419,418
28						
29	STATE TAXES					
30	NORTH DAKOTA					
31	Income	149,251		-209,408	-56,991	395,098
32	Income Tax Adjustment			1,297		-1,297
33						
34	Unemployment 2018	22			22	
35	Unemployment 2019			6,403	6,141	
36						
37	Property Tax 2018	5,462,297		50,459	5,512,755	
38	Property Tax 2019			7,164,000	15,804	
39						
40	Use					
41	TOTAL	226,727,805	2,750	372,290,821	373,681,304	2,242,846

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1						
2	SUBTOTAL	5,611,570		7,012,751	5,477,731	393,801
3						
4	STATE TAXES					
5	SOUTH DAKOTA					
6	Unemployment 2018	-102			-102	
7	Unemployment 2019			34,765	53,105	
8						
9	Personal Property 2018	4,440,000		-107,632	4,332,368	
10	Personal Property 2019			4,398,000		
11	Personal Property FCA			-575,372	575,372	
12						
13	Use					
14						
15	SUBTOTAL	4,439,898		3,749,761	4,960,743	
16						
17	STATE TAXES					
18	KANSAS					
19	Personal Property 2019			751,484	751,484	
20						
21	SUBTOTAL			751,484	751,484	
22						
23	STATE TAXES					
24	WISCONSIN					
25	Income		2,677	6,491	-5,755	-9,569
26						
27	Unemployment			-100	100	
28						
29	SUBTOTAL		2,677	6,391	-5,655	-9,569
30						
31	OTHER					
32	Georgia Unemployment		73	288	361	
33	Denver Occ'l Privilege					
34	Prop Tax on Rail Car 2018	12,000		-8,985	3,015	
35	Prop Tax on Rail Car 2019			12,000	2,433	
36	Other			200,054	200,054	
37						
38	Use	2,089,033		14,732,688	15,556,175	
39						
40						
41	TOTAL	226,727,805	2,750	372,290,821	373,681,304	2,242,846

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
4,665,184		73,916,439			6,700,424	2
		2,626,699			140,500	3
						4
						5
2,526,065		28,203,377			5,347,587	6
						7
						8
3,924		161,247			21,691	9
						10
7,195,173		104,907,762			12,210,202	11
						12
						13
						14
3,265,078		15,128,131			-6,933,851	15
		392,190			56,235	16
						17
						18
113,093		2,995,223			1,605,094	19
						20
		405,766			33,019	21
204,960,000		188,214,000			16,746,000	22
		10,074,618				23
						24
						25
						26
208,338,171		217,209,928			11,506,497	27
						28
						29
						30
391,932		-268,063			58,655	31
					1,297	32
						33
						34
262		3,954			2,449	35
						36
		17,597			32,862	37
7,148,196		6,020,400			1,143,600	38
						39
						40
228,728,234		331,832,095			40,458,726	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
7,540,390		5,773,888			1,238,863	2
						3
						4
						5
						6
-18,340		21,469			13,296	7
						8
		-107,632				9
4,398,000		4,398,000				10
		-575,372				11
						12
						13
						14
4,379,660		3,736,465			13,296	15
						16
						17
						18
					751,484	19
						20
					751,484	21
						22
						23
						24
		6,491				25
						26
-200		-62			-38	27
						28
-200		6,429			-38	29
						30
						31
-73		178			110	32
		13,779			-13,779	33
					-8,985	34
9,567					12,000	35
		183,666			16,388	36
						37
1,265,546					14,732,688	38
						39
						40
228,728,234		331,832,095			40,458,726	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 2 Column: f

Federal income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)	$220,543
Annual allocation of unitary benefit/detrement for state income taxes accrued as additional paid in capital (207)	(4,014,148)
Total	($3,793,605)

Schedule Page: 262 Line No.: 2 Column: l

Gas (Account No. 409.1)	$6,262,635
Other income and deductions (Account No. 409.2)	437,789
Total	$6,700,424

Schedule Page: 262 Line No.: 3 Column: f

Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	($2,767,199)

Schedule Page: 262 Line No.: 3 Column: l

Other income and deductions (Account No. 409.2)	$140,500

Schedule Page: 262 Line No.: 6 Column: l

Gas (Account No. 408.1)	$2,536,544
Other income and deductions (Account No. 408.2)	120,812
Other	2,690,231
Total	$5,347,587

Schedule Page: 262 Line No.: 9 Column: l

Gas (Account No. 408.1)	$14,510
Other income and deductions (Account No. 408.2)	649
Other	6,532
Total	$21,691

Schedule Page: 262 Line No.: 15 Column: f

State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)	$210,411
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid in capital (207)	18,732,050
Total	$18,942,461

Schedule Page: 262 Line No.: 15 Column: l

Gas (Account No. 409.1)	$1,392,470
Other income and deductions (Account No. 409.2)	(8,326,321)
Total	($6,933,851)

Schedule Page: 262 Line No.: 16 Column: f

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	$2,508
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	(450,933)
Total	($448,425)

Schedule Page: 262 Line No.: 16 Column: l

Other income and deductions (Account No. 409.2)	$56,235

Schedule Page: 262 Line No.: 19 Column: l

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Gas (Account No. 408.1)	$268,508
Other income and deductions (Account No. 408.2)	11,750
Other	1,324,836
Total	$1,605,094

Schedule Page: 262 Line No.: 21 Column: l

Gas (Account No. 408.1)	$33,019

Schedule Page: 262 Line No.: 22 Column: l

Gas (Account No. 408.1)	$16,679,858
Oher income and deductions (Account No. 408.2)	66,142
Total	$16,746,000

Schedule Page: 262 Line No.: 31 Column: f

Annual allocation of unitary benefit/detrement for state income taxes accrued as additional paid in capital (207)	$395,098

Schedule Page: 262 Line No.: 31 Column: l

Gas (Account No. 409.1)	$58,643
Other income and deductions (Account No. 409.2)	12
Total	$58,655

Schedule Page: 262 Line No.: 32 Column: f

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)	($54)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)	(1,243)
Total	($1,297)

Schedule Page: 262 Line No.: 32 Column: l

Other income and deductions (Account No. 409.2)	$1,297

Schedule Page: 262 Line No.: 35 Column: l

Gas (Account No. 408.1)	$354
Other income and deductions (Account No. 408.2)	15
Other	2,080
Total	$2,449

Schedule Page: 262 Line No.: 37 Column: l

Gas (Account No. 408.1)	($16,836)
Other	49,698
Total	$32,862

Schedule Page: 262 Line No.: 38 Column: l

Gas (Account No. 408.1)	$1,105,663
Other	37,937
Total	$1,143,600

Schedule Page: 262.1 Line No.: 7 Column: l

Gas (Account No. 408.1)	$1,923
Other income and deductions (Account No. 408.2)	84
Other	11,289
Total	$13,296

Schedule Page: 262.1 Line No.: 11 Column: a

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

Schedule Page: 262.1 Line No.: 19 Column: l

Gas (Account No. 408.1)	$751,484

Schedule Page: 262.1 Line No.: 25 Column: f

State income tax benefit (accrual and cash) in other accounts receivable (143)	$2,593
Annual allocation of unitary benefit/detriment for Wisconsin income tax accrued as additional paid in capital (207)	(12,162)
Total	($9,569)

Schedule Page: 262.1 Line No.: 27 Column: l

Gas (Account No. 408.1)	($7)
Other income and deductions (Account No. 408.2)	15
Other	(46)
Total	($38)

Schedule Page: 262.1 Line No.: 32 Column: l

Gas (Account No. 408.1)	$16
Other income and deductions (Account No. 408.2)	1
Other	93
Total	$110

Schedule Page: 262.1 Line No.: 33 Column: l

Gas (Account No. 408.1)	$1,253
Other income and deductions (Account No. 408.2)	59
Other	(15,091)
Total	($13,779)

Schedule Page: 262.1 Line No.: 34 Column: a

Property tax on railroad cars used to transport coal from mines to electric generating plants.

Schedule Page: 262.1 Line No.: 34 Column: l

Other	($8,985)

Schedule Page: 262.1 Line No.: 35 Column: a

Property tax on railroad cars used to transport coal from mines to electric generating plants.

Schedule Page: 262.1 Line No.: 35 Column: l

Other	$12,000

Schedule Page: 262.1 Line No.: 36 Column: l

Gas (Account No. 408.1)	$16,620
Other	(232)
Total	$16,388

Schedule Page: 262.1 Line No.: 38 Column: l

Other	$14,732,688

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	52,377			411.4	4,718	
4	7%						
5	10%	18,282,576			411.4	1,208,091	
6	30%	1,479,142			411.4	97,312	
7							
8	TOTAL	19,814,095				1,310,121	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12	4%	1,551			411.4	63	
13	10%	1,190,077			411.4	106,621	
14	TOTAL	1,191,628				106,684	
15							
16	4%	4,491			411.4	776	
17	10%	93,103			411.4	6,565	
18	TOTAL	97,594				7,341	
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
47,659	56 Years		3
			4
17,074,485	52 Years		5
1,381,830	21 Years		6
			7
18,503,974			8
			9
			10
			11
1,488	68 Years		12
1,083,456	49 Years		13
1,084,944			14
			15
3,715	50 Years		16
86,538	50 Years		17
90,253			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
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			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 266 Line No.: 8 Column: h

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.

Schedule Page: 266 Line No.: 11 Column: a

Gas Utility

Schedule Page: 266 Line No.: 15 Column: a

Common Utility

Schedule Page: 266 Line No.: 18 Column: h

(a) Common Allocation

Electric - 91.95%		82,987
Gas - 8.05%		7,265
	$	90,252

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Unfunded Nonqualified Pension	4,750,415	232	1,430,692	238,368	3,558,091
2	Benefit Costs					
3						
4	Deferred Compensation					
5	Employees	13,169,973	131	843,191	5,644,759	17,971,541
6	Employees (Wealth Op)	4,994,230	232	660,964	887,409	5,220,675
7						
8	Postemployment Benefit-Injury	15,361,469	Various	4,665,894	1,241,113	11,936,688
9	Compensation					
10						
11	Environmental & Regulatory	2,229,390			717,247	2,946,637
12	Reserves					
13						
14	Nuclear Waste Strategy Coalition	108,490	232	37,520	700	71,670
15						
16	Renewable Development Fund	39,159,180	232	35,570,345	32,500,000	36,088,835
17	Obligations					
18						
19	Long-Term Income Tax & Interest	4,199,402			3,274,225	7,473,627
20	Payable					
21						
22	Customer Prepayments	2,385,650	107	3,630,610	1,267,400	22,440
23						
24	Deferred Revenue	1,955,927	Various	770,005	508,874	1,694,796
25						
26	Wholesale Merger Settlement	82,703				82,703
27						
28	Pre-Funded AFUDC					
29	Metro Emissions Reduction Rider	54,582,714	405	2,236,214		52,346,500
30	Mercury Emission Reduction Rider	432,305	405	55,576		376,729
31	Minnesota Transmission Cost	30,325,204	405	562,344		29,762,860
32	Recovery Rider					
33	FERC Transmission	39,043,144	405	667,911		38,375,233
34	Renewable Energy Standards Rider	29,025,199	Various	1,455,440	25,717,880	53,287,639
35	South Dakota Transmission	1,892,428	Various	84,915	38,999	1,846,512
36	Cost Recovery Rider					
37	North Dakota Transmission	1,391,187	Various	87,570	98,738	1,402,355
38	Cost Recovery Rider					
39						
40	Executive PSP - Long Term	1,587,228	232	1,241,680	1,326,627	1,672,175
41						
42	Deferred Revenue-ITC Grant	1,631,219	405	173,547		1,457,672
43						
44	Mark-to-Market Adjustment	9,327,284	456	9,327,284		
45						
46						
47	TOTAL	385,835,916		128,713,628	78,033,929	335,156,217

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Mankato/Cannon Falls Lease	39,342,558	227	39,342,558		
2	Normalization					
3						
4	Long-Term Payroll Tax Liability	1,640,320				1,640,320
5						
6	Coal Car Residual Value Deficit	2,886,495			194,528	3,081,023
7						
8	401 Nicollet Lease Credit	11,697,570	Various	7,379,109	4,271,034	8,589,495
9						
10	Laurentian Biomass PPA	72,333,334	182.3	18,083,333		54,250,001
11	Termination					
12						
13	Pine Bend Biomass PPA	300,898	182.3	406,926	106,028	
14	Termination					
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	** Footnote from page 106b					
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	385,835,916		128,713,628	78,033,929	335,156,217

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 269 Line No.: 8 Column: c

Accounts charged:

131	$2,165,054
232	830,840
926	1,670,000
Total	$4,665,894

Schedule Page: 269 Line No.: 24 Column: c

Accounts charged:

447	$469,755
456	300,250
Total	$770,005

Schedule Page: 269 Line No.: 33 Column: d

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, the total company unjurisdictionalized amortization expense (405) amount is $744,299.

Schedule Page: 269 Line No.: 33 Column: e

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, the total company unjurisdictionalized Pre-funded AFUDC (Total Accounts Other Expenses - 432, Other Revenue - 419.1) amount is $0.

Schedule Page: 269 Line No.: 34 Column: c

Accounts charged:

405	$1,451,072
419.1	2,912
432	1,456
Total	$1,455,440

Schedule Page: 269 Line No.: 35 Column: c

Accounts charged:

405	$25,671
419.1	40,790
432	18,454
Total	$84,915

Schedule Page: 269 Line No.: 37 Column: c

Accounts charged:

405	$20,052
419.1	46,343
432	21,175
Total	$87,570

Schedule Page: 269.1 Line No.: 8 Column: c

Accounts charged:

101.1	$3,451,397
165	1,476,570
227	2,451,142
Total	$7,379,109

Schedule Page: 269.1 Line No.: 39 Column: a

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	28,895,301	-2,003,447	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	28,895,301	-2,003,447	
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	28,895,301	-2,003,447	
18	Classification of TOTAL			
19	Federal Income Tax	22,475,885	-1,533,263	
20	State Income Tax	6,419,416	-470,184	
21	Local Income Tax			

NOTES

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
					1	26,891,855	4
							5
							6
							7
					1	26,891,855	8
							9
							10
							11
							12
							13
							14
							15
							16
					1	26,891,855	17
							18
					1	20,942,623	19
						5,949,232	20
							21

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 272 Line No.: 4 Column: k

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.

Schedule Page: 272 Line No.: 8 Column: k

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	2,015,532,683	-13,617,468	
3	Gas	126,421,187	6,504,661	
4				
5	TOTAL (Enter Total of lines 2 thru 4)	2,141,953,870	-7,112,807	
6	Other (Non-Operating)	781,358		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	2,142,735,228	-7,112,807	
10	Classification of TOTAL			
11	Federal Income Tax	1,488,924,102	-34,145,625	
12	State Income Tax	653,811,126	27,032,818	
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
		182.3,254	6,781,110	182.3,254	148,674,477	2,143,808,582	2
		182.3,254	161,750	182.3,254	3,684,192	136,448,290	3
							4
			6,942,860		152,358,669	2,280,256,872	5
-873,992						-92,634	6
							7
							8
-873,992			6,942,860		152,358,669	2,280,164,238	9
							10
-601,723			3,421,843		117,011,073	1,567,765,984	11
-272,269			3,521,016		35,347,596	712,398,255	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: g

And 281

Schedule Page: 274 Line No.: 2 Column: i

And 282

Schedule Page: 274 Line No.: 2 Column: k

	Dec. 31, 2018	410.1 & Adjustments	Dec. 31, 2019
Electric Distribution Plant	$821,313,058	($8,243,012)	$813,070,046
Electric General Plant	83,847,122	(1,103,990)	82,743,132
Electric Intangible Plant	7,759,364	(2,522,852)	5,236,512
Electric Nuclear Fuel	42,202,335	(10,843,547)	31,358,788
Electric Nuclear Production Plant	622,842,630	(21,862,208)	600,980,422
Electric Production Plant	763,208,987	12,366,219	775,575,206
Electric Transmission Plant	836,307,392	17,626,864	853,934,256
Electric Transmission-Production Plant	15,685,313	566,902	16,252,215
Common (Allocation to Electric)	25,203,283	398,154	25,601,437
Regulatory Differences - Prior Flow Thru / Rate Change	(1,429,015,237)	63,000,110	(1,366,015,127)
Regulatory Differences - AFUDC Equity	113,352,335	(3,016,198)	110,336,137
Decommissioning Qualified	112,826,101	81,909,457	194,735,558
Total Electric Plant Related Only	$2,015,532,683	$128,275,899	$2,143,808,582

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.

Schedule Page: 274 Line No.: 3 Column: g

And 282

Schedule Page: 274 Line No.: 6 Column: k

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.

	12/31/2019 Excess	12/31/2019 Gross up	12/31/2019 Total Regulatory
Excess (Electric only)			
Flow Through	($3,266,569)	($1,277,224)	($4,543,793)
Method Life (Protected)	(797,235,741)	(311,718,035)	(1,108,953,776)
Other Basis Differences	(181,536,893)	(70,980,665)	(252,517,558)
(Unprotected)	($982,039,203)	($383,975,924)	($1,366,015,127)

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

	12/31/2019 Excess	12/31/2019 Gross up	12/31/2019 Total Regulatory
Non-utility			
Flow Through	($99,810)	($39,026)	($138,836)
Method Life (Protected)	(297)	(116)	(413)
Other Basis Differences	8	3	11
(Unprotected)	($100,099)	($39,139)	($139,238)
Common (allocated)			
Flow Through	($23,610)	($9,231)	($32,841)
Method Life (Protected)	17,098,875	6,685,636	23,784,511

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) _ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Other Basis Differences	1,391,709	544,156	1,935,865
(Unprotected)	$18,466,974	$7,220,561	$25,687,535
Common (unallocated)			
Flow Through	($28,510)	($11,147)	($39,657)
Method Life (Protected)	20,647,377	8,073,095	28,720,472
Other Basis Differences	1,680,528	657,084	2,337,612
(Unprotected)	$22,299,395	$8,719,032	$31,018,427

	12/31/2018 Excess	12/31/2018 Gross up	12/31/2018 Total Regulatory
Excess (Electric only)			
Flow Through	($3,025,265)	($1,184,350)	($4,209,615)
Method Life (Protected)	(826,002,526)	(323,368,698)	(1,149,371,224)
Other Basis Differences	(197,942,583)	(77,491,815)	(275,434,398)
(Unprotected)	($1,026,970,374)	($402,044,863)	($1,429,015,237)

Schedule Page: 274 Line No.: 9 Column: k

The Flowback of permanent items included above in 410.1 is $7,879,985 for 2018 and $8,288,663 for 2019 for Electric only.

The amortization of Excess ADIT included above in 410.1 is $48,449,164 for 2018 and $46,954,102 for 2019.

	2018 ARAM	2019 ARAM
Electric Distribution Plant	$8,482,257	$8,049,667
Electric General Plant	2,707,179	2,364,555
Electric Intangible Plant	825,913	1,723,209
Electric Nuclear Fuel	7,332,320	6,031,821
Electric Production Plant	22,423,727	22,338,760
Electric Transmission Plant	4,079,590	3,684,679
Electric Transmission-Production Plant	36,194	45,787
Common (Allocation to Electric)	2,571,359	2,700,270
	$48,458,539	$46,938,748
Non Utility	(9,375)	15,354
Total Electric	$48,449,164	$46,954,102

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

Common (Unallocated)	$2,800,435	$2,997,140

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric - Plant	55,501,768	-1,222,098	
4	Electric - Non-Plant	210,366,280	216,849,441	45,023,435
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	265,868,048	215,627,343	45,023,435
10	Gas			
11	Gas	31,379,026	21,950,576	10,596,475
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	31,379,026	21,950,576	10,596,475
18	Other (Non-Operating)	-812,266		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	296,434,808	237,577,919	55,619,910
20	Classification of TOTAL			
21	Federal Income Tax	208,738,215	165,730,381	40,100,677
22	State Income Tax	87,696,593	71,847,538	15,519,233
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
		182.3	44,761		32,911	54,267,820	3
		254	19,694,643		9,724,829	372,222,472	4
							5
							6
							7
							8
			19,739,404		9,757,740	426,490,292	9
							10
		254	1,410,746		704,347	42,026,728	11
							12
							13
							14
							15
							16
			1,410,746		704,347	42,026,728	17
						-812,266	18
			21,150,150		10,462,087	467,704,754	19
							20
			19,181,979		9,508,666	324,694,606	21
			1,968,171		953,421	143,010,148	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 3 Column: i

182.3 & 283

Schedule Page: 276 Line No.: 4 Column: i

254 & 219.1

Schedule Page: 276 Line No.: 9 Column: k

	Balance at Beginning of Year	410.1 & Adjustments	Balance at End of Year
Electric Distribution Plant	161,913	(5,071)	156,842
Electric General Plant	769,047	(25,606)	743,441
Electric Intangible Plant	4,927,658	(964,187)	3,963,471
Electric Nuclear Production Plant	3,513,747	(352,789)	3,160,958
Electric Production Plant	(4,831)	23,895	19,064
Electric Transmission Plant	54,180	(823,710)	(769,530)
Common (Allocation to Electric)	44,728,546	925,370	45,653,916
Regulatory Differences - AFUDC Equity	1,351,508	(11,850)	1,339,658
Total Electric Plant Related Only	55,501,768	(1,233,948)	54,267,820

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.

Schedule Page: 276 Line No.: 11 Column: i

254 & 219.1

Schedule Page: 276 Line No.: 19 Column: k

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	2017 Tax Cuts and Jobs Act - MN Electric	132,964,558	142	172,332,471	39,810,642	442,729
2	- MN Docket E, G999-CI-17-895					
3						
4	2017 Tax Cuts and Jobs Act - MN Gas	5,626,525	142	8,918,542	4,301,619	1,009,602
5	- MN Docket E, G999-CI-17-895					
6						
7	2017 Tax Cuts and Jobs Act - ND Electric	9,816,697	142	9,816,697		
8	- ND Docket PU-18-155					
9						
10	2018 Minnesota Deferred Property Tax	9,633,184	407.3	696,811		8,936,373
11	- MN Docket E-002/GR-15-826					
12						
13	2018 Minnesota Revenue Decoupling	13,016,954	407.4	9,226,380	52,591	3,843,165
14	- MN Docket E-002/GR-15-826					
15	- Amortized over 1 year (04/2019-03/2020)					
16						
17	2019 Minnesota Deferred Property Tax				10,946,539	10,946,539
18	- MN Docket E-002/GR-15-826					
19						
20	Conservation and Energy Management Program Costs	5,258,908	232	18,234,968	16,706,095	3,730,035
21	Minnesota Natural Gas					
22	- MN Docket G-002/M-18-246					
23	- MN Docket G-002/M-19-259					
24	- Generally amortized over 12 month					
25	period following the expenditure					
26						
27	Deferred Tax Collected in Rates in Excess	1,413,788,111	282	61,013,061		1,352,775,050
28	of Current Tax Accrual Levels					
29						
30	Department of Energy Settlement Payment	11,367,522			11,621,017	22,988,539
31	- MN Docket E-002/M-20-112					
32						
33	Derivatives & Hedging - Retail Electric & Gas	10,376,185	175	2,616,852		7,759,333
34						
35	Electric Low Income Discount Program	3,662,457	Various	18,729,513	18,842,355	3,775,299
36	and PowerON Program					
37	- MN Docket E-002/GR-15-826					
38	- MN Docket E-002/M-04-1956					
39	- MN Docket E-002/M-17-629					
40						
41	TOTAL	3,672,887,991		1,325,833,309	1,425,680,593	3,772,735,275

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Gain on Sales of Emission Allowances	110			57	167
2	- MN Docket G-002/GR-12-961					
3						
4	Gas Low Income Discount Program	1,334,120	Various	2,941,601	3,037,138	1,429,657
5	- MN Docket G-002/GR-06-1429					
6						
7	Inver Hills Gain Sharing	128,000	557	218,000	90,000	
8	- MN Docket E-002/M-17-529					
9	- ND Docket PU-18-200					
10						
11	ITC Gross-Up to Pre-Tax Rate Levels	8,900,480	190	635,785		8,264,695
12						
13	Minnesota Deferred Electric Commodity Costs	4,948,113	557	708,598,974	709,995,962	6,345,101
14	- MN Docket E-002/M-14-364					
15						
16	Minnesota Gas State Energy Policy Rider				445,602	445,602
17	- MN Docket G-002/M-18-184					
18	- MN Docket G-002/M-19-200					
19						
20	Minnesota Incentive Compensation Refund	5,257,622	241	3,236,278	1,792,199	3,813,543
21	- MN Docket E-002/M-18-121					
22						
23	Minnesota Renewable Energy Standard	8,282,596	407.4	46,301,635	38,019,039	
24	- MN Docket E-002/M-17-818					
25						
26	Minnesota Retail Asset Margin Sharing	5,983,405	557	20,342,934	19,827,250	5,467,721
27	- MN Docket E-002/GR-12-961					
28						
29	Minnesota Service Quality Program	613,000	142	846,900	1,083,900	850,000
30	- MN Docket E-002/M-19-261					
31						
32	Minnesota Transmission Cost Recovery Rider	5,252,640	407.3	85,514,334	86,860,680	6,598,986
33	- MN Docket E-002/GR-17-797					
34						
35	NOL Tracker				1,981,670	1,981,670
36	- MN Docket E-002/GR-10-971					
37	- MN Docket E-002/GR-15-826					
38						
39	Nonplant Excess ADIT	51,288,448	Various	7,575,060		43,713,388
40						
41	TOTAL	3,672,887,991		1,325,833,309	1,425,680,593	3,772,735,275

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 Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	North Dakota Deferred Electric Commodity Costs	2,414,459	557	45,266,222	45,721,156	2,869,393
2	- ND Docket PU-12-813					
3						
4	North Dakota ITC	7,582,440			2,230,552	9,812,992
5						
6	North Dakota Renewable Energy Rider	11,774	407.4	1,782,068	1,770,294	
7	- ND Docket PU-18-368					
8						
9	North Dakota Retail Asset and Non-Asset	2,164,608	557	2,867,744	2,857,866	2,154,730
10	Margin Sharing					
11	- ND Docket PU-10-657					
12						
13	North Dakota Service Quality Plan	100,000	142	100,000		
14						
15	North Dakota Transmission Cost Revovery Rider	1,403,761	407.4	6,471,640	5,075,615	7,736
16	- ND Docket PU-18-364					
17						
18	Power Purchase Agreement	835,715	555	19,541		816,174
19						
20	Pre-ARO Decommissioning	1,623,008,027			90,652,496	1,713,660,523
21						
22	Refund Liability	10,974,000	557	10,974,000		
23						
24	Renewable Development Fund Rider	538,704	182.3	538,704		
25	- MN Docket E-002/M-19-609					
26						
27	Sherco Land Sale					
28	- MN Docket E-002/M-17-528	(12,860)			12,860	
29						
30	South Dakota Deferred Electric Commodity Costs	5,831,411	557	42,777,718	42,598,814	5,652,507
31	- SD EL14-058					
32						
33	South Dakota Fuel Clause Adjustment Charge	2,848	431	4,254	1,406	
34	- SD EL14-058					
35						
36	South Dakota Infrastructure	1,345,060	407.3	14,011,870	14,872,627	2,205,817
37	- SD Docket EL18-040					
38						
39	South Dakota Production Tax Credit Sharing	786,388	557	4,573,238	4,760,414	973,564
40	- SD Docket EL12-046					
41	TOTAL	3,672,887,991		1,325,833,309	1,425,680,593	3,772,735,275

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	South Dakota Property Tax Collected in the	111,296	408.1	2,013,533	1,902,237	
2	Fuel Clause Adjustment					
3	- SD Docket EL14-058					
4						
5	South Dakota Retail Asset and Non-Asset	693,730	557	2,366,330	2,376,402	703,802
6	Margin Sharing					
7	- SD Docket EL12-046					
8						
9	South Dakota Transmission Cost Recovery Rider	1,366,329	407.4	6,657,359	6,580,612	1,289,582
10	- SD Docket EL18-036					
11						
12	Transco Administrative Services	80,106	407.4	80,106		
13	Agreement					
14	- MN Docket E002/AI-14-759					
15	- MN Docket E002/AI-15-826					
16	- Amortized over four years (01/2016-12/2019)					
17						
18	Transmission Formula Rates	11,805,164	Various	891,454	8,873,408	19,787,118
19						
20	Unrealized Gains on Decommissioning Trust	292,440,076			212,305,542	504,745,618
21						
22	Wescott Asset Sale				6,138,000	6,138,000
23	- MN Docket G-002/PA-18-294					
24	- ND Docket PU-19-103					
25						
26	Windsource	1,905,320	Various	6,640,732	11,535,937	6,800,525
27	- MN Docket E-002/M-01-1479					
28	- MN Docket E-002/GR-13-868					
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	3,672,887,991		1,325,833,309	1,425,680,593	3,772,735,275

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 278 Line No.: 35 Column: c

142	$17,637,619
232	517,936
431	573,958
Total	$18,729,513

Schedule Page: 278.1 Line No.: 4 Column: c

142	$2,815,093
232	126,508
Total	$2,941,601

Schedule Page: 278.1 Line No.: 39 Column: c

Accounts charged:

190	$2,142,214
411.1	5,432,846
Total	$7,575,060

Schedule Page: 278.1 Line No.: 39 Column: f

	Excess Nonplant ADIT – Regulatory Liability*	Gross-Up	Total
Electric	$ 29,894,573	$ 11,688,735	$ 41,583,308
Gas	1,531,332	598,748	2,130,080
Total	$ 31,425,905	$ 12,287,483	$ 43,713,388

*Total nonplant excess ADIT including current and non-current is $31,425,905. This amount would be included as an decrease to rate base for purposes of calculating the NSP companies formula rates, as applicable.

*For purposes of calculating the 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 12/31/2018	Amortization 2019	Excess Balance 12/31/2019
Book Unamortized Cost of Reaquired Debt	$ 1,904,549	$ (476,137)	$ 1,428,412
Deferred Fuel Costs	464,536	(116,134)	348,402
Electric Vehicle Charging Tariff	18,542	(4,636)	13,906
Employee Retention	10,522	(2,631)	7,891
Interest Income/Expense on Disputed Tax	186,869	(46,717)	140,152
Low Income Discount Program	16,490	(4,122)	12,368
Mark to Market Adjustment	1,050,878	(262,720)	788,158
Nuclear Refueling	7,028,587	(1,757,147)	5,271,440
Partnership Passthrough	127,158	(31,790)	95,368
Pension Expense	21,154,151	(1,511,011)	19,643,140
Prepaid Insurance	2,031,990	(507,998)	1,523,992
Property Tax - LT Total	1,666,874	(416,718)	1,250,156
Public Utility Conservation Investment Programs	6,494,258	(1,623,564)	4,870,694
Rate Case / Restructuring Expense	372,631	(93,158)	279,473
Rate Surcharge	5,142,404	(1,285,601)	3,856,803
Renewable Energy Standard/Credit	2,874	(718)	2,156

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Transmission Attachment O	168,392	(42,098)	126,294
State Tax Deduction Cash vs Accrual	421,270	(105,317)	315,953
Windsource	24,658	(6,165)	18,493
Total Electric	$ 48,287,633	$ (8,294,382)	$ 39,993,251

Schedule Page: 278.3 Line No.: 18 Column: c

Accounts charged:

456.1	$296,787
565	594,667
Total	$891,454

Schedule Page: 278.3 Line No.: 26 Column: c

555	$6,421,456
921	219,276
Total	$6,640,732

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,336,964,367	1,432,937,548
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,506,352,378	1,575,574,856
5	Large (or Ind.) (See Instr. 4)	667,753,266	716,179,408
6	(444) Public Street and Highway Lighting	25,572,567	27,408,740
7	(445) Other Sales to Public Authorities	9,820,384	10,001,817
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	587,959	692,309
10	TOTAL Sales to Ultimate Consumers	3,547,050,921	3,762,794,678
11	(447) Sales for Resale	264,152,907	165,135,625
12	TOTAL Sales of Electricity	3,811,203,828	3,927,930,303
13	(Less) (449.1) Provision for Rate Refunds	11,082,805	-2,879,310
14	TOTAL Revenues Net of Prov. for Refunds	3,800,121,023	3,930,809,613
15	Other Operating Revenues		
16	(450) Forfeited Discounts	6,486,842	7,029,827
17	(451) Miscellaneous Service Revenues	2,897,001	2,810,894
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	5,739,859	5,055,666
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	380,501,944	264,370,862
22	(456.1) Revenues from Transmission of Electricity of Others	299,665,596	285,383,048
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	695,291,242	564,650,297
27	TOTAL Electric Operating Revenues	4,495,412,265	4,495,459,910

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
10,106,076	10,476,336	1,324,114	1,313,099	2
				3
14,837,600	15,323,211	158,133	156,937	4
8,389,502	8,877,106	556	552	5
125,360	141,480	6,027	5,727	6
82,901	82,951	2,217	2,227	7
				8
5,583	6,987			9
33,547,022	34,908,071	1,491,047	1,478,542	10
11,311,704	7,656,805			11
44,858,726	42,564,876	1,491,047	1,478,542	12
				13
44,858,726	42,564,876	1,491,047	1,478,542	14

Line 12, column (b) includes $ 129,609 of unbilled revenues.

Line 12, column (d) includes -8,141,165 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 300 Line No.: 5 Column: b

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.

Schedule Page: 300 Line No.: 5 Column: c

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.

Schedule Page: 300 Line No.: 13 Column: c

Credit balance due to accrual reversal.

Schedule Page: 300 Line No.: 17 Column: b

Connection charges	$ 2,561,192
NSF Check Fees	330,329
Other, less than $250,000 each	5,480
	$ 2,897,001

Schedule Page: 300 Line No.: 17 Column: c

Connection charges	$ 2,465,210
NSF Check Fees	334,616
Other, less than $250,000 each	11,068
	$ 2,810,894

Schedule Page: 300 Line No.: 19 Column: b

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.

Schedule Page: 300 Line No.: 21 Column: b

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	$228,292,713
Variable Production Expense	167,768,943
Total Interchange Agreement	$396,061,656

Also includes the following items:

Net distribution of commodity trading margins under Joint Operating Agreement	$ 9,977,822
Renewable*Connect	7,335,706
Fees charged to burn Refuse Derived Fuel	9,193,380
Windsource Program	6,641,083
Change in net over-recovered electric commodity costs	1,267,419
Work on Customers' Equipment	467,106
Distribution Facility Fixed Charges	722,094
Solar Gardens-Subscribed	168,000
Purchased Power Reimbursement	705,565
Facilities Agreement	467,129
Manitoba Hydro Energy Service Agreement	300,000
Timber Sales	23,501
Service Quality Plans	(983,910)
Inver Hills Gain Sharing	(407,229)
Conservation Improvement Program incentive, net of accruals and recoveries	(10,129,777)
Customer refunds due to 2017 Tax Cuts and Jobs Act	(42,001,933)
Other less than $250,000 each	694,332

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

	$380,501,944

Schedule Page: 300 Line No.: 21 Column: c

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	$220,810,971
Variable Production Expense	190,423,065
Total Interchange Agreement	$411,234,036

Also includes the following items:

Fees charged to burn Refuse Derived Fuel	$ 7,580,389
Renewable*Connect	5,753,180
Windsource Program	5,477,420
EEI Mutual Aid Revenue	4,895,394
Inver Hills Gain Sharing	3,415,636
Net distribution of commodity trading margins under Joint Operating Agreement	2,459,720
Purchased Power Reimbursement	742,332
Distribution Facility Fixed Charges	720,207
Work on Customers' Equipment	458,723
Facilities Agreement	439,379
Manitoba Hydro Energy Service Agreement	300,000
Solar Gardens-Subscribed	96,300
Timber Sales	73,234
Service Quality Plans	(684,913)
North Dakota Earnings Sharing	(2,983,461)
Change in net over-recovered electric commodity costs	(12,533,597)
Conservation Improvement Program incentive, net of accruals and recoveries	(19,297,301)
Customer refunds due to 2017 Tax Cuts and Jobs Act	(144,428,431)
Other, less than $250,000 each	652,615
	$264,370,862

Schedule Page: 300 Line No.: 22 Column: b

Includes $61,350,084 reimbursement from NSP-Wisconsin for transmission costs shared under the FERC-approved Interchange Agreement between the companies. See Note 1 to the Financial Statements.

Schedule Page: 300 Line No.: 22 Column: c

Includes $62,491,776 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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					
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34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL					
2	Minnesota					
3	A00 Water Heating	163	20,425	40	4,075	0.1253
4	A01 Residential	4,834,010	668,896,540	761,555	6,348	0.1384
5	A02 Residential Time of Day	4,278	510,893	368	11,625	0.1194
6	A03 Residential Underground	3,664,104	497,005,467	393,800	9,304	0.1356
7	A04 Residential TOD Undergnd	4,852	588,760	342	14,187	0.1213
8	A05 Energy Control	39,293	3,288,797	3,106	12,651	0.0837
9	A06 Limited Off Peak	2,854	252,966	368	7,755	0.0886
10	A07 Auto Protective Lighting	6,380	1,085,748			0.1702
11	A08 Residential Vehicle Tariff	2,159	204,075			0.0945
12	A80 Resid EV Pilot Bundled	294	37,868			0.1288
13	A81 Resid EV Pilot Pre-Pay	101	10,179			0.1008
14	Unbilled	-6,484	-6,698,935			1.0331
15	North Dakota					
16	D01 Residential	608,977	62,758,730	68,323	8,913	0.1031
17	D02 Residential Time of Day	806	70,420	30	26,867	0.0874
18	D03 Residential Underground	167,360	16,154,899	12,462	13,430	0.0965
19	D04 Residential TOD Undergrnd	140	12,155	8	17,500	0.0868
20	D05 Energy Control	3,948	276,320	295	13,383	0.0700
21	D10 Limited Off Peak	853	52,763	104	8,202	0.0619
22	D11 Auto Protective Lighting	331	52,545			0.1587
23	Unbilled	-291	-403,707			1.3873
24	South Dakota					
25	E01 Residential	338,332	41,284,622	45,013	7,516	0.1220
26	E02 Residential Time of Day	80	7,702	7	11,429	0.0963
27	E03 Residential Underground	430,562	51,526,862	38,082	11,306	0.1197
28	E04 Residential Time of Day	62	7,130	5	12,400	0.1150
29	E06 Residential Heat Pump	1,887	160,629	102	18,500	0.0851
30	E10 Energy Control	1,305	96,308	103	12,670	0.0738
31	E11 Limited Off Peak	10	615	1	10,000	0.0615
32	E12 Auto Protective Lighting	339	62,708			0.1850
33	Unbilled	-629	-359,117			0.5709
34	Total Residential	10,106,076	1,336,964,367	1,324,114	7,632	0.1323
35						
36	COMMERCIAL AND INDUSTRIAL					
37	Minnesota					
38	A05 Energy Control	2,138	174,290	111	19,261	0.0815
39	A06 Limited Off Peak	2,157	237,302	84	25,679	0.1100
40	A07 Auto Protective Lighting	23,903	3,529,228			0.1476
41	TOTAL Billed	33,587,965	3,564,533,677	1,491,047	22,526	0.1061
42	Total Unbilled Rev.(See Instr. 6)	-40,943	-17,482,756	0	0	0.4270
43	TOTAL	33,547,022	3,547,050,921	1,491,047	22,499	0.1057

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	A09 Small General Service	24	12,327	99	242	0.5136
2	A10 Small General Service	760,559	95,878,046	74,291	10,238	0.1261
3	A11 Water Heating	187	21,763	78	2,397	0.1164
4	A12 Small General TOD Service	40,847	4,668,343	2,962	13,790	0.1143
5	A13 Direct Current	1	8,210	2	500	8.2100
6	A14 General Service	7,879,135	842,674,318	41,701	188,944	0.1070
7	A15 General TOD Service	7,674,664	644,493,300	4,761	1,611,986	0.0840
8	A16 Small General kWh metered	14,930	1,945,524	3,050	4,895	0.1303
9	A18 Small General TOD Service	26,748	3,139,945	4,260	6,279	0.1174
10	A22 Small Gen TOD Low Watt	2,353	315,426	735	3,201	0.1341
11	A23 Peak Control Tiered	1,086,191	111,043,603	1,389	781,995	0.1022
12	A24 Peak Control Time of Day	2,485,610	198,182,949	346	7,183,844	0.0797
13	A27 Tier 1 Energy Control	434,172	30,200,880	14	31,012,286	0.0696
14	A29 Hiawatha Light Rail	25,079	2,395,787	16	1,567,438	0.0955
15	A62 Firm Real Time Pricing	23,330	1,995,286	3	7,776,667	0.0855
16	Unbilled	-39,406	-9,545,950			0.2422
17	North Dakota					
18	D05 Energy Control	1,656	115,024	55	30,109	0.0695
19	D10 Limited Off Peak	524	42,423	34	15,412	0.0810
20	D11 Auto Protective Lighting	2,654	335,247			0.1263
21	D12 Small General Service	101,620	10,651,070	8,126	12,506	0.1048
22	D14 Small General TOD Service	2,297	229,859	213	10,784	0.1001
23	D16 General Service	685,496	63,473,097	3,746	182,994	0.0926
24	D17 General TOD Service	215,114	16,360,795	210	1,024,352	0.0761
25	D18 Small General TOD Service	558	62,326	101	5,525	0.1117
26	D19 Small General kWh metered	916	116,543	217	4,221	0.1272
27	D20 Peak Control	29,903	2,718,949	46	650,065	0.0909
28	D21 Peak Control Time of Day	131,435	8,999,376	14	9,388,214	0.0685
29	D22 Tier 1 Energy Control	226,696	14,908,365	64	3,542,125	0.0658
30	D34 Sm General TOD Low Watt	68	7,902	21	3,238	0.1162
31	Unbilled	2,282	-304,939			-0.1336
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	33,587,965	3,564,533,677	1,491,047	22,526	0.1061
42	Total Unbilled Rev.(See Instr. 6)	-40,943	-17,482,756	0	0	0.4270
43	TOTAL	33,547,022	3,547,050,921	1,491,047	22,499	0.1057

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3	South Dakota					
4	E10 Energy Control	106	7,881	11	9,636	0.0743
5	E11 Limited Off Peak	318	22,059	8	39,750	0.0694
6	E12 Auto Protective Lighting	2,119	337,056			0.1591
7	E13 Small General Service	83,938	9,573,362	7,400	11,343	0.1141
8	E14 Small General TOD Service	2,122	251,962	355	5,977	0.1187
9	E15 General Service	653,875	64,058,108	3,758	173,995	0.0980
10	E16 General TOD Service	501,546	39,349,844	236	2,125,195	0.0785
11	E18 Small General TOD Service	59	8,020	66	894	0.1359
12	E20 Peak Control	58,546	5,845,305	76	770,342	0.0998
13	E21 Peak Control Time of Day	54,626	4,056,048	15	3,641,733	0.0743
14	E22 Energy Control	24,551	1,864,180	15	1,636,733	0.0759
15	Unbilled	1,455	-354,795			-0.2438
16	Total Commercial and Industrial	23,227,102	2,174,105,644	158,689	146,369	0.0936
17						
18	PUBLIC STREET AND HIGHWAY					
19	Minnesota					
20	A30 Street Light Co Owned	34,140	17,310,518	2,041	16,727	0.5070
21	A32 Street Light Cust Owned	26,908	1,989,509	422	63,763	0.0739
22	A34 Street Lighting Metered	34,436	2,589,611	2,858	12,049	0.0752
23	A37 Street Lighting St Paul	945	138,175	1	945,000	0.1462
24	Unbilled	1,838	206,723			0.1125
25	North Dakota					
26	D30 Street Light Co Owned	924	548,365	62	14,903	0.5935
27	D31 Street Light Cust Owned	11,650	888,280	32	364,063	0.0762
28	D32 Street Lighting Ornamental	37	3,514	2	18,500	0.0950
29	D33 Street Lighting Metered	2,443	153,204	130	18,792	0.0627
30	Unbilled	55	-6,183			-0.1124
31	South Dakota					
32	E30 Street Light Co Owned	814	787,148	115	7,078	0.9670
33	E31 Street Light Cust Owned	3,355	310,865	16	209,688	0.0927
34	E32 Street Lighting Metered	6,850	582,011	252	27,183	0.0850
35	E33 Street Lighting Ornamental	1,045	89,633	96	10,885	0.0858
36	Unbilled	-80	-18,806			0.2351
37	Total Public Street and Highway	125,360	25,572,567	6,027	20,800	0.2040
38						
39						
40						
41	TOTAL Billed	33,587,965	3,564,533,677	1,491,047	22,526	0.1061
42	Total Unbilled Rev.(See Instr. 6)	-40,943	-17,482,756	0	0	0.4270
43	TOTAL	33,547,022	3,547,050,921	1,491,047	22,499	0.1057

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3	OTHER SALES TO PUBLIC					
4	Minnesota					
5	A40 Small Municipal Pumping	7,023	936,937	919	7,642	0.1334
6	A41 Municipal Pumping	60,841	7,379,225	583	104,358	0.1213
7	A42 Fire Siren		35,182	531		
8	Unbilled	314	9,561			0.0304
9	North Dakota					
10	D40 Small Municipal Pumping	737	79,143	69	10,681	0.1074
11	D41 Municipal Pumping	13,983	1,382,976	91	153,659	0.0989
12	D42 Fire Siren		997	24		
13	Unbilled	3	-6,608			-2.2027
14	South Dakota					
15	E40 Fire Siren		2,971			
16	Total Other Sales to Public Autho	82,901	9,820,384	2,217	37,393	0.1185
17						
18	Interdepartmental Sales	5,583	587,959			0.1053
19	Total Interdepartmental	5,583	587,959			0.1053
20						
21	Footnote for Instruction 5:					
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	33,587,965	3,564,533,677	1,491,047	22,526	0.1061
42	Total Unbilled Rev.(See Instr. 6)	-40,943	-17,482,756	0	0	0.4270
43	TOTAL	33,547,022	3,547,050,921	1,491,047	22,499	0.1057

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 304.3 Line No.: 21 Column: a

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

A00	$ 4,142
A01	$120,873,192
A02	$ 95,427
A03	$ 92,560,901
A04	$ 112,870
A05	$ 1,033,858
A06	$ 125,615
A07	$ 602,805
A08	$ 51,524
A80	$ 7,531
A81	$ 2,565
A09	$ 631
A10	$ 19,356,717
A11	$ 4,839
A12	$ 1,051,870
A13	$ 31
A14	$199,599,461
A15	$183,060,646
A16	$ 386,761
A18	$ 695,739
A22	$ 61,356
A23	$ 27,092,393
A24	$ 60,113,510
A27	$ 10,584,373
A29	$ 634,239
A62	$ 568,184
A30	$ 680,659
A32	$ 537,824
A34	$ 680,155
A37	$ 18,927
A40	$ 181,095
A41	$ 1,490,375
Minnesota jurisdiction	$722,270,215

D01	$12,863,918
D02	$ 17,153
D03	$ 3,531,977
D04	$ 2,954
D05	$ 122,275
D10	$ 30,194
D11	$ 46,209
D12	$ 2,221123
D14	$ 50,163
D16	$14,705,356
D17	$ 4,421,105
D18	$ 12,203
D19	$ 20,060
D20	$ 640,726
D21	$ 2,660,728
D22	$ 4,710,076
D30	$ 14,373
D31	$ 181,189

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

D32	$ 570
D33	$ 37,931
D34	$ 1,484
D40	$ 16,094
D41	$ 301,147
North Dakota jurisdiction	$46,609,007
E01	$ 6,899,721
E02	$ 1,643
E03	$ 8,793,319
E04	$ 1,275
E06	$ 38,430
E10	$ 28,512
E11	$ 6,721
E12	$ 37,837
E13	$ 1,730,829
E14	$ 44,084
E15	$ 13,242,640
E16	$ 9,877,246
E18	$ 1,237
E20	$ 1,190,014
E21	$ 1,061,649
E22	$ 497,302
E30	$ 12,664
E31	$ 52,552
E32	$ 106,477
E33	$ 16,242
South Dakota jurisdiction	$ 43,640,394
Total Company	$812,519,616

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	NSP-Wisconsin	RQ		N/A	N/A	N/A
2	City of Ada, MN	OS	V6	N/A	N/A	N/A
3	City of Ada, MN	SF	V6	N/A	N/A	N/A
4	City of Ada, MN	AD	V6	N/A	N/A	N/A
5	City of Kasota, MN	OS	V6	N/A	N/A	N/A
6	City of Kasota, MN	OS	V6	N/A	N/A	N/A
7	City of Kasota, MN	AD	V6	N/A	N/A	N/A
8	Dahlberg Light and Power Co	OS	V6	N/A	N/A	N/A
9	Dahlberg Light and Power Co	SF	V6	N/A	N/A	N/A
10	Dahlberg Light and Power Co	AD	V6	N/A	N/A	N/A
11	First Energy Ohio Utilities	SF	V6	N/A	N/A	N/A
12	Great Lakes Utilities	SF	V6	N/A	N/A	N/A
13	ICE NGX Canada Inc	OS	V6	N/A	N/A	N/A
14	Lubbock Power and Light	SF	V6	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Metropolitan Edison Company	SF	V6	N/A	N/A	N/A
2	Midcontinent Independent System Op.	OS	V6	N/A	N/A	N/A
3	Midcontinent Independent System Op.	AD	V6	N/A	N/A	N/A
4	Morgan Stanley Capital Group, Inc.	OS	V6	N/A	N/A	N/A
5	NextEra Energy Power Marketing, LLC	OS	V6	N/A	N/A	N/A
6	North Central Power Company, Inc.	OS	V6	N/A	N/A	N/A
7	North Central Power Company, Inc.	SF	V6	N/A	N/A	N/A
8	North Central Power Company, Inc.	AD	V6	N/A	N/A	N/A
9	Northwestern Wisconsin Electric Company	OS	V6	N/A	N/A	N/A
10	Northwestern Wisconsin Electric Company	SF	V6	N/A	N/A	N/A
11	Northwestern Wisconsin Electric Company	AD	V6	N/A	N/A	N/A
12	Ohio Power Company	SF	V6	N/A	N/A	N/A
13	Ohio Power Company	AD	V6	N/A	N/A	N/A
14	Pennsylvania Electric Company	SF	V6	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
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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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Pennsylvania Power	SF	V6	N/A	N/A	N/A
2	PJM Interconnection, LLC.	SF	V6	N/A	N/A	N/A
3	PJM Interconnection, LLC.	AD	V6	N/A	N/A	N/A
4	Shelleneno	OS	V6	N/A	N/A	N/A
5	West Penn Power Company	SF	V6	N/A	N/A	N/A
6						
7	Footnote from 106b					
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
5,947,074		335,596,501		335,596,501	1
	35,275			35,275	2
6,232		504,613		504,613	3
		11,388		11,388	4
	20,750			20,750	5
4,086		256,822		256,822	6
		1,123		1,123	7
3,807	172,380	76,025		248,405	8
112,548		6,087,676		6,087,676	9
		24,508		24,508	10
32,401			1,866,458	1,866,458	11
216,000			7,409,672	7,409,672	12
102,400			4,171,621	4,171,621	13
			5,600,000	5,600,000	14
5,947,074	0	335,596,501	0	335,596,501	
11,311,704	2,163,109	162,029,319	99,960,479	264,152,907	
17,258,778	**2,163,109**	**497,625,820**	**99,960,479**	**599,749,408**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
165,229			10,589,532	10,589,532	1
9,226,030	137,329	145,294,406	4,568,277	150,000,012	2
-2,805		-87,323	-18,142	-105,465	3
35,200			4,013,266	4,013,266	4
	1,500,000			1,500,000	5
12,233	46,410	219,905		266,315	6
12,840		484,680		484,680	7
		-35		-35	8
45,509	250,965	829,820		1,080,785	9
125,520		4,630,920		4,630,920	10
		2,845		2,845	11
490,227			25,408,573	25,408,573	12
1,341			65,797	65,797	13
264,256			16,238,377	16,238,377	14
5,947,074	0	335,596,501	0	335,596,501	
11,311,704	2,163,109	162,029,319	99,960,479	264,152,907	
17,258,778	**2,163,109**	**497,625,820**	**99,960,479**	**599,749,408**	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
92,435			6,647,586	6,647,586	1
140,206		3,691,946	646,681	4,338,627	2
6,571			197,960	197,960	3
33,600			1,185,336	1,185,336	4
185,838			11,369,485	11,369,485	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
5,947,074	0	335,596,501	0	335,596,501	
11,311,704	2,163,109	162,029,319	99,960,479	264,152,907	
17,258,778	**2,163,109**	**497,625,820**	**99,960,479**	**599,749,408**	

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: a

Ownership interest or affiliation per Instruction 2:

Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) are both wholly owned operating subsidiaries of Xcel Energy Inc.

Schedule Page: 310 Line No.: 4 Column: i

Prior period adjustment.

Schedule Page: 310 Line No.: 7 Column: i

Prior period adjustment.

Schedule Page: 310 Line No.: 10 Column: i

Prior period adjustment.

Schedule Page: 310 Line No.: 11 Column: j

Financial trading.

Schedule Page: 310 Line No.: 12 Column: j

Financial trading.

Schedule Page: 310 Line No.: 13 Column: j

Financial trading.

Schedule Page: 310 Line No.: 14 Column: j

Financial trading.

Schedule Page: 310.1 Line No.: 1 Column: j

Financial trading.

Schedule Page: 310.1 Line No.: 2 Column: j

Demand - Resource Adequacy Auction, Other - Ancillary services

Schedule Page: 310.1 Line No.: 3 Column: i

Prior period adjustment.

Schedule Page: 310.1 Line No.: 4 Column: j

Financial trading.

Schedule Page: 310.1 Line No.: 8 Column: i

Prior period adjustment.

Schedule Page: 310.1 Line No.: 11 Column: i

Prior period adjustment.

Schedule Page: 310.1 Line No.: 12 Column: j

Financial trading.

Schedule Page: 310.1 Line No.: 13 Column: j

Prior period adjustment.

Schedule Page: 310.1 Line No.: 14 Column: j

Financial trading.

Schedule Page: 310.2 Line No.: 1 Column: j

Financial trading.

Schedule Page: 310.2 Line No.: 2 Column: j

Financial trading.

Schedule Page: 310.2 Line No.: 3 Column: j

Prior period adjustment.

Schedule Page: 310.2 Line No.: 4 Column: j

Financial trading.

Schedule Page: 310.2 Line No.: 5 Column: j

Financial trading.

Schedule Page: 310.2 Line No.: 6 Column: a

Total revenue and volumes sold will not match pages 300-1, line 11, due to differences in accounting classification associated with the Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) Interchange Agreement.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) _ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

	Revenue	MWh
pg 300, line 11 (b)	$264,152,907	11,311,704
pg 311, total (k)	$599,749,408	17,258,778
less: net interchange agreement	(335,596,501)	(5,947,074)
	$264,152,907	11,311,704

Schedule Page: 310.2 Line No.: 7 Column: a

Sales for Resale (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.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/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	3,412,405	3,465,490
5	(501) Fuel	266,913,365	322,461,439
6	(502) Steam Expenses	20,245,803	25,430,816
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	3,675,614	3,698,247
10	(506) Miscellaneous Steam Power Expenses	12,953,741	15,383,472
11	(507) Rents	3,335,498	4,606,393
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	310,536,426	375,045,857
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,765,365	3,701,428
16	(511) Maintenance of Structures	6,419,921	5,715,120
17	(512) Maintenance of Boiler Plant	22,850,699	25,986,582
18	(513) Maintenance of Electric Plant	6,807,557	13,323,980
19	(514) Maintenance of Miscellaneous Steam Plant	11,713,257	11,506,279
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	51,556,799	60,233,389
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	362,093,225	435,279,246
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	55,329,104	58,197,932
25	(518) Fuel	118,969,264	121,888,518
26	(519) Coolants and Water	8,177,235	8,885,718
27	(520) Steam Expenses	49,396,126	49,629,249
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	3,013,734	2,824,271
31	(524) Miscellaneous Nuclear Power Expenses	127,101,515	128,488,608
32	(525) Rents	12,227,118	13,089,705
33	TOTAL Operation (Enter Total of lines 24 thru 32)	374,214,096	383,004,001
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	7,262,125	5,044,952
36	(529) Maintenance of Structures	24,683	142,945
37	(530) Maintenance of Reactor Plant Equipment	38,926,796	40,743,589
38	(531) Maintenance of Electric Plant	12,389,211	9,787,389
39	(532) Maintenance of Miscellaneous Nuclear Plant	31,045,208	32,043,555
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	89,648,023	87,762,430
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	463,862,119	470,766,431
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	30,977	31,859
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses	416,335	369,350
48	(539) Miscellaneous Hydraulic Power Generation Expenses	735,450	449,236
49	(540) Rents	65,141	50,140
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	1,247,903	900,585
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	2,653	8,644
54	(542) Maintenance of Structures	39,246	37,215
55	(543) Maintenance of Reservoirs, Dams, and Waterways	62,498	207,434
56	(544) Maintenance of Electric Plant	120,543	107,266
57	(545) Maintenance of Miscellaneous Hydraulic Plant	4,755	1,397
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	229,695	361,956
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	1,477,598	1,262,541

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	2,018,024	1,462,689
63	(547) Fuel	187,242,297	176,923,193
64	(548) Generation Expenses	7,138,051	7,756,781
65	(549) Miscellaneous Other Power Generation Expenses	7,518,551	9,807,631
66	(550) Rents	8,538,449	6,181,665
67	TOTAL Operation (Enter Total of lines 62 thru 66)	212,455,372	202,131,959
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,698,454	1,783,205
70	(552) Maintenance of Structures	6,650,945	9,901,944
71	(553) Maintenance of Generating and Electric Plant	6,306,898	9,706,726
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	5,025,921	3,667,049
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	19,682,218	25,058,924
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	232,137,590	227,190,883
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	746,707,838	731,074,163
77	(556) System Control and Load Dispatching	1,555,041	1,686,912
78	(557) Other Expenses	102,602,253	91,735,443
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	850,865,132	824,496,518
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,910,435,664	1,958,995,619
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	11,373,546	12,044,941
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	4,384,777	4,907,757
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	7,674,490	7,737,718
89	(561.5) Reliability, Planning and Standards Development	45,025	1,270
90	(561.6) Transmission Service Studies	5,313	4
91	(561.7) Generation Interconnection Studies	-11,347	-17,939
92	(561.8) Reliability, Planning and Standards Development Services	2,765,792	2,871,119
93	(562) Station Expenses	2,534,494	2,835,783
94	(563) Overhead Lines Expenses	802,711	543,045
95	(564) Underground Lines Expenses	50,459	34,349
96	(565) Transmission of Electricity by Others	337,635,227	309,789,754
97	(566) Miscellaneous Transmission Expenses	5,556,725	6,474,236
98	(567) Rents	2,740,456	2,889,594
99	TOTAL Operation (Enter Total of lines 83 thru 98)	375,557,668	350,111,631
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	66,476	38,639
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	5,709,691	4,794,615
108	(571) Maintenance of Overhead Lines	7,189,699	6,667,823
109	(572) Maintenance of Underground Lines	105,270	24,862
110	(573) Maintenance of Miscellaneous Transmission Plant	10,766	21,151
111	TOTAL Maintenance (Total of lines 101 thru 110)	13,081,902	11,547,090
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	388,639,570	361,658,721

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	160,006	213,710
116	(575.2) Day-Ahead and Real-Time Market Facilitation	108,514	90,488
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		300
120	(575.6) Market Monitoring and Compliance		1,997
121	(575.7) Market Facilitation, Monitoring and Compliance Services	10,365,211	10,493,394
122	(575.8) Rents	17,520	11,027
123	Total Operation (Lines 115 thru 122)	10,651,251	10,810,916
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 Op Expns (Total 123 and 130)	10,651,251	10,810,916
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	14,368,219	7,611,747
135	(581) Load Dispatching	663,877	1,624,788
136	(582) Station Expenses	3,110,278	4,463,218
137	(583) Overhead Line Expenses	2,047,233	1,757,946
138	(584) Underground Line Expenses	5,665,154	1,064,811
139	(585) Street Lighting and Signal System Expenses	716,351	187,718
140	(586) Meter Expenses	188,026	1,682,761
141	(587) Customer Installations Expenses	1,312,626	1,267,028
142	(588) Miscellaneous Expenses	22,336,577	27,877,917
143	(589) Rents	4,480,484	3,925,985
144	TOTAL Operation (Enter Total of lines 134 thru 143)	54,888,825	51,463,919
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	71,824	92,286
147	(591) Maintenance of Structures		41,783
148	(592) Maintenance of Station Equipment	4,715,836	8,195,160
149	(593) Maintenance of Overhead Lines	51,673,233	46,810,911
150	(594) Maintenance of Underground Lines	7,876,091	6,203,726
151	(595) Maintenance of Line Transformers	124,501	381,758
152	(596) Maintenance of Street Lighting and Signal Systems	1,588,926	2,461,662
153	(597) Maintenance of Meters	164,279	116,148
154	(598) Maintenance of Miscellaneous Distribution Plant	231,578	6,928,512
155	TOTAL Maintenance (Total of lines 146 thru 154)	66,446,268	71,231,946
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	121,335,093	122,695,865
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	121,386	77,304
160	(902) Meter Reading Expenses	21,835,052	21,230,378
161	(903) Customer Records and Collection Expenses	23,317,809	20,760,549
162	(904) Uncollectible Accounts	11,678,776	13,718,359
163	(905) Miscellaneous Customer Accounts Expenses		250
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	56,953,023	55,786,840

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	108,955,823	101,566,235
169	(909) Informational and Instructional Expenses	1,085,846	1,385,792
170	(910) Miscellaneous Customer Service and Informational Expenses	1,706,565	314,922
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	111,748,234	103,266,949
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	46,029	66
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	46,029	66
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	95,838,854	83,040,317
182	(921) Office Supplies and Expenses	55,171,334	59,319,663
183	(Less) (922) Administrative Expenses Transferred-Credit	42,157,400	39,870,986
184	(923) Outside Services Employed	22,639,829	33,023,798
185	(924) Property Insurance	-6,426,703	731,717
186	(925) Injuries and Damages	15,090,178	15,155,347
187	(926) Employee Pensions and Benefits	76,963,890	84,162,025
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,710,054	6,447,393
190	(929) (Less) Duplicate Charges-Cr.	5,562,067	5,602,402
191	(930.1) General Advertising Expenses	4,011,565	4,073,171
192	(930.2) Miscellaneous General Expenses	3,287,410	3,614,161
193	(931) Rents	37,912,666	34,485,243
194	TOTAL Operation (Enter Total of lines 181 thru 193)	264,479,610	278,579,447
195	Maintenance		
196	(935) Maintenance of General Plant	310,659	687,260
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	264,790,269	279,266,707
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,864,599,133	2,892,481,683

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 320 Line No.: 64 Column: b

Account No. 548 Generation Expenses	$	7,138,051
Account No. 548.1 Operation of Energy Storage Equipment		0
	$	7,138,051

See Note 13 to the Financial Statements

Schedule Page: 320 Line No.: 64 Column: c

Account No. 548 Generation Expenses	$	7,756,781
Account No. 548.1 Operation of Energy Storage Equipment		0
	$	7,756,781

See Note 13 to the Financial Statements

Schedule Page: 320 Line No.: 71 Column: b

Account No. 553 Maintenance of Generating and Electric Plant	$	6,306,898
Account No. 553.1 Maintenance of Energy Storage Equipment		0
	$	6,306,898

See Note 13 to the Financial Statements

Schedule Page: 320 Line No.: 71 Column: c

Account No. 553 Maintenance of Generating and Electric Plant	$	9,706,726
Account No. 553.1 Maintenance of Energy Storage Equipment		0
	$	9,706,726

See Note 13 to the Financial Statements

Schedule Page: 320 Line No.: 76 Column: b

Account No. 555 Purchased Power	$	746,768,456
Account No. 555.1 Power Purchased for Storage Operations		(60,618)
	$	746,707,838

See Note 13 to the Financial Statements

Schedule Page: 320 Line No.: 76 Column: c

Account No. 555 Purchased Power	$	731,194,515
Account No. 555.1 Power Purchased for Storage Operations		(120,352)
	$	731,074,163

See Note 13 to the Financial Statements

Schedule Page: 320 Line No.: 78 Column: b

Includes $45,143,188 of fixed costs and $15,321,966 of variable costs reimbursed to NSP-Wisconsin for production costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

Schedule Page: 320 Line No.: 78 Column: c

Includes $44,821,290 of fixed costs and $16,271,338 of variable costs reimbursed to NSP-Wisconsin for production costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

Schedule Page: 320 Line No.: 91 Column: b

Credit balance results from Pension, Insurance and Taxes on Company labor billed for performing generation interconnection studies being recorded to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is recorded to Account No. 561.7.

Schedule Page: 320 Line No.: 91 Column: c

Credit balance results from Pension, Insurance and Taxes on Company labor billed for performing generation interconnection studies being recorded to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is recorded to Account No. 561.7.

Schedule Page: 320 Line No.: 96 Column: b

Includes $116,159,129 of fixed costs reimbursed to NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

Schedule Page: 320 Line No.: 96 Column: c

Includes $96,779,594 of fixed costs reimbursed to NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

Schedule Page: 320 Line No.: 112 Column: b

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.

Schedule Page: 320 Line No.: 185 Column: b

Credit balance due to nuclear insurance distribution.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	ACE Lincoln Heights Wind Holdings, LLC	LU		N/A	N/A	N/A
2	Adams Wind Generations	LU		N/A	N/A	N/A
3	AEP Ohio Power Company	AD		N/A	N/A	N/A
4	AEP Ohio Power Company	OS		N/A	N/A	N/A
5	Agassiz Beach, LLC	LU		N/A	N/A	N/A
6	Aurora Distributed Solar, LLC	AD		N/A	N/A	N/A
7	Aurora Distributed Solar, LLC	LU		N/A	N/A	N/A
8	Best Power International, LLC	LU		N/A	N/A	N/A
9	Big Blue Wind Farm, LLC	LU		N/A	N/A	N/A
10	Bisson Wind Farm, LLC	LU		N/A	N/A	N/A
11	Boeve Wind Farm, LLC	LU		N/A	N/A	N/A
12	Byllesby	LU		2	N/A	N/A
13	Cannon Falls Energy Center	AD		N/A	N/A	N/A
14	Cannon Falls Energy Center	LU		345	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Carleton College	LU		N/A	N/A	N/A
2	Central Electric Cooperative	OS		N/A	N/A	N/A
3	CG Wind Farm, LLC	LU		N/A	N/A	N/A
4	Chanarambie Power Partners, LLC	LU		N/A	N/A	N/A
5	Cisco Wind Energy, LLC	LU		N/A	N/A	N/A
6	Citigroup Energy, LLC	OS		N/A	N/A	N/A
7	Covanta Hennepin Energy Resource Co LP	AD		N/A	N/A	N/A
8	Covanta Hennepin Energy Resource Co LP	LU		34	N/A	N/A
9	Crowned Ridge Wind, LLC	LU		N/A	N/A	N/A
10	Dairyland Electric Cooperative Inc.	LU		N/A	N/A	N/A
11	Danielson Wind Farms, LLC	LU		N/A	N/A	N/A
12	Diamond K Dairy Inc.	LU		N/A	N/A	N/A
13	Dragonfly Solar, LLC	LU		N/A	N/A	N/A
14	East Ridge Group	LU		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	EnXco, Inc.	AD		N/A	N/A	N/A
2	EnXco, Inc.	OS		N/A	N/A	N/A
3	ERCOT	OS		N/A	N/A	N/A
4	Ewington Energy Systems, LLC	LU		N/A	N/A	N/A
5	Fenton Power Partners I, LLC	AD		N/A	N/A	N/A
6	Fenton Power Partners I, LLC	LU		N/A	N/A	N/A
7	Fey Wind Farm, LLC	LU		N/A	N/A	N/A
8	First Energy Ohio Utilities	OS		N/A	N/A	N/A
9	FPL Energy Mower County, LLC	LU		N/A	N/A	N/A
10	Garwin McNeilus	LU		N/A	N/A	N/A
11	Grant County Wind Farm, LLC	LU		N/A	N/A	N/A
12	Great American West Wind, LLC	LU		N/A	N/A	N/A
13	Hastings Lock & Dam	LU		2	N/A	N/A
14	Hilltop Power, LLC	LU		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	Jeffers Wind Energy Center	LU		N/A	N/A	N/A
2	JJN Wind Farm, LLC	LU		N/A	N/A	N/A
3	Kas Brothers Wind Farm, LLC	LU		N/A	N/A	N/A
4	K-Brink Wind Farm, LLC	LU		N/A	N/A	N/A
5	KODA Energy, LLC	LU		N/A	N/A	N/A
6	Lake Benton Power Partners, LLC	LU		N/A	N/A	N/A
7	LCO Hydro	LU		N/A	N/A	N/A
8	LSP Cottage Grove Incorporated	AD		N/A	N/A	N/A
9	LSP Cottage Grove Incorporated	LU		245	N/A	N/A
10	LSP Cottage Grove Incorporated	OS		N/A	N/A	N/A
11	Manitoba Hydro	LU		350	N/A	N/A
12	Mankato Energy Center I, LLC	AD		N/A	N/A	N/A
13	Mankato Energy Center I, LLC	LU		375	N/A	N/A
14	Mankato Energy Center II, LLC	LU		345	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Marshall Solar	LU		N/A	N/A	N/A
2	Metro Wind LLC	AD		N/A	N/A	N/A
3	Metro Wind LLC	LU		N/A	N/A	N/A
4	Metropolitan Edison Company	OS		N/A	N/A	N/A
5	Midcontinental ISO	AD		N/A	N/A	N/A
6	Midcontinental ISO	SF		N/A	N/A	N/A
7	MinnDakota Wind LLC	LU		N/A	N/A	N/A
8	Miscellaneous	OS		N/A	N/A	N/A
9	Moraine Wind, LLC	LU		N/A	N/A	N/A
10	N A E Lakota Ridge, LLC	LU		N/A	N/A	N/A
11	N A E Lakota Ridge, LLC	OS		N/A	N/A	N/A
12	N A E Shaokatan Hills, LLC	LU	NAEMA	N/A	N/A	N/A
13	N A E Shaokatan Hills, LLC	OS		N/A	N/A	N/A
14	N A E Shaokatan, LLC	LU		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Natural Gas Exchange Inc.	OS		N/A	N/A	N/A
2	Neshkoro (Neshonoc)	LU		0	N/A	N/A
3	New England ISO	OS		N/A	N/A	N/A
4	New York ISO	OS		N/A	N/A	N/A
5	North Community Turbines LLC	LU		N/A	N/A	N/A
6	North Star Solar	LU		N/A	N/A	N/A
7	North Wind Turbines LLC	LU		N/A	N/A	N/A
8	NSP-M Solar Gardens	AD		N/A	N/A	N/A
9	NSP-M Solar Gardens	LU		N/A	N/A	N/A
10	Odell Wind Farm, LLC	LU		N/A	N/A	N/A
11	Olsen Wind Farm	LU		N/A	N/A	N/A
12	Pennsylvania Electric Company	OS		N/A	N/A	N/A
13	Pennsylvania Power Company	OS		N/A	N/A	N/A
14	Pipestone	LU		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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PURCHASED POWER (Account 555)
(Including power exchanges)

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3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PJM Interconnection, LLC	OS		N/A	N/A	N/A
2	Prairie Rose Wind, LLC	LU		N/A	N/A	N/A
3	Rapidan Hydroelectric Facility	LU		3	N/A	N/A
4	Ridgewind Power Partners, LLC	LU		N/A	N/A	N/A
5	Rock County Energy	LU		N/A	N/A	N/A
6	Rock Ridge Power Partners, LLC	LU		N/A	N/A	N/A
7	Ruthton Ridge	LU		N/A	N/A	N/A
8	SAF Hydroelectric, LLC	LU		N/A	N/A	N/A
9	Shane's Wind Machine, LLC	LU		N/A	N/A	N/A
10	Shell Energy North America US, LP	OS		N/A	N/A	N/A
11	Slayton Solar, LLC	LU		N/A	N/A	N/A
12	South Ridge Power Partners, LLC	LU		N/A	N/A	N/A
13	Southwest Power Pool, Inc.	AD		N/A	N/A	N/A
14	Southwest Power Pool, Inc.	OS		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	St. Cloud	LU		7	N/A	N/A
2	St. Olaf College	LU		N/A	N/A	N/A
3	St. Paul Cogeneration	LU		N/A	N/A	N/A
4	TG Wind Farm, LLC	LU		N/A	N/A	N/A
5	Tholen Transmission-Trust	LU		N/A	N/A	N/A
6	Tofteland Wind Farm, LLC	LU		N/A	N/A	N/A
7	Uilk Wind Farm, LLC	LU		N/A	N/A	N/A
8	University of Minnesota	LU		N/A	N/A	N/A
9	Valley View Transmission	LU		N/A	N/A	N/A
10	Velva Wind Farm, LLC	LU		N/A	N/A	N/A
11	Viking Wind Partners	LU		N/A	N/A	N/A
12	West Penn Power Company	OS		N/A	N/A	N/A
13	Western Area Power Administration	LU	NAEMA, WSPP	N/A	N/A	N/A
14	Westridge Wind Farm, LLC	LU		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Windcurrent Farms, LLC	LU		N/A	N/A	N/A
2	Windvest Power Partners, LLC	LU		N/A	N/A	N/A
3	Winona County Wind, LLC	AD		N/A	N/A	N/A
4	WM Renewable Energy, LLC	LU		N/A	N/A	N/A
5	Woodstock Hills, LLC	LU		N/A	N/A	N/A
6	Woodstock Municipal Wind, LLC	LU		N/A	N/A	N/A
7	Zephyr Wind, LLC	LU		N/A	N/A	N/A
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
18,739				626,564		626,564	1
55,318				3,816,927		3,816,927	2
3,240					158,865	158,865	3
12,122					590,332	590,332	4
3,919				89,356		89,356	5
-4				-402		-402	6
171,931				16,875,194		16,875,194	7
1,683				160,769		160,769	8
102,827				5,923,848		5,923,848	9
5,015				170,523		170,523	10
5,216				174,746		174,746	11
14,817			422,815	279,023		701,838	12
				-3,098		-3,098	13
92,073			28,436,910	5,383,129		33,820,039	14
14,814,736			127,450,370	553,198,579	66,058,889	746,707,838	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
4,006				132,201		132,201	1
141			13,861	16,354		30,215	2
2,282				77,585		77,585	3
203,203				5,385,551		5,385,551	4
17,583				588,572		588,572	5
35,200					1,716,070	1,716,070	6
				153		153	7
196,070				4,247,123		4,247,123	8
10				139		139	9
17,232				212,815		212,815	10
48,055				3,286,966		3,286,966	11
-24				-1,550		-1,550	12
871				82,817		82,817	13
22,889				755,333		755,333	14
14,814,736			127,450,370	553,198,579	66,058,889	746,707,838	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					407	407	1
					2,428	2,428	2
					24,757	24,757	3
58,514				2,047,990		2,047,990	4
				54,715		54,715	5
562,245				28,138,633		28,138,633	6
5,073				177,568		177,568	7
295					14,227	14,227	8
258,576				11,661,742		11,661,742	9
73,397				2,410,977		2,410,977	10
54,817				3,787,869		3,787,869	11
28,696				319,964		319,964	12
13,268			425,874	236,274		662,148	13
3,378				152,432		152,432	14
14,814,736			127,450,370	553,198,579	66,058,889	746,707,838	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
155,011				5,223,501		5,223,501	1
3,374				113,040		113,040	2
2,841				108,070		108,070	3
4,608				154,357		154,357	4
38,341				2,891,741		2,891,741	5
262,885				7,730,364		7,730,364	6
15,457				175,876		175,876	7
				-1,265,175		-1,265,175	8
476,498			14,798,025	11,567,464		26,365,489	9
					992,425	992,425	10
1,614,414			36,200,038	102,397,257		138,597,295	11
				1,782		1,782	12
1,130,524			31,840,177	46,103,546		77,943,723	13
890,194			13,360,384	3,080,874		16,441,258	14
14,814,736			127,450,370	553,198,579	66,058,889	746,707,838	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
95,991				5,970,917		5,970,917	1
-4				-101		-101	2
597				13,608		13,608	3
327					15,788	15,788	4
-7,382				-207,406		-207,406	5
2,435,644				35,851,159		35,851,159	6
464,818				18,456,228		18,456,228	7
32,267					-534,171	-534,171	8
146,023				3,418,976		3,418,976	9
19,390				424,594		424,594	10
					-13,940	-13,940	11
22,600				480,721		480,721	12
					-1,890,108	-1,890,108	13
23,457				534,827		534,827	14
14,814,736			127,450,370	553,198,579	66,058,889	746,707,838	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
102,400					6,614,517	6,614,517	1
2,614			79,075	47,981		127,056	2
					15,149	15,149	3
					54,781	54,781	4
43,395				2,864,102		2,864,102	5
177,390				11,620,304		11,620,304	6
41,305				2,726,148		2,726,148	7
				-68,250		-68,250	8
834,508				105,624,546		105,624,546	9
748,301				17,773,655		17,773,655	10
2,515				96,318		96,318	11
3,404					171,922	171,922	12
					-1,027	-1,027	13
21,131				697,312		697,312	14
14,814,736			127,450,370	553,198,579	66,058,889	746,707,838	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,530,148					56,966,089	56,966,089	1
606,424				24,062,868		24,062,868	2
14,132			361,521	252,469		613,990	3
77,414				5,101,443		5,101,443	4
11,480				378,851		378,851	5
4,848				159,993		159,993	6
35,748				815,051		815,051	7
30,951				1,599,555		1,599,555	8
5,002				165,061		165,061	9
33,600					1,161,964	1,161,964	10
2,155				245,650		245,650	11
5,150				169,941		169,941	12
-52				-1,070		-1,070	13
5,081				73,579		73,579	14
14,814,736			127,450,370	553,198,579	66,058,889	746,707,838	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
55,234			1,511,690	1,244,215		2,755,905	1
15				490		490	2
148,761				21,957,586		21,957,586	3
4,885				166,099		166,099	4
40,024				1,320,789		1,320,789	5
4,232				143,877		143,877	6
11,536				807,152		807,152	7
2,744				55,618		55,618	8
26,763				1,707,450		1,707,450	9
27,449				905,802		905,802	10
32,301				459,812		459,812	11
					-1,586	-1,586	12
11,789				282,960		282,960	13
1,661				56,464		56,464	14
14,814,736			127,450,370	553,198,579	66,058,889	746,707,838	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,503				122,590		122,590	1
3,095				102,151		102,151	2
9				638		638	3
32,866				1,478,993		1,478,993	4
36,520				1,003,456		1,003,456	5
2,093				142,028		142,028	6
109,664				6,339,880		6,339,880	7
							8
							9
							10
							11
							12
							13
							14
14,814,736			127,450,370	553,198,579	66,058,889	746,707,838	

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: k
Formerly Lincoln Heights Wind Holdings.
Schedule Page: 326 Line No.: 3 Column: l
Prior period adjustment.
Schedule Page: 326 Line No.: 4 Column: l
Financial trading.
Schedule Page: 326 Line No.: 6 Column: k
Prior period adjustment.
Schedule Page: 326 Line No.: 13 Column: k
Prior period adjustment.
Schedule Page: 326.1 Line No.: 2 Column: k
Emergency interconnection agreement.
Schedule Page: 326.1 Line No.: 6 Column: l
Financial trading.
Schedule Page: 326.1 Line No.: 7 Column: k
Prior period adjustment.
Schedule Page: 326.2 Line No.: 1 Column: l
Prior period adjustment.
Schedule Page: 326.2 Line No.: 2 Column: l
Comp. for non-renewable energy rebate.
Schedule Page: 326.2 Line No.: 3 Column: l
Financial trading.
Schedule Page: 326.2 Line No.: 5 Column: k
Prior period adjustment.
Schedule Page: 326.2 Line No.: 8 Column: l
Financial trading.
Schedule Page: 326.3 Line No.: 8 Column: k
Prior period adjustment.
Schedule Page: 326.3 Line No.: 10 Column: l
Settlement agreement for prior periods.
Schedule Page: 326.3 Line No.: 12 Column: k
Prior period adjustment.
Schedule Page: 326.4 Line No.: 2 Column: k
Prior period adjustment.
Schedule Page: 326.4 Line No.: 4 Column: l
Financial trading.
Schedule Page: 326.4 Line No.: 5 Column: k
Prior period adjustment.
Schedule Page: 326.4 Line No.: 8 Column: l
Miscellaneous.
Schedule Page: 326.4 Line No.: 11 Column: l
Settlement agreement for prior periods.
Schedule Page: 326.4 Line No.: 13 Column: l
Settlement agreement for prior periods.
Schedule Page: 326.5 Line No.: 1 Column: l
Financial trading.
Schedule Page: 326.5 Line No.: 3 Column: l
Financial trading.
Schedule Page: 326.5 Line No.: 4 Column: l
Financial trading.
Schedule Page: 326.5 Line No.: 8 Column: k
Prior period adjustment.
Schedule Page: 326.5 Line No.: 12 Column: l
Financial trading.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 326.5 Line No.: 13 Column: l

Financial trading.

Schedule Page: 326.6 Line No.: 1 Column: l

Financial trading.

Schedule Page: 326.6 Line No.: 10 Column: l

Financial trading.

Schedule Page: 326.6 Line No.: 13 Column: k

Prior period adjustment.

Schedule Page: 326.7 Line No.: 12 Column: l

Financial trading.

Schedule Page: 326.8 Line No.: 3 Column: k

Prior period adjustment.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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 Classifi-cation (d)
1	East Grand Forks, City of	WAPA	East Grand Forks, City of	OS
2	Granite Falls, City of	WAPA	Granite Falls, City of	OS
3	Great River Energy	Various	Various	FNO
4	Midcontinent ISO (MISO)	Various	Various	
5	Missouri River Energy Services (MRES)	Various	Various	FNO
6	Sioux Falls, City of	WAPA	Sioux Falls, City of	OS
7	South Dakota State Penitentiary (SDSP)	WAPA	SDSP	OS
8	Southern MN Municipal Power Agency	Various	Various	FNO
9	University of North Dakota	WAPA	University of North Dakota	OS
10	Wisconsin Public Power, Inc. (WPPI)	MP	WPPI	OS
11	Northern States Power-Wisconsin	Various	Various	OS
12				
13				
14	Footnote from page 106b			
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
483	WAPA	East Grand Forks, C				1
436	WAPA	Granite Falls, City				2
Various	Various	Various				3
MISO OATT	Various	Various				4
304	Various	Various				5
484	WAPA	Sioux Falls, City o				6
385	WAPA	SDSP				7
304	Various	Various				8
440	WAPA	UND				9
466						10
437	Various	Various				11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	0	0	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS				
Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		52,752	52,752	1
		16,807	16,807	2
42,944,570		126,983	43,071,553	3
110,821,745	72,168,687		182,990,432	4
5,489,929			5,489,929	5
		182,218	182,218	6
		14,088	14,088	7
6,392,256			6,392,256	8
		65,157	65,157	9
		40,320	40,320	10
61,350,084			61,350,084	11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
226,998,584	**72,168,687**	**498,325**	**299,665,596**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 2 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 3 Column: e

28, 304 and OA97-25-000 et al.

Schedule Page: 328 Line No.: 3 Column: m

Schedule 2 Revenue

Schedule Page: 328 Line No.: 4 Column: d

FNO, LFP, SFP, NF

Schedule Page: 328 Line No.: 4 Column: l

MISO Schedule 26-A revenue

Schedule Page: 328 Line No.: 6 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 7 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 9 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 10 Column: m

Meter Charge

Schedule Page: 328 Line No.: 11 Column: a

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

Schedule Page: 328 Line No.: 11 Column: b

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

Schedule Page: 328 Line No.: 14 Column: a

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Basin Electric Power	OS					2,400	2,400
2	Central MN Municipal Pw	FNS			1,116,508			1,116,508
3	Dairyland Power	OS					21,389	21,389
4	Great River Energy	FNS			39,820,452			39,820,452
5	McLeod Coop Power	OLF			25,342			25,342
6	Midcontinent Ipt (MISO)				88,761,501	64,934,108	1,000	153,696,609
7	MN Municipal Pwr Agy	FNS			1,177,244			1,177,244
8	Minnkota Power Coop	OLF				20,604	780,000	800,604
9	Missouri Riv Engy Serv	FNS			1,722,123			1,722,123
10	Northwestern Wis Elect	FNS			543,201			543,201
11	Otter Tail Pwr Co	OS					928,471	928,471
12	Southern MN Muncipl Pwr	FNS			13,948,447			13,948,447
13	Southwest Power Pool	FNS			81,290	526		81,816
14	Stearns Coop Electric					531	2,796	3,327
15	Rochester Public Util	FNS			2,075,737			2,075,737
16	PJM Interconnection	FNS			5,512,428			5,512,428
	TOTAL				270,943,402	64,955,769	1,736,056	337,635,227

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Northern States Pwr-WI	OLF			116,159,129			116,159,129
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL				270,943,402	64,955,769	1,736,056	337,635,227

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 332 Line No.: 1 Column: g

Meter Agent Service Charges

Schedule Page: 332 Line No.: 3 Column: g

Facility Charges

Schedule Page: 332 Line No.: 5 Column: b

Two year notification required for termination

Schedule Page: 332 Line No.: 6 Column: b

LFP, FNS, FNO

Schedule Page: 332 Line No.: 6 Column: f

MISO Schedule 26-A expense & MISO Admin FERC fee

Schedule Page: 332 Line No.: 6 Column: g

2019 MISO Annual Membership Fee

Schedule Page: 332 Line No.: 8 Column: b

Four year notification required for termination

Schedule Page: 332 Line No.: 8 Column: g

Fixed Transmission Service Charge

Schedule Page: 332 Line No.: 11 Column: g

Interconnection Upgrade fixed charge

Schedule Page: 332 Line No.: 14 Column: b

OS, LFP - Two year notification required for termination

Schedule Page: 332 Line No.: 14 Column: g

Fixed Facility Charge

Schedule Page: 332 Line No.: 16 Column: a

Network Integration Transmission Services Charges in PJM

Schedule Page: 332.1 Line No.: 1 Column: a

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

Schedule Page: 332.1 Line No.: 1 Column: b

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,538,696
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	265,907
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Director Fees & Expenses	1,311,197
7	SEC Filing Expenses	171,610
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
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46	TOTAL	3,287,410

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	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			32,830,663		32,830,663
2	Steam Production Plant	97,634,841	-4,467,861		-1,033,675	92,133,305
3	Nuclear Production Plant	161,834,407	-10,439,460			151,394,947
4	Hydraulic Production Plant-Conventional	1,439,693			-67,063	1,372,630
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	109,950,090	3,357,522	718,284	-2,458,451	111,567,445
7	Transmission Plant	72,579,956	5,255		-1,179,460	71,405,751
8	Distribution Plant	116,482,158	234,059			116,716,217
9	Regional Transmission and Market Operation					
10	General Plant	24,348,000			-1,741	24,346,259
11	Common Plant-Electric	24,041,570	11,248	41,289,115	459	65,342,392
12	TOTAL	608,310,715	-11,299,237	74,838,062	-4,739,931	667,109,609

B. Basis for Amortization Charges

Account 404 Column (d) Computer software is amortized over its expected useful life of 3, 5, 7, 10, or 15 years.

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

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production						
13	310	8,545					
14	311	291,925					
15	312	1,462,821					
16	314	321,715					
17	315	187,403					
18	316	53,977					
19	317	1,580					
20	Subtotal Steam Prod	2,327,966					
21							
22	Nuclear Production						
23	320	1,762					
24	321	565,627					
25	322	1,863,891					
26	323	587,048					
27	324	523,349					
28	325	207,129					
29	326	-6,803					
30	Subtotal Nuclear Prod	3,742,003					
31							
32	Hydro Production						
33	330	1,693					
34	331	1,417					
35	332	11,066					
36	333	10,166					
37	334	3,257					
38	335	61					
39	337						
40	Subtotal Hydro Prod	27,660					
41							
42	Other Production						
43	340	31,168					
44	341	300,486					
45	342	27,271					
46	343	140,129					
47	344	2,351,983					
48	345	290,971					
49	346	32,892					
50	347	85,918					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	348	4,129					
13	Subtotal Other Prod	3,264,947					
14							
15	Transmission						
16	350	160,402					
17	352	121,419	70.00	-5.00	1.51	R5	58.27
18	353	1,267,301	56.00	-15.00	2.07	R2	44.20
19	354	118,082	75.00	-35.00	1.85	R4	41.87
20	355	1,420,367	62.00	-50.00	2.44	R2	55.37
21	356	594,577	67.00	-35.00	2.05	R1	57.99
22	357	29,412	73.00		1.38	R4	62.36
23	358	37,151	50.00	-5.00	2.12	R3	40.24
24	359.1	173					
25	Subtotal Transmission	3,748,884					
26							
27	Distribution						
28	360	18,354					
29	361	53,715	63.00	-30.00	2.06	R2.5	47.17
30	362	664,823	53.00	-25.00	2.31	R2	38.71
31	364	456,257	47.00	-120.00	4.70	R1	34.77
32	365	503,165	39.00	-25.00	3.21	L0	30.60
33	366	319,393	56.00	-20.00	2.15	R3	42.00
34	367	1,209,463	49.00	-10.00	2.25	R1.5	36.14
35	368	448,041	32.00	-5.00	3.21		18.49
36	368	24,828	25.00	-7.00	4.03		12.90
37	369	85,362	42.00	-85.00	4.41	R1.5	24.78
38	369	243,172	44.00	-5.00	2.40	R4	24.96
39	370	108,163	15.00	-5.00	5.99		8.38
40	373	74,533	29.00	-40.00	5.40	L0	22.62
41	374	12,231					
42	Subtotal Distribution	4,221,500					
43							
44	General						
45	389	4,484					
46	390	73,307	55.00	-20.00	2.27	R1.5	36.62
47	390	1,072				SQ	
48	391	31,211	20.00		4.52		9.37
49	391	41,364	6.00		14.16		3.45
50	392	6,034	10.00	5.00	9.71		9.04

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	392	34,611	10.00	10.00	7.76		4.40
13	392	21,418	12.00	20.00	6.32		7.27
14	392	115,322	12.00	15.00	6.62		7.20
15	393	1,632	20.00		4.51		10.68
16	394	100,867	15.00		6.28		9.17
17	395	3,065	10.00		9.53		5.21
18	396	51,373	12.00	15.00	5.98		6.92
19	397	17,410	10.00		8.74		3.69
20	397	53,531	10.00		10.14		8.89
21	397	7,084	15.00		6.02		6.42
22	397	43,291	15.00		6.22		12.12
23	398	3,491	15.00		5.73		5.21
24	Subtotal General	610,567					
25							
26	Total	17,943,527					
27							
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Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Schedule Page: 336 Line No.: 1 Column: d

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

Intangible Plant	$	19,973,745
Nuclear Production Plant		12,750,090
Hydraulic Production Plant-Conventional		106,828
Total	$	32,830,663

Schedule Page: 336 Line No.: 7 Column: b

Transmission Serving Production	$	1,708,536

Schedule Page: 336 Line No.: 8 Column: b

Distribution Serving Production	$	78,695

Schedule Page: 336 Line No.: 12 Column: b

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	$	(5,615,399)
Transmssion Plant		(4,171,205)
General Plant		(253,125)
Total	$	(10,039,729)

Schedule Page: 336.1 Line No.: 35 Column: a

368 Line Transformers

Schedule Page: 336.1 Line No.: 36 Column: a

368 Line Capacitors

Schedule Page: 336.1 Line No.: 37 Column: a

369 Overhead Services

Schedule Page: 336.1 Line No.: 38 Column: a

369 Underground Services

Schedule Page: 336.1 Line No.: 46 Column: a

390 Structures and Improvements

Schedule Page: 336.1 Line No.: 47 Column: a

390 Structures and Improvements - Leasehold Improvements

Schedule Page: 336.1 Line No.: 47 Column: c

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 336.1 Line No.: 47 Column: e

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

Schedule Page: 336.1 Line No.: 47 Column: g

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

Schedule Page: 336.1 Line No.: 48 Column: a

391 Office Furniture and Equipment

Schedule Page: 336.1 Line No.: 49 Column: a

391 Network Equipment

Schedule Page: 336.1 Line No.: 50 Column: a

392 Transportation Equipment - Automobiles

Schedule Page: 336.2 Line No.: 12 Column: a

392 Transportation Equipment - Light Trucks

Schedule Page: 336.2 Line No.: 13 Column: a

392 Transportation Equipment - Trailers

Schedule Page: 336.2 Line No.: 14 Column: a

392 Transportation Equipment - Heavy Trucks

Schedule Page: 336.2 Line No.: 18 Column: a

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

	Charged to Clearing Accts	Depreciable Plant Base
392 Transportation Equipment	$ 10,291,884	$ 177,385,000
396 Power Operated Equipment	3,193,086	51,373,000
Total	$ 13,484,970	$ 228,758,000

Schedule Page: 336.2 Line No.: 19 Column: a

397 Communication Equipment

Schedule Page: 336.2 Line No.: 20 Column: a

397 Communication Equipment - Two Way

Schedule Page: 336.2 Line No.: 21 Column: a

397 Communication Equipment - AMR

Schedule Page: 336.2 Line No.: 22 Column: a

397

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report 2019/Q4

FOOTNOTE DATA

Communication Equipment - EMS

Schedule Page: 336.2 Line No.: 26 Column: b

(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.

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-18-523.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	MINNESOTA PUBLIC UTILITIES COMMISSION				
2	Assessments	5,608,997		5,608,997	
3	Assessments	797,672		797,672	
4	GR-15-826 2016 Retail Rate Case		1,152,323	1,152,323	
5	M-17-694 Dakota Range Wind Project		50,740	50,740	
6	PA-18-702 & AI-19-622 Mankato Energy Center		181,436	181,436	
7	GR-19-564 Retail Rate Case		8,279	8,279	
8					
9	NORTH DAKOTA PUBLIC SERVICE COMMISSION				
10	PU-18-144 Foxtail	-4,959		-4,959	
11	PU-18-364 Transmission Cost Recovery	-9,855		-9,855	
12	PU-19-368 Renewable Energy Rider	-9,854		-9,854	
13	PU-12-813 Resource Treatment Framework		213,086	213,086	
14	PU-19-328 Transmission Cost Recovery Rider		10,000	10,000	
15	PU-19329 Renewable Energy Rider		10,000	10,000	
16					
17	SOUTH DAKOTA PUBLIC UTILITIES COMMISSION				
18	Assessments	318,699		318,699	
19	EL18-036 Transmission Cost Recovery Rider		1,028	1,028	
20	EL18-040 Infrastructure Rider		981	981	
21	EL19-032 Transmission Cost Recovery Rider		2,820	2,820	
22	EL19-035 Infrastructure Rider		2,345	2,345	
23	Retail Rate Case Settlement		-93,706	-93,706	
24					
25	FEDERAL ENERGY REGULATORY COMMISSION				
26	ER19-751 Buffalo Ridge		9,900	9,900	
27	ER19 -1355 GRE Attachment O		54,022	54,022	
28	ER20-26 Interchange ROE		33,695	33,695	
29					
30	Other				
31	Mandated Notices		985	985	
32	Mandated Notices		381	381	
33	Miscellaneous		177,389	177,389	
34	Miscellaneous		23	23	
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	6,700,700	1,815,727	8,516,427	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	5,608,997					2
Gas	928	797,672					3
Electric	928	1,152,323		186	834,996		4
Electric	928	50,740					5
Electric	928	181,436					6
Gas	928	8,279					7
							8
							9
Electric	928	-4,959					10
Electric	928	-9,855					11
Electric	928	-9,854					12
Electric	928	213,086					13
Electric	928	10,000					14
Electric	928	10,000					15
							16
							17
Electric	928	318,699					18
Electric	928	1,028					19
Electric	928	981					20
Electric	928	2,820					21
Electric	928	2,345					22
Electric	928	-93,706					23
							24
							25
Electric	928	9,900					26
Electric	928	54,022					27
Electric	928	33,695					28
							29
							30
Electric	928	985					31
Gas	928	381					32
Electric	928	177,371					33
Gas	928	41					34
							35
							36
							37
							38
							39
							40
							41
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							45
		8,516,427			834,996		46

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 350 Line No.: 4 Column: k

GR-15-826 - 48 month amortization period ending Dec. 31, 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B(1)	Electric Power Research Institute
2		
3	B(2)	Edison Electric Institute
4		
5	B(4)	Renewable Development Fund
6		
7	B(5)	Total
8		
9		
10		
11		
12		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $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 & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
	3,014,054	Various	3,014,054		1
					2
	972,120	Various	972,120		3
					4
	2,597,306	253	2,597,306		5
					6
	6,583,480		6,583,480		7
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 352 Line No.: 1 Column: e

Accounts charged:

506	300
524	2,423,396
539	297,640
921	
923	10,435
930.2	282,283
	$3,014,054

Schedule Page: 352 Line No.: 3 Column: e

Accounts charged:

426.1	$13,332
426.4	131,025
560	23,217
580	206
908	751
921	18,057
930.2	785,532
	$972,120

Schedule Page: 352 Line No.: 5 Column: e

The "Renewable Development Fund" is a program authorized by Minnesota Statute 116C3.779. Funding through this statutue 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-Dairy	$27,574
University of Minnesota-VWS	320,758
University of Minnesota-Noise	137,671
University of Minnesota-NRRI Torrefact	580,348
Interphases Solar	174,673
University of Minnesota-Gasification	291,182
Minnesota West Community & Technical College	1,050,000
Barr Engineering	15,100
	$2,597,306

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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	190,566,468		
4	Transmission	14,738,617		
5	Regional Market	266,789		
6	Distribution	31,772,526		
7	Customer Accounts	13,193,212		
8	Customer Service and Informational	2,266,436		
9	Sales			
10	Administrative and General	95,838,854		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	348,642,902		
12	Maintenance			
13	Production	69,945,495		
14	Transmission	4,348,486		
15	Regional Market			
16	Distribution	22,904,506		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	97,198,487		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	260,511,963		
21	Transmission (Enter Total of lines 4 and 14)	19,087,103		
22	Regional Market (Enter Total of Lines 5 and 15)	266,789		
23	Distribution (Enter Total of lines 6 and 16)	54,677,032		
24	Customer Accounts (Transcribe from line 7)	13,193,212		
25	Customer Service and Informational (Transcribe from line 8)	2,266,436		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	95,838,854		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	445,841,389	10,801,443	456,642,832
29	Gas			
30	Operation			
31	Production-Manufactured Gas	132,579		
32	Production-Nat. Gas (Including Expl. and Dev.)	161,764		
33	Other Gas Supply	154,214		
34	Storage, LNG Terminaling and Processing	1,851,509		
35	Transmission	509,091		
36	Distribution	17,380,119		
37	Customer Accounts	3,211,168		
38	Customer Service and Informational	361,182		
39	Sales			
40	Administrative and General	8,648,836		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	32,410,462		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	476,158		
47	Transmission	26,161		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	6,512,387		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	7,014,706		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	132,579		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	161,764		
54	Other Gas Supply (Enter Total of lines 33 and 45)	154,214		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	2,327,667		
56	Transmission (Lines 35 and 47)	535,252		
57	Distribution (Lines 36 and 48)	23,892,506		
58	Customer Accounts (Line 37)	3,211,168		
59	Customer Service and Informational (Line 38)	361,182		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	8,648,836		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	39,425,168	1,425,440	40,850,608
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	485,266,557	12,226,883	497,493,440
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	102,004,131	42,813,639	144,817,770
69	Gas Plant	7,266,550	9,104,926	16,371,476
70	Other (provide details in footnote):	884,241		884,241
71	TOTAL Construction (Total of lines 68 thru 70)	110,154,922	51,918,565	162,073,487
72	Plant Removal (By Utility Departments)			
73	Electric Plant	8,171,500	3,401,181	11,572,681
74	Gas Plant	579,376	723,309	1,302,685
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	8,750,876	4,124,490	12,875,366
77	Other Accounts (Specify, provide details in footnote):			
78	Regulatory Assets (Acct. No. 182.3)	8,057,428	342,395	8,399,823
79	Preliminary Survey and Investigation (Acct. No. 183)	6,124	5,213	11,337
80	Misc. Deferred Debits (Acct. No. 186)		11,580	11,580
81	Misc. Deferred Credits (Acct. No. 253)	15,631	981	16,612
82	Regulatory Liabilities (Acct. No. 254)	185,968	3,565	189,533
83	Non-utility (Accts. No. 416-417.1)	1,062,530	23,141	1,085,671
84	Misc. Income and Deductions (Accts. No. 426.1-426.5)	433,868	3,002	436,870
85	Non-utility CWP and RWP	43,895	5,977	49,872
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	9,805,444	395,854	10,201,298
96	TOTAL SALARIES AND WAGES	613,977,799	68,665,792	682,643,591

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 354 Line No.: 70 Column: b

E120.1 Nuclear Fuel In Process Of Refinement

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Instruction 1:

Account		Allocated to Utility Departments: Electric	Gas	Cost at Dec. 31, 2019
COMMON UTILITY PLANT IN SERVICE AND COMPLETED NOT CLASSIFIED (ACCOUNTS 101 AND 106)				
301	Organization	$90,205	$10,403	$100,608
303	Computer Software	420,855,940	48,535,026	469,390,966
	Total intangible plant	$420,946,145	$48,545,429	$469,491,574
389	Land and land rights	$5,672,501	$524,407	$6,196,908
390	Structures and improvements	188,562,456	17,432,082	205,994,538
391	Office furniture and equipment	159,129,323	14,711,069	173,840,392
392	Transportation equipment	10,315,570	2,202,481	12,518,051
393	Stores equipment	225,331	20,831	246,162
394	Tools/shop/garage equipment	4,502,092	416,206	4,918,298
395	Laboratory equipment	-	-	-
396	Power operated equipment	879,328	147,794	1,027,122
397	Communications equipment	691,095	63,890	754,985
398	Miscellaneous equipment	215,670	19,938	235,608
399.1	Asset retirement costs for general plant	595,393	55,042	650,435
	TOTAL	$791,734,904	$84,139,169	$875,874,073
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	$ 41,553,846	$ 4,488,607	$ 46,042,453

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Instruction 2:

COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (ACCOUNTS 108 AND 111)

General Plant	$326,751,981	$35,828,339	$362,580,320

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

	"Non-Legal" ARO Balances
Common General	$(7,374,950)
Common Intangible	-
Total Common	$(7,374,950)

Instruction 3:

COMMON UTILITY PLANT EXPENSES

		Electric	Gas	Total
403	Depreciation Expense	$24,041,570	$2,069,018	$26,110,588
403.1	Depreciation Expense - ARC	11,248	1,026	12,274
404	Amortization of limited term plant	41,289,115	4,656,123	45,945,238
405	Amortization of other plant	459	(459)	---
407.4	Amortization of regulatory credits	355,188	32,883	388,071
411.1	Accretion expense	27,022	2,465	29,487
	TOTAL	$65,724,602	$6,761,056	$72,485,658

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Basis of allocation of Common Utility Plant 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	MISO				
8	Net Purchases (Account 555)	14,730,729	26,827,677	39,182,497	52,405,235
9	Net Sales (Account 447)	(29,179,090)	(72,410,384)	(111,236,318)	(149,894,547)
10	Transmission Rights	(3,322,317)	(6,386,460)	(16,964,947)	(19,747,767)
11	Ancillary Services	673,979	1,326,651	1,473,291	1,489,534
12	Other Items (list separately)				
13	Admin Fees	2,170,299	4,957,038	7,154,518	9,791,059
14	Net Purchases for Storage Operations	27,338	42,528	60,743	60,618
15	ERCOT				
16	Net Purchases (Account 555)	(131,229)	(61,350)	4,032	24,636
17	Net Sales (Account 447)				
18	Transmission Rights				
19	Ancillary Services				
20	Other Items				
21	Uplift Charges	69	103	103	121
22	NEISO				
23	Net Purchases (Account 555)				
24	Net Sales (Account 447)				
25	Ancillary Services				
26	Other Items				
27	Admin Fees	1,922	6,202	11,215	15,149
28	Uplift Charges				
29	NYISO				
30	Net Purchases (Account 555)	65,626	75,530	48,242	41,557
31	Transmission Rights				
32	Admin Fees	1,295	4,320	9,083	13,223
33	PJM				
34	Net Purchases (Account 555)	6,444,799	9,538,675	29,422,376	42,740,756
35	Net Sales (Account 447)				
36	Transmission Rights	(87,532)	(217,597)	(270,967)	(254,346)
37	Ancillary Services				
38	Other Items				
39	Admin Fees	93,884	114,606	982,777	1,595,172
40	Uplift Charges	2,535,057	4,329,549	9,293,231	13,464,558
41	SPP				
42	Net Purchases (Account 555)	50,291	56,133	2,988	32,843
43	Transmission Rights		(1,786)	(1,786)	(1,786)
44	Uplift Charges	3,921	10,616	28,836	39,860
45	Ancillary Services	368	748	1,079	1,593
46	TOTAL	(5,920,591)	(31,787,201)	(40,799,007)	(48,182,532)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			7,910,979			527,832
2	Reactive Supply and Voltage			9,625,116			8,719,403
3	Regulation and Frequency Response			1,378,922			2,644,692
4	Energy Imbalance						
5	Operating Reserve - Spinning			1,222,728			2,728,747
6	Operating Reserve - Supplement			297,166			534,022
7	Other						51,412
8	Total (Lines 1 thru 7)			20,434,911			15,206,108

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 1 Column: b

Number of units is not available

Schedule Page: 398 Line No.: 1 Column: e

Number of units is not available

Schedule Page: 398 Line No.: 7 Column: g

NSPM MISO NSPP RT_RC_AMT	5,965
NSPM MISO NSPP DA_RC_AMT	45,447
	51,412

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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.

NAME OF SYSTEM: Northern States Power Co. Integrated System

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)
1	January	7,706	29	19	6,424	1,628				
2	February	7,244	1	9	6,007	1,567				
3	March	7,310	4	19	6,018	1,593				
4	Total for Quarter 1				18,449	4,788				
5	April	6,493	10	18	5,434	1,303				
6	May	7,232	31	15	6,009	1,490				
7	June	8,693	7	16	7,268	1,744				
8	Total for Quarter 2				18,711	4,537				
9	July	10,206	19	17	8,587	1,961				
10	August	9,207	7	17	7,574	1,949				
11	September	8,968	17	17	7,466	1,831				
12	Total for Quarter 3				23,627	5,741				
13	October	6,442	31	11	5,287	1,408				
14	November	7,165	12	18	5,874	1,579				
15	December	7,408	18	18	6,096	1,630				
16	Total for Quarter 4				17,257	4,617				
17	Total Year to Date/Year				78,044	19,683				

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 400 Line No.: 1 Column: b

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.

Schedule Page: 400 Line No.: 1 Column: e

"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	363
February	345
March	316
April	255
May	282
June	335
July	362
August	333
September	347
October	266
November	304
December	333
Total	3,841

"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	61
February	70
March	60
April	47
May	40
June	65
July	70
August	73
September	66
October	55
November	51
December	58
Total	716

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

MONTHLY ISO/RTO 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 Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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)	33,547,022
3	Steam	11,012,426			
4	Nuclear	14,104,547	23	Requirements Sales for Resale (See instruction 4, page 311.)	5,947,074
5	Hydro-Conventional	64,244			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	11,311,704
7	Other	11,638,992			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	463
9	Net Generation (Enter Total of lines 3 through 8)	36,820,209	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	56,119
10	Purchases	14,814,736	27	Total Energy Losses	772,563
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	51,634,945
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	51,634,945			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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).

NAME OF SYSTEM: Northern States Power Co. Integrated System

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	4,440,499	784,581	5,523	29	1900
30	February	3,994,224	703,188	5,137	5	1900
31	March	4,051,347	763,630	5,133	4	1900
32	April	3,418,179	549,654	4,679	10	1800
33	May	4,288,135	1,401,357	5,168	31	1600
34	June	4,346,824	846,588	6,388	7	1600
35	July	5,108,797	1,067,866	7,469	19	1700
36	August	4,763,218	1,040,989	6,539	7	1600
37	September	4,320,387	1,091,724	6,619	17	1700
38	October	4,074,322	923,079	4,535	31	1000
39	November	4,256,613	1,070,545	5,026	12	1800
40	December	4,572,400	1,068,503	5,196	18	1800
41	TOTAL	51,634,945	11,311,704			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) _ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 401 Line No.: 27 Column: b

MWH stored in Wind2Battery project on Dec. 31, 2019 1.000

Schedule Page: 401 Line No.: 29 Column: Sys

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

			Northern States Power Co. (a Minnesota corporation)			Northern States Power Co. (a Wisconsin corporation)	
Day	Hour	Integrated System	Minnesota	North Dakota	South Dakota	Wisconsin	Michigan
29-Jan	1900	6,679	4,726	435	362	1,129	27
5-Feb	1900	6,220	4,417	392	328	1,057	26
4-Mar	1900	6,231	4,442	365	326	1,075	23
10-Apr	1800	5,615	4,136	288	255	917	19
31-May	1600	6,156	4,538	274	356	970	18
7-Jun	1600	7,454	5,582	385	421	1,046	20
19-Jul	1700	8,774	6,601	351	517	1,282	23
7-Aug	1600	7,748	5,781	312	446	1,187	22
17-Sep	1700	7,712	5,770	397	452	1,067	26
31-Oct	1000	5,473	3,945	308	282	923	15
12-Nov	1800	6,090	4,369	353	304	1,041	23
18-Dec	1800	6,293	4,536	361	299	1,073	24

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 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.

Line No.	Item (a)	Plant Name: *Riverside* (b)			Plant Name: *Wilmarth* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1911			1948		
4	Year Last Unit was Installed	2009			1951		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	585.90			25.00		
6	Net Peak Demand on Plant - MW (60 minutes)	510			20		
7	Plant Hours Connected to Load	7316			7981		
8	Net Continuous Plant Capability (Megawatts)	500			18		
9	When Not Limited by Condenser Water	500			18		
10	When Limited by Condenser Water	454			18		
11	Average Number of Employees	21			26		
12	Net Generation, Exclusive of Plant Use - KWh	3087626175			105400436		
13	Cost of Plant: Land and Land Rights	450133			499773		
14	Structures and Improvements	52441362			11196195		
15	Equipment Costs	256045205			50451525		
16	Asset Retirement Costs	860791			765149		
17	Total Cost	309797491			62912642		
18	Cost per KW of Installed Capacity (line 17/5) Including	528.7549			2516.5057		
19	Production Expenses: Oper, Supv, & Engr	706991			362319		
20	Fuel	72287160			2513384		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			1771334		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2044019			10326		
26	Misc Steam (or Nuclear) Power Expenses	767802			979064		
27	Rents	727660			62921		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	533170			33959		
30	Maintenance of Structures	882584			312133		
31	Maintenance of Boiler (or reactor) Plant	0			1595864		
32	Maintenance of Electric Plant	2218592			231555		
33	Maintenance of Misc Steam (or Nuclear) Plant	319226			769920		
34	Total Production Expenses	80487204			8642779		
35	Expenses per Net KWh	0.0261			0.0820		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Gas	Oil	RDF	Gas	Wood
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		MCF	Barrels	Tons	MCF	Tons
38	Quantity (Units) of Fuel Burned	0	20375317	6	181204	43627	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1089	137401	5355	1089	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	3.548	58.744	2.158	4.415	0.000
41	Average Cost of Fuel per Unit Burned	0.000	3.548	58.744	13.921	4.415	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	3.259	10.243	1.300	4.055	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.024	0.000	0.000	0.030	0.000
44	Average BTU per KWh Net Generation	0.000	7355.450	0.000	0.000	18720.720	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: *Sherburne County* (b)			Plant Name: *Granite City* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Ind Enclosures		
3	Year Originally Constructed	1976			1969		
4	Year Last Unit was Installed	1987			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2084.45			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	1894			0		
7	Plant Hours Connected to Load	8754			0		
8	Net Continuous Plant Capability (Megawatts)	1879			0		
9	When Not Limited by Condenser Water	1879			0		
10	When Limited by Condenser Water	1879			0		
11	Average Number of Employees	195			0		
12	Net Generation, Exclusive of Plant Use - KWh	9031136191			-475120		
13	Cost of Plant: Land and Land Rights	5916542			40240		
14	Structures and Improvements	228629615			1241718		
15	Equipment Costs	1248161751			7542107		
16	Asset Retirement Costs	-4298077			63539		
17	Total Cost	1478409831			8887604		
18	Cost per KW of Installed Capacity (line 17/5) Including	709.2566			0		
19	Production Expenses: Oper, Supv, & Engr	2334963			536		
20	Fuel	207137934			2100		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	9685543			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	3648157			555		
26	Misc Steam (or Nuclear) Power Expenses	8998045			5953		
27	Rents	2498136			1096		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1924279			514		
30	Maintenance of Structures	2843135			96130		
31	Maintenance of Boiler (or reactor) Plant	15538501			0		
32	Maintenance of Electric Plant	3758221			14245		
33	Maintenance of Misc Steam (or Nuclear) Plant	8233208			49		
34	Total Production Expenses	266600122			121178		
35	Expenses per Net KWh	0.0295			-0.2550		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal		Oil	Gas		Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons		Barrels	MCF		Barrels
38	Quantity (Units) of Fuel Burned	5386853	0	28424	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8698	0	135741	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	35.892	0.000	83.961	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	38.036	0.000	83.961	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.186	0.000	14.727	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.020	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	10394.280	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: *Angus Anson* (b)	Plant Name: *Black Dog 2, 5, & 6* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbines	CC / Gas Turb
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		Conventional
3	Year Originally Constructed	1994	1987
4	Year Last Unit was Installed	2005	2018
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	405.66	554.29
6	Net Peak Demand on Plant - MW (60 minutes)	339	553
7	Plant Hours Connected to Load	796	6421
8	Net Continuous Plant Capability (Megawatts)	386	526
9	When Not Limited by Condenser Water	386	526
10	When Limited by Condenser Water	327	494
11	Average Number of Employees	8	23
12	Net Generation, Exclusive of Plant Use - KWh	110504985	1816973000
13	Cost of Plant: Land and Land Rights	1155577	952692
14	Structures and Improvements	7721804	56599492
15	Equipment Costs	125533845	274115972
16	Asset Retirement Costs	652565	11246760
17	Total Cost	135063791	342914916
18	Cost per KW of Installed Capacity (line 17/5) Including	332.9483	618.6561
19	Production Expenses: Oper, Supv, & Engr	97299	250542
20	Fuel	3928964	32138518
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	38073	881859
26	Misc Steam (or Nuclear) Power Expenses	557785	267347
27	Rents	55807	337585
28	Allowances	0	0
29	Maintenance Supervision and Engineering	26201	163110
30	Maintenance of Structures	562656	1654544
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	887787	1177812
33	Maintenance of Misc Steam (or Nuclear) Plant	18281	426336
34	Total Production Expenses	6172853	37297653
35	Expenses per Net KWh	0.0559	0.0205

Line No.	Item (a)	(b)	(b)	(b)	(b)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas		Oil		Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF		Barrels		MCF	
38	Quantity (Units) of Fuel Burned	1129765	0	9145	0	10083806	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1091	0	142873	0	1129	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.873	0.000	74.682	0.000	3.187	0.000
41	Average Cost of Fuel per Unit Burned	2.873	0.000	74.682	0.000	3.187	0.000
42	Average Cost of Fuel Burned per Million BTU	2.634	0.000	12.446	0.000	2.824	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.040	0.000	0.000	0.020	0.000
44	Average BTU per KWh Net Generation	0.000	11808.390	0.000	0.000	6812.560	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 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.

Plant Name: *A S King* (d)			Plant Name: *Prairie Island* (e)			Plant Name: *Blue Lake* (f)			Line No.
Steam			Nuclear			Gas Turbine			1
Conventional			Conventional			Ind Enclosures			2
1968			1973			1974			3
1968			1974			2005			4
598.40			1186.20			559.32			5
537			1121			342			6
4312			8760			411			7
511			1092			545			8
511			1092			545			9
511			1040			453			10
77			529			4			11
1739180000			9139972000			67001000			12
1335100			969282			141878			13
39623999			314803450			1703454			14
669421950			1938496786			94376508			15
2638413			-139278542			619224			16
713019462			2114990976			96841064			17
1191.5432			1782.9969			173.1407			18
528202			33391837			22456			19
46058220			77620425			3808076			20
0			4628634			0			21
5810824			27425259			0			22
0			0			0			23
0			0			0			24
13678			2867497			285467			25
2358874			74029288			74691			26
597753			7384507			50402			27
0			0			0			28
1316268			3063412			38220			29
1600536			24683			277656			30
4063127			23860739			0			31
2130580			7428872			507554			32
1662280			19479066			12385			33
66140342			281204219			5076907			34
0.0380			0.0308			0.0758			35
Coal	Gas	Oil		Nuclear		Gas		Oil	36
Tons	MCF	Barrels		Grams U-235		MCF		Barrels	37
1017298	102064	51	0	850419	0	670457	0	7941	38
8753	1079	137500	0	112337	0	1102	0	200095	39
39.594	4.189	81.975	0.000	0.000	0.000	4.685	0.000	80.705	40
45.272	4.189	81.975	0.000	0.000	0.000	4.685	0.000	80.705	41
2.586	3.882	14.195	0.000	0.818	0.000	4.251	0.000	9.603	42
0.000	0.030	0.000	0.000	0.010	0.000	0.000	0.060	0.000	43
0.000	10303.270	0.000	0.000	10439.330	0.000	0.000	12051.970	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 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.

Plant Name: *Inver Hills* (d)			Plant Name: *High Bridge 7, 8, 9* (e)			Plant Name: *Monticello* (f)			Line No.
Gas Turbine			Combined Cycle			Nuclear			1
Ind Enclosures			Conventional			Conventional			2
1972			1924			1971			3
1972			2008			1971			4
280.50			644.06			684.97			5
140			627			664			6
128			7444			8024			7
371			606			646			8
371			606			646			9
282			530			617			10
6			24			415			11
2707720			3506289090			4964575000			12
351801			528150			783302			13
1618514			71113002			246709312			14
58984351			319104340			1279762108			15
23827			7162633			132475222			16
60978493			397908125			1659729944			17
217.3921			617.8122			2423.0695			18
26163			638406			21937267			19
906014			74171393			41348839			20
0			0			3548601			21
0			0			21970867			22
0			0			0			23
0			0			0			24
605679			2216205			146237			25
52529			566332			53071519			26
19987			742860			4842611			27
0			0			0			28
9384			844933			4198713			29
102625			1200026			0			30
0			0			15066057			31
475139			1527572			4962471			32
13227			191283			11566142			33
2210747			82099010			182659324			34
0.8165			0.0234			0.0368			35
	Gas	Oil		Gas			Nuclear		36
	MCF	Barrels		MCF			Grams U-235		37
0	44764	0	0	22174681	0	0	474574	0	38
0	1092	0	0	1087	0	0	110383	0	39
0.000	3.400	0.000	0.000	3.345	0.000	0.000	0.000	0.000	40
0.000	3.400	0.000	0.000	3.345	0.000	0.000	0.000	0.000	41
0.000	3.112	0.000	0.000	3.078	0.000	0.000	0.794	0.000	42
0.000	0.330	0.000	0.000	0.020	0.000	0.000	0.010	0.000	43
0.000	18065.390	0.000	0.000	7118.650	0.000	0.000	11229.930	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 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.

Plant Name: *Black Dog 3 & 4* (d)	Plant Name: *Key City* (e)	Plant Name: *Benson* (f)	Line No.
Steam	Gas Turbine	Steam	1
Conventional	Ind Enclosures	Conventional	2
1952	1970	2007	3
1960	1970	2007	4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	67495	0	13
0	1002265	0	14
0	7597648	0	15
0	0	0	16
0	8667408	0	17
0	0	0	18
146422	25	-1489	19
7893452	0	-1	20
0	0	0	21
1304894	0	0	22
0	0	0	23
0	0	0	24
-5368	4	-211	25
275959	19	52448	26
111001	51	-3044	27
0	0	0	28
261746	24	-1429	29
910898	1450	0	30
95537	0	0	31
126162	4094	-382811	32
240009	2	-137	33
11360712	5669	-336674	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
	Oil					RDF		Wood	36
	Barrels					Tons		Tons	37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 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.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 403 Line No.: -1 Column: e

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

(a) Operating and maintenance costs of the Prairie Island Plant are expensed as incurred. NSP-Minnesota uses a deferral and amortization method for nuclear refueling operation and maintenance costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric cases.

(b) NSP-Minnesota buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.

(c) The Prairie Island Plant has two identical Westinghouse 2 loop PWR Nuclear Power Plants. Fuel material is U02 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 47 metric tons of uranium metal with a nominal U-235 enrichment of 4.95 weight percent in the fresh fuel. The reactor is licensed to operate at 1677 MWt.

Schedule Page: 402.1 Line No.: -1 Column: b

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.

Schedule Page: 403.1 Line No.: -1 Column: f

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

(a) Operating and maintenance costs of the Monticello Plant are expensed as incurred. NSP-Minnesota uses a deferral and amortization method for nuclear refueling operation and maintenance costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric cases.

(b) NSP-Minnesota buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.

(c) The Monticello Plant is a General Electric BWR-3 Nuclear Power Plant. Fuel material is U02 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 84 metric tons of uranium metal with a nominal U-235 enrichment of 3.8 weight percent in the fresh fuel. The reactor is licensed to operate at 2,004 MWt.

Schedule Page: 403.2 Line No.: -1 Column: f

On June 29, 2018 NSP-Minnesota acquired the Benson Power Facility. For additional information, see page 108 item 3.

Schedule Page: 402.2 Line No.: 1 Column: c

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

Schedule Page: 402.1 Line No.: 39 Column: b1

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Henn Is & Upper Dam (b)	FERC Licensed Project No. 0 Plant Name: (c)
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	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	12	0
7	Plant Hours Connect to Load	7,831	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	7	0
10	(b) Under the Most Adverse Oper Conditions	6	0
11	Average Number of Employees	2	0
12	Net Generation, Exclusive of Plant Use - Kwh	64,244,243	0
13	Cost of Plant		
14	Land and Land Rights	1,548,707	0
15	Structures and Improvements	1,407,680	0
16	Reservoirs, Dams, and Waterways	8,889,960	0
17	Equipment Costs	13,494,863	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	25,341,210	0
21	Cost per KW of Installed Capacity (line 20 / 5)	1,824.4212	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	8,818	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	416,335	0
27	Misc Hydraulic Power Generation Expenses	735,450	0
28	Rents	65,141	0
29	Maintenance Supervision and Engineering	2,653	0
30	Maintenance of Structures	38,404	0
31	Maintenance of Reservoirs, Dams, and Waterways	62,498	0
32	Maintenance of Electric Plant	120,543	0
33	Maintenance of Misc Hydraulic Plant	4,755	0
34	Total Production Expenses (total 23 thru 33)	1,454,597	0
35	Expenses per net KWh	0.0226	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

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 the 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."

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)
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 Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
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	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
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)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
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			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	STEAM PLANTS					
2						
3	Red Wing	1949	24.00	18.0	136,709,459	67,842,812
4	Minnesota Valley	1932				
5						
6						
7	WIND TURBINES					
8						
9	Blazing Star Wind					
10	Lake Benton Wind	1997	102.00	99.0	53,802,452	170,796,828
11	Grand Meadow Wind	2008	100.50	100.0	265,357,055	220,504,146
12	Nobles Wind	2010	201.00	201.0	634,135,122	538,171,654
13	Borders Wind	2015	150.00	147.0	612,373,544	276,348,588
14	Pleasant Valley Wind	2015	200.00	195.0	772,925,308	354,086,943
15	Courtenay Wind	2016	200.00	193.0	709,772,118	296,083,116
16	Foxtail Wind	2019	163.60			252,112,277
17						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
2,826,784	2,032,909	3,310,310	3,479,511	RDF, Gas		3
	938	66	25,519			4
						5
						6
						7
						8
	5,591		28	Wind		9
1,674,479	35,858		131,420	Wind		10
2,194,071	1,206,912		1,356,842	Wind		11
2,677,471	2,549,626		1,228,617	Wind		12
1,842,324	2,216,288		962,281	Wind		13
1,770,435	4,415,340		1,323,584	Wind		14
1,480,416	2,772,743		1,269,305	Wind		15
1,541,029	39,932		10,270	Wind		16
						17
						18
						19
						20
						21
						22
						23
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						45
						46

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 410 Line No.: 1 Column: g

The Plant Cost is manually calculated (not calculated by the FERC software) - (col g = col f / col c)

Schedule Page: 410 Line No.: 9 Column: d

Commercial Operations Date Feb. 29, 2020

Schedule Page: 410 Line No.: 16 Column: d

Commercial Operations Date Dec. 31, 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	(5703;01) CHISAGO CO.	FORBES	500.00	500.00	TOWER	61.45		1
2	(5702;01) FORBES	RIE	500.00	500.00	TOWER	203.77		1
3	(0998;01) SOC	SPLIT ROCK	345.00	345.00	SINGLE POLE		4.43	1
4			345.00	345.00	SINGLE POLE		0.63	1
5	(0997;01) SPLIT ROCK	WHITE (WAPA)	345.00	345.00	SINGLE POLE	4.91	0.24	1
6	(0996;01) DICKINSON SW	PARKERS LAKE	345.00	345.00	TOWER	0.13	9.62	1
7	(0994;01) ALLEN S KING	CHISAGO CO.	345.00	345.00	SINGLE POLE		31.56	1
8			345.00	345.00	TOWER		6.62	1
9	(0992;02) COON CREEK	SHERBURNE CO.	345.00	345.00	K-FRAME	16.94	0.66	1
10			345.00	345.00	SINGLE POLE		14.18	1
11			345.00	345.00	TOWER		11.62	1
12	(0991;01) MONTICELLO SUB	SHERBURNE CO.	345.00	345.00	TOWER		5.81	1
13	(0989;01) BLUE LAKE	INVER HILLS	345.00	345.00	K-FRAME	0.78		1
14			345.00	345.00	SINGLE POLE		1.04	1
15			345.00	345.00	TOWER	3.52	16.95	1
16	(0989;01) INVER HILLS	RED ROCK	345.00	345.00	H-FRAME	0.52		1
17			345.00	345.00	K-FRAME	2.00		1
18			345.00	345.00	TOWER	5.98		1
19	(0988;01) BLUE LAKE	PARKERS LAKE	345.00	345.00	SINGLE POLE		2.11	1
20			345.00	345.00	TOWER		12.67	1
21	(0987;01) PRAIRIE ISLAND	RED ROCK	345.00	345.00	K-FRAME	20.69	0.59	1
22			345.00	345.00	SINGLE POLE		5.91	1
23			345.00	345.00	TOWER		2.28	1
24			345.00	345.00	TOWER	0.15	2.34	1
25	(0986;02) PRAIRIE ISLAND	RED ROCK	345.00	345.00	K-FRAME	21.26		1
26			345.00	345.00	SINGLE POLE	5.91		1
27			345.00	345.00	TOWER	2.28		1
28			345.00	345.00	TOWER	0.12	2.37	1
29	(0985;01) COON CREEK	SHERBURNE CO.	345.00	345.00	H-FRAME	16.26	1.12	1
30			345.00	345.00	K-FRAME	3.36		1
31			345.00	345.00	SINGLE POLE	0.29	0.51	1
32			345.00	345.00	TOWER	5.79	5.79	1
33	(0984;03) COON CREEK	SHERBURNE CO.	345.00	345.00	K-FRAME	19.79		1
34			345.00	345.00	SINGLE POLE	14.81		1
35			345.00	345.00	TOWER	8.84		1
36					TOTAL	5,131.68	609.05	150

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	(0984;01) COON CREEK	TERMINAL	345.00	345.00	SINGLE POLE		4.49	1
2			345.00	345.00	TOWER		9.14	1
3	(0982;01) BLUE LAKE	SCOTT CO.	345.00	345.00	TOWER	8.15		1
4	(0982;01) CRANDALL	LAKEFIELD GENERATING	345.00	345.00	K-FRAME	2.20		1
5	(0982;01) CRANDALL	WILMARTH	345.00	345.00	K-FRAME	50.51		1
6			345.00	345.00	TOWER	1.87		1
7	(0982;01) HELENA	SCOTT CO.	345.00	345.00	K-FRAME	15.00		1
8			345.00	345.00	TOWER	2.17		1
9	(0982;01) HELENA	SHEAS LAKE	345.00	345.00	K-FRAME	7.45		1
10	(0982;01) LAKEFIELD JCT	LAKEFIELD GENERATING	345.00	345.00	K-FRAME	18.71		1
11	(0982;01) SHEAS LAKE	WILMARTH	345.00	345.00	K-FRAME	23.61		1
12			345.00	345.00	TOWER	1.11		1
13	(0981-MN;01) ALLEN S KING	EAU CLAIRE	345.00	345.00	K-FRAME	3.69		1
14			345.00	345.00	TOWER	1.01	15.19	1
15	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.00	345.00	SINGLE POLE	31.38	0.55	1
16			345.00	345.00	TOWER		5.68	1
17	(0980;01) COON CREEK	KOHLMAN LAKE	345.00	345.00	SINGLE POLE	4.54	2.82	1
18			345.00	345.00	TOWER	6.94	5.62	1
19	(0979;01) ADAMS	PLEASANT VALLEY (GRE)	345.00	345.00	K-FRAME	16.83		1
20	(0979;01) BYRON (SMMPA)	NORTH ROCHESTER	345.00	345.00	K-FRAME	13.54		1
21	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	345.00	345.00	H-FRAME	1.10		1
22			345.00	345.00	K-FRAME	15.19		1
23	(0979;01) NORTH	PRAIRIE ISLAND	345.00	345.00	H-FRAME	1.04		1
24			345.00	345.00	K-FRAME	26.19		1
25			345.00	345.00	TOWER	2.40		1
26	(0978;01) ELM CREEK	MONTICELLO SUB	345.00	345.00	H-FRAME	16.90		1
27			345.00	345.00	K-FRAME	3.37		1
28			345.00	345.00	TOWER	5.82		1
29	(0978;01) ELM CREEK	PARKERS LAKE	345.00	345.00	SINGLE POLE	0.59		1
30			345.00	345.00	TOWER	10.46		1
31	(0977;01) ALLEN S KING	KOHLMAN LAKE	345.00	345.00	TOWER	12.67		1
32	(0977;01) KOHLMAN LAKE	TERMINAL	345.00	345.00	SINGLE POLE	2.82		1
33			345.00	345.00	TOWER	7.33		1
34	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.00	345.00	SINGLE POLE	3.80		1
35			345.00	345.00	TOWER	1.74		1
36					TOTAL	5,131.68	609.05	150

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	(0976;01) BLUE LAKE	HAMPTON	345.00	345.00	K-FRAME	3.08		1
2			345.00	345.00	K-FRAME	6.00		1
3			345.00	345.00	SINGLE POLE	1.04		1
4			345.00	345.00	TOWER	22.91		1
5	(0976;01) EDEN PRAIRIE	PARKERS LAKE	345.00	345.00	TOWER	9.47		1
6	(0976;01) HAMPTON	PRAIRIE ISLAND	345.00	345.00	K-FRAME	16.00		1
7			345.00	345.00	TOWER	3.55		1
8	(0975;01) ALLEN S KING	RED ROCK	345.00	345.00	K-FRAME	3.54		1
9			345.00	345.00	TOWER	21.83		1
10	(0974;01) MANKATO	WILMARTH	345.00	345.00	SINGLE POLE	0.22		1
11	(0973;01) MONTICELLO SUB	QUARRY	345.00	345.00	SINGLE POLE	30.04		1
12	(0972-MN;01) BROOKINGS	STEEP BANK LAKE	345.00	345.00	SINGLE POLE	8.74		1
13	(0972-SD;01) BROOKINGS	STEEP BANK LAKE	345.00	345.00	SINGLE POLE	10.31		1
14	(0972;01) HAWKS NEST	LYON CO.	345.00	345.00	SINGLE POLE	30.55		1
15	(0972;01) HAWKS NEST	STEEP BANK LAKE	345.00	345.00	SINGLE POLE	9.96		1
16	(0971;01) BROOKINGS CO.	WHITE (WAPA)	345.00	345.00	SINGLE POLE	0.42		1
17	(0970;02) BROOKINGS CO.	WHITE (WAPA)	345.00	345.00	SINGLE POLE	0.38		1
18	(0966;01) BROOKINGS CO.	BIG STONE SOUTH	345.00	345.00	SINGLE POLE	71.56		1
19	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.00	345.00	2 POLE	3.12		1
20			345.00	345.00	SINGLE POLE	40.07		1
21	(0964;01) HAMPTON	NORTH ROCHESTER	345.00	345.00	SINGLE POLE	37.85		1
22	(0962;01) HAZEL CREEK	LYON CO.	345.00	345.00	SINGLE POLE	24.54		1
23	(0961;01) CHUB LAKE (GRE)	HAMPTON	345.00	345.00	SINGLE POLE	18.10		1
24	(0960;01) CHUB LAKE (GRE)	HELENA	345.00	345.00	SINGLE POLE	20.87		1
25	(0959;02) CEDAR MTN.	HELENA	345.00	345.00	SINGLE POLE		73.06	1
26	(0958;01) CEDAR MTN.	HELENA	345.00	345.00	SINGLE POLE	73.10		1
27	(0957;02) CEDAR MTN.	LYON CO.	345.00	345.00	SINGLE POLE		49.49	1
28	(0956;01) CEDAR MTN.	LYON CO.	345.00	345.00	SINGLE POLE	49.49		1
29	(0955-MN;01) ALEXANDRIA	BISON	345.00	345.00	2 POLE	3.35		1
30			345.00	345.00	SINGLE POLE	100.95		1
31	(0955-ND;01) ALEXANDRIA	BISON	345.00	345.00	SINGLE POLE	34.47		1
32	(0954;01) ALEXANDRIA SW.	RIVERVIEW (GRE)	345.00	345.00	SINGLE POLE	45.16		1
33	(0954;01) QUARRY	RIVERVIEW (GRE)	345.00	345.00	SINGLE POLE	36.09		1
34	(0953;01) LAKEFIELD JCT	NOBLES CO.	345.00	345.00	SINGLE POLE	22.67		1
35			345.00	345.00	SINGLE POLE	13.27		1
36					TOTAL	5,131.68	609.05	150

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	(0953-MN;01) NOBLES CO.	SPLIT ROCK	345.00	345.00	SINGLE POLE	10.69		1
2			345.00	345.00	SINGLE POLE	31.88		1
3	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.00	345.00	SINGLE POLE	4.43		1
4			345.00	345.00	SINGLE POLE	5.24		1
5	(0963;01) HAZEL CREEK	MINNESOTA VALLEY	230.00	345.00	SINGLE POLE	4.97		1
6	(0924;01) MCHENRY (GRE)	MAGIC CITY	230.00	230.00	SINGLE POLE	20.57		1
7	(0923;01) CASS LAKE (OTP)	WILTON (MPC)	230.00	230.00	SINGLE POLE	19.32		1
8	(0922;01) BOSWELL	CASS LAKE (OTP)	230.00	230.00	SINGLE POLE	51.46		1
9	(0920;01) GBR	PEACE GARDEN	230.00	230.00	H-FRAME	1.98		1
10	(0920;01) PEACE GARDEN	RUGBY (OTP)	230.00	230.00	H-FRAME	54.67		1
11	(0919;01) PAYNESVILLE	WILLMAR (GRE)	230.00	230.00	H-FRAME	2.42		1
12			230.00	230.00	SINGLE POLE	27.31		1
13	(0918;01) SIOUX FALLS	SPLIT ROCK	230.00	230.00	SINGLE POLE	0.96		1
14	(0916;01) GRAND FORKS	PRAIRIE	230.00	230.00	H-FRAME	6.35		1
15			230.00	230.00	SINGLE POLE	0.48		1
16	(0915;01) FARGO (WAPA)	SHEYENNE	230.00	230.00	H-FRAME	4.04	0.21	1
17	(0912;01) DRAYTON	LTL	230.00	230.00	H-FRAME	28.66		1
18			230.00	230.00	SINGLE POLE	0.07		1
19	(0911;01) AUDUBON (OTP)	SHEYENNE	230.00	230.00	H-FRAME	1.41		1
20	(0911;01) MAPLE RIVER	SHEYENNE	230.00	230.00	H-FRAME	2.80		1
21			230.00	230.00	TOWER	0.05	3.72	1
22	(0910;01) MAPLE RIVER	WAHPETON (MINNKOTA)	230.00	230.00	TOWER	3.59		1
23	(0909;01) AUDUBON (OTP)	HUBBARD (GRE)	230.00	230.00	H-FRAME	38.56		1
24	(0902,0921;01) ROCK	RUSH CITY (GRE)	230.00	230.00	SINGLE POLE	11.06	0.09	1
25			230.00	230.00	SINGLE POLE	53.91		1
26			230.00	230.00	TOWER	2.61		1
27	(0902;01) BEAR CREEK	ROCK CREEK	230.00	230.00	SINGLE POLE	12.55		1
28	(0900;01) BLUE LAKE	MCLEOD (MUNI)	230.00	230.00	H-FRAME	1.35		1
29			230.00	230.00	SINGLE POLE	0.73		1
30			230.00	230.00	TOWER	44.38		1
31	(0900;02) GRANITE FALLS	PANTHER (GRE)	230.00	230.00	TOWER	32.84		1
32	(0900;01) MCLEOD (MUNI)	PANTHER (GRE)	230.00	230.00	TOWER	28.45		1
33	(5310;01) NORTHERN HILLS	NORTH ROCHESTER	161.00	161.00	SINGLE POLE	15.51		1
34	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.00	161.00	SINGLE POLE	11.41		1
35			161.00	161.00	SINGLE POLE	1.25	15.00	1
36					TOTAL	5,131.68	609.05	150

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	(5306;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	161.00	161.00	SINGLE POLE	16.60		1
2	(5305-MN;01) LAWRENCE	ST CROIX FALLS	161.00	161.00	SINGLE POLE	1.57		1
3			161.00	161.00	UNDERGROU	0.58		1
4	(5301;01) ELK (ALLIANT)	ROCK CO.	161.00	161.00	H-FRAME	5.26	0.14	1
5	(5301-MN;01) ROCK CO.	SPLIT ROCK	161.00	161.00	H-FRAME	3.44		1
6			161.00	161.00	SINGLE POLE	0.08		1
7	(5301-SD;01) ROCK CO.	SPLIT ROCK	161.00	161.00	H-FRAME	10.28		1
8			161.00	161.00	SINGLE POLE	0.87		1
9	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.00	161.00	H-FRAME	29.96	0.15	1
10			161.00	161.00	SINGLE POLE		1.41	1
11								
12	SUMMARY OF 115 KV		115.00	115.00	Overhead	1,451.85	152.69	
13			115.00	115.00	Underground	13.22		
14	SUMMARY OF 69 KV		69.00	69.00	Overhead	1,485.47	98.13	
15			69.00	69.00	Underground	1.53		
16	SUMMARY OF 34.5 KV		34.50	34.50	Overhead	60.04	32.42	
17			34.50	34.50	Underground	0.59		
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	5,131.68	609.05	150

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
9-1192 ACSR	2,237,403	16,105,734	18,343,137					1
9-1192 ACSR	1,723,645	64,576,923	66,300,568					2
6-954 ACSS		654,289	654,289					3
6-954 ACSS/TW								4
6-954 ACSS/TW	139,860	8,177,511	8,317,371					5
6-954 ACSR		564,837	564,837					6
6-954 ACSR		1,648,291	1,648,291					7
6-795 ACSR								8
6-954 ACSR	472,775	3,814,830	4,287,605					9
6-954 ACSR								10
6-954 ACSR								11
6-954 ACSR		196,978	196,978					12
6-795 ACSR	80,238	1,436,429	1,516,667					13
6-795 ACSR								14
6-795 ACSR								15
6-795 ACSR	272,767	1,672,480	1,945,247					16
6-795 ACSR								17
6-795 ACSR								18
6-795 ACSR		478,209	478,209					19
6-795 ACSR								20
6-795 ACSR		3,015,477	3,015,477					21
6-795 ACSR								22
6-795 ACSR								23
6-954 ACSR								24
6-795 ACSR	661,692	7,062,208	7,723,900					25
6-795 ACSR								26
6-795 ACSR								27
6-954 ACSR								28
6-954 ACSR	17,816	14,701,916	14,719,732					29
6-954 ACSR								30
6-954 ACSR								31
6-954 ACSR								32
6-954 ACSR	506,296	7,510,256	8,016,552					33
6-954 ACSR								34
6-954 ACSR								35
	147,918,697	2,159,858,036	2,307,776,729	853,170	7,294,969	2,740,456	10,888,595	36

TRANSMISSION LINE STATISTICS (Continued)

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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
6-795 ACSR	160,760	2,309,570	2,470,331					1
6-795 ACSR								2
6-795 ACSR	155,241	3,347,694	3,502,935					3
6-795 ACSR								4
6-795 ACSR	1,467,013	9,733,517	11,200,530					5
6-795 ACSR								6
6-795 ACSR		401,875	401,875					7
6-795 ACSR								8
6-795 ACSR	95,480	1,602,336	1,697,816					9
6-795 ACSR	214,005	7,167,427	7,381,431					10
6-795 ACSR	271,747	4,686,702	4,958,449					11
6-795 ACSR								12
6-795 ACSR	24,099	872,818	896,916					13
6-795 ACSR								14
6-954 ACSR	4,408,021	10,856,196	15,264,217					15
6-795 ACSR								16
6-795 ACSR	1,384,573	2,657,526	4,042,099					17
6-795 ACSR								18
6-795 ACSR	41,979	5,181,967	5,223,946					19
6-795 ACSR	35,037	4,307,001	4,342,038					20
6-795 ACSR	43,098	5,272,671	5,315,769					21
6-795 ACSR								22
6-795 ACSR	67,126	8,739,281	8,806,407					23
6-795 ACSR								24
6-954 ACSR								25
6-954 ACSR	868,700	13,963,593	14,832,293					26
6-954 ACSR								27
6-954 ACSR								28
6-954 ACSR	13,498	912,965	926,462					29
6-954 ACSR								30
6-795 ACSR	1,136,939	2,280,784	3,417,723					31
6-795 ACSR	1,136,938	2,189,075	3,326,013					32
6-795 ACSR								33
6-795 ACSR	104,148	551,531	655,679					34
6-795 ACSR								35
	147,918,697	2,159,858,036	2,307,776,729	853,170	7,294,969	2,740,456	10,888,595	36

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
6-795 ACSR	873,092	4,547,510	5,420,603					1
6-954 ACSR								2
6-795 ACSR								3
6-795 ACSR								4
6-795 ACSR	45,639	512,475	558,113					5
6-795 ACSR	1,296,677	6,949,323	8,246,000					6
6-795 ACSR								7
6-795 ACSR	401,128	2,690,173	3,091,301					8
6-795 ACSR								9
6-795 ACSR		888,655	888,655					10
6-954 ACSS/TW	5,368,656	10,768,099	16,136,755					11
6-954 ACSS/TW	4,923,502	73,110,433	78,033,935					12
6-954 ACSS/TW								13
6-954 ACSS/TW		141,636	141,636					14
6-954 ACSS/TW		382,411	382,411					15
6-795 ACSS	13,748	916,154	929,902					16
6-795 ACSS		1,215,849	1,215,849					17
6-556.5 ACSR/T2	3,526,999	58,530,377	62,057,375					18
6-954 ACSS/TW	5,280,808	52,856,396	58,137,204					19
6-954 ACSS/TW								20
6-397.5 TACSRVR2	9,430,408	50,423,159	59,853,568					21
6-954 ACSS/TW	2,289,672	25,572,616	27,862,289					22
6-954 ACSS/TW	7,244,068	36,395,228	43,639,296					23
6-954 ACSS/TW	9,545,985	34,612,451	44,158,436					24
6-954 ACSS/TW								25
6-954 ACSS/TW	15,584,347	102,190,856	117,775,203					26
6-954 ACSS/TW		-4,181,645	-4,181,645					27
6-954 ACSS/TW	5,315,434	65,839,990	71,155,424					28
6-954 ACSS/TW	6,637,015	77,753,910	84,390,924					29
6-954 ACSS/TW								30
6-954 ACSS/TW	1,513,232	20,413,564	21,926,795					31
6-954 ACSS/TW	4,188,286	61,643,859	65,832,145					32
6-954 ACSS/TW								33
6-397.5 ACSR/T2	7,139,056	108,508,023	115,647,079					34
6-954 ACSS/TW								35
	147,918,697	2,159,858,036	2,307,776,729	853,170	7,294,969	2,740,456	10,888,595	36

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
6-397.5 ZTACSR		6,425,041	6,425,041					1
6-954 ACSS/TW								2
6-954 ACSR	554,100	4,451,932	5,006,032					3
6-954 ACSS/TW								4
6-954 ACSS/TW	655,395	8,756,369	9,411,764					5
6-477 ACSR/VR2	727,998	26,185,229	26,913,227					6
3-795 ACSS	884,508	8,672,159	9,556,667					7
3-795 ACSS	1,023,124	22,057,949	23,081,073					8
3-954 ACSR	1,288,507	12,521,625	13,810,132					9
3-954 ACSR								10
3-795 ACSR	302,577	7,615,686	7,918,263					11
3-795 ACSR								12
3-795 ACSS	531,676	605,867	1,137,542					13
3-954 ACSR	24,662	1,531,625	1,556,287					14
3-954 ACSR								15
3-795 ACSR	21,223	806,965	828,188					16
3-954 ACSR	57,281	3,006,613	3,063,895					17
3-954 ACSR								18
3-795 ACSR	10,733	237,425	248,158					19
3-795 ACSR	21,002	597,200	618,203					20
3-795 ACSR								21
3-795 ACSR	55,625	283,964	339,589					22
3-795 ACSR	57,863	7,828,503	7,886,366					23
3-1272 ACSR	407,857	7,395,748	7,803,605					24
3-795 ACSR								25
3-1272 ACSR								26
3-795 ACSR	29,881	1,251,046	1,280,927					27
3-795 ACSR	371,590	5,207,409	5,578,999					28
3-795 ACSR								29
3-795 ACSR								30
3-795 ACSR	5,902	1,351,603	1,357,504					31
3-795 ACSR	59,673	1,635,478	1,695,151					32
3-795 ACSS	1,314,415	8,563,739	9,878,154					33
6-397.5 TACSR/TW	567,003	11,435,121	12,002,124					34
6-954 ACSS/TW								35
	147,918,697	2,159,858,036	2,307,776,729	853,170	7,294,969	2,740,456	10,888,595	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
3-795 ACSS	477,246	9,886,399	10,363,645					1
3-795 ACSS	52,746	9,233,982	9,286,728					2
3000 CU								3
3-477 ACSR	6,491	200,388	206,879					4
3-477 ACSR	17,390	603,450	620,840					5
3-477 ACSR								6
3-477 ACSR	35,391	1,879,633	1,915,023					7
3-2312 ACSR								8
3-477 ACSR	143,079	1,950,065	2,093,144					9
3-565.3 ACSS/TW								10
								11
	23,301,803	679,231,283	702,533,086					12
								13
	6,117,242	267,987,149	274,104,391					14
								15
	436,068	29,128,992	29,565,060					16
								17
								18
				853,170	7,294,969	2,740,456	10,888,595	19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	147,918,697	2,159,858,036	2,307,776,729	853,170	7,294,969	2,740,456	10,888,595	36

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 422.2 Line No.: 11 Column: a

NSM ((0973;01) MONTICELLO SUB-QUARRY) : Xcel Energy owns 31.38%(9.43 miles) of 30.04 miles of this circuit: remaining 68.62%(20.61 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 12 Column: a

NSM ((0972-MN;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 68.51%(5.99 miles) of 8.74 miles of this circuit: remaining 31.49%(2.75 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 13 Column: a

NSM ((0972-SD;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 68.51%(7.07 miles) of 10.31 miles of this circuit: remaining 31.49%(3.25 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 14 Column: a

NSM ((0972;01) HAWKS NEST LAKE-LYON CO.) : Xcel Energy owns 68.51%(20.93 miles) of 30.55 miles of this circuit: remaining 31.49%(9.62 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 15 Column: a

NSM ((0972;01) HAWKS NEST LAKE-STEEP BANK LAKE) : Xcel Energy owns 68.51%(6.82 miles) of 9.96 miles of this circuit: remaining 31.49%(3.14 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 18 Column: a

NSM ((0966;01) BROOKINGS CO.-BIG STONE SOUTH) : Xcel Energy owns 50.0%(35.78 miles) of 71.56 miles of this circuit: remaining 50.0%(35.78 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 19 Column: a

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

Schedule Page: 422.2 Line No.: 21 Column: a

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

Schedule Page: 422.2 Line No.: 22 Column: a

NSM ((0962;01) HAZEL CREEK-LYON CO.) : Xcel Energy owns 68.51%(16.81 miles) of 24.54 miles of this circuit: remaining 31.49%(7.73 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 23 Column: a

NSM ((0961;01) CHUB LAKE (GRE)-HAMPTON) : Xcel Energy owns 68.51%(12.4 miles) of 18.1 miles of this circuit: remaining 31.49%(5.7 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 24 Column: a

NSM ((0960;01) CHUB LAKE (GRE)-HELENA) : Xcel Energy owns 68.51%(14.3 miles) of 20.87 miles of this circuit: remaining 31.49%(6.57 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 25 Column: a

NSM ((0959;02) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 68.51%(50.06 miles) of 73.06 miles of this circuit: remaining 31.49%(23.01 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 26 Column: a

NSM ((0958;01) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 68.51%(50.08 miles) of 73.1 miles of this circuit: remaining 31.49%(23.02 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 27 Column: a

NSM ((0957;02) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 68.51%(33.9 miles) of 49.49 miles of this circuit: remaining 31.49%(15.58 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 28 Column: a

NSM ((0956;01) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 68.51%(33.9 miles) of 49.49 miles of this circuit: remaining 31.49%(15.58 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 29 Column: a

NSM ((0955-MN;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 31.38%(32.73 miles) of 104.3 miles of this circuit:

remaining 68.62%(71.57 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 31 Column: a

NSM ((0955-ND;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 31.38%(10.82 miles) of 34.47 miles of this circuit: remaining 68.62%(23.65 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 32 Column: a

NSM ((0954;01) ALEXANDRIA SW. ST.-RIVERVIEW (GRE)) : Xcel Energy owns 31.38%(14.17 miles) of 45.16 miles of this circuit: remaining 68.62%(30.99 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.2 Line No.: 33 Column: a

NSM ((0954;01) QUARRY-RIVERVIEW (GRE)) : Xcel Energy owns 31.38%(11.33 miles) of 36.09 miles of this circuit: remaining 68.62%(24.77 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.3 Line No.: 5 Column: a

NSM ((0963;01) HAZEL CREEK-MINNESOTA VALLEY) : Xcel Energy owns 68.51%(3.4 miles) of 4.97 miles of this circuit: remaining 31.49%(1.56 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.3 Line No.: 7 Column: a

NSM ((0923;01) CASS LAKE (OTP)-WILTON (MPC)) : Xcel Energy owns 29.8962%(5.78 miles) of 19.32 miles of this circuit: remaining 70.1038%(13.54 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.3 Line No.: 8 Column: a

NSM ((0922;01) BOSWELL (MINNESOTA POWER)-CASS LAKE (OTP)) : Xcel Energy owns 29.9%(15.39 miles) of 51.46 miles of this circuit: remaining 70.1%(36.07 miles) is owned by other members of a joint venture partnership

Schedule Page: 422.3 Line No.: 33 Column: a

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

Schedule Page: 422.3 Line No.: 34 Column: a

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

Schedule Page: 422.4 Line No.: 12 Column: a

NSM ((5558;01) CEDAR MTN. (GRE)-FRANKLIN) : Xcel Energy owns 68.51%(2.95 miles) of 4.3 miles of this circuit: remaining 31.49%(1.36 miles) is owned by other members of a joint venture partnership

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	(0839;01) MAPLE RIVER	RED RIVER	1.66	SINGLE POLE	12.00	1	1
2	(5571;02) MAPLE RIVER	RED RIVER	2.86	SINGLE POLE	19.00	1	1
3	(0795;01) ALBANY	RIVERVIEW (GRE)	0.83	SINGLE POLE	26.00	2	2
4	(0795;01) BLACK OAK	RIVERVIEW (GRE)	0.83	SINGLE POLE	18.00	2	2
5	(5409;01) MEDINA (GRE)	POMERLEAU LAKE	0.54	SINGLE POLE	141.00	2	2
6							
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43							
44	TOTAL		6.72		216.00	8	8

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS Size (h)	Specification (i)	Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	Line No.
3-795	ACSS	26/7	115		3,912	49,086		52,998	1
3-795	ACSS	26/7	115		8,741,790	1,238,230		9,980,020	2
3-477	ACSR	26/7	69		2,092,002	130,291		2,222,293	3
3-477	ACSR	26/7	69		49,657	107,146		156,803	4
3-795	ACSS	26/7	69		1,458,869	972,580		2,431,449	5
									6
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									43
					12,346,230	2,497,333		14,843,563	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ADAMS-TR09	UNATTENDED TRANSM	345.00	161.00	13.80
2	ADA-TR01	UNATTENDED DISTRIB	69.00	23.00	4.16
3	AFTON-TR01	UNATTENDED DISTRIB	115.00	34.50	
4	AFTON-TR02	UNATTENDED DISTRIB	115.00	34.50	
5	AIR LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
6	AIR LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
7	AIRPORT-TR01	UNATTENDED DISTRIB	115.00	13.80	
8	AIRPORT-TR02	UNATTENDED DISTRIB	115.00	13.80	
9	ALBANY-TR02	UNATTENDED DISTRIB	69.00	12.50	
10	ALBANY-TR03	UNATTENDED DISTRIB	12.50	4.16	
11	ALDRICH-TR02	UNATTENDED DISTRIB	115.00	13.80	
12	ALDRICH-TR03	UNATTENDED DISTRIB	115.00	13.80	
13	ALDRICH-TR04	UNATTENDED DISTRIB	115.00	13.80	
14	ALEXANDRIA-TR01ABC	UNATTENDED DISTRIB	34.50	4.16	
15	ALTURA-TR01	UNATTENDED DISTRIB	69.00	13.80	
16	ANNANDALE-TR01	UNATTENDED DISTRIB	69.00	13.80	
17	APACHE-TR01	UNATTENDED DISTRIB	115.00	13.80	
18	APACHE-TR02	UNATTENDED DISTRIB	115.00	13.80	
19	ARDEN HILLS-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
20	ARDEN HILLS-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
21	ARLINGTON-TR01	UNATTENDED DISTRIB	69.00	4.16	
22	AS KING-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
23	AS KING-TR91	UNATTENDED DISTRIB	115.00	34.50	
24	ATWATER-TR01	UNATTENDED DISTRIB	69.00	13.80	
25	AVERILL-TR01	UNATTENDED DISTRIB	69.00	23.00	4.00
26	AVON-TR01	UNATTENDED DISTRIB	69.00	12.50	
27	BASSETT CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
28	BASSETT CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
29	BATTLE CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
30	BATTLE CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
31	BAYTOWN-TR01	UNATTENDED DISTRIB	118.00	13.80	
32	BECKER-TR01	UNATTENDED DISTRIB	69.00	12.50	
33	BECKER-TR02	UNATTENDED DISTRIB	69.00	34.50	
34	BELGRADE-TR01	UNATTENDED DISTRIB	69.00	4.16	
35	BELLE PLAINE-TR01	UNATTENDED DISTRIB	69.00	13.80	
36	BIRCH-TR01	UNATTENDED DISTRIB	69.00	34.50	
37	BIRD ISLAND-TR02	UNATTENDED DISTRIB	69.00	4.16	
38	BLUE HERON-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	BLUE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	BLUE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BLUE LAKE-TR07	UNATTENDED TRANSM	230.00	115.00	13.80
2	BLUE LAKE-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
3	BLUFF CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
4	BLUFF CREEK-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
5	BROOKINGS COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
6	BROOKINGS COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
7	BROOKLYN PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
8	BROOKLYN PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
9	BROOK-TR01ABC	UNATTENDED DISTRIB	34.50	4.16	
10	BROOTEN-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	BROWNTON-TR01	UNATTENDED DISTRIB	69.00	2.40	
12	BUFFALO LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
13	BUFFALO RIDGE-TR01	UNATTENDED DISTRIB	115.00	34.50	13.80
14	BUFFALO RIDGE-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
15	BURNSIDE-TR01	UNATTENDED DISTRIB	69.00	12.50	
16	BURNSIDE-TR02	UNATTENDED DISTRIB	69.00	12.50	
17	BUTTERFIELD-TR01	UNATTENDED DISTRIB	69.00	4.16	
18	CANISTOTA JCT-TR01	UNATTENDED DISTRIB	69.00	13.80	
19	CANISTOTA-TR01ABC	UNATTENDED DISTRIB	69.00	4.16	
20	CANNON FALLS XMSN-TR06	UNATTENDED TRANSM	115.00	69.00	13.80
21	CANNON FALLS XMSN-TR07	UNATTENDED TRANSM	115.00	69.00	14.00
22	CANNON FALLS-TR01	UNATTENDED DISTRIB	69.00	12.50	
23	CANTON-TR01	UNATTENDED DISTRIB	69.00	13.80	
24	CANTON-TR02	UNATTENDED DISTRIB	69.00	13.80	
25	CARVER COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	35.00
26	CARVER COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	35.00
27	CASS COUNTY-TR01XY	UNATTENDED DISTRIB	115.00	23.00	3.00
28	CASS COUNTY-TR02	UNATTENDED DISTRIB	115.00	23.00	
29	CASS COUNTY-TR03	UNATTENDED DISTRIB	115.00	23.00	14.00
30	CASTLE ROCK-TR01	UNATTENDED DISTRIB	69.00	4.00	
31	CEDAR LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
32	CEDAR LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
33	CEDARVALE-TR01	UNATTENDED DISTRIB	115.00	13.80	
34	CEDARVALE-TR02	UNATTENDED DISTRIB	115.00	13.80	
35	CENTERVILLE-TR01	UNATTENDED DISTRIB	69.00	13.80	
36	CHANARAMBIE-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
37	CHANARAMBIE-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
38	CHANARAMBIE-TR04	UNATTENDED DISTRIB	115.00	34.50	14.00
39	CHEMOLITE-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	CHEMOLITE-TR02	UNATTENDED DISTRIB	115.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	CHERRY CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	CHERRY CREEK-TR03	UNATTENDED DISTRIB	115.00	34.50	
3	CHISAGO COUNTY-TR02	UNATTENDED DISTRIB	115.00	34.50	
4	CHISAGO COUNTY-TR05	UNATTENDED TRANSM	345.00	115.00	35.00
5	CHISAGO COUNTY-TR06	UNATTENDED TRANSM	345.00	115.00	35.00
6	CHISAGO COUNTY-TR09ABC	UNATTENDED TRANSM	500.00	345.00	35.00
7	CHISAGO COUNTY-TR10ABC	UNATTENDED TRANSM	500.00	345.00	35.00
8	CLARA CITY-TR01	UNATTENDED DISTRIB	69.00	12.50	
9	CLARA CITY-TR02	UNATTENDED DISTRIB	69.00	23.00	
10	CLARKS GROVE-TR01	UNATTENDED DISTRIB	69.00	7.20	
11	CLIFF AVENUE-TR01	UNATTENDED DISTRIB	69.00	4.16	
12	CLIFF AVENUE-TR02	UNATTENDED DISTRIB	69.00	13.80	
13	COKATO-TR01	UNATTENDED DISTRIB	69.00	13.80	
14	COLVILL-TR04	UNATTENDED TRANSM	115.00	69.00	14.00
15	COLVILL-TR05	UNATTENDED TRANSM	161.00	115.00	14.00
16	COON CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
17	COON CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
18	COON CREEK-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
19	COON CREEK-TR10	UNATTENDED TRANSM	345.00	115.00	35.00
20	COTTAGE GROVE-TR01	UNATTENDED DISTRIB	115.00	13.80	
21	COTTAGE GROVE-TR02	UNATTENDED DISTRIB	115.00	13.80	
22	CREDIT RIVER-TR01	UNATTENDED DISTRIB	69.00	12.50	
23	CREDIT RIVER-TR02	UNATTENDED DISTRIB	69.00	12.50	
24	CROOKED LAKE-TR01	UNATTENDED DISTRIB	119.00	13.80	
25	CROOKED LAKE-TR02	UNATTENDED DISTRIB	119.00	13.80	
26	CROOKED LAKE-TR03	UNATTENDED DISTRIB	115.00	12.50	
27	CROOKED LAKE-TR65ABC	UNATTENDED DISTRIB	13.80	12.50	
28	CROSSROADS-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	CROSSROADS-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	CROSSROADS-TR03	UNATTENDED DISTRIB	115.00	13.80	
31	CRYSTAL FOODS-TR01	UNATTENDED DISTRIB	69.00	13.80	
32	DAHLGREN-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	DANUBE-TR01	UNATTENDED DISTRIB	69.00	12.50	
34	DASSEL-TR01	UNATTENDED DISTRIB	69.00	13.80	
35	DAYTONS BLUFF-TR01	UNATTENDED DISTRIB	115.00	13.80	
36	DAYTONS BLUFF-TR02	UNATTENDED DISTRIB	115.00	13.80	
37	DAYTONS BLUFF-TR03	UNATTENDED DISTRIB	115.00	13.80	
38	DEEPHAVEN-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	DEEPHAVEN-TR02	UNATTENDED DISTRIB	69.00	13.80	
40	DELANO-TR01XY	UNATTENDED DISTRIB	69.00	7.20	

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	DELL RAPIDS-TR02	UNATTENDED DISTRIB	34.50	12.50	
2	DODGE CENTER-TR01	UNATTENDED DISTRIB	69.00	23.00	
3	DODGE CENTER-TR02	UNATTENDED DISTRIB	69.00	12.50	
4	DODGE CENTER-TR03	UNATTENDED DISTRIB	69.00	12.50	
5	DOME PIPELINE-TR01	UNATTENDED DISTRIB	115.00	4.16	
6	DOUGLAS COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	35.00
7	DOUGLAS COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
8	DOUGLAS COUNTY-TR03	UNATTENDED DISTRIB	69.00	13.80	
9	DUNDAS-TR01	UNATTENDED DISTRIB	69.00	13.80	
10	DUNDAS-TR02	UNATTENDED DISTRIB	69.00	13.80	
11	EAGLE LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	EAST BLOOMINGTON-TR01	UNATTENDED DISTRIB	115.00	13.80	
13	EAST BLOOMINGTON-TR02	UNATTENDED DISTRIB	115.00	13.80	
14	EAST BLOOMINGTON-TR03	UNATTENDED DISTRIB	115.00	13.80	
15	EAST WINONA-TR01	UNATTENDED DISTRIB	69.00	13.80	
16	EASTWOOD-TR01	UNATTENDED DISTRIB	69.00	13.80	
17	EASTWOOD-TR02	UNATTENDED DISTRIB	69.00	13.80	
18	EASTWOOD-TR03	UNATTENDED DISTRIB	115.00	13.80	
19	EDEN PRAIRIE-TR01	UNATTENDED DISTRIB	115.00	13.80	
20	EDEN PRAIRIE-TR03	UNATTENDED DISTRIB	115.00	13.80	
21	EDEN PRAIRIE-TR04	UNATTENDED DISTRIB	115.00	13.80	
22	EDEN PRAIRIE-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
23	EDEN PRAIRIE-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
24	EDGERTON-TR01	UNATTENDED DISTRIB	23.00	4.16	
25	EDINA-TR01	UNATTENDED DISTRIB	115.00	13.80	
26	EDINA-TR02	UNATTENDED DISTRIB	115.00	13.80	
27	EDINA-TR03	UNATTENDED DISTRIB	115.00	13.80	
28	ELLIOT PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	ELLIOT PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	ELLIOT PARK-TR03	UNATTENDED DISTRIB	115.00	13.80	
31	ELM CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
32	ELM CREEK-TR02	UNATTENDED DISTRIB	115.00	34.50	
33	ELM CREEK-TR03	UNATTENDED DISTRIB	115.00	13.80	
34	ELM CREEK-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
35	EMERY-TR01ABC	UNATTENDED DISTRIB	34.50	4.16	
36	ESSIG-TR01ABC	UNATTENDED DISTRIB	69.00	2.40	
37	EXCELSIOR-TR01	UNATTENDED DISTRIB	69.00	13.80	
38	FAIR PARK-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	FAIR PARK-TR02	UNATTENDED DISTRIB	69.00	13.80	
40	FALLS-TR01	UNATTENDED DISTRIB	115.00	13.80	

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	FALLS-TR02	UNATTENDED DISTRIB	115.00	13.80	
2	FARIBAULT-TR01	UNATTENDED DISTRIB	69.00	13.80	
3	FARIBAULT-TR02	UNATTENDED DISTRIB	69.00	13.80	
4	FARMINGTON-TR01	UNATTENDED DISTRIB	69.00	13.80	
5	FARMINGTON-TR02	UNATTENDED DISTRIB	69.00	13.80	
6	FENTON-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
7	FENTON-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
8	FENTON-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
9	FIESTA CITY-TR01	UNATTENDED DISTRIB	69.00	12.50	
10	FIESTA CITY-TR02	UNATTENDED DISTRIB	69.00	12.50	
11	FIFTH STREET-TR01	UNATTENDED DISTRIB	115.00	13.80	
12	FIFTH STREET-TR02	UNATTENDED DISTRIB	115.00	13.80	
13	FIFTH STREET-TR03	UNATTENDED DISTRIB	115.00	13.80	
14	FIFTH STREET-TR04	UNATTENDED DISTRIB	115.00	13.80	
15	FIRST LAKE-TR01	UNATTENDED DISTRIB	115.00	34.50	
16	FOLEY-TR01	UNATTENDED DISTRIB	34.50	4.16	
17	FORBES-TR09	UNATTENDED DISTRIB	500.00	20.00	
18	FORT RIDGELY-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
19	FRANKLIN-TR04	UNATTENDED DISTRIB	69.00	23.00	
20	FRANKLIN-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
21	FRANKLIN-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
22	FRANKLIN-TR07	UNATTENDED DISTRIB	69.00	4.16	
23	FRONTENAC-TR01	UNATTENDED DISTRIB	69.00	12.50	
24	GATEWAY-TR01	UNATTENDED DISTRIB	69.00	12.50	
25	GATEWAY-TR02	UNATTENDED DISTRIB	69.00	12.50	
26	GAYLORD-TR01	UNATTENDED DISTRIB	69.00	4.00	
27	GIBBON-TR01	UNATTENDED DISTRIB	69.00	12.50	
28	GLEASON LAKE-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
29	GLEASON LAKE-TR03	UNATTENDED DISTRIB	34.50	13.80	
30	GLEASON LAKE-TR04	UNATTENDED DISTRIB	115.00	34.50	
31	GLEASON LAKE-TR07	UNATTENDED DISTRIB	115.00	13.80	
32	GLEASON LAKE-TR08	UNATTENDED DISTRIB	115.00	13.80	
33	GLEN LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
34	GLEN LAKE-TR02	UNATTENDED DISTRIB	69.00	13.80	
35	GLENWOOD-TR01	UNATTENDED DISTRIB	69.00	13.80	
36	GLENWOOD-TR02	UNATTENDED DISTRIB	69.00	12.50	
37	GOODVIEW-TR01	UNATTENDED DISTRIB	69.00	12.50	
38	GOODVIEW-TR02	UNATTENDED DISTRIB	69.00	12.50	
39	GOOSE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	GOOSE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GOPHER-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	GOPHER-TR02	UNATTENDED DISTRIB	115.00	13.80	
3	GRANITE CITY-TR01	UNATTENDED DISTRIB	115.00	13.80	
4	GRANITE CITY-TR02	UNATTENDED DISTRIB	115.00	13.80	
5	GRANITE CITY-TR03	UNATTENDED DISTRIB	115.00	34.50	
6	GRANT-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
7	GRANT-TR03	UNATTENDED DISTRIB	115.00	34.50	
8	GREEN ISLE-TR01	UNATTENDED DISTRIB	69.00	4.16	
9	GREENFIELD-TR01	UNATTENDED DISTRIB	69.00	12.50	
10	HADLEY-TR01	UNATTENDED DISTRIB	69.00	13.80	
11	HASSAN-TR01	UNATTENDED DISTRIB	115.00	34.50	
12	HASSAN-TR02	UNATTENDED DISTRIB	115.00	34.50	
13	HASTINGS-TR01	UNATTENDED DISTRIB	69.00	12.50	
14	HASTINGS-TR02	UNATTENDED DISTRIB	69.00	12.50	
15	HATFIELD-TR01ABC	UNATTENDED DISTRIB	23.00	12.50	
16	HATTON-TR01	UNATTENDED DISTRIB	69.00	4.16	
17	HAZEL CREEK-TR09	UNATTENDED TRANSM	345.00	230.00	14.00
18	HECTOR-TR01	UNATTENDED DISTRIB	69.00	4.16	
19	HENDERSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
20	HIAWATHA WEST-TR01	UNATTENDED DISTRIB	115.00	13.80	
21	HIGH BRIDGE-TR04	UNATTENDED DISTRIB	115.00	13.80	
22	HOLLYDALE-TR01	UNATTENDED DISTRIB	69.00	13.80	
23	HOLLYDALE-TR02	UNATTENDED DISTRIB	34.50	13.80	
24	HOWARD LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
25	HUGO-TR01	UNATTENDED DISTRIB	115.00	34.50	
26	HUGO-TR02	UNATTENDED DISTRIB	115.00	34.50	
27	HYLAND LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
28	HYLAND LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
29	INDIANA-TR01	UNATTENDED DISTRIB	115.00	13.80	
30	INDIANA-TR02	UNATTENDED DISTRIB	115.00	13.80	
31	INVER GROVE-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
32	INVER GROVE-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
33	INVER HILLS-PLTSDU	UNATTENDED DISTRIB	34.50	13.80	
34	INVER HILLS-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
35	JORDAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
36	KASSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
37	KASSON-TR02	UNATTENDED DISTRIB	69.00	12.50	
38	KEGAN LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	KENYON-TR01	UNATTENDED DISTRIB	69.00	12.50	
40	KIMBALL-TR01	UNATTENDED DISTRIB	69.00	12.50	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	KOCH REFINERY-TR11	UNATTENDED DISTRIB	115.00	13.80	
2	KOCH REFINERY-TR12	UNATTENDED DISTRIB	115.00	13.80	
3	KOCH REFINERY-TR13	UNATTENDED DISTRIB	115.00	13.80	
4	KOCH REFINERY-TR14	UNATTENDED DISTRIB	115.00	13.80	
5	KOCH REFINERY-TR15	UNATTENDED DISTRIB	115.00	13.80	
6	KOCH REFINERY-TR16	UNATTENDED DISTRIB	115.00	13.80	
7	KOHLMAN LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
8	KOHLMAN LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
9	KOHLMAN LAKE-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
10	KOHLMAN LAKE-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
11	LA CRESCENT-TR01	UNATTENDED DISTRIB	69.00	13.80	
12	LAFAYETTE-TR01	UNATTENDED DISTRIB	69.00	4.16	
13	LAKE BAVARIA-TR01	UNATTENDED DISTRIB	115.00	34.50	
14	LAKE EMILY-TR01	UNATTENDED DISTRIB	69.00	13.80	
15	LAKE LILLIAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
16	LAKE PULASKI-TR03	UNATTENDED DISTRIB	115.00	34.50	
17	LAKE PULASKI-TR05	UNATTENDED TRANSM	115.00	69.00	35.00
18	LAKE PULASKI-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
19	LAKE YANKTON-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
20	LAKE YANKTON-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
21	LAKE YANKTON-TR03	UNATTENDED DISTRIB	69.00	13.80	
22	LARIMORE-TR01	UNATTENDED DISTRIB	69.00	4.16	
23	LAWRENCE CREEK-TR01	UNATTENDED DISTRIB	115.00	34.50	
24	LAWRENCE CREEK-TR04	UNATTENDED TRANSM	115.00	69.00	14.00
25	LAWRENCE CREEK-TR05	UNATTENDED TRANSM	161.00	115.00	14.00
26	LAWRENCE-TR01	UNATTENDED DISTRIB	115.00	34.50	
27	LAWRENCE-TR07	UNATTENDED TRANSM	115.00	69.00	14.00
28	LAWRENCE-TR08	UNATTENDED TRANSM	115.00	69.00	14.00
29	LENNOX-TR01	UNATTENDED DISTRIB	69.00	13.80	
30	LESTER PRAIRIE-TR01	UNATTENDED DISTRIB	69.00	13.80	
31	LEXINGTON-TR01	UNATTENDED DISTRIB	115.00	13.80	
32	LEXINGTON-TR02	UNATTENDED DISTRIB	115.00	13.80	
33	LEXINGTON-TR03	UNATTENDED DISTRIB	115.00	34.50	
34	LEXINGTON-TR04	UNATTENDED DISTRIB	34.50	13.80	
35	LINCOLN COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
36	LINCOLN COUNTY-TR07	UNATTENDED DISTRIB	115.00	13.80	
37	LINCOLN COUNTY-TR08	UNATTENDED DISTRIB	115.00	13.80	
38	LINDE-TR01	UNATTENDED DISTRIB	115.00	13.80	
39	LINDSTROM-TR01	UNATTENDED DISTRIB	115.00	12.50	
40	LINDSTROM-TR02	UNATTENDED DISTRIB	115.00	12.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LINN STREET-TR01	UNATTENDED DISTRIB	69.00	12.50	
2	LINN STREET-TR02	UNATTENDED DISTRIB	69.00	12.50	
3	LONE OAK-TR01	UNATTENDED DISTRIB	115.00	13.80	
4	LONE OAK-TR02	UNATTENDED DISTRIB	115.00	13.80	
5	LONG LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
6	LONG LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
7	LOUISE-TR01	UNATTENDED DISTRIB	115.00	13.80	
8	LOWRY-TR01	UNATTENDED DISTRIB	69.00	12.50	
9	LYON COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
10	LYON COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
11	M E INTERNATIONAL-TR01	UNATTENDED DISTRIB	115.00	13.80	
12	M E INTERNATIONAL-TR02	UNATTENDED DISTRIB	115.00	13.80	
13	MAIN STREET-TR01	UNATTENDED DISTRIB	115.00	13.80	
14	MAIN STREET-TR02	UNATTENDED DISTRIB	115.00	13.80	
15	MAPLE LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
16	MAPLE RIVER-TR05	UNATTENDED TRANSM	230.00	115.00	14.00
17	MAPLE RIVER-TR06	UNATTENDED TRANSM	230.00	115.00	14.00
18	MAPLETON-TR01	UNATTENDED DISTRIB	69.00	13.80	
19	MARION-TR01	UNATTENDED DISTRIB	23.00	4.16	
20	MAXWELL-TR01	UNATTENDED DISTRIB	115.00	4.16	
21	MAYHEW LAKE-TR01	UNATTENDED DISTRIB	115.00	34.50	
22	MAYNARD TRANSMISSION-TR01	UNATTENDED TRANSM	115.00	69.00	
23	MAYNARD-TR01	UNATTENDED DISTRIB	69.00	12.50	
24	MAYVILLE-TR01	UNATTENDED DISTRIB	69.00	4.16	
25	MAYVILLE-TR02	UNATTENDED DISTRIB	69.00	12.50	
26	MAZEPPA-TR01	UNATTENDED DISTRIB	69.00	12.50	
27	MEDFORD JUNCTION-TR01	UNATTENDED DISTRIB	69.00	12.50	
28	MEDICINE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	MEDICINE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	MEDICINE LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
31	MEIRE GROVE-TR01	UNATTENDED DISTRIB	69.00	12.50	
32	MERIDEN-TR01	UNATTENDED DISTRIB	69.00	12.50	
33	MERRIAM PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
34	MERRIAM PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
35	MERRIAM PARK-TR03	UNATTENDED DISTRIB	115.00	13.80	
36	MIDTOWN-TR01	UNATTENDED DISTRIB	115.00	13.80	
37	MINNEHAHA-TR01	UNATTENDED DISTRIB	115.00	13.80	
38	MINNEHAHA-TR02	UNATTENDED DISTRIB	115.00	13.80	
39	MINNESOTA LAKE-TR01	UNATTENDED DISTRIB	69.00	4.16	
40	MINNESOTA PIPELINE-TR01	UNATTENDED DISTRIB	115.00	4.16	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	MINNESOTA VALLEY-TR02	UNATTENDED DISTRIB	69.00	23.00	
2	MINNESOTA VALLEY-TR05	UNATTENDED TRANSM	230.00	115.00	14.00
3	MINNESOTA VALLEY-TR06	UNATTENDED TRANSM	230.00	115.00	14.00
4	MINNESOTA VALLEY-TR11	UNATTENDED TRANSM	115.00	69.00	14.00
5	MINNESOTA VALLEY-TR12	UNATTENDED TRANSM	115.00	69.00	14.00
6	MONTEVIDEO-TR01	UNATTENDED DISTRIB	69.00	4.16	
7	MONTEVIDEO-TR02	UNATTENDED DISTRIB	69.00	12.50	
8	MONTICELLO-TR06	UNATTENDED TRANSM	345.00	230.00	14.00
9	MONTICELLO-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
10	MONTROSE-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	MOORE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
12	MOORE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
13	MOORE LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
14	MORGAN-TR01	UNATTENDED DISTRIB	69.00	23.00	
15	MORRISTOWN-TR01	UNATTENDED DISTRIB	69.00	12.50	
16	MOUND-TR01	UNATTENDED DISTRIB	69.00	13.80	
17	MOUND-TR02	UNATTENDED DISTRIB	69.00	13.80	
18	NERSTRAND-TR01XY	UNATTENDED DISTRIB	69.00	12.50	
19	NINE MILE CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
20	NINE MILE CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
21	NOBLES COUNTY-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
22	NOBLES COUNTY-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
23	NOBLES COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
24	NOBLES COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	35.00
25	NORDIC-TR01	UNATTENDED DISTRIB	115.00	13.80	
26	NORDIC-TR02	UNATTENDED DISTRIB	115.00	13.80	
27	NORTH BROADWAY-TR01	UNATTENDED DISTRIB	23.00	4.16	
28	NORTH BROADWAY-TR02	UNATTENDED DISTRIB	23.00	4.16	
29	NORTH ROCHESTER-TR09	UNATTENDED TRANSM	345.00	161.00	35.00
30	NORTH STAR STEEL-TR01	UNATTENDED DISTRIB	115.00	13.80	
31	NORTH STAR STEEL-TR02	UNATTENDED DISTRIB	115.00	13.80	
32	NORTH STAR STEEL-TR03	UNATTENDED DISTRIB	115.00	13.80	
33	NORTHFIELD-TR01	UNATTENDED DISTRIB	69.00	13.80	
34	NORTHFIELD-TR02	UNATTENDED DISTRIB	69.00	13.80	
35	OAK PARK-TR01	UNATTENDED DISTRIB	115.00	23.00	14.00
36	OAK PARK-TR07	UNATTENDED DISTRIB	115.00	13.80	
37	OAK PARK-TR08	UNATTENDED DISTRIB	115.00	13.80	
38	OAKDALE-TR01	UNATTENDED DISTRIB	115.00	13.80	
39	OAKDALE-TR02	UNATTENDED DISTRIB	115.00	13.80	
40	ORONO-TR01	UNATTENDED DISTRIB	115.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	OSSEO-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	OSSEO-TR02	UNATTENDED DISTRIB	115.00	13.80	
3	PARKERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
4	PARKERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
5	PARKERS LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
6	PARKERS LAKE-TR09ABC	UNATTENDED TRANSM	345.00	115.00	14.00
7	PARKERS LAKE-TR10ABC	UNATTENDED TRANSM	345.00	115.00	14.00
8	PAYNESVILLE XMSN-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
9	PAYNESVILLE XMSN-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
10	PAYNESVILLE XMSN-TR04	UNATTENDED DISTRIB	115.00	34.50	
11	PAYNESVILLE XMSN-TR09	UNATTENDED TRANSM	230.00	115.00	14.00
12	PINE BEND-TR03	UNATTENDED DISTRIB	69.00	13.80	
13	PINE ISLAND-TR01	UNATTENDED DISTRIB	69.00	12.50	
14	PINE ISLAND-TR02	UNATTENDED DISTRIB	69.00	12.50	
15	PIPESTONE-TR01	UNATTENDED DISTRIB	69.00	13.80	
16	PIPESTONE-TR02	UNATTENDED DISTRIB	69.00	4.16	
17	PIPESTONE-TR03	UNATTENDED DISTRIB	69.00	25.00	
18	PIPESTONE-TR05	UNATTENDED TRANSM	115.00	69.00	3.00
19	PIPESTONE-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
20	PLATO-TR01	UNATTENDED DISTRIB	115.00	12.50	
21	PRAIRIE ISLAND-TR10	UNATTENDED TRANSM	345.00	161.00	14.00
22	PRAIRIE-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
23	PRAIRIE-TR03	UNATTENDED TRANSM	115.00	69.00	14.00
24	PRAIRIE-TR05	UNATTENDED TRANSM	230.00	115.00	14.00
25	PRAIRIE-TR07	UNATTENDED TRANSM	230.00	115.00	14.00
26	PRAIRIE-TR08	UNATTENDED TRANSM	230.00	115.00	14.00
27	PRIOR-TR01	UNATTENDED DISTRIB	115.00	14.00	
28	QUARRY-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
29	RAMSEY-TR01	UNATTENDED DISTRIB	115.00	13.80	
30	RAMSEY-TR02	UNATTENDED DISTRIB	115.00	13.80	
31	RAPIDAN-TR01	UNATTENDED DISTRIB	69.00	13.80	
32	RED RIVER-TR01	UNATTENDED DISTRIB	115.00	23.00	14.00
33	RED RIVER-TR02	UNATTENDED DISTRIB	115.00	23.00	14.00
34	RED RIVER-TR03	UNATTENDED DISTRIB	115.00	23.00	5.00
35	RED ROCK-TR01	UNATTENDED DISTRIB	115.00	13.80	
36	RED ROCK-TR02	UNATTENDED DISTRIB	115.00	13.80	
37	RED ROCK-TR03	UNATTENDED DISTRIB	115.00	13.80	
38	RED ROCK-TR05	UNATTENDED TRANSM	345.00	230.00	14.00
39	RED ROCK-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
40	RED ROCK-TR10	UNATTENDED TRANSM	345.00	115.00	14.00

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	RED WING-TR01	UNATTENDED DISTRIB	69.00	13.80	
2	RED WING-TR02	UNATTENDED DISTRIB	69.00	13.80	
3	RENVILLE-TR01	UNATTENDED DISTRIB	69.00	12.50	
4	REYNOLDS-TR01	UNATTENDED DISTRIB	69.00	12.50	
5	RICH SPRING-TR01	UNATTENDED DISTRIB	69.00	13.80	
6	RICH VALLEY-TR01	UNATTENDED DISTRIB	115.00	13.80	
7	RICHMOND-TR01	UNATTENDED DISTRIB	69.00	13.80	
8	RIVERSIDE-TR01	UNATTENDED DISTRIB	115.00	13.80	
9	RIVERSIDE-TR02	UNATTENDED DISTRIB	115.00	13.80	
10	RIVERWOOD-TR01	UNATTENDED DISTRIB	115.00	13.80	
11	RIVERWOOD-TR02	UNATTENDED DISTRIB	115.00	13.80	
12	ROCK RIVER-TR01	UNATTENDED DISTRIB	69.00	23.00	
13	ROGERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
14	ROGERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
15	ROSE PLACE-TR01	UNATTENDED DISTRIB	115.00	13.80	
16	ROSE PLACE-TR02	UNATTENDED DISTRIB	115.00	13.80	
17	ROSEMOUNT-TR01	UNATTENDED DISTRIB	115.00	34.50	
18	SACRED HEART-TR01	UNATTENDED DISTRIB	69.00	13.80	4.00
19	SALEM-TR01ABC	UNATTENDED DISTRIB	69.00	34.50	3.00
20	SALEM-TR02	UNATTENDED DISTRIB	69.00	13.80	
21	SALIDA CROSSING-TR01	UNATTENDED DISTRIB	115.00	13.80	
22	SALIDA CROSSING-TR02	UNATTENDED DISTRIB	115.00	13.80	
23	SARTELL-TR01	UNATTENDED DISTRIB	34.50	12.50	2.00
24	SAUK RIVER-TR01	UNATTENDED DISTRIB	115.00	34.50	
25	SAUK RIVER-TR02	UNATTENDED DISTRIB	115.00	34.50	
26	SAVAGE-TR01	UNATTENDED DISTRIB	115.00	13.80	
27	SAVAGE-TR02	UNATTENDED DISTRIB	115.00	13.80	
28	SCANDIA-TR01	UNATTENDED DISTRIB	69.00	12.50	
29	SCOTT COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
30	SCOTT COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
31	SCOTT COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
32	SCOTT COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	35.00
33	SEDAN-TR01 AB	UNATTENDED DISTRIB	69.00	7.20	
34	SHEAS LAKE-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
35	SHEAS LAKE-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
36	SHEPARD-TR01	UNATTENDED DISTRIB	115.00	13.80	
37	SHEPARD-TR02	UNATTENDED DISTRIB	115.00	13.80	
38	SHERBURNE COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
39	SHEYENNE-TR05	UNATTENDED TRANSM	230.00	115.00	14.00
40	SHEYENNE-TR06	UNATTENDED TRANSM	230.00	115.00	14.00

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SIBLEY PARK-TR01	UNATTENDED DISTRIB	69.00	13.80	
2	SIBLEY PARK-TR02	UNATTENDED DISTRIB	69.00	13.80	
3	SLAYTON WEST-TR01	UNATTENDED DISTRIB	69.00	13.80	
4	SOURIS-TR01	UNATTENDED DISTRIB	115.00	13.80	
5	SOURIS-TR02	UNATTENDED DISTRIB	115.00	13.80	
6	SOURIS-TR03	UNATTENDED DISTRIB	115.00	13.80	
7	SOUTH BEND-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
8	SOUTH BEND-TR06	UNATTENDED TRANSM	161.00	115.00	14.00
9	SOUTH HAVEN-TR01	UNATTENDED DISTRIB	69.00	34.50	
10	SOUTH RENNER-TR01	UNATTENDED DISTRIB	115.00	34.50	
11	SOUTH RIDGE-TR01	UNATTENDED DISTRIB	69.00	23.00	
12	SOUTH SIOUX FALLS-TR01	UNATTENDED DISTRIB	69.00	4.16	
13	SOUTH SIOUX FALLS-TR02	UNATTENDED DISTRIB	69.00	4.16	
14	SOUTH SIOUX FALLS-TR03	UNATTENDED DISTRIB	69.00	13.80	
15	SOUTH SIOUX FALLS-TR04	UNATTENDED DISTRIB	69.00	13.80	
16	SOUTHTOWN-TR01	UNATTENDED DISTRIB	115.00	13.80	
17	SOUTHTOWN-TR02	UNATTENDED DISTRIB	115.00	13.80	
18	SOUTHTOWN-TR03	UNATTENDED DISTRIB	115.00	13.80	
19	SOUTH-TR01ABC	UNATTENDED DISTRIB	69.00	2.40	
20	SPLIT ROCK-TR06	UNATTENDED TRANSM	161.00	115.00	35.00
21	SPLIT ROCK-TR07	UNATTENDED TRANSM	230.00	115.00	14.00
22	SPLIT ROCK-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
23	SPLIT ROCK-TR11	UNATTENDED TRANSM	345.00	115.00	14.00
24	ST CLOUD-TR01	UNATTENDED DISTRIB	115.00	34.50	
25	ST CLOUD-TR02	UNATTENDED DISTRIB	115.00	34.50	
26	ST JAMES MUNICIPAL-TR01	UNATTENDED DISTRIB	69.00	12.50	
27	ST JOHNS-TR01	UNATTENDED DISTRIB	69.00	4.16	
28	ST JOSEPH-TR01	UNATTENDED DISTRIB	69.00	4.16	
29	ST LOUIS PARK-TR02	UNATTENDED DISTRIB	115.00	34.50	
30	ST LOUIS PARK-TR04	UNATTENDED DISTRIB	115.00	13.80	
31	ST LOUIS PARK-TR05	UNATTENDED DISTRIB	115.00	13.80	
32	ST LOUIS PARK-TR06	UNATTENDED DISTRIB	115.00	13.80	
33	ST. PAUL WATER-TR01	UNATTENDED DISTRIB	13.80	4.16	
34	STEWART-TR01	UNATTENDED DISTRIB	69.00	12.50	
35	STOCKYARDS-TR01	UNATTENDED DISTRIB	115.00	13.80	
36	STOCKYARDS-TR02	UNATTENDED DISTRIB	118.00	13.80	
37	SUMMIT AVENUE-TR01	UNATTENDED DISTRIB	115.00	13.80	
38	SUMMIT AVENUE-TR02	UNATTENDED DISTRIB	115.00	13.80	
39	SWAN LAKE-TR01	UNATTENDED DISTRIB	115.00	12.50	
40	TANNERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TANNERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
2	TANNERS LAKE-TR23A1B1C1	UNATTENDED DISTRIB	13.80	12.50	
3	TANNERS LAKE-TR23A2B2C2	UNATTENDED DISTRIB	13.80	12.50	
4	TANNERS LAKE-TR32A1B1C1	UNATTENDED DISTRIB	13.80	12.50	
5	TANNERS LAKE-TR32A2B2C2	UNATTENDED DISTRIB	13.80	12.50	
6	TANNERS LAKE-TR34A1B1C1	UNATTENDED DISTRIB	13.80	12.50	
7	TANNERS LAKE-TR34A2B2C2	UNATTENDED DISTRIB	13.80	12.50	
8	TERMINAL-TR01	UNATTENDED DISTRIB	115.00	13.80	
9	TERMINAL-TR02	UNATTENDED DISTRIB	115.00	13.80	
10	TERMINAL-TR03	UNATTENDED DISTRIB	115.00	13.80	
11	TERMINAL-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
12	TERMINAL-TR10	UNATTENDED TRANSM	345.00	115.00	35.00
13	THOMPSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
14	TRACY SWITCHING-TR01	UNATTENDED DISTRIB	69.00	13.80	
15	TRACY-TR01	UNATTENDED DISTRIB	69.00	4.16	2.00
16	TWIN LAKES-TR01	UNATTENDED DISTRIB	115.00	13.80	
17	TWIN LAKES-TR02	UNATTENDED DISTRIB	115.00	13.80	
18	TWIN LAKES-TR03	UNATTENDED DISTRIB	115.00	13.80	
19	UPPER LEVEE-TR01	UNATTENDED DISTRIB	115.00	13.80	
20	UPPER LEVEE-TR02	UNATTENDED DISTRIB	115.00	13.80	
21	UPPER LEVEE-TR03	UNATTENDED DISTRIB	115.00	13.80	
22	VERMILLION RIVER-TR03	UNATTENDED DISTRIB	115.00	13.80	
23	VESELI-TR01	UNATTENDED DISTRIB	69.00	12.50	
24	VIKING-TR01	UNATTENDED DISTRIB	115.00	13.80	
25	VILLARD-TR01	UNATTENDED DISTRIB	69.00	12.50	
26	WABASHA-TR01	UNATTENDED DISTRIB	69.00	13.80	
27	WABASHA-TR02	UNATTENDED DISTRIB	69.00	2.40	
28	WACONIA-TR01	UNATTENDED DISTRIB	69.00	13.80	
29	WAKEFIELD-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
30	WAKEFIELD-TR02ABC	UNATTENDED DISTRIB	34.50	13.80	
31	WAKEFIELD-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
32	WASECA-TR02	UNATTENDED DISTRIB	69.00	23.00	
33	WASECA-TR03	UNATTENDED DISTRIB	69.00	23.00	
34	WASECA-TR04	UNATTENDED DISTRIB	69.00	23.00	
35	WATAB RIVER-TR01	UNATTENDED DISTRIB	69.00	12.50	
36	WATERTOWN-TR01	UNATTENDED DISTRIB	69.00	13.80	
37	WATERVILLE-TR01	UNATTENDED DISTRIB	69.00	23.00	
38	WATERVILLE-TR02	UNATTENDED DISTRIB	69.00	4.16	
39	WATERVILLE-TR03	UNATTENDED DISTRIB	69.00	12.50	
40	WATKINS-TR01	UNATTENDED DISTRIB	69.00	4.16	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WAVERLY-TR01	UNATTENDED DISTRIB	69.00	12.50	
2	WELLS CREEK-TR01	UNATTENDED DISTRIB	69.00	12.50	
3	WESCOTT PROPANE PLANT-TR01	UNATTENDED DISTRIB	69.00	13.80	
4	WEST BYRON-TR01	UNATTENDED DISTRIB	69.00	12.50	
5	WEST COON RAPIDS-TR01	UNATTENDED DISTRIB	115.00	34.50	
6	WEST COON RAPIDS-TR02	UNATTENDED DISTRIB	115.00	34.50	
7	WEST COON RAPIDS-TR03	UNATTENDED DISTRIB	34.50	13.80	
8	WEST FARIBAULT-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
9	WEST FARIBAULT-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
10	WEST FARIBAULT-TR03	UNATTENDED DISTRIB	69.00	13.80	
11	WEST FARIBAULT-TR07	UNATTENDED DISTRIB	69.00	13.80	
12	WEST HASTINGS-TR01	UNATTENDED DISTRIB	115.00	12.50	
13	WEST HASTINGS-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
14	WEST NEW ULM-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
15	WEST RIVER ROAD-TR01	UNATTENDED DISTRIB	115.00	13.80	
16	WEST RIVER ROAD-TR02	UNATTENDED DISTRIB	115.00	13.80	
17	WEST RIVER ROAD-TR03	UNATTENDED DISTRIB	115.00	13.80	
18	WEST SIOUX FALLS-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
19	WEST SIOUX FALLS-TR07	UNATTENDED DISTRIB	115.00	13.80	
20	WEST SIOUX FALLS-TR08	UNATTENDED DISTRIB	115.00	13.80	
21	WEST WACONIA-TR01	UNATTENDED DISTRIB	115.00	34.50	
22	WEST WACONIA-TR02	UNATTENDED DISTRIB	115.00	34.50	
23	WESTERN-TR01	UNATTENDED DISTRIB	115.00	13.80	
24	WESTERN-TR02	UNATTENDED DISTRIB	115.00	13.80	
25	WESTGATE-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
26	WESTGATE-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
27	WESTGATE-TR03	UNATTENDED DISTRIB	115.00	13.80	
28	WESTGATE-TR04	UNATTENDED DISTRIB	115.00	13.80	
29	WESTGATE-TR05	UNATTENDED DISTRIB	115.00	34.50	
30	WESTGATE-TR06	UNATTENDED DISTRIB	115.00	34.50	
31	WESTPORT-TR01X AB,Y CB	UNATTENDED DISTRIB	69.00	7.20	
32	WILLIAM BROS PIPELINE-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	WILLIAM BROS PIPELINE-TR01B	UNATTENDED DISTRIB	13.80	13.80	
34	WILLIAM BROS PIPELINE-TR02	UNATTENDED DISTRIB	13.80	2.40	
35	WILLIAM BROS PIPELINE-TR03	UNATTENDED DISTRIB	115.00	13.80	
36	WILMARTH-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
37	WILMARTH-TR07	UNATTENDED TRANSM	115.00	69.00	14.00
38	WILMARTH-TR08	UNATTENDED TRANSM	115.00	69.00	14.00
39	WILMARTH-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
40	WILMARTH-TR10	UNATTENDED TRANSM	345.00	115.00	14.00

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Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WINONA-TR01	UNATTENDED DISTRIB	69.00	13.80	
2	WINONA-TR02	UNATTENDED DISTRIB	69.00	13.80	
3	WINONA-TR03	UNATTENDED DISTRIB	69.00	13.80	
4	WINSTED-TR01	UNATTENDED DISTRIB	69.00	13.80	
5	WINTHROP-TR01	UNATTENDED DISTRIB	69.00	4.16	
6	WOBEGON TRAIL-TR01	UNATTENDED DISTRIB	69.00	12.50	
7	WOODBURY-TR01	UNATTENDED DISTRIB	115.00	34.50	
8	WOODBURY-TR02	UNATTENDED DISTRIB	115.00	34.50	
9	WYOMING-TR01	UNATTENDED DISTRIB	115.00	12.50	
10	WYOMING-TR02	UNATTENDED DISTRIB	115.00	12.50	
11	YANKEE-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
12	YANKEE-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
13	YELLOW MEDICINE-TR01	UNATTENDED DISTRIB	69.00	23.00	
14	YOUNG AMERICA-TR01	UNATTENDED DISTRIB	69.00	13.80	
15	YOUNG AMERICA-TR02	UNATTENDED DISTRIB	69.00	13.80	
16	ZUMBRO FALLS-TR01	UNATTENDED DISTRIB	69.00	12.50	
17	ZUMBROTA-TR01	UNATTENDED DISTRIB	69.00	13.80	
18	577				
19					
20	Count TTL Transformer Banks	577			
21	Count TTL Transformers In Service	621			
22	TTL MVA In Service	44,802			
23	Count TTL Substations with Transformers	306			
24	Count TTL Substations without Transformer	40			
25	Count TTL Substations	346			
26	Count TTL Spares	41			
27					
28					
29	Spare Transformers				
30	Canistota Junc-2741803	N/A	25.00	13.00	
31	Chanarambie-TB80229802	N/A	115.00	35.00	14.00
32	Clarks Grove-8975520	N/A	69.00	7.50	
33	Falls Sub-D-561747	N/A	69.00	14.00	
34	Falls Sub-P660522	N/A	69.00	14.00	
35	Hugo Trg Ctr-242601941	N/A	115.00	14.00	
36	Inver Hills sub-10075845-001	N/A	345.00	115.00	35.00
37	Linde-9157699	N/A	115.00	14.00	
38	MGRV-1174820415	N/A	69.00	14.00	
39	MGRV-13915/1	N/A	115.00	14.00	
40	MGRV-249834	N/A	69.00	14.00	

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MGRV-249866	N/A	69.00	14.00	
2	MGRV-4089204	N/A	14.00	5.00	
3	MGRV-48042MR002UZA186B	N/A	115.00	69.00	14.00
4	MGRV-6993529	N/A	69.00	5.00	
5	MGRV-8779073	N/A	345.00	115.00	35.00
6	MGRV-9F1025	N/A	69.00	14.00	
7	MGRV-C184245	N/A	69.00	14.00	
8	MGRV-F80331214	N/A	115.00	14.00	
9	MGRV-F8080	N/A	115.00	14.00	
10	MGRV-F8138	N/A	115.00	14.00	
11	MGRV-GT-3547	N/A	69.00	14.00	
12	MGRV-L252825C	N/A	115.00	14.00	
13	MGRV-L71020651212	N/A	115.00	14.00	
14	MGRV-TP80240801	N/A	161.00	115.00	14.00
15	MGRV-TP80279701	N/A	345.00	161.00	14.00
16	MGRV-TP80306401	N/A	230.00	115.00	14.00
17	MGRV-WT02255	N/A	345.00	115.00	35.00
18	MGRV-WT02258	N/A	115.00	69.00	13.00
19	Minn Valley-2621682	N/A	69.00	25.00	3.00
20	Minn Valley-5063761	N/A	230.00	115.00	15.00
21	Minn Valley-5069576	N/A	230.00	115.00	15.00
22	Minn Valley-6600565	N/A	230.00	115.00	15.00
23	Paynsville Transmission-A4555T	N/A	115.00	69.00	13.00
24	Paynsville Transmission-A4557T	N/A	115.00	69.00	13.00
25	Portal Pipeline (Minot)-4088687	N/A	14.00	2.50	
26	Siemens(Mexico)-T040N00142701	N/A	115.00	35.00	
27	SPX-WT-03820	N/A	230.00	115.00	14.00
28	NSPM Sys Spare 230-118-13.8kV 336MVA TR	N/A	230.00	115.00	
29	NSPM System Spare 118-36.2kV 70MVA DCP	N/A	115.00	36.20	
30	NSPM System Spare 69-13.2kV 7MVA DCP	N/A	69.00	13.20	
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	1					1
14	1					2
70	1					3
70	1					4
25	1					5
25	1					6
47	1					7
47	1					8
11	1					9
6	1					10
70	1					11
70	1					12
70	1					13
2	3					14
7	1					15
14	1					16
70	1					17
70	1					18
70	1					19
70	1					20
6	1					21
448	1					22
25	1					23
14	1					24
14	1					25
14	1					26
28	1					27
25	1					28
48	1					29
48	1					30
28	1					31
7	1					32
5	1					33
4	1					34
14	1					35
14	1					36
3	1					37
9	1					38
25	1					39
25	1					40

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
336	1					1
336	1					2
47	1					3
112	1					4
448	1					5
448	1					6
25	1					7
25	1					8
3	3					9
6	1					10
1	1					11
6	1					12
120	1					13
120	1					14
28	1					15
11	1					16
2	1					17
8	1					18
3	3					19
112	1					20
112	1					21
11	1					22
14	1					23
14	1					24
70	1					25
70	1					26
50	2					27
47	1					28
47	1					29
1	1					30
47	1					31
50	1					32
20	1					33
23	1					34
7	1					35
120	1					36
120	1					37
120	1					38
50	1					39
50	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
37	1					1
70	1					2
47	1					3
448	1					4
448	1					5
1203	3					6
1203	3					7
7	1					8
14	1					9
2	1					10
7	1					11
11	1					12
11	1					13
112	1					14
187	1					15
28	1					16
47	1					17
672	1					18
672	1					19
47	1					20
47	1					21
14	1					22
14	1					23
47	1					24
47	1					25
28	1					26
10	3					27
28	1					28
25	1					29
22	1					30
14	1					31
14	1					32
7	1					33
6	1					34
63	1					35
63	1					36
63	1					37
28	1					38
28	1					39
	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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11	1					1
5	1					2
14	1					3
11	1					4
8	1					5
47	1					6
70	1					7
7	1					8
20	1					9
28	1					10
5	1					11
47	1					12
47	1					13
47	1					14
11	1					15
28	1					16
28	1					17
53	1					18
47	1					19
47	1					20
51	1					21
448	1					22
448	1					23
2	1					24
70	1					25
70	1					26
70	1					27
70	1					28
70	1					29
73	1					30
25	1					31
70	1					32
47	1					33
448	1					34
2	3					35
	3					36
19	1					37
11	1					38
14	1					39
63	1					40

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Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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63	1					1
22	1					2
14	1					3
14	1					4
11	1					5
120	1					6
120	1					7
47	1					8
11	1					9
28	1					10
84	1					11
84	1					12
84	1					13
84	1					14
70	1					15
3	1					16
168	1					17
70	1					18
7	1					19
70	1					20
70	1					21
2	1					22
4	1					23
28	1					24
28	1					25
5	1					26
3	1					27
112	1					28
28	1					29
70	1					30
47	1					31
70	1					32
28	1					33
28	1					34
14	1					35
5	1					36
28	1					37
28	1					38
47	1					39
47	1					40

SUBSTATIONS (Continued)

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47	1					1
47	1					2
47	1					3
47	1					4
70	1					5
25	1					6
47	1					7
2	1					8
11	1					9
3	1					10
70	1					11
70	1					12
28	1					13
28	1					14
2	3					15
2	1					16
336	1					17
3	1					18
3	1					19
70	1					20
47	1					21
25	1					22
28	1					23
14	1					24
70	1					25
70	1					26
47	1					27
47	1					28
47	1					29
47	1					30
63	1					31
63	1					32
1	1					33
672	1					34
14	1					35
11	1					36
14	1					37
14	1					38
3	1					39
7	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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47	1					1
47	1					2
47	1					3
47	1					4
47	1					5
47	1					6
47	1					7
50	1					8
448	1					9
450	1					10
16	1					11
1	1					12
74	1					13
14	1					14
4	1					15
28	1					16
47	1					17
47	1					18
120	1					19
15	1					20
11	1					21
4	1					22
28	1					23
70	1					24
336	1					25
70	1					26
112	1					27
112	1					28
14	1					29
9	1					30
47	1					31
47	1					32
70	1					33
47	1					34
70	1					35
50	1					36
50	1					37
50	1					38
29	1					39
29	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS (Continued)

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11	1					1
11	1					2
47	1					3
47	1					4
12	1					5
28	1					6
52	1					7
14	1					8
70	1					9
270	1					10
47	1					11
47	1					12
70	1					13
70	1					14
7	1					15
187	1					16
187	1					17
6	1					18
4	1					19
25	1					20
70	1					21
47	1					22
3	1					23
6	1					24
14	1					25
5	1					26
4	1					27
70	1					28
70	1					29
70	1					30
2	1					31
3	1					32
63	1					33
72	1					34
70	1					35
70	1					36
28	1					37
28	1					38
2	1					39
8	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1					1
187	1					2
187	1					3
47	1					4
47	1					5
6	1					6
5	1					7
336	1					8
345	1					9
7	1					10
70	1					11
70	1					12
47	1					13
14	1					14
5	1					15
28	1					16
28	1					17
3	2					18
47	1					19
47	1					20
120	1					21
120	1					22
672	1					23
672	1					24
47	1					25
47	1					26
5	1					27
5	1					28
672	1					29
47	1					30
47	1					31
50	1					32
28	1					33
17	1					34
28	1					35
47	1					36
47	1					37
47	1					38
47	1					39
28	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
70	1					1
70	1					2
47	1					3
47	1					4
50	1					5
450	3					6
450	3					7
70	1					8
70	1					9
28	1					10
336	1					11
14	1					12
7	1					13
7	1					14
14	1					15
9	1					16
6	1					17
25	1					18
25	1					19
15	1					20
224	1					21
70	1					22
70	1					23
336	1					24
336	1					25
336	1					26
28	1					27
448	1					28
50	1					29
50	1					30
3	1					31
91	1					32
91	1					33
91	1					34
47	1					35
20	1					36
47	1					37
336	1					38
448	1					39
448	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	1					1
28	1					2
7	1					3
7	1					4
14	1					5
28	1					6
5	1					7
47	1					8
47	1					9
25	1					10
25	1					11
8	1					12
47	1					13
47	1					14
47	1					15
47	1					16
70	1					17
5	1					18
4	3					19
7	1					20
28	1					21
70	1					22
7	1					23
70	1					24
70	1					25
25	1					26
28	1					27
14	1					28
70	1					29
70	1					30
672	1					31
672	1					32
	1					33
112	1					34
336	1					35
28	1					36
28	1					37
448	1					38
187	1					39
187	1					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/08/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	1					1
28	1					2
14	1					3
47	1					4
47	1					5
53	1					6
47	1					7
187	1					8
1	1					9
74	1					10
5	1					11
7	1					12
6	1					13
28	1					14
28	1					15
70	1					16
70	1					17
63	1					18
1	3					19
187	1					20
336	1					21
448	1					22
448	1					23
42	1					24
42	1					25
14	1					26
4	1					27
7	1					28
70	1					29
70	1					30
70	1					31
70	1					32
5	1					33
6	1					34
47	1					35
47	1					36
47	1					37
47	1					38
11	1					39
70	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
70	1					1
10	3					2
10	3					3
10	3					4
10	3					5
10	3					6
10	3					7
47	1					8
47	1					9
47	1					10
672	1					11
672	1					12
4	1					13
5	1					14
5	1					15
70	1					16
70	1					17
70	1					18
70	1					19
70	1					20
70	1					21
28	1					22
8	1					23
73	1					24
3	1					25
11	1					26
20	1					27
22	1					28
10	1					29
2	3					30
70	1					31
14	1					32
28	1					33
28	1					34
7	1					35
11	1					36
14	1					37
2	1					38
4	1					39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
4	1					1
5	1					2
11	1					3
11	1					4
70	1					5
70	1					6
28	1					7
112	1					8
112	1					9
22	1					10
7	1					11
28	1					12
112	1					13
112	1					14
70	1					15
73	1					16
70	1					17
70	1					18
70	1					19
70	1					20
70	1					21
70	1					22
70	1					23
70	1					24
70	1					25
112	1					26
70	1					27
70	1					28
70	1					29
70	1					30
	2					31
8	1					32
3	1					33
8	1					34
28	1					35
70	1					36
70	1					37
70	1					38
448	1					39
448	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	1					1
22	1					2
25	1					3
11	1					4
6	1					5
5	1					6
47	1					7
47	1					8
28	1					9
28	1					10
120	1					11
120	1					12
14	1					13
11	1					14
11	1					15
4	1					16
14	1					17
44802	621					18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
5		1				30
120		1				31
2		1				32
28		1				33
28		1				34
14		1				35
672		1				36
50		1				37
7		1				38
52		1				39
4		1				40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
4		1				1
5		1				2
70		1				3
11		1				4
448		1				5
11		1				6
11		1				7
74		1				8
53		1				9
74		1				10
14		1				11
47		1				12
28		1				13
187		1				14
336		1				15
336		1				16
672		1				17
112		1				18
5		1				19
50		1				20
50		1				21
112		1				22
47		1				23
47		1				24
5		1				25
120		1				26
336		1				27
336		1				28
70		1				29
7		1				30
						31
		41				32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/08/2020	End of 2019/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 Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Interchange agreement	NSP-Wisconsin	557 and 565	176,624,283
3	Receipts from Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	-219,000,000
4	Services provided by Xcel Energy Services Inc.	Xcel Energy Services Inc.	see note	
5	Contribution of Capital	Xcel Energy Inc.	207	-354,334,013
6	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	-696,000,000
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Interchange agreement	NSP-Wisconsin	456.1 and 456	-457,411,740
22	Company labor, benefits, and related payments	NSP-Wisconsin	see note	-14,087,181
23	Company labor, benefits, and related payments	PSCo	see note	-476,858
24	Vehicle and equipment use	NSP-Wisconsin	see note	-3,646,193
25	Gas dispatch and SCADA system agreement	NSP-Wisconsin	G495	-464,433
26	Fuel oil transfer	NSP-Wisconsin	151	-851,504
27	Repayments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	696,000,000
28	Investments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	805,000,000
29	Dividends on Common Stock	Xcel Energy Inc.	215/216	466,592,100
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Schedule Page: 429 Line No.: 2 Column: c

E557	$ 60,465,154
E565	116,159,129
	$ 176,624,283

Schedule Page: 429 Line No.: 4 Column: c

Service Function Group	FERC Group	Total
Accounting, Financial Reporting & Taxes	107-108 CWIP and Accum Dep	60,291
	181-190-Deferred Debits	2,303
	408-409-Taxes	728,639
	417-421-Other Income	(2,359,278)
	426.1-426.5-Other Income Deductions	1,543
	427-432-Interest Charges	59,311
	500-514-Steam Power Generation	93,769
	517-532-Nuclear Power Generation	19,701
	535-545-Hydraulic Power Generation	2
	546-557-Other Power Generation	178,420
	560-573-Transmission Expenses	26,499
	575.1-575.8-Regional Market Expenses	1
	580-598-Distribution Expenses	114,826
	725-742-Gas Raw Materials	8,169
	800-813-Other Gas Supply Expenses	20,180
	840-843-Other Storage Expense	5
	850-870-Transmission Expenses	188
	871-893-Distribution Expenses	2,108
	901-905-Customer Accounts Expenses	(374,733)
	908-910-Customer Service and Informational Expenses	(889)
	920-935-Administrative and General Expense	39,742,018

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Accounting, Financial Reporting & Taxes Total		38,323,072
Aviation Services	408-409-Taxes	30,576
	426.1-426.5-Other Income Deductions	253
	920-935-Administrative and General Expense	2,156,476
Aviation Services Total		2,187,305
Business Systems	107-108 CWIP and Accum Dep	78,509,849
	181-190-Deferred Debits	134,731
	252-283-Deferred Credits	3,052
	408-409-Taxes	1,834,756
	417-421-Other Income	2,067,687
	426.1-426.5-Other Income Deductions	68,357
	500-514-Steam Power Generation	1,001,476
	517-532-Nuclear Power Generation	3,704,610
	535-545-Hydraulic Power Generation	13,673
	546-557-Other Power Generation	1,605,438
	560-573-Transmission Expenses	4,786,824
	580-598-Distribution Expenses	4,534,519
	800-813-Other Gas Supply Expenses	76,978
	840-843-Other Storage Expense	518
	850-870-Transmission Expenses	86,894
	871-893-Distribution Expenses	1,291,026
	901-905-Customer Accounts Expenses	10,736,952
	908-910-Customer Service and Informational Expenses	16,237
	920-935-Administrative and General Expense	119,327,194
Business Systems Total		229,800,769
Claims Services	408-409-Taxes	36,807
	426.1-426.5-Other Income Deductions	80
	517-532-Nuclear Power Generation	6,567
	908-910-Customer Service and Informational Expenses	2,190
	920-935-Administrative and General Expense	668,177

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Claims Services Total		713,822
Corporate Communications	107-108 CWIP and Accum Dep	1,378
	181-190-Deferred Debits	931,056
	252-283-Deferred Credits	26,237
	408-409-Taxes	187,079
	417-421-Other Income	42,931
	426.1-426.5-Other Income Deductions	32,976
	560-573-Transmission Expenses	438
	580-598-Distribution Expenses	78
	901-905-Customer Accounts Expenses	1,430
	908-910-Customer Service and Informational Expenses	305,352
	920-935-Administrative and General Expense	4,443,074
Corporate Communications Total		5,972,028
Corporate Strategy & Business Development	408-409-Taxes	77,884
	417-421-Other Income	(16,047)
	426.1-426.5-Other Income Deductions	31,930
	546-557-Other Power Generation	459
	908-910-Customer Service and Informational Expenses	1,778
	920-935-Administrative and General Expense	1,420,115
Corporate Strategy & Business Development Total		1,516,118
Customer Service	107-108 CWIP and Accum Dep	17,320
	181-190-Deferred Debits	1,367,162
	252-283-Deferred Credits	274,286
	408-409-Taxes	871,213
	417-421-Other Income	40,854
	426.1-426.5-Other Income Deductions	49,229
	580-598-Distribution Expenses	361

Name of Respondent		This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)		(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/08/2020	2019/Q4

FOOTNOTE DATA

	871-893-Distribution Expenses	19
	901-905-Customer Accounts Expenses	15,135,220
	908-910-Customer Service and Informational Expenses	316,574
	920-935-Administrative and General Expense	2,761,702
Customer Service Total		20,833,940
Employee Communications	408-409-Taxes	16,329
	920-935-Administrative and General Expense	704,246
Employee Communications Total		720,574
Energy Delivery - Engineering/Design	107-108 CWIP and Accum Dep	29,609,873
	181-190-Deferred Debits	357,347
	231-245-Current and Accrued Liabilities	28,220
	408-409-Taxes	807,124
	417-421-Other Income	(1,673,694)
	426.1-426.5-Other Income Deductions	25,740
	500-514-Steam Power Generation	120,733
	517-532-Nuclear Power Generation	769
	535-545-Hydraulic Power Generation	6,681
	546-557-Other Power Generation	68,283
	560-573-Transmission Expenses	8,734,843
	575.1-575.8-Regional Market Expenses	1
	580-598-Distribution Expenses	2,000,151
	725-742-Gas Raw Materials	1,230
	750-769-Natural Gas Production	1
	840-843-Other Storage Expense	10
	844-847-Liquified Natural Gas Terminaling Expenses	518
	850-870-Transmission Expenses	852,730

	871-893-Distribution Expenses	418,821
	901-905-Customer Accounts Expenses	(1,039,880)
	908-910-Customer Service and Informational Expenses	27,497
	920-935-Administrative and General Expense	2,674,153
Energy Delivery - Engineering/Design Total		43,021,150
Energy Delivery Construction, Operations & Maintenance (COM)	107-108 CWIP and Accum Dep	3,351,735
	181-190-Deferred Debits	16,080
	252-283-Deferred Credits	8,560
	408-409-Taxes	257,166
	417-421-Other Income	16
	426.1-426.5-Other Income Deductions	48,067
	500-514-Steam Power Generation	1,929
	546-557-Other Power Generation	40,252
	560-573-Transmission Expenses	2,316,630
	580-598-Distribution Expenses	4,444,904
	725-742-Gas Raw Materials	11,246
	814-837-Underground Storage Expenses	112,370
	840-843-Other Storage Expense	451,710
	844-847-Liquified Natural Gas Terminaling Expenses	10,577
	850-870-Transmission Expenses	1,541,260
	871-893-Distribution Expenses	505,602
	901-905-Customer Accounts Expenses	2,438
	908-910-Customer Service and Informational Expenses	409
	920-935-Administrative and General Expense	3,991,695
Energy Delivery Construction, Operations & Maintenance (COM) Total		17,112,646
Energy Markets - Fuel Procurement	107-108 CWIP and Accum Dep	11,150
	408-409-Taxes	52,521

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

	426.1-426.5-Other Income Deductions	187
	500-514-Steam Power Generation	750,764
	546-557-Other Power Generation	67,646
	800-813-Other Gas Supply Expenses	108,676
	920-935-Administrative and General Expense	530,896
Energy Markets - Fuel Procurement Total		1,521,839
Energy Markets Regulated Trading & Marketing	107-108 CWIP and Accum Dep	2,306
	408-409-Taxes	370,041
	426.1-426.5-Other Income Deductions	27,506
	500-514-Steam Power Generation	20,545
	535-545-Hydraulic Power Generation	2,339
	546-557-Other Power Generation	5,322,276
	560-573-Transmission Expenses	449,074
	575.1-575.8-Regional Market Expenses	268,520
	580-598-Distribution Expenses	58,622
	800-813-Other Gas Supply Expenses	69,279
	850-870-Transmission Expenses	521
	920-935-Administrative and General Expense	2,083,403
Energy Markets Regulated Trading & Marketing Total		8,674,433
Energy Supply Business Resources	107-108 CWIP and Accum Dep	2,046,818
	181-190-Deferred Debits	1,482
	252-283-Deferred Credits	278
	408-409-Taxes	617,950
	417-421-Other Income	8,476
	426.1-426.5-Other Income Deductions	(61,186)
	500-514-Steam Power Generation	7,735,686
	517-532-Nuclear Power Generation	1,433,337
	535-545-Hydraulic Power Generation	28,982
	546-557-Other Power Generation	2,727,948
	560-573-Transmission Expenses	154,418
	580-598-Distribution Expenses	85,704
	725-742-Gas Raw Materials	774
	871-893-Distribution Expenses	554
	901-905-Customer Accounts Expenses	48,778
	908-910-Customer Service and Informational Expenses	3,520
	920-935-Administrative and General Expense	2,588,790
Energy Supply Business Resources Total		17,422,308
Energy Supply Engineering & Environmental	107-108 CWIP and Accum Dep	9,809,944
	181-190-Deferred Debits	175,209
	408-409-Taxes	381,674
	426.1-426.5-Other Income Deductions	1,092
	500-514-Steam Power Generation	1,989,884
	517-532-Nuclear Power Generation	56,503

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

	535-545-Hydraulic Power Generation	668,636
	546-557-Other Power Generation	154,777
	560-573-Transmission Expenses	72,632
	580-598-Distribution Expenses	70,785
	725-742-Gas Raw Materials	32,276
	840-843-Other Storage Expense	831
	871-893-Distribution Expenses	11,501
	908-910-Customer Service and Informational Expenses	505
	920-935-Administrative and General Expense	3,226,466
Energy Supply Engineering & Environmental Total		16,652,715
Executive Management Services	107-108 CWIP and Accum Dep	219,971
	130-176-Current and Accrued Assets	(115,775)
	181-190-Deferred Debits	30,470
	408-409-Taxes	148,126
	417-421-Other Income	23
	426.1-426.5-Other Income Deductions	3,406,959
	500-514-Steam Power Generation	(90,564)
	517-532-Nuclear Power Generation	(449,138)
	535-545-Hydraulic Power Generation	(2,520)
	546-557-Other Power Generation	(108,265)
	560-573-Transmission Expenses	(95,091)
	575.1-575.8-Regional Market Expenses	(651)
	580-598-Distribution Expenses	(148,230)
	725-742-Gas Raw Materials	(347)
	750-769-Natural Gas Production	(406)
	800-813-Other Gas Supply Expenses	(71)
	814-837-Underground Storage Expenses	4,341
	840-843-Other Storage Expense	(5,396)
	850-870-Transmission Expenses	300,048
	871-893-Distribution Expenses	(70,524)
	908-910-Customer Service and Informational Expenses	5,065
	920-935-Administrative and General Expense	6,066,408
Executive Management Services Total		9,094,433
Facilities & Real Estate	107-108 CWIP and Accum Dep	1,688,758
	130-176-Current and Accrued Assets	1
	181-190-Deferred Debits	292
	231-245-Current and Accrued Liabilities	(7)
	252-283-Deferred Credits	2
	408-409-Taxes	147,657
	417-421-Other Income	26,694
	426.1-426.5-Other Income Deductions	1,938
	500-514-Steam Power Generation	2,230,626
	517-532-Nuclear Power Generation	7,861,869
	535-545-Hydraulic Power Generation	41,617
	546-557-Other Power Generation	1,481,301

	560-573-Transmission Expenses	1,595,194
	575.1-575.8-Regional Market Expenses	11,397
	580-598-Distribution Expenses	2,585,841
	725-742-Gas Raw Materials	5,933
	750-769-Natural Gas Production	7,242
	800-813-Other Gas Supply Expenses	707
	814-837-Underground Storage Expenses	1,086
	840-843-Other Storage Expense	94,754
	844-847-Liquified Natural Gas Terminaling Expenses	2
	850-870-Transmission Expenses	47,706
	871-893-Distribution Expenses	1,230,486
	901-905-Customer Accounts Expenses	80
	908-910-Customer Service and Informational Expenses	2
	920-935-Administrative and General Expense	14,883,524
Facilities & Real Estate Total		33,944,697
Finance & Treasury	107-108 CWIP and Accum Dep	1,671
	181-190-Deferred Debits	2,070,867
	408-409-Taxes	263,607
	417-421-Other Income	(88,264)
	426.1-426.5-Other Income Deductions	85,663
	427-432-Interest Charges	2,275,248
	500-514-Steam Power Generation	6,208
	535-545-Hydraulic Power Generation	29
	546-557-Other Power Generation	512,059
	580-598-Distribution Expenses	16,703
	901-905-Customer Accounts Expenses	5,407
	920-935-Administrative and General Expense	11,658,796
Finance & Treasury Total		16,807,995
Fleet	107-108 CWIP and Accum Dep	(11,547)
	901-905-Customer Accounts Expenses	1,773
	920-935-Administrative and General Expense	(1,189)
Fleet Total		(10,963)
Government Affairs	408-409-Taxes	75,478
	426.1-426.5-Other Income Deductions	586,122
	920-935-Administrative and General Expense	1,215,517
Government Affairs Total		1,877,117
Human Resources	107-108 CWIP and Accum Dep	45,038
	181-190-Deferred Debits	865
	227-230-Other Noncurrent Liabilities	1,059,316
	231-245-Current and Accrued Liabilities	19,550,006
	408-409-Taxes	662,245
	426.1-426.5-Other Income Deductions	56,271
	500-514-Steam Power Generation	46,828
	517-532-Nuclear Power Generation	402,257
	535-545-Hydraulic Power Generation	162
	546-557-Other Power Generation	24,479

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

	560-573-Transmission Expenses	36,921
	580-598-Distribution Expenses	224,783
	725-742-Gas Raw Materials	261
	850-870-Transmission Expenses	19,925
	871-893-Distribution Expenses	245,988
	908-910-Customer Service and Informational Expenses	169,959
	920-935-Administrative and General Expense	11,467,555
Human Resources Total		34,012,859
Internal Audit	408-409-Taxes	56,667
	426.1-426.5-Other Income Deductions	357
	920-935-Administrative and General Expense	1,193,752
Internal Audit Total		1,250,776
Investor Relations	408-409-Taxes	16,268
	426.1-426.5-Other Income Deductions	1,177
	920-935-Administrative and General Expense	885,893
Investor Relations Total		903,338
Legal	107-108 CWIP and Accum Dep	53,122
	181-190-Deferred Debits	3,861
	408-409-Taxes	326,392
	426.1-426.5-Other Income Deductions	3,257
	517-532-Nuclear Power Generation	171,944
	535-545-Hydraulic Power Generation	154
	546-557-Other Power Generation	3,815
	560-573-Transmission Expenses	37,916
	580-598-Distribution Expenses	56,664
	725-742-Gas Raw Materials	82,913
	800-813-Other Gas Supply Expenses	1,308
	901-905-Customer Accounts Expenses	143
	920-935-Administrative and General Expense	6,528,553
Legal Total		7,270,043
Marketing & Sales	107-108 CWIP and Accum Dep	773,107
	181-190-Deferred Debits	8,257,580
	252-283-Deferred Credits	310,038
	408-409-Taxes	155,590
	417-421-Other Income	221,597
	426.1-426.5-Other Income Deductions	7,797
	500-514-Steam Power Generation	70
	517-532-Nuclear Power Generation	32,738
	546-557-Other Power Generation	2
	560-573-Transmission Expenses	3
	580-598-Distribution Expenses	13,115
	871-893-Distribution Expenses	4
	901-905-Customer Accounts Expenses	156
	908-910-Customer Service and Informational Expenses	1,619,337
	920-935-Administrative and General Expense	5,653,584
Marketing & Sales Total		17,044,718

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

Payment & Reporting	107-108 CWIP and Accum Dep	9,696
	408-409-Taxes	25,386
	920-935-Administrative and General Expense	611,967
Payment & Reporting Total		647,048
Payroll	408-409-Taxes	55,815
	426.1-426.5-Other Income Deductions	128
	920-935-Administrative and General Expense	1,020,159
Payroll Total		1,076,101
Rates & Regulation	107-108 CWIP and Accum Dep	1,934
	181-190-Deferred Debits	32,575
	408-409-Taxes	117,750
	426.1-426.5-Other Income Deductions	(1)
	500-514-Steam Power Generation	1,039
	517-532-Nuclear Power Generation	67
	546-557-Other Power Generation	6,835
	580-598-Distribution Expenses	10,261
	800-813-Other Gas Supply Expenses	300
	901-905-Customer Accounts Expenses	1,067
	908-910-Customer Service and Informational Expenses	700
	920-935-Administrative and General Expense	2,294,001
Rates & Regulation Total		2,466,529
Receipts Processing	408-409-Taxes	44,491
	426.1-426.5-Other Income Deductions	984
	560-573-Transmission Expenses	1,757
	901-905-Customer Accounts Expenses	363,433
	920-935-Administrative and General Expense	351,561
Receipts Processing Total		762,227
Supply Chain	107-108 CWIP and Accum Dep	404,392
	130-176-Current and Accrued Assets	(59)
	181-190-Deferred Debits	22,467
	231-245-Current and Accrued Liabilities	(284)
	252-283-Deferred Credits	(17)
	408-409-Taxes	3,754
	417-421-Other Income	1,122
	426.1-426.5-Other Income Deductions	33,280
	500-514-Steam Power Generation	2,793
	517-532-Nuclear Power Generation	(10,196)
	535-545-Hydraulic Power Generation	7
	546-557-Other Power Generation	141,706
	560-573-Transmission Expenses	11,661
	580-598-Distribution Expenses	28,768
	725-742-Gas Raw Materials	(5)
	800-813-Other Gas Supply Expenses	(26)
	840-843-Other Storage Expense	6
	844-847-Liquified Natural Gas Terminaling Expenses	(36)
	850-870-Transmission Expenses	926

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

	871-893-Distribution Expenses	(525)
	901-905-Customer Accounts Expenses	4,599
	908-910-Customer Service and Informational Expenses	(102)
	920-935-Administrative and General Expense	863,257
Supply Chain Total		1,507,487
Grand Total		533,127,126

Schedule Page: 429 Line No.: 21 Column: c

E456	$ (396,061,656)
E456.1	(61,350,084)
	$ (457,411,740)

Schedule Page: 429 Line No.: 22 Column: c

107	$ (12,391,581)
108	(1,044,296)
163	(27,788)
184	(67,981)
E501	(47,532)
E511	(26,575)
E512	(169,596)
E513	(58,682)
E514	(264)
E541	(187)
E542	(60)
E543	(5,011)
E544	(40)
E552	(3,988)
E553	(1,970)
E562	(873)
E563	(8,812)
E570	(6,534)
E571	(148,415)
E582	(545)
E583	(1,278)
E586	(6,851)
E587	(325)
E588	66,006
E591	(6,257)
E592	(44,813)
E593	(57,097)
E921	(417)
G593	(7,040)
G759	(46)
G844.3	(5,230)
G846.2	(2,968)
G847.2	(1,013)
G874	(1,608)
G878	(33)
G879	(142)
G880	(5,724)
G887	(483)
G892	(1,132)
	$ (14,087,181)

Schedule Page: 429 Line No.: 23 Column: c

107	(280,067)
108	(30,577)
163	(1,396)
184	(35,302)
E182.3	(2)
E512	(2,916)
E513	(231)
E539	(3,724)
E542	(15,333)
E553	(399)
E554	(167)
E560	1,006
E562	(122)
E566	(485)
E570	(999)
E571	(22)
E584	(34)
E585	(1,842)
E586	(12,907)
E588	(33,542)
E592	(47)
E593	(18,825)
E594	(7)
E596	(959)
E903	(1,858)
E921	(3,392)
G598	(375)
G857	(153)
G863	(399)
G874	(6,041)
G875	(397)
G877	(111)
G878	(201)
G879	(4,217)
G887	(497)
G892	(19,166)
G893	(907)
G902	(95)
G903	(38)
N417.1	(112)
	(476,858)

Schedule Page: 429 Line No.: 24 Column: c

107	$ (3,308,248)
108	(277,886)
C903	(483)
E542	(6)
E562	(92)
E570	(3,838)
E571	(36,846)
E584	(80)
E585	(503)
E586	(2,368)
E587	(113)
E592	(1,286)
E593	(13,331)
E596	(6)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/08/2020	2019/Q4

FOOTNOTE DATA

E598	(45)
E903	(52)
G874	(238)
G878	(193)
G879	(33)
G887	(158)
G892	(373)
G902	(15)
	$ (3,646,193)

INDEX

Schedule	Page No.

Schedule	Page No.
Interest	
charges, paid on long-term debt, advances, etc	256-257
Investments	
nonutility property	221
subsidiary companies	224-225
Investment tax credits, accumulated deferred	266-267
Law, excerpts applicable to this report form	iv
List of schedules, this report form	2-4
Long-term debt	256-257
Losses-Extraordinary property	230
Materials and supplies	227
Miscellaneous general expenses	335
Notes	
to balance sheet	122-123
to statement of changes in financial position	122-123
to statement of income	122-123
to statement of retained earnings	122-123
Nonutility property	221
Nuclear fuel materials	202-203
Nuclear generating plant, statistics	402-403
Officers and officers' salaries	104
Operating	
expenses-electric	320-323
expenses-electric (summary)	323
Other	
paid-in capital	253
donations received from stockholders	253
gains on resale or cancellation of reacquired capital stock	253
miscellaneous paid-in capital	253
reduction in par or stated value of capital stock	253
regulatory assets	232
regulatory liabilities	278
Peaks, monthly, and output	401
Plant, Common utility	
accumulated provision for depreciation	356
acquisition adjustments	356
allocated to utility departments	356
completed construction not classified	356
construction work in progress	356
expenses	356
held for future use	356
in service	356
leased to others	356
Plant data	336-337 401-429

Document Content(s)